HARZA-EBASCO SUSITNA JOINT VENTURE

Design Office: 400-112th Avenue, NE Bellevue, |) 451-4500
Main Office: 8740 Hartzell Road Anchor) 349-8581

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June 6, 1983
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6.2.2.1

Mr. Robert A. Mohn
Project Manager
Alaska Power Authority
334 West 5th Avenue
Anchorage, Alaska 99501

Subject: Susitna Hydroelectric Project
June 7 & 8 1983 Review Committee Meeting

Dear Robert:

Enclosed are three copies of responses to FERC non-conforming items scheduled for the June 7 - 8, 1983 Review Committee meeting. Attachment I of this package lists revisions to sections of Exhibits B + D transmitted for your review. Also contained herein are draft responses to FERC Schedule A, Exhibit F items.

Very truly yours,

Richard L. Meagher

Richard L. Meagher
Acting Project Manager

RLM/MU/ml

Enc: As noted

cc: D. Jane Drennan, PMS, w/enc.
C. Debelius, Acres, w/enc.
D. Meagher, H-E, w/enc.
H. Chen, H-E, w/enc.
S. Simmons, H-E, w/enc.
J. Robinson, H-E, w/o enc.

PMS
Paul - This is Review Comm. info for the central files. (dist. is done) Michele

June 6, 1983

Attachment 1

List of Draft Responses for Exhibits B and D

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B 5.2	System Description
B 5.2.1	The Interconnected Railbelt Market
B 5.2.2	Railbelt Electric Utilities
5 5.2.3	Historical Data for the Market Area
B 5.3	Forecasting Methodology
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D 1.5	Allowance For Funds Used During Const.
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HHC
This contains revised parts only

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

[redacted].

PROJECT COSTS AND FINANCING

EFC
6/6/83

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Allowances have also been made for environmental mitigation as well as a contingency for unforeseen costs.

Estimates for Susitna have been based on original estimates and actual experience at Churchill Falls. It should be realized that alternative operating plans are possible which would eliminate the need for permanent town site facilities and rely on more remote supervisory systems and/or operations/maintenance crews transported to the plant on a retating shift basis. Cost implications of these alternatives have not yet been examined.

1.5 - Allowance for Funds Used During Construction (AFDC)

At current high levels of interest rates in the financial marketplace, AFDC will amount to a significant element of financing cost for the lengthy period required for construction of the Watana and Devil Canyon porjects. Howver, in economic evaluations of the Susitna project the low real rates of interest assumed would have a much reduced impact on assumed project development costs. Furthermore, direct state involvement in financing of the Susitna project will also have a significant impact on the amount, if any, of AFDC. Provisions for AFDC at appropriate rates of interest are made in the economic and financial analyses included in this Exhibit.

$$1 + f_{co} = (1 + X)\,\frac{B[(1+f)^{B}-1]}{B\ \ln\ (1+f)}\left[\,1 - \frac{1}{\left[1 + \dfrac{2}{B\ \ln\ (1+f)}\right]}\;2\,\right]$$

where

$1 + f_{co}$ = Total cost upon commercial service (%)

$$1 + f = \frac{1 + y}{1 + x}$$

x = effective interest rate
y = escalation rate
B = construction period

The value of the variables used in the computations are summarized in Table D.6 The Watana and Devil Canyon constructions periods were taken from Exhibit C as 8.5 years and 7.5 years, respectively.

The resultant total project cost was then calculated for each interest/escalation scenario used in econimic and financial studies as shown in Table D.1.

1.6 - Escalation

Provision must be made for future cost escalation which will take place over the construction periods involved. The financial evaluation takes full account of such escalation, as discussed in the previous paragraph.

1.7 - Cash Flow and Manpower Loading Requirements

The cash flow requirements for construction of Watana and Devil Canyon are an essential input to economic and financial planning studies. The bases for the cash flow are the construction cost estimates in January 1982 dollars and the construction schedules presented in Exhibit C. The cash flow estimates were computed opn an annual basis and do not include adjustments for advances payments for mobilization or for holdbacks on construction contracts. The results are presented in Table D.7 and Figures D.1 through D.3. The manpower loading requirements were developed from cash flow projections. These curves were used as the basis for camp loading and associated socioeconomic impact studies.

1.8 - Contingency

An overall contingency allowance of approximately 15 percent oif construction costs has been included in the cost estimates. Contingencies have been assessed for each account and range from 10 to 20 percent. The contingency is estimated to include cost increases which may occur in the detailed engineering phase of the project after more comprehensive site investigations and final designs have been completed and after the requirements of various concerned agencies have been satisfied. The contingency estimate also includes allowances for inherent uncertainties in costs of labor, equipment and materials, and for unforeseen conditions which may be encountered during construction. No allowance has been included for costs associated with significant delays in project implementation. These items have been accounted for in economic and financial planning studies.

1.9 - Previously Constructed Project Facilities

An electrical intertie between the major load centers of Fairbanks and Anchorage will be completed in the mid-1980s. The line will connect existing transmission systems at Willow in the south and Healy in the north. The intertie ~~is being~~ will be built to the same standards as those proposed for the Susitna project transmission lines and will become part of the licensed project. The line will be energized initially at 138 kV in 1984 and will operate at 345 kV after the Watana phase of the Susitna project is complete.

The current estimate for the completed intertie is $130.8 million. This cost is not included in the Susitna project cost estimates. A breakout of the cost estimate is shown in Table D.8.

1.10 - EBASCO Check Estimate

An independent check estimate was undertaken by EBASCO Services Incorporated (EBASCO 1982). The estimate was based on engineering drawings, technical information and quantities prepared by Acres American in the feasibility study. Major quantity items were checked. The EBASCO check estimated capital cost was approximately 7 percent above the Acres estimate.

A summary of EBASCO's check estimate has been included in Table D.9 of this exhibit.

2 - ESTIMATED ANNUAL PROJECT COSTS

As a two-stage (Watana and Devil Canyon) development with varying levels of energy output and the assumption of ongoing inflation (at 7 percent per annum), the real cost of Susitna power will continually vary. As a consequence, no simple single value real cost of power can be used.

Table D.~~X~~ 10 gives the projected year-by-year energy levels on the first line and, on the second, the year-by-year unit cost of power in 1982 dollars. A breakout of this cost into operation, plant replacements and debt service is included on Sheet 4 of Table D.~~X~~ 10. The remainder of the table is a cash flow summary of revenue (RL516), operating costs (170), interest, and cash sources and uses. These costs are in nominal dollars assuming 7 percent inflation and 10 percent cost of capital. Costs are based on power sales at cost assuming 100 percent debt financed at 10 percent interest. This results in a real cost of power of 128 mills in 1994 (first full year of Watana) falling to 73 mills in 2003 (the first full year of Watana and Devil Canyon). The real cost of power, adjusted for inflation of 7 percent per annum, would then fall progressively for the remaining life.

To be Change based on DGP

To be changed based on DGP

No taxes have been assessed to the project's annual costs. Although these taxes would be expressed as a percentage of project plant in service in this type of annual cost estimate, the taxes would be based on revenues. As a corporation of the State, the Alaska Power Authority is a not-for-profit entity. As such, the Authority would not be subject to a revenue tax.

The cost of power given in Table D.~~IX~~ 11 is designed to reflect as fully as possible the economic cost of power for purposes of broad comparison with alternative power options. It is, therefore, based on the capacity cost which would arise if the project were 100 percent debt financed at market rates of interest. It does not reflect the price at which power will be charged into the system.

3 - MARKET VALUE OF PROJECT POWER

This section presents an assessment of the range of rates at which energy and capacity of the Susitna development could be priced [redacted] together with a proposed basis for contracting for the supply of Susitna energy. The Susitna project is scheduled to begin generating power for the Railbelt in 1993. At that time the project will meet growing electrical demand, replace retiring units and displace capacity having more expensive running rates.

3.1 - The Railbelt Power System

The Railbelt region covers the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area. A complete discussion of the Railbelt System is presented in Exhibit B.

Susitna capacity and energy will be delivered to the Region via the linkage of the Anchorage and Fairbanks systems by an intertie to be completed in the mid-1980s. The proposed intertie will allow a capacity transfer of up to 70 MW in either direction. The proposed plan of interconnection envisages initial operation at 138 kv with subsequent uprating to 345 kv allowing the line to be integrated into the Susitna transmission facilities.

3.2 - Regional Electric Power Demand and Supply

The base case forecast of electric power demand is presented in Exhibit B. The results of studies presented in Exhibit B and Section 4 of the Exhibit call for Watana to come into operation in 1993 and to deliver a full year's energy generation in 1994. Devil Canyon will come into operation in 2002 and deliver a full year's energy in 2003. Energy demand in the Railbelt region and the deliveries from Susitna are shown in Figure D.4.

3.3 - Market and Price for Watana Output in 1994

It has been projected that Watana energy will be supplied at a single wholesale rate on a free-market basis. This requires, in effect, that Susitna energy be priced so that it is attractive even to utilities with the lowest cost alternative source of energy. On this basis ~~it~~ is estimated that for the initially marketable 3315 GWh of energy generated by Watana in 1994 to be attractive, a price of 145 mills per kWh in 1994 dollars is required. This estimate assumes a prevailing 7 percent rate of inflation per annum. Justification for this price, as compared to the price of alternatives, is illustrated in Figure D.5. The costs for alternatives in Figure D.5 are based on calculations using the financial parameters in Table D.12. Plant capital and operating costs are shown in Table D.18. The most cost effective alternative plan is specified in Section 4.6.

To be checked

Figure D.5 shows on the far right of the figure the area in which costs of the best thermal and Susitna options are common. These costs are incurred by plants required in both system configurations to meet the full generating requirements of 1994. Watana, coming on-line at that time, would effectively avoid all costs represented by ~~the shaded~~ areas. These costs divided by the marketable Watana output of 3315 GWh gives a wholesale energy rate of approximately 145 mills/kWh (in 1994 dollars) which is the maximum to be charged if consumers were to be neither better nor worse off in 1994 under the with-Susitna plan or the best alternative plan. The with- and without-Susitna plans and the generation planning program described in this exhibit were used to calculate the power value.

to be checked

Note that the assumption is made that the only capital costs which would be avoided in the early 1990s would be those due to the alternative addition of new coal-fired generating plants (i.e., the 2 x 200 MW coal-fired Beluga station).

to be checked

The financing considerations under which ~~it would be~~ appropriate for Watana energy to be sold at approximately 145 mills per kWh price are considered in Section 6 of this Exhibit; however, it should be noted that some of the energy which would be displaced by Watana's production would have been generated at a lower cost than 145 mills, and utilities might wish to delay accepting it at this price until the escalating cost of natural gas or other fuels made it more attractive. The projected real escalation used in the study of the market price are presented in Section 4.5. ~~the mid-level forecasts on Tables D.23 through D.26~~. A number of approaches to the resolution of this problem can be postulated, including precontract arrangements.

The Power Authority will seek to contract with Railbelt utilities for the purchase of Susitna capacity and energy on a basis appropriate to support financing of the project.

Pricing policies for Susitna output, as defined by the Alaska legislature, will be constrained both by cost and by the price of energy from the best alternative option. These options are discussed in Section 4 of this Exhibit.

Marketing Susitna's output within these twin constraints would ensure that all state financial support for Susitna flowed through to consumers and under no circumstances would prices to consumers be higher than they would have been under the best alternative option. In addition, consumers would also obtain the long-term economic benefits of Susitna's stable cost of energy.

3.4 - Market and Price for Watana Output 1995-2001

After its first full year of operation in the system in 1994, 3315 GWh of the total 3387 GWh of Watana output is initially marketable. The excess energy occurs in the summer. The market for the project strengthens over the years to 2001 since energy demand will increase by 20 percent over this period as projected in Exhibit B forecasts.

As a result there would be a 70 percent increase in cost savings compared with the best thermal generating alternative; the increasing cost per unit of output from a system without Susitna is illustrated in Figure D.~~X~~. 6

The addition of the Susitna project will add a large generating resource in the system in 1993, displacing a significant amount of the existing generating resources in the system. The project will provide about 70 percent of total energy demand. The displaced units will be used as reserve capacity and to meet growing load until the Devil Canyon project comes on line. This effect is illustrated on Figure D.~~X~~. 4

3.5 - Market and Price for Watana and Devil Canyon Output in 2003

A diagrammatic analysis of the total cost savings which the combined Watana and Devil Canyon output will confer on the system compared with the alternative thermal option in the year 2003 is shown in Figure D.~~X~~. 7 These total savings are divided by the energy contributed by Susitna to indicate a price of 250 mills per kWh (2003 dollars, 7 percent general escalation per annum) as the maximum price which can be charged for Susitna output.

to be checked

Only about 90 percent of the total Susitna energy output will be absorbed by the system in 2002; the balance of the output will be progressively absorbed over the following decade. This will provide additional total savings to the system with Susitna since no other resources will be needed.

After the Devil Canyon project comes on line, the Susitna project will provide 90 percent of the energy demand. The excess Susitna power occurs in the summer while additional energy from other resources is required in the winter. The generating resources displaced are units nearing retirement and will be used as reserve capacity. This effect is shown on the shaded portion of Figure D.10.

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3.6 - Potential Impact of State Appropriations

In the preceding paragraphs, the maximum price at which Susitna energy could be sold has been identified. Sale of the energy at these prices will depend upon the magnitude of any proposed state appropriation designed to reduce the cost of Susitna energy in the earlier years. At significantly lower prices, it is likely that the total system demand will be higher than assumed. This, combined with a state appropriation to reduce the energy cost of Watana energy, would make it correspondingly easier to market the output from the Susitna development; however, as the preceding analysis shows, a viable and strengthening market exists for the energy from the development that would make it possible to price the output up to the cost of the best thermal alternative.

The effect of pricing policy on power demand has been taken into account by the elasticity loop of the Battelle load forecasting methodology described in Section 5 of Exhibit B. The forecasts used for market price studies resulted from pricing assumptions consistent with those presented.

3.7 - Conclusions

Based on the assessment of the market for power and energy output from the Susitna Hydroelectric Project, it has been concluded that, with the appropriate level of state appropriation and with pricing policy as defined in Alaska State Laws, a viable basis exists for the Susitna power to be absorbed by the Railbelt utilities.

4 - EVALUATION OF ALTERNATIVE ENERGY PLANS

4.1 - General

This section describes the process of assembling the information necessary to carry out the systemwide generation planning studies for assessment of the economic feasibility of the Susitna project. Included is a discussion of the existing system characteristics, the planned Anchorage-Fairbanks intertie, and details of various generating options including hydroelectric and thermal. Performance and cost information required for the generation planning studies is presented for the hydroelectric and thermal generation options considered.

The approach taken in economically evaluating the Susitna project involved the development of long-term generation plans for the Railbelt electrical supply system with and without the proposed project. In order to compare the with-and-without plans, the cost of the plans were compared on a present worth basis. A generation planning model which simulated the operation of the system annually was used to project the annual generation costs.

During the pre-license phase of the Susitna project planning, two studies proceeded in parallel which addressed the alternatives in generating power in the Alaska Railbelt. These studies are the Susitna Hydroelectric Project Feasibility Study ~~done by Acres American Incorporated for~~ ponsored by the Alaska Power Authority and the Railbelt Electric Power Alternatives Study ~~done by Battelle Pacific Northwest Laboratories for~~ the Office of the Governor, State of Alaska.

~~One~~ The objective of the Susitna Feasibility Study was to determine the feasibility of the proposed project. The economic evaluations performed during the study found the project to be feasible as documented in this exhibit. The independent study conducted by Battelle focused on the feasibility of all possible generating and conservation alternatives.

Although the studies were independent, several key factors were consistent. Both studies used the approach of comparing costs by using generation planning simulation models. Thus, selected alternatives were put into a plan context and their economic performance compared by comparing costs of the plans. Additionally, parameters such as costs for fuel and capital costs and escalation were consistent between the two studies.

The following presentation focuses primarily on the Susitna Feasibility Study process and findings. A separate section provides the findings of the Battelle study, which generally agree with the feasibility study findings.

4.2 - Existing System Characteristics

(a) System Description

The two major load centers of the Railbelt region are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area ~~(see Figure D.5)~~ which at present operate independently. The existing transmission system between Anchorage and Willow consists of a network of 115 kV and 138 kV lines with interconnection to Palmer. Fairbanks is primarily served by a 138 kV line from the 28 MW coal-fired plant at Healy. Communities between Willow and Healy are served by local distribution.

~~There are currently nine electric utilities (including the Alaska Power Administration) providing power and energy to the Railbelt system.~~ Table D.13 summarizes the total generating capacity within the Railbelt system in 1980, based on information provided by Railbelt utilities and other sources. Table D.14 presents the resulting detailed listing of units currently operating in the Railbelt, information on their performance characteristics, and their on-line and projected retirement dates for generation planning purposes. The total Railbelt installed capacity of ~~984~~ 964.4 MW consists of two hydroelectric plants totaling 46 MW plus ~~938~~ 918.4 MW of thermal generation units fired by oil, gas, or coal, as summarized in Table D.14.

(b) Retirement Schedule

In order to establish a retirement policy for the existing generating units, several sources were consulted, including the Power Authority's draft feasibility study guidelines, FERC guidelines (FERC 1979), the Battelle Railbelt Alternatives Study (Battelle 1982), and historical records. Utilities, particularly those in the Fairbanks area, were also consulted. Based on these sources, the following retirement periods of operation were adopted for use in this analysis:

- Large Coal-Fired Steam Turbines (> 100 MW):	30 years
- Small Coal-Fired Steam Turbines (< 100 MW):	35 years
- Oil-Fired Gas Turbines:	20 years
- Natural Gas-Fired Gas Turbines:	30 years
- Diesels:	30 years
- Combined Cycle Units:	30 years
- Conventional Hydro:	50 years

Table D.1~~5~~ 4 lists the retirement dates for each of the current generating units based on the above retirement policy.

(c) Schedule of Additions

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~~Six~~ Five new projects were expected to be added to the Railbelt system prior to 1990, as shown in Table D.1~~6~~. The Chugach Electric Association is in the process of adding gas-fired combined-cycle capacity in Anchorage at a plant called Beluga No. 8. When complete, the total plant capacity will be 178 MW, but the plant will encompass existing Units 6 and 7. Chugach added a 26.4 MW gas turbine rehabilitation at Bernice Lake No. 4 in August 1982.

In recent years, the Corps of Engineers has conducted post-authorization planning studies for the Bradley Lake hydroelectric project located on the Kenai Peninsula. This project was deauthorized as a Federal development in December 1982. The Alaska Power Authority now plans to prepare a license application for submittal to the Federal Energy Regulatory Commission in mid-1983 and to proceed with detailed design concurrent with license processing. The project would include between 60 and 135 MW of installed capacity and would produce an average annual energy of 350 GWh. For analysis purposes, the project is assumed to come on line in 1988.

~~Three other units are also scheduled or have been added to the system since 1980.~~ Anchorage Municipal Light and Power Department is planning to add a 90 MW gas turbine in 1983-84 called AMLPD No. 8. ~~Copper Valley Electric Association is operating the new 12 MW Solomon Gulch Hydroelectric Project which is owned by the Alaska Power Authority.~~

4.3 - Fairbanks - Anchorage Intertie

Engineering studies have been undertaken for construction of an intertie between the Anchorage and Fairbanks systems. As presently envisaged, this connection will involve a 345 kV transmission line between Willow and Healy scheduled for completion in 1984. The line will initially be operated at 138 kV with capability of expansion as the loads grow in the load centers.

Based on these evaluations, it was concluded that an interconnected system should be assumed for the generation planning studies and that the basic intertie facilities would be common to all generation scenarios considered.

Costs of additional transmission facilities were added to the scenarios as necessary for each unit added. In the "with Susitna" scenarios, the costs of adding circuits to the intertie corridor were added to the

~~gas desulfurization for sulphur control, highly efficient combustion technology for control of nitrogen acids, and baghouses for particulate removal.~~

4.5 (b) Coal-Fired Steam

(ii) Fuel Costs

Coal prices and real coal price escalation were analyzed from production cost and market value perspectives. The details of the coal pricing studies are contained in Exhibit B, Appendix B-2, a brief summary follows.

The price of Nenana field coal delivered to Nenana was set at $1.72/MMBtu (1983). This price is based on the production costing approach, existing contracts for Nenana coal and assumes domestic consumption. The price of mine mouth Beluga coal was set at $1.86/MMBtu (1983). This price assumes that an export market is available in the Pacific Rim countries. The net back approach was used to obtain the price.

Real escalation of these values was based on supply-demand factors. A 2.6% real rate of increase is applied to the mine-mouth price of Nenana Field coal as this mine is used to supply a domestic market. For the

Beluga Field there is sufficient evidence to support the use of an export market driven value. Therefore, an export-specific escalator of 1.6% is applied. With exports as the basis for Beluga field development, all prices of that coal will reflect world market conditions, as power plant sales will comprise a modest share of mine output.

For the analysis it was assumed that when each coal plant was added to the system the coal price in existence would be fixed and the price would not experience real escalation for the economic life of the plant.

(iii) <u>Other Performance Characteristics</u>

Annual operation and maintenance costs and representative forced outage rates are shown in Table D.18.

(c) <u>Combined Cycle</u>

A combined cycle plant is one in which electricity is generated partly in a gas turbine and partly in a steam turbine cycle. Combined cycle plants achieve higher efficiencies than conventional gas turbines. There are two combined cycle plants in Alaska at present. One is operational and the other is under construction. The plant under construction is the Beluga No. 8 unit owned by Chugach Electric Association (CEA). It is a 42-MW steam turbine, which will be added to the system in late 1982, and utilize heat from currently operating gas turbine units, Beluga Nos. 6 and 7.

(i) Capital Costs

A new combined cycle plant unit size of 200-MW capacity was considered to be representative of future additions to generating capability in the Anchorage area. This is based on economic sizing for plants in the lower 48 states and projected load increases in the Railbelt. A heat rate of 8000 Btu/kWh was adopted based on the alternative study completed by Battelle.

The capital cost was estimated sing the Battelle study basis (Battelle 1982, Vol. XIII) and is listed in Table D.18. A bid line item cost is shown on Table 21.

(ii) Fuel Costs

The combined cycle facilities would burn gas with a domestic market value of $2.38/MMBtu (1983) with an additional demand charge of $0.35/MMBtu (1983) beginning in 1986. The gas price is based on the plant being located at the wellhead and a recent contract for the purchase of uncommitted reserves in the Anchorage area. Real escalation of the gas price corresponds with escalation of the base case world oil price scenario, as follows:

Period	Real Escalation Rate %
1984	-4.63
1985	-4.74
1986-1988	0
1989-2010	3.0
2011-2020	2.5
2021-2030	1.5
2031-2040	1.0

A detailed discussion of gas pricing and world oil prices is contained in Exhibit B, Appendix B-2.

(iii) Other Performance Characteristics

Annual operation and maintenance costs, along with a representative forced outage rate, are given in Table D.18.

(d) Gas-Turbine

Gas turbines burn natural gas or oil in units similar to jet engines which are coupled to electric generators. These also require an appropriate water cooling arrangement.

Gas turbines are by far the main source of thermal power generating resources in the Railbelt area at present. There are 470 MW of installed gas turbines operating on natural gas in the Anchorage area and approximately 168 MW of oil-fired gas turbines supplying the Fairbanks area (see Table D.14). Their low initial cost, simplicity of construction and operation, and relatively short implementation lead time have made them attractive as a Railbelt generating alternative. The extremely low-cost contract gas in the Anchroage area also has made this type of generating facility cost-effective for the Anchorage load center.

(i) Capital Costs

A unit size of 75 MW was considered to be representative of a modern gas turbine plant addition in the Railbelt region.

Gas turbine plants can be built over a two-year construction period and have an average heat rate of approximately 10,000 Btu/kWh. The capital costs were again taken from the Battelle alternatives study.

(ii) Fuel Costs

Gas turbine units can be operated on oil as well as natural gas. The market cost for oil is $5.58/MMBtu (1983). The real annual growth rates in oil costs were discussed above.

(iii) Other Performance Characteristics

Annual operation and maintenance costs and forced outage rates are shown in Table D.18.

(e) Diesel Power Generation

Most diesel plants in the Railbelt today are on standby status or are operated only for peak load service. Nearly all the continuous duty units were retired in the past several years because of high fuel prices. About 65 MW of diesel plant capacity is currently available.

(i) Capital Costs

The high cost of diesel fuel and low capital cost make new diesel plants most effective for emergency use or in remote areas where small loads exist. A unit size of 10 MW was selected as appropriate for this type of facility, large by diesel engine standards. Units of up to 20 MW are under construction in other areas. Potentially, capital cost savings of 10-20 percent could be realized by going to the larger units. However, these larger units operate at very low speeds and may not have the reliability required if used as a major alternative for Railbelt electrical power. The capital cost was derived from the same source as given in Table D.18 (Battelle 1982, Vol. IV).

(ii) Fuel Costs

Diesel fuel costs and growth rates are the same as oil costs for gas turbines.

(iii) Other Performance Characteristics

Annual operation and maintenance costs and the forced outage rate are given in Table D.18.

(f) Plan Formulation and Evaluation

The four candidate unit types and sizes were used to formulate plans for meeting future Railbelt power generation requirements. The objective of this exercise was defined as the formulation of appropriate plans for meeting the projected Railbelt demand on the basis of economic preferences.

Economic evaluation of any Susitna basin development plan requires that the impact of the plan on the cost of energy to the Railbelt . . .

area consumer be assessed on a systemwide basis. Since the consumer is supplied by a large number of different generating sources, it is necessary to determine the total Railbelt system cost in each case to compare the various Susitna basin development options.

(6) The primary tool used for system costs was the mathematical model developed by the Electricity Utility Systems Engineering Department of the General Electric Company. The model is commonly known as OGP~~5~~6 or Optimized Generation Planning Model, Version ~~5~~ 6. The following information is paraphrased from GE literature on the program. (6)

The OGP5 program was developed over ten years to combine the three main elements of generation expansion planning (system reliability, operating and investment costs) and automate generation addition decision analysis. OGP~~5~~6 will automatically develop optimum generation expansion patterns in terms of economics, reliability and operation. ~~Many utilities use OGP5 to study load management, unit size, capital and fuel costs, energy storage, forced outage rates, and forecast uncertainty.~~

The OGP~~5~~6 program requires an extensive system of specific data to perform its planning function. In developing an optimal plan, the program considers the existing and committed units (planned and under construction) available to the system and the characteristics of these units including age, heat rate, size and outage rates as the base generation plan. The program then considers the given load forecast and operation criteria to determine the need for additional system capacity based on given reliability criteria. This determines "how much" capacity to add and "when" it should be installed. If a need exists during any monthly iteration, the program will consider additions from a list of alternatives and select the available unit best fitting the system needs. Unit selection is made by computing production costs for the system for each alternative included and comparing the results.

The unit resulting in the lowest system production costs is selected and added to the system. Finally, an investment cost analysis of the capital costs is completed to answer the question of "what kind" of generation to add to the system.

The model is then further used to compare alternative plans for meeting variable electrical demands, based on system reliability and production costs for the study period.

Thus, it should be recognized that the production costs modeled represent only a portion of ultimate consumer costs and in effect are only a portion, albeit major, of total costs.

The use of the output from the generation planning model is in Section 4.6(a).

4.6 - Without Susitna Plan

In order to analyze the economics of developing the Susitna project, it was necessary to analyze the costs of meeting the projected Alaska Railbelt load forecast with and without the project. Thus, a plan using the identified components was developed.

Using the generation planning model, a base case "without Susitna" plan was structured based on middle range projections. The base case input to the model included:

- The Base Case ~~Battelle's middle range~~ load forecast (~~Exhibit B~~ Section 5.4.3);

- Fuel cost as specified;

- Coal-fired steam and gas-fired combined-cycle and combustion turbine units as future additions to the system;

- Costs and characteristics of future additions as specified;

- The existing system as specified and scheduled commitments listed in Tables D.14 and D.15;

- ~~Middle range~~ fuel escalation as specified;

- Economic parameters of 3 percent interest and 0 percent general inflation; and

- ~~Real escalation on operation and maintenance and capital costs at a rate of 1.8 percent to 1992 and 2 percent thereafter; and~~

- Generation system reliability set to a loss of load probability of one day in ten years. This is a probabilistic measure of the inability of the generating system to meet projected load. One day in ten years is a value generally accepted in the industry for planning generation systems.

The model was initially to be operated for a period from 1982-2000. It was found that, under the medium load forecast, the critical period for capacity addition to the system would be in the winter of 1992-1993. Until that time, the existing system, given the additions of the planned intertie and the planned units, appears to be sufficient to meet Railbelt demands. Given this information, the period of plan development using the model was set as 1993-2020.

In early years (1993-1996), the economically preferred units are those which generate base load power. After 600 MW of this type of power in the form of coal units are added, the preference switches to gas turbine units which are used to meet seasonal (winter) peak months and daily peaking needs. During the later stage, the generating system needs capacity to meet target reliability rather than to generate power continually.

The following was established as the non-Susitna Railbelt base plan (see Figure D.~~14~~ 11):

(a) System as of January 1993

Coal-fired steam:	59 MW
Natural gas GT:	452 MW
Oil GT:	140 MW
Diesel:	67 MW
Natural gas CC:	317 MW
Hydropower:	155 MW
Total (including committed conditions):	1190 MW

remove CVEA

(b) System Additions

Year	Gas Fired Gas Turbine (MW)	Coal Fired Unit (MW)
1993		1 x 200 (Beluga Coal)
1994		1 x 200 (Beluga Coal)
1996		1 x 200 (Nenana/Healy Coal)
1997	1 x 70	
1998	1 x 70	
2001	1 x 70	
2003	1 x 70	
2004	1 x 70	
2005	2 x 70	
2006	1 x 70	
2007		1 x 200 (Beluga Coal)
2009	1 x 70	
Total	630	800

revise with results of OGP6 runs

(c) System as of 2010

Coal-fired steam:	813 MW
Natural gas GT:	746 MW
Oil GT:	0 MW
Diesel:	6 MW
Natural gas CC:	317 MW
Hydropower:	155 MW
Total (accounting for retirements and additions)	2037 MW

see note above

There is one particularly important assumption underlying the plan. The costs associated with the Beluga development are based on the opening of that coal field for commercial development. That development is not a certainty now and is somewhat beyond the control of the state, since the rights are in the hands of private interests. Even if the seam is mined for export, there will be environmental problems to overcome. The greatest problem will be the availability of cooling water for the units. The problem could be solved in the "worst" case by using the sea water from Cook Inlet as cooling water; however, this solution would add significantly to project costs.

Two alternatives which Battelle included in their base plan which have not been included in this plan are the Chakachamna and Allison Creek hydroelectric plants. The Chakachamna plant is currently the subject of a feasibility study by the Power Authority. The current plan would develop a 330 MW plant at a cost of $1.45 billion at January 1982 price levels. The plant would produce nearly 1500 GWh on an average annual basis.

~~Due to some current questions regarding the feasibility of the Chakachamna plant, it has not been included in the non-Susitna plan. It has been checked, however, in the sensitivity analysis presented later in this section.~~

The Allison Creek Hydroelectric Project was included in the non-Susitna base plan by Battelle. It has not been included in this base plan due to its high costs ($125/MWh in 1981 dollars).

The thermal plan described above has been selected as representative of the generation scenario that would be pursued in the absence of Susitna. The selection has been confirmed by the Battelle results which show an almost identical plan to be the lowest cost of any non-Susitna plan.

4.7 - Economic Evaluation

This section provides a discussion of the key economic parameters used in the study and develops the net economic benefits stemming from the Susitna Hydroelectric Project. Section 4.7 (a) deals with those economic principles relevant to the analysis of net economic benefits and develops inflation and discount rates. ~~and the Alaskan opportunity values (shadow prices) of oil, natural gas and coal. In particular the analysis is focused on the longer-term prospects for coal markets and prices. This follows from the evaluation that, in the absence of Susitna, the next best thermal generation plan would rely on exploitation of Alaskan coal. The future coal price is therefore considered in detail to provide rigorous estimates of prices in the most likely alternative markets and hence the market price of coal at the mine-mouth within the state.~~

Section 4.7 (b) presents the net economic benefits of the proposed hydroelectric power investments compared with this thermal alternative.

rates have averaged about 2 to 3 percent in the U.S. in real (inflation-adjusted) terms (Data Resources 1980; U. S. Department of Commerce). Forecasts of real interest rates show average values of about 3 percent and 2 percent in the periods of 1985 to 1990 and 1990 to 2000, respectively. The U.S. Nuclear Regulatory Commission has also analyzed the choice of discount rates for investment appraisal in the electric utility industry and has recommended a 3 percent real rate (Roberts 1980). Therefore, a real rate of 3 percent has been adopted as the base case discount and interest rate for the period 1982 to 2040.

. Nominal Discount and Interest Rates

The nominal discount and interest rates are derived from the real values and the anticipated rate of general price inflation. Given a 3 percent real discount rate and a 7 percent rate of price inflation, the nominal discount rate is determined as 10.2 percent or about 10 percent*.

Note all the material discussed on p.4.21 → D-4-28 will be covered in Exhibit B, App B-2. Etc

. Capital Cost Escalation

The forecasts of the Battelle alternatives study (Battelle 1982, Vol. 4) indicate that, as a long term trend, there will be moderate real escalation in capital costs of power plants. These escalation rates were incorporated into the ~~generation~~ planning ~~and~~ financial evaluation. The effect of this incremental escalation is to favor lower capital cost projects as compared to higher capital cost projects. The rates used for real escalation on capital costs are 1.8 percent until 1992 and 2 percent from that point foreward.

Not in OAPB!

(iii) Oil and Gas Prices

- Oil Prices

Refined petroleum products are the only fuels in which Alaska is currently not self-sufficient. This is because of insufficient refinery capacity for some products, rather than lack of resources. Alaska's royalty share of crude oil production is sufficient to meet in-state consumption at least through the year 2000, but some

* (1 + the nominal rate) = (1 + the real rate) x (1 + the inflation rate) = 1.03 x 1.07, or 1.102

refined products are imported. The supply of petroleum products is not believed to be a problem through the forecast period, however. The current price of utility fuel oil is a good indicator of its current opportunity value, especially in view of the recent price decontrol on oil.

In the base period (January 1982), the Alaskan 1982 dollar price of No. 2 fuel oil is estimated at $6.50/MMBtu.

Long-term trends in oil prices will be influenced by events that are economic, political and technological in nature, and are therefore estimated within a probabilistic framework.

As shown in Table D.23, the base case (most likely escalation rate) is estimated to be 2 percent to 2000 and 1 percent from 2000 to 2040. To be consistent with Battelle forecasts, a 2 percent rate was used throughout the OGP planning period 1982 to 2010 and 0 percent thereafter. In other scenarios the growth rates were estimated at 0 percent from 1982-2051 (low growth); and at 4 percent to 2000, and 2 percent beyond 2000 (high growth). These projections are also consistent with those recently advanced by such organizations as Data Resources (1981), World Bank (1981), U. S. Department of Energy (1980), and the National Energy Board of Canada (1981).

A September 1982 review of major forecasts for oil price trends reaffirms the Battelle projection. Projections from seven sources indicated ten forecasts which varied from a low trend projection of -0.5 to a high of 5.3 percent. Seven of the ten trend forecasts were within a band of +1.7 to +3.4 percent. The trends are summarized in Table D.25.

- Gas Prices

The availability and cost of Cook Inlet natural gas for electric power generation is the most complex of all alternative fuels for the Railbelt. This is due to the uncertainty in estimates of recoverable reserves, the low costs of fuels under existing contracts and the potential for export of the fuels to the world markets. Many existing contracts in the Railbelt reflect prices and escalation clauses established when the market for the gas was restricted to Cook Inlet. However, new supplies used to meet demand in excess of the contracted supply are priced by their opportunity value. The opportunity value is based on the net-back from liquid natural gas sales to Japan.

Railbelt gas prices have been forecast using both export opportunity values (netting back CIF prices from Japan to Cook Inlet) and domestic market prices as likely to be faced in the future by Alaskan electric utilities. The generation planning analysis used market prices as estimated by Battelle (1982, Vol. VII). Since there are indications that Cook Inlet reserves may remain insufficient to serve new export markets, the study conducted a review of both price and quantity from potential sources.

. Availability of Natural Gas

The Battelle study developed a number of possible supply and use scenarios, all of which have uncertainty attached to their underlying assumptions. The results of the study indicated that the existing reserves currently committed for in-state use become exhausted in the early 1990s. As contracts expire and new reserves are secured, extreme price changes are likely to take place.

A major factor in the future scenarios of natural gas use is the Pacific Alaska LNG (PALNG) Project. This project would include construction of an LNG plant which would supply gas to the lower 48. Currently, large amounts of Cook Inlet reserves are committed to this project. If it proceeds, all new gas contracts will compete with PALNG for reserves, driving up prices. If it does not go through, prices may remain lower.

Details on supply volumes and possible utilization scenarios are given in Battelle 1982, Vol. VII.

. Domestic Market Prices

The Cook Inlet area consumer has in recent decades benefitted greatly from a buyer's market position for natural gas. In the 1950s and 1960s, oil companies in search of crude oil, a readily transportable commodity, found more natural gas than oil. Due to transportation difficulties, the gas was more of a problem than an asset. In order to sell the gas, the companies offered it at very low prices. Resulting contracts which are still in existence today enable the Cook Inlet consumer to pay some of the lowest prices for natural gas in the world. For example, in April 1982, Chugach Electric Association (the largest producer of electricity in the Railbelt) paid a weighted average of $0.41 per Mcf. This amount is 12 percent of what the rest of the utilities which report costs to DOE paid. Anchorage Municipal Gas and Electric currently pays over $1.00/Mcf for gas. Although high, the price still reflects favorable conditions of long term contracts.

It is not expected that these costs will be indicative of future prices for Cook Inlet. As the contracts expire, new gas will be sold at prices reflecting the opportunity value of the gas. Studies of alternative pricing futures by Battelle (1982, Vol. VII) indicate that there will be significant domestic price disruptions in the early 1990s as competition for the uncommitted reserves develops. Actual prices vary depending on the scenario with the key factor the development of the PALNG plant. For example, a weighted average of the cost of gas to Chugach and Enstar (Alaska Gas and Service Co.) results in an estimate of \$3.03/Mcf in 1993 in the absence of the plant. If the plant goes ahead, the estimate increases to \$3.92/Mcf. Details behind these estimates are in Battelle's Vol. VII.

Recent contracts for gas support these estimates. In December 1982, Enstar signed contracts with Marathon Oil Company and Shell Oil Company for gas from the Beluga and Kenai fields. The base price of the gas is \$2.32 in 1982. In addition to the base price, Enstar will need to build a pipeline to take delivery and pay a demand charge triggered by high volume deliveries. It has been projected by Enstar officials that the demand charge will be in force by 1990. Furthermore, Enstar expects that the cost of the pipeline, demand charge and taxes will raise their acquisition cost to about \$3.00/Mcf in 1990. In addition to the base plus fringe costs, the cost of the fuel will be tied directly to the cost of No. 2 fuel oil in the Railbelt. Thus the gas contract price will track the price of oil annually. The contracts will be in force until 1997 and 2000. Enstar is currently the major supplier of gas to Anchorage Municipal Power and Light.

Table D.25 depicts the low, medium and high domestic market prices used in the generation planning analysis. In the medium (most likely) case, prices escalate at real rates of 2.5 percent from 1993 to 2000 and 2 percent beyond 2000. In the low case, there is zero escalation; in the high case, gas prices grow at 4 percent 1982 to 2000 and 2 percent beyond 2000. The starting point for these prices is \$3.03/MMBtu beginning in 1993.

Export Opportunity Values

Table D.25 also shows the current and projected opportunity values of Cook Inlet gas in a scenario where the Japanese export market for LNG continues to be the alternative to domestic demand. From a base period plant-gate price of \$4.65/MMBtu (CIF Japan), low, medium and high price escalation rates have been estimated for the intervals 1982 to 2000 and 2000 to 2040.

The cost of liquefaction and shipping (assumed to be constant in real terms) was subtracted from the escalated CIF prices to derive the Cook Inlet plant-gate prices and their growth rates. These Alaskan opportunity values are projected to escalate at 2.7 percent and 1.2 percent in the medium (most likely) case. Note that the export opportunity values consistently exceed the domestic prices. In the year 2000, for example, the opportunity value is nearly double the domestic price estimated by Battelle. It is expected that the Japanese market will hold firm at current levels. As previously discussed, the PALNG plant is another possibility for gas export. Its future is uncertain as previously discussed.

(iv) Coal Prices

The shadow price or opportunity value of Beluga and Healy coal is the delivered price in alternative markets less the cost of transportation to those markets. The most likely alternative demand for thermal coal is the East Asian market, principally Japan, South Korea, and Taiwan. The development of 60-year forecasts of coal prices in these markets is conditional on the procurement policies of the importing nations. These factors, in turn, are influenced to a large extent by the price movements of crude oil.

- Historical Trends

Examination of historical coal price trends reveals that FOB and CIF prices have escalated at annual real rates of 1.5 percent to 6.3 percent as shown below:

. Coal prices (bituminous, export unit value, FOB U.S. ports) grew at real annual rates of 1.5 percent (1950 to 1979) and 2.8 percent (1972 to 1979) (U. S. Department of Energy 1980).

. In Alaska, the price of thermal coal sold to the GVEA utility advanced at real rates of 2.2 percent (1965 to 1978) and 2.3 percent (1970 to 1978).

. In Japan, the average CIF prices of steam coal experienced real escalation rates of 6.3 percent per year in the period 1977 to 1981 (Coal Week International; Japanese Ministry of International Trade and Industry 1982). This represents an increase in the average price from approximately $35.22 per metric ton (mt) (2200 pounds) in 1977 to about $76.63/mt in 1981.

As shown below, export prices of coal are highly correlated with oil prices, and an analysis of production costs has not predicted accurately the level of coal prices.

Even if the production cost forecast itself is accurate, it will establisn a minimum coal price, rather than the market clearing price set by both supply and demand conditions.

. In real terms export prices of U.S. coal showed a 94 percent and 92 percent correlation with oil prices (1950 to 1979 and 1972 to 1979).*

. Supply function (production cost) analysis has estimated Canadian coal at a price of $23.70 (1980 U.S. $/ton) for S.E. British Columbia (B.C.) coking coal, FOB Roberts Bank, B.C., Canada (Battelle 1980), (Battelle 1982, Vol. VII.) In fact, Kaiser Resources (now B.C. Coal Ltd.) has signed agreements with Japan at an FOB Price of about $47.50 (1980 U.S. $/ton) (B.C. Business 1981). This is 100 percent more than the price estimate based on production costs.

. The same comparison for Canadian B.C. thermal coal indicates that the expected price of $55.00/mt (1981 Canadian $) or about $37.00 (1980 U.S. $) per ton would be 60 percent above estimates founded on production costs (Battelle 1980; B.C. Business 1981; Battelle 1982, Vol. VII).

. In longer-term coal export contracts, there has been provision for reviewing the base price (regardless of escalation clauses) if significant developments occur in pricing or markets. That is, prices may respond to market conditions even before the expiration of the contract.**

. Energy-importing nations in Asia, especially Japan, have a stated policy of diversified procurement for their coal supplies. They will not buy only from the lowest-cost supplier (as would be the case in a perfectly competitive model of coal trade) but instead will pay a risk premium to ensure security of supply (Battelle 1980; Battelle 1982, Vol. VII).

- Survey of Forecasts

Data Resources Incorporated (1980) is projecting an average annual real growth rate of 2.6 percent for U.S. coal prices in the period 1981 to 2000. The World Bank (1981) has forecast that the real price of steam coal

* Analysis is based on data from the World Bank.

** This clause forms part of the recently concluded agreement between Denison Mines and Teck Corporation and Japanese steel makers.

would advance at approximately the same rate as oil prices (3 percent/a) in the period 1980 to 1990. Canadian Resourcecon Limited (1980) has recently forecast growth rates of 2 percent to 4 percent (1980 to 2010) for subbituminous and bituminous steam coal.

- Opportunity Value of Alaskan Coal

. Delivered Prices, CIF Japan

Based on these considerations, the shadow price of coal (CIF price in Japan) was forecast using conditional probabilities given low, medium, and high oil price scenarios. Table D.26 depicts the estimated coal price growth rates and their associated probabilities, given the three sets of oil prices. Combining these probabilities with those attached to the oil price cases yields the following coal price scenarios, CIF Japan.

Scenario	Probability	Real Price Growth
Medium (most likely)	49 percent	2 percent (1982-2000) 1 percent (2000-2040)
Low	24 percent	0 percent (1982-2040)
High	27 percent	4 percent (1982-2000) 2 percent (2000-2040)

The 1982 base period price was initially estimated using the data from the Battelle Beluga Market Study (Battelle 1980). Based on this study, a sample of 1980 spot prices published in Coal Week International (averaging $1.66/MMBtu) was escalated to January 1982 to provide a starting value of $1.95/MMBtu in January 1982 dollars.*

As more recent and more complete coal import price statistics became available, this method of estimating was found to give a significant underestimate of actual CIF prices. By late 1981, Japan's average import price of steam coal reached $2.96/MMBtu.** An important

*The escalation factor was 1.03 x 1.14, where 3 percent is the forecast real growth in prices (mid-1980 to January 1982) at an annual rate of 2 percent, and 14 percent is the 18-month increase if the CPI is used to convert from mid-1980 dollars to January 1982 dollars.

**As reported by Coal Week International in October 1981, the average CIF value of steam coal was $75.50/mt. At an average heat value of 11,500 Btu/lb, this is equivalent to $2.96/MMBtu.

sensitivity case was therefore developed reflecting these updated actual CIF prices. The updated base period value of $2.96 was reduced by 10 percent to $2.66 to recognize the price discount dictated by quality differentials between Alaskan coal and other sources of Japanese coal imports (Battelle 1980).

. Opportunity Values in Alaska

.. Base Case - Battelle-based CIF Prices, No Export Potential for Healy Coal

Transportation costs of $0.52/MMBtu were subtracted from the initially estimated CIF price of $1.95 to determine the opportunity value of Beluga coal at Anchorage. In January 1982 dollars, this base period net-back price is therefore $1.43. In subsequent years, the opportunity value is derived as the difference between the escalated CIF price and the transport cost (estimated to be constant in real terms). The real growth rate in these FOB prices is determined residually from the forecast opportunity values. In the medium (most likely) case, the Beluga opportunity values escalate at annual rates of 2.6 percent and 1.2 percent during the intervals 1982 to 2000 and 2000 to 2040, respectively.

For Healy coal, it was estimated that the base period price of $1.75/MMBtu (at Healy) would also escalate at 2.6 percent (to 2000) and 1.2 percent (2000 to 2040). Adding the escalated cost of transportation from Healy to Nenana results in a January 1982 price of $1.75/MMBtu (National Energy Board of Canada 1981; World Bank 1980). In subsequent years, the cost of transportation (of which 30 percent is represented by fuel cost which escalates at 2 percent) is added to the Healy price, resulting in Nenana prices that grow at real rates of 2.3 percent (1982 to 2000) and 1.1 percent (2000 to 2040). Table D.20 summarizes the real escalation rates applicable to Nenana and Beluga coal in the low, medium, and high price scenarios.

.. Sensitivity Case - Updated CIF Prices, Export Potential for Healy Coal

The updated CIF price of steam coal ($2.66/MMBtu after adjusting for quality differentials) was reduced by shipping costs from Healy and Beluga to Japan to yield Alaskan opportunity values. In

January 1982, prices were $2.08 and $1.74 at Anchorage and Nenana, respectively. The differences between escalated CIF prices and shipping costs result in FOB prices that have real growth rates of 2.5 percent and 1.2 percent for Beluga coal and 2.7 percent and 1.2 percent for Healy coal (at Nenana). Table D.26 shows escalation rates for the opportunity value of Alaskan coal in the low, medium, and high price scenarios, using updated base period values.

(v) Generation Planning Analysis - Base Case Study Values

Based on the considerations presented in (i) through (iv) above, a consistent set of fuel prices was assembled for the base case probabilistic generation planning analysis, as shown in Table D.27. The study values include probabilities for the low, medium and high fuel price scenarios. The probabilities are common for the three fuels (oil, gas and coal) within each scenario in order to keep the number of generation planning runs to manageable size. In the case of the natural gas prices, domestic market prices were selected for the base case analysis with the export opportunity values used in sensitivity runs. The base period value of $3 was derived by deflating the 1996 Battelle prices to 1982 by 2.5 percent per year. Coal prices were also selected from the base case using Battelle's 1980 sample of prices as the starting point, with the updated CIF prices of coal reserved for sensitivity runs. Oil prices have been escalated by 2 percent (1982 to 2040).

(b) Analysis of Net Economic Benefits

(i) Modeling Approach

Using the economic parameters discussed in the previous section and data relating to the electrical energy generation alternatives available for the Railbelt, an analysis was made comparing the costs of electrical energy production with and without the Susitna project. ~~The primary tool for the analysis was a generation planning model (OGP5) which simulates production costs over a planning period extending from 1982 to 2010.~~

The method of comparing the "with" and "without" Susitna alternative generation scenarios is based on the long-term present worth (PW) or total system costs. The planning model determines the total production costs of alternative plans on a year-by-year basis. These total costs for the period of modeling include all costs of fuel and operation and maintenance (O&M) for all generating units included as part of the system, and the annualized investment costs of any generating and system transmission plants added during the period 1993 to ~~2010~~. 2020

Factors which contribute to the ultimate consumer cost of power but which are not included as input to this model are investment costs for all generation plants in service prior to 1993 investment, cost of the transmission and distribution facilities already in service, and administrative costs of utilities. These costs are common to all scenarios and therefore have been omitted from the study.

In order to aggregate and compare costs on a significantly long-term basis, annual costs have been aggregated for the period 1993 to 2051. Costs have been computed as the sum of two components and converted to a 1982 PW. The first component is the 1982 PW of cost output from the first ~~18~~ 28 years of model simulation from 1993 to ~~2010~~ 2020. The second component is the estimated PW of long-term system costs from ~~2011~~ 2021 to 2051.

For an assumed set of economic parameters on a particular generation alternative, the first element of the PW value represents the amount of cash (not including those costs noted above) needed in 1982 to meet electrical production needs in the Railbelt for the period 1993 to ~~2010~~ 2020. The second element of the aggregated PW value is the long-term (~~2011~~ 2021 to 2051) PW estimate of production costs. In considering the value to the system of the addition of a hydroelectric power plant which has a useful life of approximately 50 years, the shorter study period would be inadequate. A hydroelectric plant added in 1993 or 2002 would accrue PW benefits for only ~~18~~ 28 or ~~9~~ 19 years, respectively, using an investment horizon that extends to ~~2010~~ 2020. However, to model the system for an additional 30 years, it would be necessary to develop future load forecasts and generation alternatives which are beyond the realm of any prudent projections. For this reason, it has been assumed that the production costs for the final study year (~~2010~~ 2020) would simply recur for an additional 31 years, and the PW of these was added to the 28-year PW (1993 to ~~2010~~ 2020) to establish the long-term cost differences between alternative methods of power generation.

(ii) Base Case Analysis

- Pattern of Investments "With" and "Without" Susitna

The base case comparison of the "with" and "without" Susitna plans is based on an assessment of the PW production costs for the period 1993 to 2051, the base case ~~using mid-range~~ values for the energy demand and load forecast, fuel prices, fuel price escalation rates, capital costs, and capital cost escalation rates. ~~The capital cost escalation rate was set at approximately 2 percent per year based on studies of long-term trends in the Battelle Study (Battelle 1982, Vol. IV)~~.

The with-Susitna plan calls for 680 MW of generating capacity at Watana to be available to the system in 1993. Although the project may come on line in stages during that year, for modeling purposes full-load generating capability is assumed to be available for the entire year. The additional two units, totaling 340 MW of capacity, will come on line in 1994. These units add flexibility of operation and project reliability. They will also be a source of additional capacity if high load growth is realized. Providing for these units in planning for Watana allows for the project to become a peaking project well into the future.

The second stage of Susitna, the Devil Canyon project, is scheduled to come on line in 2002. The optimum timing for the addition of Devil Canyon was tested for earlier and later dates. Addition in the year 2002 was found to result in the lowest long-term cost. Devil Canyon will have 600 MW of installed capacity.

The without-Susitna plan is discussed in Section 4.5. It includes three 200 MW coal-fired plants added at Beluga in 1993, 1994, and 2007. A 200 MW unit is added at Nenana in 1996 and nine 70 MW gas-fired combustion turbines (GT's) would be added during the 1997 to 2010 period.

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- Base Case Net Economic Benefits

The economic comparison of these plans is shown in Table D.~~22~~. During the 1993 to 2020 study period, the 1982 PW cost for the Susitna plan is ~~$3.119~~ ___ billion. The annual production cost in 2020 is ~~$0.385~~ ___ billion. The PW of this level cost, which remains virtually constant for a period extending to the end of the life of the Devil Canyon plant (2051), is ~~$3.943~~ ___ billion. The resulting total present worth ~~cost~~ of the with-Susitna plan is ~~$7.06~~ ___ billion in 1982 dollars. ~~presently valued to 1988~~.

The non-Susitna plan (Section 4.5) which was modeled has a 1982 PW cost of ~~$3.213~~ ___ billion for the 1993 to 2020 period with a 2020 annual cost of ~~$0.491~~ ___ billion. The total long-term cost has a PW of ~~$8.24~~ ___ billion. Therefore, the net economic benefit of adopting the Susitna plan is ~~[illegible]~~ billion.* In other words, the present-value cost difference between the Susitna plan and the expansion plan based on thermal plant addition is ~~[illegible]~~ billion in 1982 dollars. ~~This is equivalent to a 1982 net economic benefit of $2,700 per capita for the 1982 population of the State of Alaska. Expressed in 1993 dollars (at the on-line date of Watana), the net benefits would have a levelized value of $2.48 billion.**~~

It is noted that the magnitude of net economic benefits (~~[illegible]~~ billion) is not particularly sensitive to alternative assumptions concerning the overall rate of price inflation as measured by the Consumer Price Index. The analysis has been carried out in real (inflation- adjusted) terms. Therefore, the present valued cost savings will remain close to ~~[illegible]~~ billion regardless of CPI movements, as long as the real (inflation-adjusted) discount and interest rates are maintained at 3 percent.

to be Checked

The Susitna project's internal rate of return (IRR), i.e., the real (inflation-adjusted) discount rate at which the with-Susitna plan has zero net economic benefits, or the discount rate at which the costs of the with-Susitna and the alternative plans have equal costs, has also been determined. The IRR is about 4.1 percent in real terms, and 11.4 percent in nominal (inflation-inclusive) terms. Therefore, the investment in Susitna would significantly exceed the 5 percent nominal rate of return "test" proposed by the State of Alaska in cases where state appropriations may be involved.***

It is emphasized that these net economic benefits and the rate of return stemming from the Susitna project are inherently conservative estimates due to several assumptions made in the OGP5 analysis. These items are discussed individually in the following paragraphs.

~~*This is different from the expected value net benefit of 1.45 billion calculated in the multivariate analysis of Section 4.8. The multivariate is based on ranges and probabilities of variables rather than single point estimates.~~

~~**$1.18 billion times 2.105, where 2.105 is the general price inflation index for the period 1982 to 1993.~~

***See Alaska legislation A5 44.83.670

Numbers will be checked with results of OGP6 Runs

. Zero Growth in Long-term Costs

From 2010 to 2051, the OGP6 analysis assumed constant annual production costs in both the Susitna and non-Susitna plans. This has the effect of excluding real escalation in fuel prices and the capital costs of thermal plant replacements, thereby understating the long-term PW costs of thermal generation plans.

. Loss of Load Probabilities

The loss of load probability in the non-Susitna plan is calculated at ~~[illegible]~~ in the year 2020. This means that the system in 2020 is on the verge of adding an additional plant, and would do so in 2011. These costs are, however, not included in the analysis, which is cut off at 2010. On the other hand, the Susitna plan has a loss of load probability of 0.025, and may not require additional capacity for several years beyond 2010.

. Long-term Energy From Susitna

Some of the Susitna energy output (about 350 GWh) is still not used by 2010. This energy output would be available to meet future increases in projected demand in the summer months. No benefit is attributed to this energy in the analysis.

. Equal Estimation of Environmental Costs

The generation planning analysis has implicitly assumed that all environmental costs for both the Susitna and the non-Susitna plans have been costed. To the extent that the thermal generation expansion plan may carry greater environmental costs than the Susitna plan, the economic cost savings from the Susitna project may be understated. Due to the greater level of study of the Susitna project, costs for mitigation plans were included. This may not be the case with the coal alternative. For example, cooling water may not be available at the Beluga sites in necessary quantities. The consequences of this and similiar problems have not been studied or costed in detail equal to the Susitna study. These differences or added costs cannot be quantified at this stage of study on the Beluga coal alternative.

4.8 - Sensitivity to World Oil Price Forecasts

Assumptions regarding future world oil prices impact the forecasts of electric power demand for the Railbelt area. This relationship is discussed in detail in Exhibit B, Seciton 5.4. Table D.23 contains a summary of the load forecasts considered. A sensitivity analysis was performed to identify the effect of power demand forecasts lower and higher than the base case demand forecast. Table D.24 depicts the results of the sensitivity analysis.

(NOTE FOR DRAFT Add discussion of results here when results are available.)

4.9 - Other Sensitivity and Probability Assessments

(a) Introduction

(NOTE FOR DRAFT)

The other sensitivity and probability analyses described below were completed prior to the sensitivity analyses of world oil prices discussed above. A transitional paragraph will be added here to relate the oil price sensitivity analyses to the other sensitivity and probablity analyses.

(b) Sensitivity Analysis

Rather than rely on a single point comparison to assess the net benefit of the Susitna project, a sensitivity analysis was carried out to identify the impact of modified assumptions on the results. The analysis was directed at the following variables.

- Load forecast (Table D.29)
- Real interest and discount rate
- Construction period
- Period of analysis
- Capital costs
  - Susitna
  - Thermal alternatives

- O&M costs

- Base period fuel price

- Real escalation in capital costs, O&M costs, and fuel prices

- System reliability

- Chackachamna

- Susitna Project delay.

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Tables D.~~30~~ 25 to D.~~37~~ 33 depict the results of the sensitivity analysis. In particular, Table D.~~37~~ 33 summarizes the net economic benefits of the Susitna project associated with each sensitivity test. The net benefits have been compared using indexes relative to the base case value ($1.176 billion) which is set to 100.

The greatest variability in results occurs in sensitivity tests pertaining to fuel escalation rates, discount rates, and base period coal prices. For example, a scenario with high fuel price escalation results in net benefits that have a value of 253 relative to the base case. In other words, the high case provides 253 percent of the base case net benefits. In general, the Susitna plan maintains its positive net benefits over a reasonably wide range of values assigned to the key variables.

A multivariate analysis in the form of probability trees has been undertaken to test the joint effects of varying several assumptions in combination rather than individually. This probabilistic analysis reported in Section 4.8 provides a range of expected net economic benefits and probability distributions that identify the chances of exceeding particular values of net benefits at given levels of confidence.

~~4.8 - Probability Assessment~~

(a) Multivariate Sensitivity Analysis

The feasibility study of the Susitna Hydroelectric Project included an economic analysis based on a comparison of generation system production costs with and without the proposed project using a computerized model of the Railbelt generation system. In order to carry out this analysis, numerous projections and forecasts of future conditions were made. These forecasts of uncertain conditions include future electrical demand, costs, and escalation. In order to address these uncertain conditions, a sensitivity analysis on key factors was carried out. This analysis focused on the variance of each of a number of forecast conditions and determined the impact of variance on the economic feasibility of the project. Each factor was varied singularly with all other variables held constant to determine clearly its importance.

The purpose of this multivariable analysis was to select the most critical and sensitive variables in the economic analysis and to test the economic feasibility of the Susitna project in each possible combination of the selected variables.

While a number of variables were identified and tested in the single variable sensitivity analysis for the Susitna economic feasibility study, the variables which were chosen for the multivariate sensitivity analysis represent the key issues such as load forecasts, capital cost of alternatives, fuel escalation and Susitna capital cost.

The methodology for the multivariate analysis was implemented by constructing probability trees of future conditions for the Alaska Railbelt electrical system, with and without the Susitna project. Each branching of the tree represents three values for a given variable. These were assigned a high, medium, and low value as well as a corresponding probability of occurrence. The three values represent the expected range and midpoint for a given variable. In some cases, the midpoint represents the most likely value which would be expected to occur. End limbs of the probability tree represent scenarios of mixed variable conditions and a probability of occurrence of the scenario.

The OGP5 production cost model was then used to determine the PW (in 1982 dollars) of the long-term cost of the electric generation related to each variable. The PW of the long-term costs for each "with" and "without" Susitna scenario in terms of cumulative probability of occurrence were determined and plotted. Net benefits of the project have also been calculated and analyzed in a probabilistic manner.

Figures D.12 and D.13 present the non-Susitna and Susitna probability trees with resultant long-term costs.

(d) Comparison of Long-term Costs

Figure D.14 presents the two histograms of long-term costs for the "with" and "without" Susitna cases plotted on the same axes. From these plots it is seen that the non-Susitna plan costs could be expected to be significantly less than the Susitna plan costs for about 6 percent of the time, approximately equal to the Susitna costs 16 percent of the time, and significantly greater 78 percent of the time.

A comparison of the expected value of long-term costs of the "with" and "without" Susitna cases yields an expected value net benefit of $1.45 billion. This value represents the difference between the non-Susitna LTC of $8.48 billion and the Susitna LTC of $7.03 billion. These expected net values were calculated by summing the products of each LTC and associated probability as shown on Figures B.16 and B.17, respectively.

(e) Net Benefit Comparison

A second method of comparing the "with" and "without" Susitna probability trees is by making a direct comparison of similar scenarios and calculating the net benefit which applies. As in the case of the individual tree cases, the net benefits were ranked from low to high and plotted against cumulative probability. This graph has been represented as a single line due to the number of points on the curve. It would, however, be most accurately portrayed as a histogram in the manner of Figure D.18. The net benefits vary from a negative $2.92 billion with an associated probability of .0015 to a high of $4.80 billion with an associated probability of .018. The single comparison with the highest probability of occurrence of .108 has a net benefit of $2.09 billion.

Figure D.~~18~~ 15 plots the net benefit with the crossover between the "with" and "without" Susitna costs occurring at about 23 percent. This is consistent with the previous comparison and with the expected value net benefit calculated by this method of $1.45 billion.

f (~~f~~) Sensitivity of Results to Probabilities

In assigning the probabilities of occurrence for each set of variables, a number of subjective assumptions were made. An exception was the Susitna capital cost probability distribution which was supported by a probabilistic risk assessment of construction cost. The probabilities for load forecast of 0.2, 0.6 and 0.2 for the low, medium and high cases, respectively, reflect the analysis by Battelle and the probability of exceedence of approximately 10 percent for the high level of demand.

Capital costs for alternative generation modes estimated in the Battelle study reflect a 0.20, 0.60 and 0.20 distribution, again within a range of a 90 percent chance of exceedence of the low and 10 percent exceedence of the high level.

The single variable to which the results are most sensitive is the rate of real fuel escalation adopted. (This conclusion is supported by the single variable analysis as well.) The distribution of probabilities was 0.25, 0.50 and 0.25 for low, medium and high fuel cost escalation scenarios. A case can be made for the argu- ment that some of the combined events, for example high fuel cost escalation, load and capital cost, are not (as our results assume) independent of each other. High fuel prices, it may be argued, would result in lower load and increased capital cost. It is probable, however, that the greater revenues consequent on higher fuel prices would result in greater economic activity in Alaska, thus increasing demand for energy. This and other considerations led to the conclusion that the results would be relatively insensitive to probable ranges of interdependence.

4.10 ~~4.9~~ - Battelle Railbelt Alternatives Study

The Office of the Governor, State of Alaska, Division of Policy Development and Planning, and the Governor's Policy Review Committee contracted with Battelle Pacific Northwest Laboratories to investigate potential strategies for future electric power development in the Railbelt region of Alaska. This section presents a summary of final results of the Railbelt Electric Power Alternatives Study.

The overall approach taken on this study involved five major tasks or activities that led to the results of the project, a comparative evaluation of electric energy plans for the Railbelt. The five tasks conducted as part of the study evaluated the following aspects of electrical power planning:

- fuel supply and price analysis
- electrical demand forecasts
- generation and conservation alternatives evaluation
- development of electric energy themes or "futures" available to the Railbelt
- systems integration/evaluation of electric energy plans.

Note that while each of the tasks contributed data and information to the final results of the project, they also developed important results that are of interest independently of the final results of this project. Output from the first three tasks contributed directly as input to analysis of the Susitna project presented in this Exhibit. The results of the last two tasks are presented in this subsection.

The first task evaluated the price and availability of fuels that either directly could be used as fuels for electrical generation or indirectly could compete with electricity in end-use applications such as space or water heating.

6 - FINANCING

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6.1 - Forecast Financial Parameters

The financial, economic, and engineering estimates used in the financial analysis are summarized in Table D.[illegible]. The interest rates and forecast rates of inflation (in the Consumer Price Index - CPI) are of special importance. They have been based on the forecast inflation rates and the forecast of interest rates on industrial bonds (Data Resources Inc. 1980) and conform to a range of other authoritative forecasts. To allow for the factors which have brought about a narrowing of the differential between tax exempt and taxable securities, it has been assumed that any tax exempt financing would be at a rate of 80 percent rather than the historical 75 percent or so of the taxable interest rate. This identifies the forecast interest rates in the financing periods from 1985 in successive five-year periods as being on the order of 8.6 percent, 7.8 percent, and 7 percent. The accompanying rate of inflation would be about 7 percent. In view of the uncertainty attaching to such forecasts and in the interest of conservatism, the financial projections which follow have been based upon the assumption of a 10 percent rate of interest for tax-exempt bonds and an ongoing inflation rate of 7 percent.

Numbers will be checked with results of OGP 6 Runs

6.2 - Inflationary Financing Deficit

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The basic financing problem of Susitna is the magnitude of its "inflationary financing deficits." Under inflationary conditions these deficits (early year losses) are an inherent characteristic of almost all debt financed, long life, capital intensive projects (see Figure D.[illegible]). As such, they are entirely compatible (as in the Susitna case) with a project showing a good economic rate of return. However, unless additional state equity is included to meet this "inflationary financing deficit" the project may be unable to proceed without imposing a substantial and possibly unacceptable burden of high early-year costs on consumers.

6.3 - Legislative Status of Alaska Power Authority and Susitna Project

The Alaska Power Authority is a public corporation of the State in the Department of Commerce and Economic Development but with separate and independent legal existence.

The Authority was created with all general powers necessary to finance, construct and operate power production and transmission facilities throughout the State. The Authority is not regulated by the Alaska Public Utilities Commission, but is subject to the Executive Budget Act of the State and must identify projects for development in accordance with the project selection process outlined within Alaska Statutes. The Authority must receive legislative authorization prior to proceeding with the issuance of bonds for the financing of construction of any project which involves the appropriation of State funds or a project which exceeds 1.5 megawatts of installed capacity.

The Alaska State Legislature has specifically addressed the Susitna project in legislation (Statute 44.83.300 Susitna River Hydroelectric Project). The legislation states that the purpose of the project is to generate, transmit and distribute electric power in a manner which will:

(1) Minimize market area electrical power costs;
(2) Minimize adverse environmental and social impacts while enhancing environmental values to the extent possible; and
(3) Safeguard both life and property.

Section 44.83.36 Project Financing states that "the Susitna River Hydroelectric Project shall be financed by general fund appropriations, general obligation bonds, revenue bonds, or other plans of finance as approved by the legislature."

6.4 - Financing Plan

The financing of the Susitna project is expected to be accomplished by a combination of direct State of Alaska appropriations and revenue bonds issued by the Power Authority but carrying the "moral obligation" of the State. On this basis it is expected that project costs for Watana through the end of 1989 will be financed by $1.8 billion (1982 dollars) of state appropriations. Thereafter completion of Watana is expected to be accomplished by issuance of approximately $2.4 billion (1982 dollars) of revenue bonds. The year-by-year expenditures in constant and then current dollars are detailed in Table D.~~[illegible]~~. These annual borrowing amounts do not exceed the Authority's estimated annual debt capacity for the period. 37

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The revenue bonds are expected to be secured by project power sales contracts, other available revenues, and by a Capital Reserve Fund (funded by a State appropriation equal to a maximum annual debt service) and backed by the "moral obligation" of the State of Alaska.

The completion of the Susitna project by the building of Devil Canyon is expected to be financed on the same basis requiring (as detailed in Table D.~~[illegible]~~) the issuance of approximately $2.1 billion of revenue bonds (in 1982 dollars) over the years 1994 to 2002.

Summary financial statements based on the assumption of 7 percent inflation and bond financing at a 10 percent interest rate and other estimates in accordance with the above economic analysis are given in Tables D.~~[illegible]~~ and D.~~[illegible]~~.

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The actual interest rates at which the project will be financed in the 1990s and the related rate of inflation cannot be determined with any certainty at the present time.

A material factor will be securing tax exempt status for the revenue bonds. This issue has been extensively reviewed by the Power Authority's financial advisors and it has been concluded that it would be reasonable to assume that by the operative date the relevant requirements of Section 103 of the IRS code would be met. On this assumption the 7 percent inflation and 10 percent interest rates used in the analysis are consistent with authoritative estimates of Data Resources (U.S. Review July 1982) forecasting a CPI rate of inflation 1982-1991 of approximately 7 percent and interest rates of AA Utility Bonds (non exempt) of 11.43 percent in 1991, dropping to 10.02 percent in 1995.

TABLE D.1: SUMMARY OF COST ESTIMATE (REVISED)

Category	January 1982 Dollars $ X 10^6		
	Watana	Devil Canyon	Total
Production Plant	$ 2,293	$ 1,065	$ 3,358
Transmission Plant	456	105	561
General Plant	5	5	10
Indirect	442	206	648
Total Construction	3,196	1,381	4,577
Overhead Construction	400	173	573
TOTAL PROJECT CONSTRUCTION COST	$ 3,596	$ 1,554	$ 5,150

ECONOMIC ANALYSIS

Escalation

AFDC

TOTAL PROJECT COST

FINANCIAL ANALYSIS

Escalation

AFDC

TOTAL PROJECT COST

TABLE D.6: VARIABLES FOR AFDC COMPUTATIONS (NEW)

Analysis	Effective Interest Rate (x) %	Escalation Rate (y)
Economic	3	0
Financial	10	7

UTILITY	Generating Capacity 1981 MW at 0°F Rating	Predominant Type of Generation	Tax Status Re: IRS Section 103	Purchases Wholesale Electrical Energy	Provides Wholesale Supply	Utility Annual Energy Demand 1980 GWh
IN ANCHORAGE-COOK INLET AREA						
Anchorage Municipal Light and Power	221.6	SCCT	Exempt	•	–	585.8
Chugach Electric Association	395.1	SCCT	Non-Exempt	•	•	941.3
Matanuska Electric Association	0.9	Diesel	Non-Exempt	•	–	268.0
Homer Electric Association	2.6	Diesel	Non-Exempt	•	–	284.8
Seward Electric System	5.5	Diesel	Non-Exempt	•	–	26.4
Alaska Power Administration	30.0	Hydro	Non-Exempt	–	•	–
National Defense	58.8	ST	Non-Exempt	–	–	–
Industrial – Kenai	25.0	SCCT	Non-Exempt	–	–	–
IN FAIRBANKS – TANANA VALLEY						
Fairbanks Municipal Utility System[1]	68.5	ST/Diesel	Exempt	–	–	116.7
Golden Valley Electric Association[1]	221.6	SCCT/Diesel	Non-Exempt	–	–	316.7
University of Alaska	18.6	ST	Non-Exempt	–	–	–
National Defense[1]	46.5	ST	Non-Exempt	–	–	–
IN GLENALLEN/VALDEZ AREA						
Copper Valley Electric Association	19.6	SCCT	Non-Exempt	–	–	37.4
TOTAL	1114.3					2577.1

[1]Pooling Arrangements in Force

TABLE D.12 – RAILBELT UTILITIES PROVIDING MARKET POTENTIAL

PLANT LIST

PLANT No.	NAME OF PLANT	UTILITY	TYPE OF OWNERSHIP
2	Anchorage No. 1	Anchorage Municipal Light and Power	Municipal
3	Anchorage	Anchorage Municipal Light and Power	Municipal
6	Eklutna	Alaska Power Administration	Federal
7	Chena	Fairbanks Municipal Utilities System	Municipal
10	Knik Arm	Chugach Electric Association, Inc.	Cooperative
22	Elmendorf-West	United States Air Force	Federal
23	Fairbanks	Golden Valley Electric Association, Inc.	Cooperative
32	Cooper Lake	Chugach Electric Association, Inc.	Cooperative
34	Elmendorf-East	United States Air Force	Federal
35	Ft. Richardson	United States Army	Federal
36	Ft. Wainright	United States Air Force	Federal
37	Eilson	United States Air Force	Federal
38	Ft. Greeley	United States Army	Federal
47	Bernice Lake	Chugach Electric Association, Inc.	Cooperative
55	International Station	Chugach Electric Association, Inc.	Cooperative
58	Healy	Golden Valley Electric Association, Inc.	Cooperative
59	Beluga	Chugach Electric Association, Inc.	Cooperative
75	Clear AFB	United States Air Force	Federal
80	Collier-Kenai	Collier-Kenai	Municipal
81	Eyak	Cordova Public Utilities	Municipal
82	North Pole	Golden Valley Electric Association, Inc.	Cooperative
83	Valdez	Golden Valley Electric Association, Inc.	Cooperative
84	Glennallen	Golden Valley Electric Association, Inc.	Cooperative

TABLE D.13 – LIST OF GENERATING PLANTS SUPPLYING RAILBELT REGION

TABLE D.~~1~~3: TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM (Revised)

Abbreviations	Railbelt Utility	Installed Capacity[1]
AMLPD	Anchorage Municipal Light & Power Department	221.6
CEA	Chugach Electric Association	395.1
GVEA	Golden Valley Electric Association	221.6
FMUS	Fairbanks Municipal Utility System	68.5
~~CVEA~~	~~Copper Valley Electric Association~~	~~19.8~~
MEA	Matanuska Electric Association	0.9
HEA	Homer Electric Association	2.6
SES	Seward Electric System	5.5
APAd	Alaska Power Administration	30.0
U of A	University of Alaska	18.6
TOTAL		~~[illegible]~~ 964.4[2]

(1) Installed capacity as of 1980 at 0°F
(2) Excludes National Defense installed capacity of 46.5 MW

TABLE D.~~13~~8: GENERATING UNITS WITHIN THE RAILBELT - 1980 (Revised)

Railbelt Utility	Station Name	Unit No.	Unit Type	Installation Year	Heat Rate (Btu/kWh)	Installed Capacity (MW)	Fuel Type	Retirement Year
Anchorage Municipal Light & Power Department (AMLPD)	AMLPD	1	GT	1962	14,000	16.3	NG	1992
	AMLPD	2	GT	1964	14,000	16.3	NG	1994
	AMLPD	3	GT	1968	14,000	18.0	NG	1998
	AMLPD	4	GT	1972	12,000	32.0	NG	2002
	G.M. Sullivan	5,6,7	CC	1979	8,500	139.0	NG	2011
Chugach Electric Association (CEA)	Beluga	1	GT	1968	15,000	16.1	NG	1998
	Beluga	2	GT	1968	15,000	16.1	NG	1998
	Beluga	3	GT	1973	10,000	53.0	NG	2003
	Beluga	5	GT	1975	15,000	58.0	NG	2005
	Beluga	6	GT	1976	15,000	68.0	NG	2012
	Beluga	7	GT	1977	15,000	68.0	NG	2012
	Bernice Lake	1	GT	1963	23,440	8.6	NG	1993
		2	GT	1972	23,440	18.9	NG	2002
		3	GT	1978	23,440	26.4	NG	2008
		4*						
	International Station	1	GT	1964	40,000	14.0	NG	1994
		2	GT	1965	--*	14.0	NG	1995
		3	GT	1970	--*	18.0	NG	2000
	Copper Lake	1	HY	1961	--*	16.0	--	2011
Golden Valley Electric Association (GVEA)	Healy	1	ST	1967	11,808	25.0	Coal	2002
		2	IC	1967	14,000	2.8	Oil	1997
	North Pole	1	GT	1976	13,000	65.0	Oil	1996
		2	GT	1977	13,500	65.0	Oil	1997
	Zehander	1	GT	1971	14,500	18.4	Oil	1991
		2	GT	1972	14,500	17.4	Oil	1992
		3	GT	1975	14,900	3.5	Oil	1995
		4	GT	1975	14,900	3.5	Oil	1995
		5	IC	1965	14,000	3.5	Oil	1995
		6	IC	1965	14,000	3.5	Oil	1995
		7	IC	1965	14,000	3.5	Oil	1995
		8	IC	1965	14,000	3.5	Oil	1995
		9	IC	1965	14,000	3.5	Oil	1995
		10	IC	1965	14,000	3.5	Oil	1995
Fairbanks Municipal Utility System (FMUS)	Chena	1	ST	1954	14,000	5.0	Coal	1989
		2	ST	1952	14,000	2.5	Coal	1987
		3	ST	1952	14,000	1.5	Coal	1987
		4	GT	1963	16,500	7.0	Oil	1993
		5	ST	1970	14,500	21.0	Coal	2005
		6	GT	1976	12,490	23.1	Oil	1997
	FMUS	1	IC	1967	11,000	2.8	Oil	1997
		2	IC	1968	11,000	2.8	Oil	1998
		3	IC	1968	11,000	2.8	Oil	1998

* Bernice Lake #4 24.3 to 2012

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TABLE D.~~14~~ (Continued)

Railbelt Utility	Station Name	Unit No.	Unit Type	Installation Year	Heat Rate (Btu/kWh)	Installed Capacity (MW)	Fuel Type	Retirement Year
Homer Electric Association (HEA)	Homer							
	Kenai	1	IC	1979	15,000	0.9	Oil	2009
	Pt. Graham	1	IC	1971	15,000	0.2	Oil	2001
	Seldovia	1	IC	1952	15,000	0.3	Oil	1982
		2	IC	1964	15,000	0.6	Oil	1994
		3	IC	1970	15,000	0.6	Oil	2000
University of Alaska (U of A)	University	1	ST	1980	12,000	1.5	Coal	2015
	University	2	ST	1980	12,000	1.5	Coal	2015
	University	3	ST	1980	12,000	10.0	Coal	2015
	University	1	IC	1980	10,500	2.8	Oil	2011
	University	2	IC	1980	10,500	2.8	Oil	2011
~~Copper Valley~~ Electric Association (CVEA)	~~CVEA~~	~~1-3~~	~~IC~~	~~1963~~	~~10,500~~	~~1.2~~	~~Oil~~	~~1993~~
	CVEA	4-5	IC	1966	10,500	2.4	Oil	1996
	CVEA	6-7	IC	1976	10,500	5.2	Oil	2006
	CVEA	1-3	IC	1967	10,500	1.8	Oil	1997
	CVEA	4	IC	1972	10,500	1.9	Oil	2002
	CVEA	5	IC	1975	10,500	1.0	Oil	2005
	CVEA	6	IC	1975	10,500	2.6	Oil	2005
	CVEA	7	GT	1976	14,000	3.5	Oil	1996
Matanuska Elec. Association (MEA)	Talkeetna	1	IC	1967	15,000	0.9	Oil	1997
Seward Electric System (SES)	SES	1	IC	1965	15,000	1.5	Oil	1995
		2	IC	1965	15,000	1.5	Oil	1995
		3	IC	1965	15,000	2.5	Oil	1995
Alaska Power Administration (APAd)	Eklutna	-	HY	1955	--	30.0	--	2005
TOTAL						~~984.0~~ 964.4		

Notes:

GT = Gas turbine
CC = Combined cycle
HY = Conventional hydro
IC = Internal combustion
ST = Steam turbine
NG = Natural gas
NA = Not available

*This value judged to be unrealistic for large range planning and therefore is adjusted to 15,000 for generation planning studies. For purposes of generation planning studies, O&M costs and outage rates were assumed equal to those rates given for new plants in Table D.17.

TABLE D. ~~16~~ 15: SCHEDULE OF PLANNED UTILITY ADDITIONS (1980-1988) (Revised)

Utility	Unit	Type	MW	Year	Avg. Energy (GWh)
~~GVEA~~	~~Solomon Gulch~~	~~HY~~	~~12~~	~~1981~~	~~39~~ out
CEA	Bernice Lake #4	GT	26.4	1982	--
AMLPD	AMLPD #8	GT	90.0	198~~2~~3-84	--
CEA	Beluga #6,7,8	CC	42*	1982	--
COE	Bradley Lake	Hydro	90.0	1988	347
APA	Grant Lake	Hydro	7.0	1988	33
TOTAL			267.4		

* New Unit No. 8 will encompass Units 6 and 7, each rated at 68 MW. Total new station capacity will be 178 MW.

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TABLE D.17: SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS/1982$ (Revised)

Parameter	C 200 MW	Combined Cycle 200 MW	Gas Turbine 70 MW	Diesel 10 MW
Heat Rate (Btu/kWh)	10,000	8,000	12,200	11,500
Earliest Availability	1989	1980	1984	1980
O&M Costs				
Fixed O&M ($/yr/kW)	16.83	7.25	2.7	0.55
Variable O&M ($/MWH)	0.6	1.69	4.8	5.38
Outages				
Planned Outages (%)	8	7	3.2	1
Forced Outages (%)	5.7	8	8	5
Construction Period (yrs)	6	2	1	1
Startup Time (yrs)	6	4	4	1
Unit Capital Cost ($/kW)[1]				
Railbelt	-	1,075	627	856
Beluga	2,061	-	-	-
Nenana	2,107	-	-	-
Unit Capital Cost ($/kW)[2]				
Railbelt	2,242	1,107	636	869
Beluga	-	-	-	-
Nenana	2,309 ?	-	-	-
Nenana[3]		-	-	-

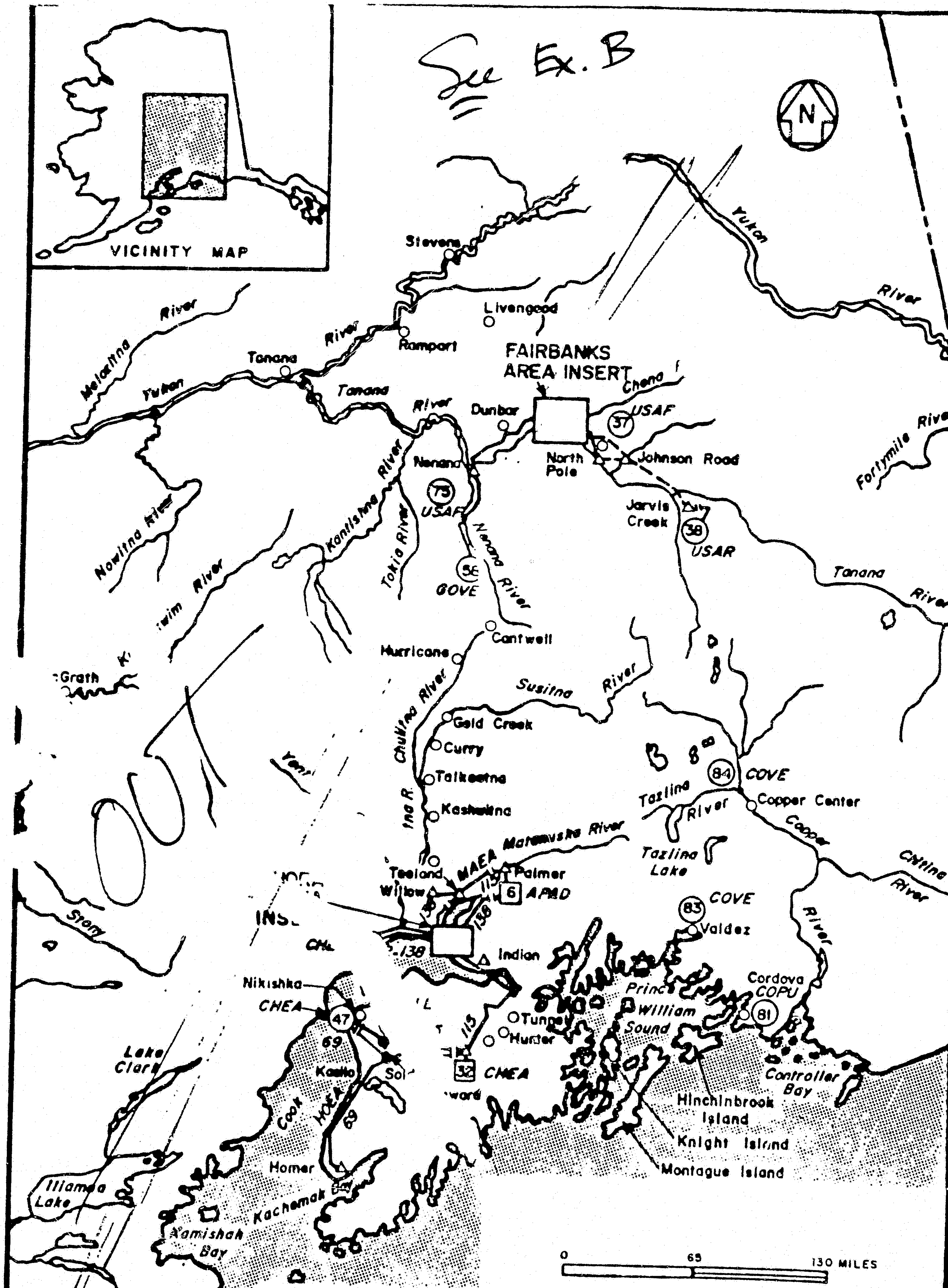
Notes:

(1) As estimated by Battelle/Ebasco without AFDC.
(2) Including IDC at 0 pecent escalation and 3 percent interest, assuming an S-shaped expenditure curve.

(3) Includes the cost of bulk transmission associated with the installation of the first Nenana Coal-fired plant.

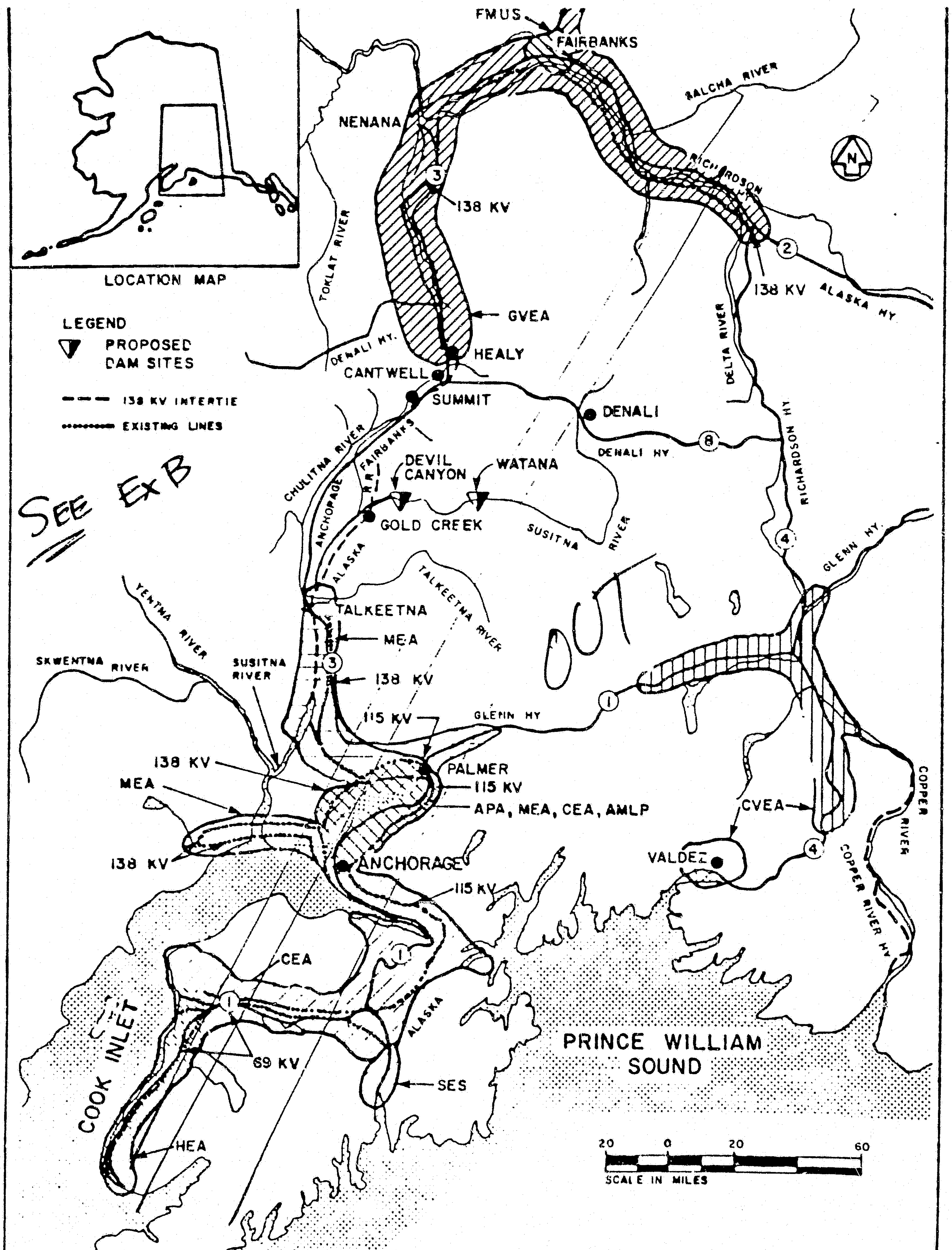
Source: Battelle 1982, Vol. II, IV, XIII, XIII

See Ex. B



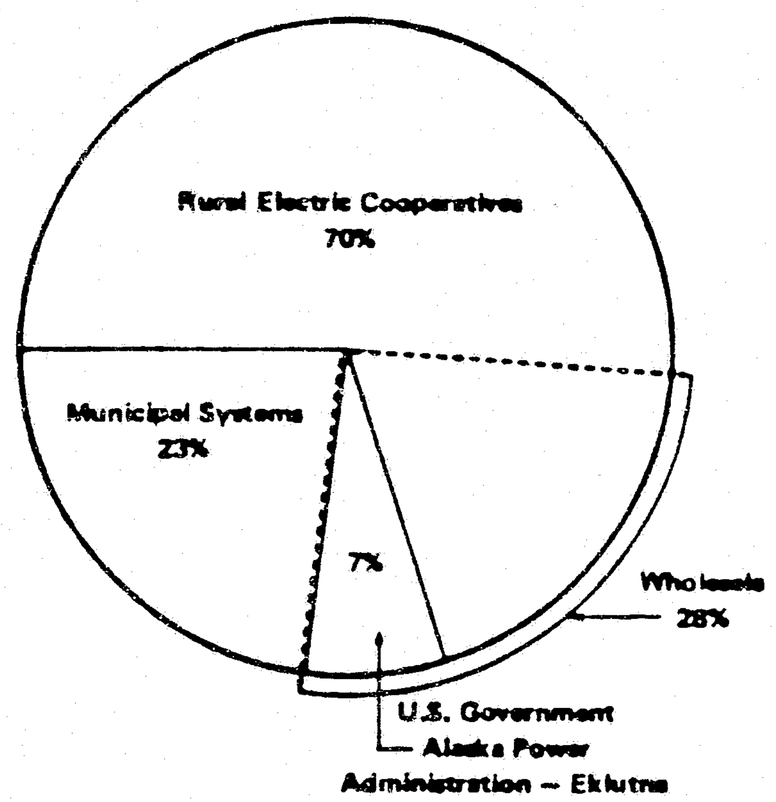
RAILBELT REGION
GENERATING AND TRANSMISSION FACILITIES

FIGURE D.4



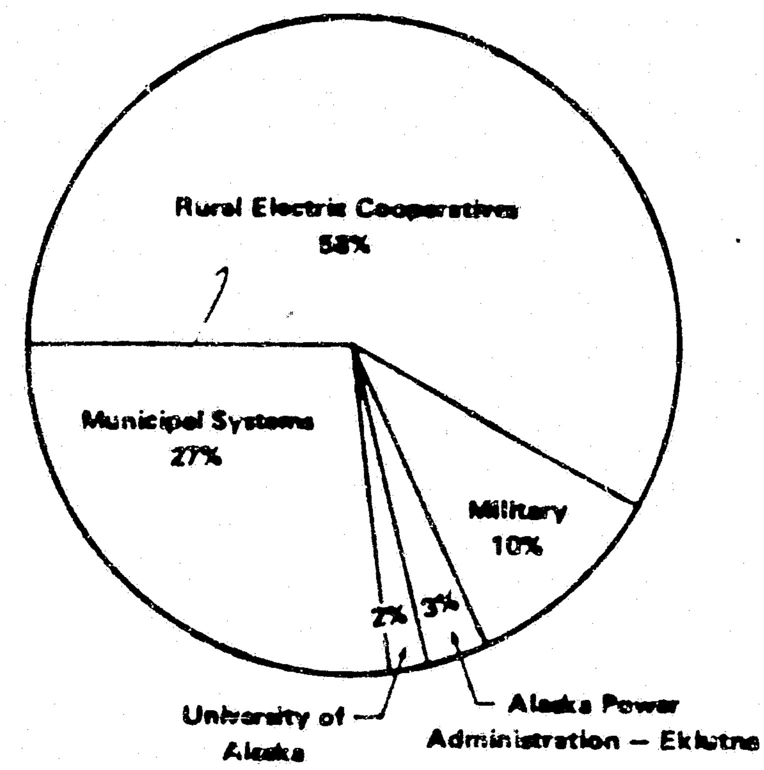
SERVICE AREAS OF RAILBELT UTILITIES

FIGURE D.5



1. Does Not Include Self Supplied Energy from Military Installations and The University of Alaska

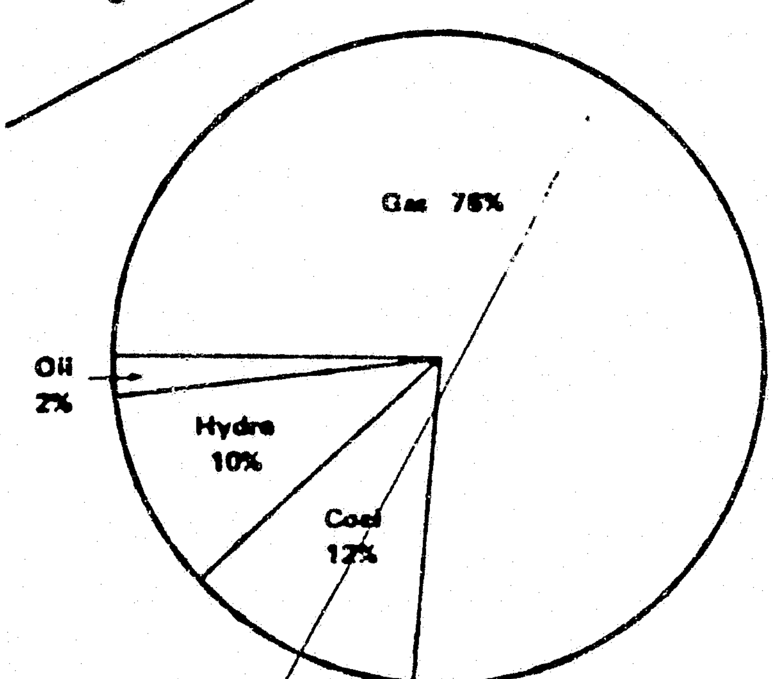
A. ENERGY SUPPLY
(Based on Net Generation 1980)



B. GENERATING FACILITIES
(Based on Nameplate Generating Capacity 1980)

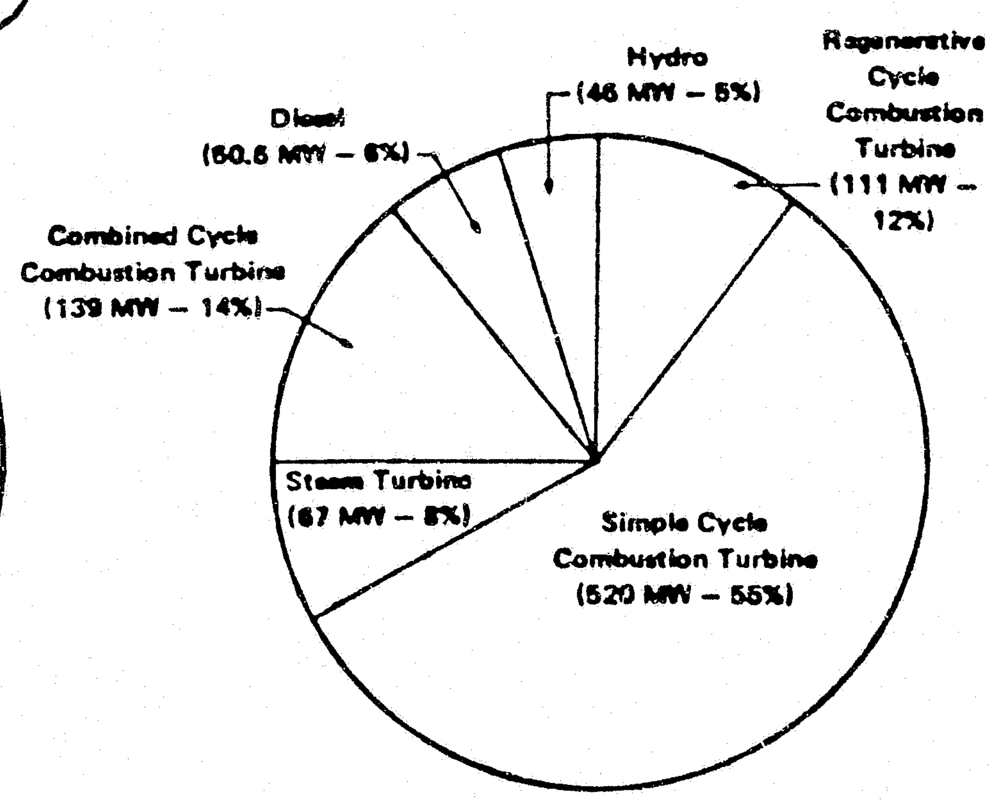
OUT

SEE ExB



1. Does Not Include Generation by Military Installations and The University of Alaska

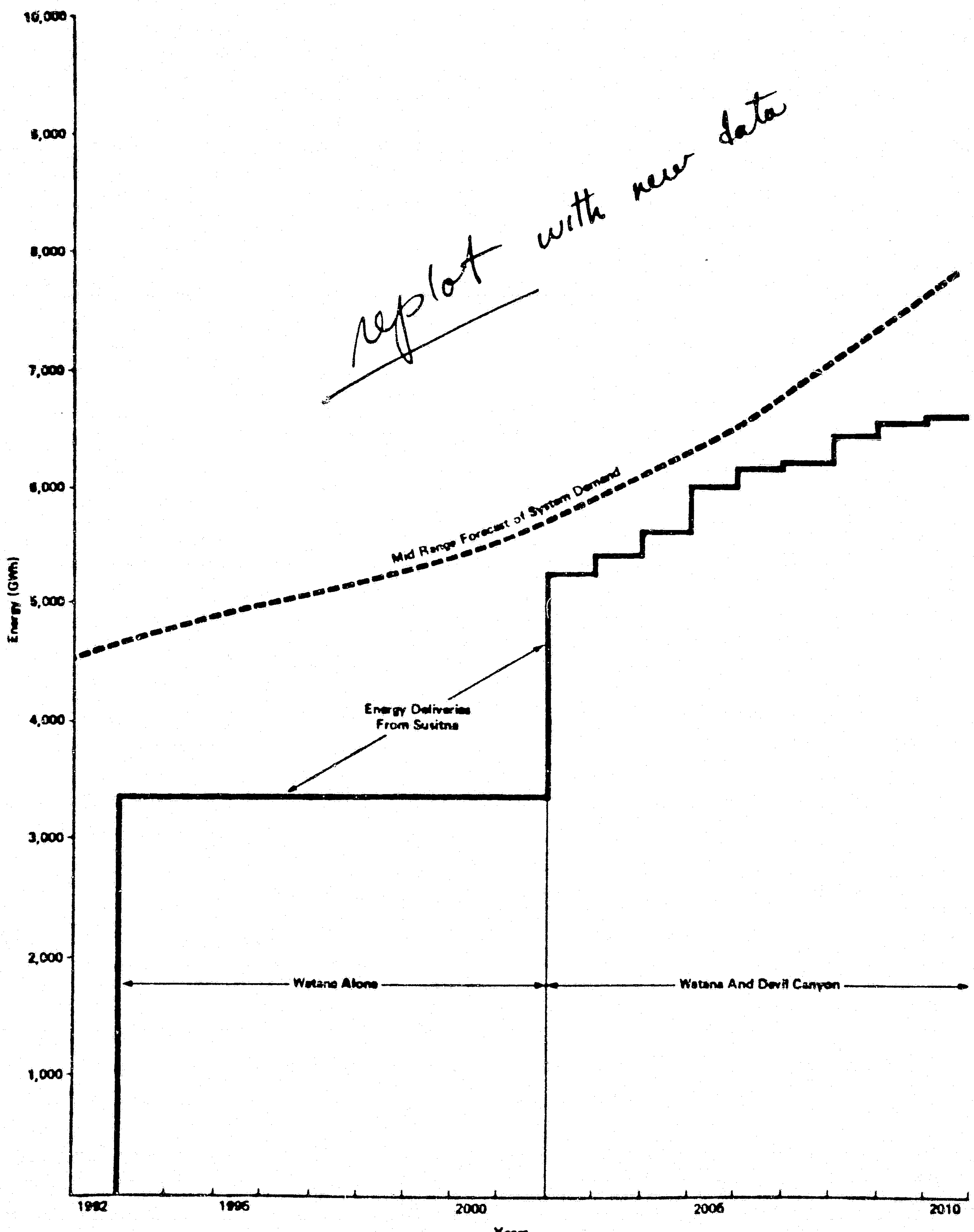
C. NET GENERATION
BY TYPES OF FUEL
(Based on Net Generation 1980)



D. RELATIVE MIX OF
ELECTRICAL GENERATING
TECHNOLOGY

RAILBELT UTILITIES - 1980

FIGURE D.6



4

ENERGY DEMAND AND DELIVERIES FROM SUSITNA

FIGURE D

TABLE 0.23: REAL (INFLATION-ADJUSTED) ANNUAL GROWTH IN OIL PRICES

	Growth Rates (Percent)			
	1982-2000	2000-2040	2011-2040	Probability
Low Case	0	0	0	0.3
Medium Case (most likely)	2.0	1.0	0	0.5
High Case	4.0	2.0	0	0.2

Base Period
(January 1982)

Price of No. 2 Fuel Oil - $6.50/MMBtu.

cut

TABLE D.24: SUMMARY OF MAJOR FORECASTS OF OIL PRICE TRENDS

SOURCE	DATE OF FORECAST	FORECAST TREND (percent)
Data Resources Inc.	Summer 1982	+2.8
International Energy Agency	Spring 1982	
- Low		-0.5
- High		+2.0
US Energy Information Administration	Spring 1982	above +3
Energy Mines and Resources Canada	Summer 1982	+1.7
Ontario Hydro	Spring 1982	+1.8
Energy Modeling Forum, World Oil Report*	February 1982	
- average of 10 models		+3.4
- range of 10 models		+1.9
Dr. F. Fesharaki, Resource Systems Institute, East-West Centre, Honolulu	Spring 1982	+1.7

* The 10 models are: Gately-Kyle-Fischer (New York Univ.), IEES - OMS (U.S. Dept. of Energy), IPE (M.I.T.), Salant-ICF (U.S. Federal Trade Commission and ICF, Inc.), ETA-MACRO (Stamford Univ.), WOIL (U.S. Dept. of Energy and Environmental Analysis, Inc.), Kennedy-Nehring (Univ. of Texas and the Rand Corp.), OILTANK (Chr. Michelsen Institute), Opecoromics (BP Co. Ltd.), OILMAR (Energy and Power Subcommittee, U.S. House of Representatives).

TABLE D.25: DOMESTIC MARKET PRICES AND EXPORT OPPORTUNITY VALUES OF NATURAL GAS

	Domestic Market Price[1]			Export Opportunity Value		
	Low	Medium	High	Low	Medium	High
Probability of Occurrence	N.A.	N.A.	N.A.	27%	46%	27%
Base Period Value	-	$3.03/MMBtu[3]	-	-	$4.65/MMBtu[2]	-
Real Escalation CIF Price, Japan						
1982 - 2000	-	N.A.	-	0%	2%	4%
2000 - 2040	-		-	0%	1%	2%
Real Escalation Alaska Price[4]						
1993 - 2000	0%	2.5%	5.0%	0%	2.7%	5.2%
2000 - 2040	0%	2.0%	2.0%	0%	1.2%	2.2%

1 Generation planning analysis used domestic market prices with zero escalation beyond 2010.

2 Based on CIF price in Japan ($6.75) less estimated cost of liquefaction and shipping ($2.10).

3 Price estimated for 1993, after adjustment of prices due to expiration of long term contracts.

4 Alaska opportunity value escalates more rapidly than CIF prices as liquefaction and shipping costs are estimated to remain constant in real terms.

out

$ 2.38 1983 MMBtu

TABLE D.26: SUMMARY OF COAL OPPORTUNITY VALUES

	Base Period (Jan. 1982) Value ($/MMBtu)	Annual Real Growth Rate 1980 - 2000 (%)	Annual Real Growth Rate 2000 - 2040 (%)	Probability of Occurrence %
Base Case				
Battelle Base Period CIF Price				
Medium Scenario				
- CIF Japan	1.95	2.0	1.0	49
- FOB Beluga	1.43	2.6	1.2	49
- Nenana	1.75	2.3	1.1	49
Low Scenario				
- CIF Japan	1.95	0	0	24
- FOB Beluga	1.43	0	0	24
- Nenana	1.75	0.1	0.1	24
High Scenario				
- CIF Japan	1.95	4.0	2.0	27
- FOB Beluga	1.43	5.0	2.2	27
- Nenana	1.75	4.5	1.9	27
Sensitivity Case				
Updated Base Period CIF Price[1]				
Medium Scenario				
- CIF Japan	2.66	2.0	1.0	49
- FOB Beluga	2.08	2.5	1.2	49
- FOB Nenana	1.74	2.7	1.2	49
Low Scenario				
- CIF Japan	2.66	0	0	24
- FOB Beluga	2.08	0	0	24
- FOB Nenana	1.74	-0.2	-0.1	24
High Scenario				
- CIF Japan	2.66	4.0	2.0	27
- FOB Beluga	2.08	4.8	2.2	27
- FOB Nenana	1.74	5.3	2.3	27

1 Assuming a 10 percent discount for Alaskan coal due to quality differentials, and export potential for Healy coal.

out

TABLE D.27: SUMMARY OF FUEL PRICES USED IN THE OGP5 PROBABILITY TREE ANALYSIS

	Fuel Price Scenario		
	Low	Medium	High
Probability of occurrence	25%	50%	25%
Base period January 1982 prices			
(1982$/MMBtu)			
Fuel Oil	6.50	6.50	6.50
Natural Gas	3.00	3.00	3.00
Coal			
- Beluga	1.43	1.43	1.43
- Nenana	1.75	1.75	1.75
Real escalation rates per year (percent)			
Fuel Oil			
- 1982 - 2000	0	2.0	4.0
- 2000 - 2010	0	2.0	2.0
- 2011 - 2040	0	0	0
Natural Gas			
- 1982 - 2000	0	2.5	5.0
- 2000 - 2010	0	2.0	2.0
- 2011 - 2040	0	0	0
Beluga Coal			
- 1982 - 2000	0	2.6	5.0
- 2000 - 2010	0	1.2	2.2
- 2011 - 2040	0	0	0
Nenana Coal			
- 1982 - 2000	0.1	2.3	4.5
- 2000 - 2010	0.1	1.1	1.9
- 2011 - 2040	0	0	0

out

22

TABLE D.~~26~~: ECONOMIC ANALYSIS
SUSITNA PROJECT - BASE PLAN (Revised)

Plan	Components	1993-~~2010~~ 2020	~~2010~~ 2020	Estimated ~~2011~~ 2021-2051	1993-2051
		1982 Present Worth of System Costs $ x 10^6			
Non-Susitna	600 MW Coal-Beluga	3,213	491	5,025	8,258
	200 MW Coal-Nenana				
	630 MW GT				
Susitna	680 MW Watana	3,119	585	3,943	7,062
	600 MW Devil Canyon				
	180 MW GT				-
Net Economic Benefit of Susitna Plan		-	-	-	1,176

2

to be revised with OGP6 production runs.

25

TABLE D.~~25~~: SUMMARY OF LOAD FORECASTS
USED FOR SENSITIVITY ANALYSIS

	Medium		Low		High	
	MW	GWh	MW	GWh	MW	GWh
1990	892	4,456	802	3,999	1,098	5,703
2000	1,084	5,469	921	4,641	1,439	7,457
2010	1,537	7,791	1,245	6,303	2,165	11,435

TABLE D.23: FORECASTS OF ELECTRIC POWER DEMAND (NEW)

Year	SCA Base MW	SCA Base GWh	SCA NSD MW	SCA NSD GWh	+2 Percent Escalation MW	+2 Percent Escalation GWh	0 Percent Escalation MW	0 Percent Escalation GWh	-1 Percent Escalation MW	-1 Percent Escalation GWh	-2 Percent Escalation MW	-2 Percent Escalation GWh
1990												
2000												
2010												
2020												

TABLE D.24: ELECTRIC POWER DEMAND SESIT~~WITU~~IVITY ANALYSIS (NEW)

		1982 Present Worth of System Costs $\$ \times 10^6$			
Plan	~~Component~~	1993-2020	2020	Estimated 2021-2051	1993-2051
Non-Susitna SCA Base					
Susitna SCA Base					
Non-Susitna SCA NSD					
Susitna SCA NSD					
etc.					

EXHIBIT B

SECTIONS 5.1

5.2

5.3

5.4.

5.5

5.6

APP B 2

6 JUNE 1983

6/06/83

5 - STATEMENT OF POWER NEEDS AND UTILIZATION

5.1 - Introduction

There are three primary objectives of the power market forecasts: first, to provide estimates of the power needs in the Railbelt system and region under various world price of oil assumptions; second, to present data which characterizes the electric loads as well as measures the effect of conservation and energy prices on those electric demands; and third, to provide required information for the economic and financial evaluations associated with the Susitna Hydroelectric Project contained in Exhibit D.

In order to achieve these objectives, the forecasts are presented on an aggregate as well as on a disaggregated basis from 1983 until 2010. Total energy demand and peak load requirement for the Railbelt region are provided each year over the period of reference. Also, the electric forecasts are shown for the load centers, by sector, and by end-use depending upon the availability of data. Because of the important role that world oil prices plays in the Alaskan economy, different electric demand forecasts are developed to cover a range of expected world price of oil projections.

Section 5.2 describes the electric power system in the Railbelt, including utility load characteristics and conservation and rate structures. Electric power load forecasts and the methodological bases for those forecasts are presented in Sections 5.3 and 5.4. Section 5.3 summarizes the four computer-based models that were utilized in preparing the economic and electric power load forecasts and the generation expansion plan for meeting laods. Section 5.4 presents the forecasts themselves and the key variables involved in producing the forecasts. A key part of section 5.4 is the summary of the base case electric power load forecast that serves as the principal basis for generation planning and project economic and financial analysis. The base case was selected from among several cases each of which corresponds to a set of projected world petroleum prices.

Section 5.5 provides a summary of the power demand forecasts, including a discussion of previous Railbelt forecasts; the impact of world oil prices on power market forecasts, and the sensitivity of the forecasts to key factors other than world oil prices. Section 5.6 summarizes the planned utilization of the Susitna Hydroelecttric Project's power.

Three important reference documents provide information in support of the forecasts. Appendix B-2, Fuels Pricing Studies, presents the methods and results of studies relating to alternative energy sources in the Railbelt, including natural gas, fuel oil, and coal. Appendix B-3, Man in the Arctic Program (MAP) Model Technical Documentation Report, provides a complete explanation of the economic forecasting model used in developing load forecasts for the Railbelt. Appendix B-4, Railbelt Electricity Demand (RED) Model Documentation, provides similar information for the load forecasting model.

5.2 - SYSTEM DESCRIPTION

In this section, a comprehensive description of the Railbelt electric power system is presented. The system description is covered in three parts. The first part describes the interconnected Railbelt market by characterizing electric utility and other sources of power generation. The characteristics of utility electric loads and conservative programs are discussed in the second part. Finally, historical data covering Railbelt electric demands and State and Railbelt regional economic factors are presented to indicate trends and changes that have occurred in the past.

5.2.1 The Interconnected Railbelt Market

The Railbelt region, shown in Figure 1, contains two electrical load centers: the Anchorage-Cook Inlet Area and the Fairbanks-Tanana Valley area. These two load centers comprise the inter- connected Railbelt market.

At the present time, however, the two major load centers operate independently of each other. The existing transmission system between Anchorage and Willow consists of a network of 115 kV and 138 kV line with interconnection to Palmer. Fairbanks is primarily served by a 138 kV line from the 28 MW coal-fired plant at Healy. Communities between Willow and Healy are served by local distribution. Figure 2 illustrates the existing transmission system in the Railbelt region.

5.2.1.1 Characteristics of Electric Utility Systems

Anchorage-Cook Inlet Area

The Anchorage-Cook Inlet area has three rural electric cooperative associations (REAs), two municipal utilities, a Federal Power Administration, and two military installations. These systems are listed below:

Municipal Utilities

Anchorage Municipal Light and Power (ML&P)
Seward Electric System (SES)

Rural Electric

Chugach Electric Association, Inc. (CEA)

Homer Electric Association, Inc. (HEA)

Matanuska Electric Association, Inc. (MEA)

U.S. Government

Alaska Power Administration (APAD)

Elmendorf AFB - Military

Fort Richardson - Military

The Alaska Power Authority (APA) will be a source of electric power generation in the next few years and should be considered as one of the utilities servicing the Anchorage-Cook Inlet area. All of these organizations, with the exception of MEA and APA have electrical generating facilities. MEA buys its power from the Chugach Electric Association, Inc. HEA and SES have relatively small generating facilities that are used for standby operation only. They also purchase their power during normal operations from the Chugach Electric Association, Inc.

In 1981, the level of installed capacity accounted for by the industrial firms in the Cook Inlet Anchorage area was about 114.6 MW. The industrial firms in this area produced about 373.5 GWH in 1981. The major industrial sources of self generation are HEA's service area. The main industrial firms with operations in Kenai are listed below:

are briefly described in conjunction with relevant customer and energy sales data for 1982.

Municipal Light and Power (ML&P) Service Area

The service area of ML&P includes most areas within the City of Anchorage except for some sections which are served by CEA. The northern boundary of ML&P's primary service area is indicated by the Port of Anchorage and Elmendorf A.F.B. The eastern boundary is roughly determined by Boniface Parkway extending down to Tudor Road on the south end of the City. Tudor Road, between Boniface Parkway and Arctic Boulevard, traces out approximately the southern boundary. Finally, the western boundary of the service area is denoted by Arctic Blvd., until it connects with Northern Lights Blvd., continuing along the Alaska Railroad route towards Westchester Lake and Knik Arm. Knik Arm forms the northwest boundary. Because ML&P and CEA are in negotiations concerning an interim interconnection agreement, slight changes in certain portions of ML&P's service area may take place.

Also, ML&P serves a separate land area which contains the Anchorage International Airport. ML&P has proposed that this area be served by CEA in the future. ML&P provides electrical energy to Elmendorf AFB and Fort Richardson on a non-firm basis.

Municipal Light and Power (ML&P) Customers and Sales

ML&P provides service for mainly residential and commercial customers. Two other customer classes are street lighting and sales for resale. The number of customers and associated sales for each customer class in 1982 are listed below:

Customer Class	Number	Energy Sales (MWH)
Residential	14,745	129,010
Commercial	3,229	474,344
Street Lighting	---	7,663
Total	17,975	611,017

The above list denotes that residential customers are over 4.5 times greater than the number of commercial customers. However, residential sales represent slightly over one fourth of total commercial sales in 1982.

Chugach Electric Association, Inc. (CEA) Service Area

The service area of CEA includes certain urban and suburban sections of the Anchorage area which are not covered in ML&P's service area. In addition to customers served in the Anchorage area, CEA serves customers at Kenai Lake, Moose Pass, Whittier, Beluga, and Hope. These areas can be located in Figure 2.

Chugach Electric Association, Inc. (CEA) Customers and Sales

CEA serves retail customers as well as wholesale customers - HEA, MEA and SES. A list of the average number of customers and energy sales by class of service for 1982 is presented below:

Class of Service	Number	Energy Sales (MWH)
Residential Sales	46,560	546,736
Commercial & Industrial (50 kVA or less)	4,519	161,290
Commercial & Industrial (over 50 kVA)	359	214,679
Public St. & Hwy. Lighting	26	5,216
Sales for Resale	3	702,357
Total	51,467	1,630,278

It is evident from the above list that the residential sales class has the greatest number of customers and accounts for most of the energy sales to ultimate consumers. CEA had over 51 thousand customers in 1982 with total sales esceeding 1,630 GWH. Sales for resale represent 43 percent of total sales.

Other Utility Service Areas

In the Anchorage-Cook Inlet area there are three other electric utilities with separate sevice areas: (1) Seward Electric System (SES); (2) Homer Electric Association, Inc. (HEA); and (3) Matanuska Electric Association, Inc. (MEA). The U.S. government sources of generation include those of the Alaska Power Administration, Fort Richardson, and Elmendorf Air Force Base.

Chugach Electric Association, Inc. provides firm power to SES, MEA, and HEA, thus supplying their total system requirements. In 1982, HEA, MEA, and SES purchased about 347, 326, and 306 WH respectively from CEA. Homer Electric Association serves the City of Homer and other customers on the Kenai peninsula. SES serves ultimate consumers in the City of Seward and MEA has a service area encompassing the Matanuska Valley and related areas. These areas are depicted in Figure 2.

The Alaska Power Administration provides firm power to CEA and ML&P. Fort Richardson and Elmendorf AFB has the capacity to satisfy their electrical requirements which were approximately 70 and 87 GWH respectively in 1982. However, both bases have non- irm power agreements with ML&P. Fort Richardson has recently entered into a new contract with ML&P to purchase about 30 GW" on an interruptible basis.

Fairbanks-Tanana Valley Area

The Fairbanks-Tanana Valley area is currently served by one REA cooperative, one municipal utility, a university generation system, and three military installations. These sources are identified in the list below:

Municipal and Non-Government

Fairbanks Municipal Utilities System (FMUS)
Golden Valley Electric Association, Inc. (GVEA)
University of Alaska, Fairbanks

U.S. Government

Eielson AFB - Military

Fort Greeley - Military

Fort Wainwright - Military

The industrial sector had approximately 33.4 MW of installed capacity in 1981 with nearly 60 GWH of net generation.

Fairbanks Municipal Utilities System (FMUS) Service Area

The service area of FMUS encompasses the land area approximately bounded by the city limits of Fairbanks. FMUS serves all of the electric loads within the city limits except for the Aurora and Hamilton Acres subdivisions and an area south of 23rd Avenue. These exceptions are principally residential areas annexed by the City of Fairbanks but served by Golden Valley Electric Association. The Chena River flows through the northern part of the service area with Fort Wainwright Military Reservation providing a border on the east. The downtown business district lies in the northeast corner of the FMUS service area along the south bank of the Chena River. There is an industrial area which is contained in part within the City of Fairbanks. The north bank of the Chena River provides the southern boundary of this industrial area.

Fairbanks Municipal Utilities System (FMUS) Customers and Sales

FMUS serves residential, commercial and government customers. In addition, FMUS provides power to Golden Valley Electric Association for resale. The following list provides the number of customers served by FMUS in 1982 and sales for each associated customer category:

Customer Class	Number	Energy Sales (MWH)
Residential	4663	27,758
Commercial	1050	68,695
Other Government	144	27,923
Street Lighting	--	4,911
GVEA and Other Utilities	1	33,479
Total	5858	162,766

The commercial class of customers are significant in number but more importantly in terms of total sales of energy. The residential and government sectors had about the same level of energy salesin 1982. The second largest category of energy sales is accounted for by sales to GVEA for resale.

Golden Valley Electric Association (GVEA) Service Area

GVEA is a "full service" rural electric cooperative responsible for generation of power as well as distribution and sales. GVEA serves some residential areas within the City of Fairbanks.

Golden Electric Association, Inc. (GVEA) Customers and Sales

In 1982, the average number of customers receiving service by class of service and the cumulative energy sales for GVEA are as folows:

Class of Service	Number	Energy Sales (MWH)
Residential	16,176	150,487
Commercial & Industrial (50 kVA or less)	1,859	43,195
Commercial & Industrial (over 50 kVA)	233	129,394
Public St. & Hwy. Lighting	9	328

Union Oil of California

Phillips Petroleum Company

Chevron U.S.A., Inc.

Tesoro-Alaskan Petroleum Corp.

Other industrial sources having offices in Anchorage include the following:

Shell Oil Company

Cook Inlet Pipeline Company

Alyeska Pipeline Service Company

ARCO Alaska, Inc.

Amoco Production Company

Marathon Oil Company

Sohio Alaska Petroleum Company

The service area and customers served by the two main utilities servicing the Anchorage-Cook Inlet area are discussed in the following paragraphs. The service areas for the remaining sources of existing power supply

Residential customers represent GVEA's most important service class in terms of numbers and total annual sales in 1982. Residential customers account for 88 percent of total customers and 45 percent of total energy sales. Large commercial and industrial customers (over 50 kVA) lines is GVEA's second largest consumer of electricity.

Other Utility Service Areas

The remaining service areas are comprised of the University of Alaska at Fairbanks, Fort Wainwright, Fort Greeley and Eielson AFB. With the exception of Fort Greeley, these sources generate their own power requirements. At the present time, Fort Wainwright supplies all of Fort Greeley's electricity needs by having GVEA whell the power on their transmission lines.

5.2.1.2 The Existing Electric Supply Situation

The purpose of this subsection is to describe the current electric supply situation. Because electricity is a form of energy which must compete with alternative fuels in the market place, a brief discussion of the demand and supply for energy in toto is provided to provide an overall setting. The electric energy demands experienced by Railbelt utilities are examined in detail in Section 5.2(c).

Total Energy Demand and Supply

The State of Alaska is a major consumer of energy resources. For example, in 1981, Alaska's energy input was about 543 billion Btus. The largest share of the input can be explained by crude oil input to refineries (44%) followed by natural gas (37%) and imported petroleum products (15%). Coal, hydro, and wood resourcce inputs accounted for the residual 4 percent of total energy input.

Table 3 represents the 1981 energy consumption for Alaska and the Railbelt. The total energy consumption for the Railbelt area was 236,000 Billion Btus (BBtus) in 1981. In 1981, Railbelt per capita consumption was about 752 Btus, which is approximtely 5 percent greater than the average Alaskan per capita consumption.

Table 3

TOTAL 1981 ENERGY CONSUMPTION
(Billion Btus - BBtus)

Sector	Alaska (BBtus)	Alaska (%)	Railbelt (BBtus)	Railbelt (%)
Transportation	114,672	38	88,715	38
Industrial	64,823	21	44,699	19
Utility	46,344	15	40,115	17
Military	25,847	9	25,847	11
Residential	26,571	9	19,434	8
Commercial/Public	11,913	4	10,658	5
Off-highway	13,069	4	6,430	3
Total	303,239	100	235,929	100

The Railbelt region accounts for almost 78 percent of the total energy consumption in the State of Alaska. In 1981, the Bush, North Slope and Southeast accounted for the remaining 10, 4 and 8 percents respectively. The transportation sector is an energy intensive sector as denoted by the high percentage of total energy consumption shown in Table 3. Besides transportation, the industrial and utility sectors are major consumer sectors of energy.

[a]Does not include electricity consumption. The total electricity consumption is reported in the utility sector.

Source: 1983 Long Term Energy Plan (Working Draft), Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska. 1983 Figure II-9 p. 11-14.

Table 4 provides a breakdown of energy consumption by fuel type for various sectors. The dependence of transportation sector on fuel oil is denoted by figures in Table 4. Moreover, this sector far exceeds any other sector in terms of the quality of fuel oil consumed. The residential sector's fuel oil consumption exceeds 40 percent of total fuel consumption. In the transporation, industrial, military, and residential sectors, fuel oil accounts for over 25 percent of the total fuel consumed in each sector.

Natural gas represents the next most important fuel source. In the industrial, utility, and commercial public sectors, natural gas consumption accounts for over 50 percent of each sector's total consumption. Natural gas consumption in the residential sector is sightly less than that of fuel oil.

Other primary fuels like coal and wood are of secondary importance. Coal is of some significance in the utility and national defense industries; wood based fuels are similarly of some consequence in the residential sector.

TABLE 4

Railbelt 1981 Energy Consumption By
Fuel Type for Each Sector
(Billions Btus)

Sector/Fuel Type	Energy Consumption (BBtus)	Percent (%)
Transportation		
Fuel Oil	88,649	99.9
Coal	66	0.1
Total	88,715	100.0
Industrial		
Fuel Oil	13,264	28.3
Natural Gas	31,435	67.1
Electricity	2,130	4.6
Total	46,829	100.0
Utility		
Fuel Oil	2,152	5.9
Natural Gas	29,652	73.9
Coal	5,407	13.5
Hydro	2,904	7.2
Total	40,115	100.0
Military		
Fuel Oil	15,364	55.8
Natural Gas	4,590	16.7
Coal	5,893	21.4
Electricity	2,904	7.2
Total	40,115	100.0
Residential		
Fuel Oil	9,647	41.6
Natural Gas	8,109	35.0
Coal	140	0.6
Wood	1,561	6.7
Electricity	3,745	16.1
Total	23,202	100.0
Commercial/Public		
Fuel Oil	2,256	15.6
Natural Gas	7,333	50.5
Coal	1,069	7.4
Electricity	3,842	26.5
	14,500	100.0

Electricity consumption is included in the total for the utility sector.

Source: Department of Commerce and Economic Development 1983. (Working Draft 1983 Long Term Energy Plan.) Appendix S, Table S-2.

Electric Energy Supply

In the following paragraphs, the existing generating facilities and planned additions for each load center are presented and briefly discussed.

Anchorage-Cook Inlet Acea

Table 5 presents the total generating capacity of the utilities and the two military installations by type of units. A more detailed description of each unit is presented in Appendix I.

The Anchorage-Cook Inlet area is almost entirely dependent on natural gas to generate electricity. About 84.5 percent of the total capacity is provided by gas-fired units. The remaining are coal-fired units (8 percent), hydroelectric units (5.5 percent), and diesel units (2 percent).

Fairbanks-Tanana Valley Area

Table 7 presents the total generating capacity of the utilities and of thre three military installations by type of units. A more detailed description of each unit is presented in Appendix I.

Table 7
INSTALLED CAPACITY OF THE FAIRBANKS-TANANA VALLEY AREA
(1982 - MW)

Utilit es

Fairba
Util y
Golden a
Asso
Univer
Alas

Subtot

Militar

Eielson F
Fort Gr l
Fort Wa

Subtota

Total

Source: Ba
Generati
Region

Table 5

Utilities	Comb Cycle	Diesel	Hydro	Simple Cycle	Steam Turbine	Total
Alaska Power Administration	0	0	30.0	0	0	30.0
Anchorage Municipal Light and Power	33.3	0	0	240.0	0	273.0
Chugach Electric Association	178.0	0	16.0	143.0	14.5	462.
Homer Electric Association	0	1.5	0	0	0	1.
Seward Electric Association	0	5.5	0	0	0	5.
Subtotal	211.0	7.0	46.0	383.0	14.5	772.
Military Installations						
Elmendorf AFB	0	2.1	0	0	31.5	33.
Fort Richardson	0	7.2	0	0	18.0	25.
Subtotal	0	9.3	0	0	49.5	58
Total	211.0	16.3	46.0	383.0	64.0	831

a/ Total includes 111 MW Regenerated Cycle Combustion Turbine U
(CEA).

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities And Planned Addition for the Railbelt Region of Alaska, Volume VI, September, 1982.

Table 5

Utilities	Comb Cycle	Diesel	Hydro	Simple Cycle	Steam Turbine	Total
Alaska Power Administration	0	0	30.0	0	0	30.0
Anchorage Municipal Light and Power	33.3	0	0	240.0	0	273.0
Chugach Electric Association	178.0	0	16.0	143.0	14.5	462.5[a/]
Homer Electric Association	0	1.5	0	0	0	1.5
Seward Electric Association	0	5.5	0	0	0	5.5
Subtotal	211.0	7.0	46.0	383.0	14.5	772.5[a/]
Military Installations						
Elmendorf AFB	0	2.1	0	0	31.5	33.6
Fort Richardson	0	7.2	0	0	18.0	25.2
Subtotal	0	9.3	0	0	49.5	58.8
Total	211.0	16.3	46.0	383.0	64.0	831.3[a/]

[a/] Total includes 111 MW Regenerated Cycle Combustion Turbine Untis (CEA).

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities And Planned Addition [illegible] the Railbelt Region of Alaska, Volume VI, September, 1982.

Table 7
INSTALLED CAPACITY OF THE FAIRBANKS-TANANA VALLEY AREA
(1982 - MW)

Utilities	Comb Cycle	Diesel	Hydro	Simple Cycle	Steam Turbine	Total
Fairbanks Municipal Utility System	0	8.3	0	28.3	29.0	65.6
Golden Valley Electric Association	0	23.7	0	170.8	25.0	219.5
University of Alaska	0	5.5	0	0	13.0	18 5
Subtotal	211.0	7.0	46.0	383.0	14.5	772.5
Military Installations						
Eielson AFB	0	0	0	0	8.7	8.7
Fort Greeley	0	5.5	0	0	0	5.5
Fort Wainwright	0	0	0	0	20.0	20.0
Subtotal	0	5.5	0	0	28.7	34.2
Total	0	43.0	0	199.1	95.7	337.8

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities And Planned Addition for the Railbelt Region of Alaska, Volume VI, September 1982.

The Fairbanks-Tanana Valley depends heavily on oil-fired combustion turbines (59 percent), and coal steam turbine (26 percent). The remaining capacity is provided by diesel units. The proposed transmission intertie between Anchorage and Fairbanks will allow Fairbanks utilities to purchase relatively inexpensive power (generated by natural gas) from Anchorage. It will also allow both load centers to take advantage of the additional peaking capacity available in the Fairbanks area.

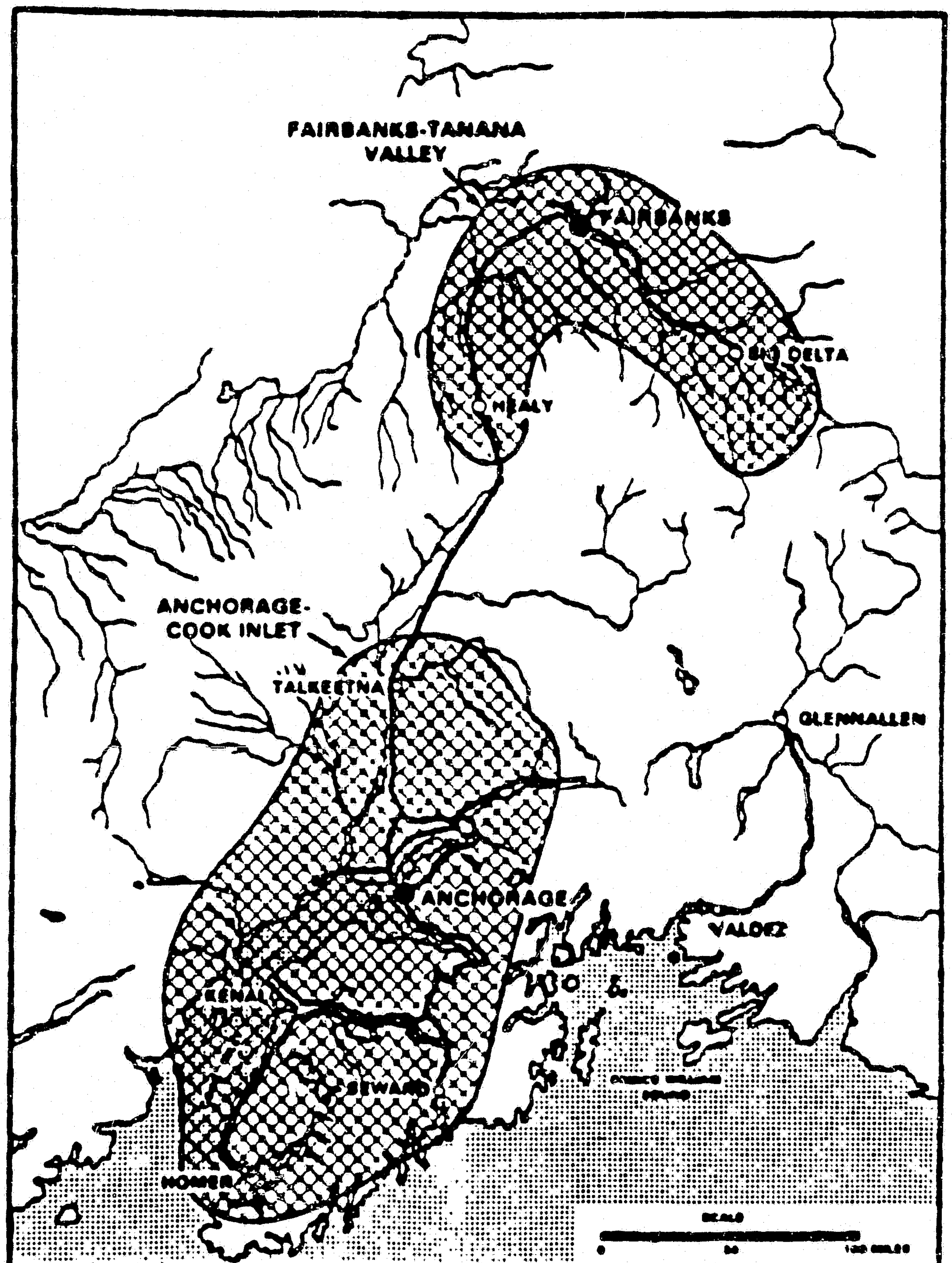


FIGURE 1.1. Railbelt Area of Alaska Showing Electrical Load Centers

FIGURE 1

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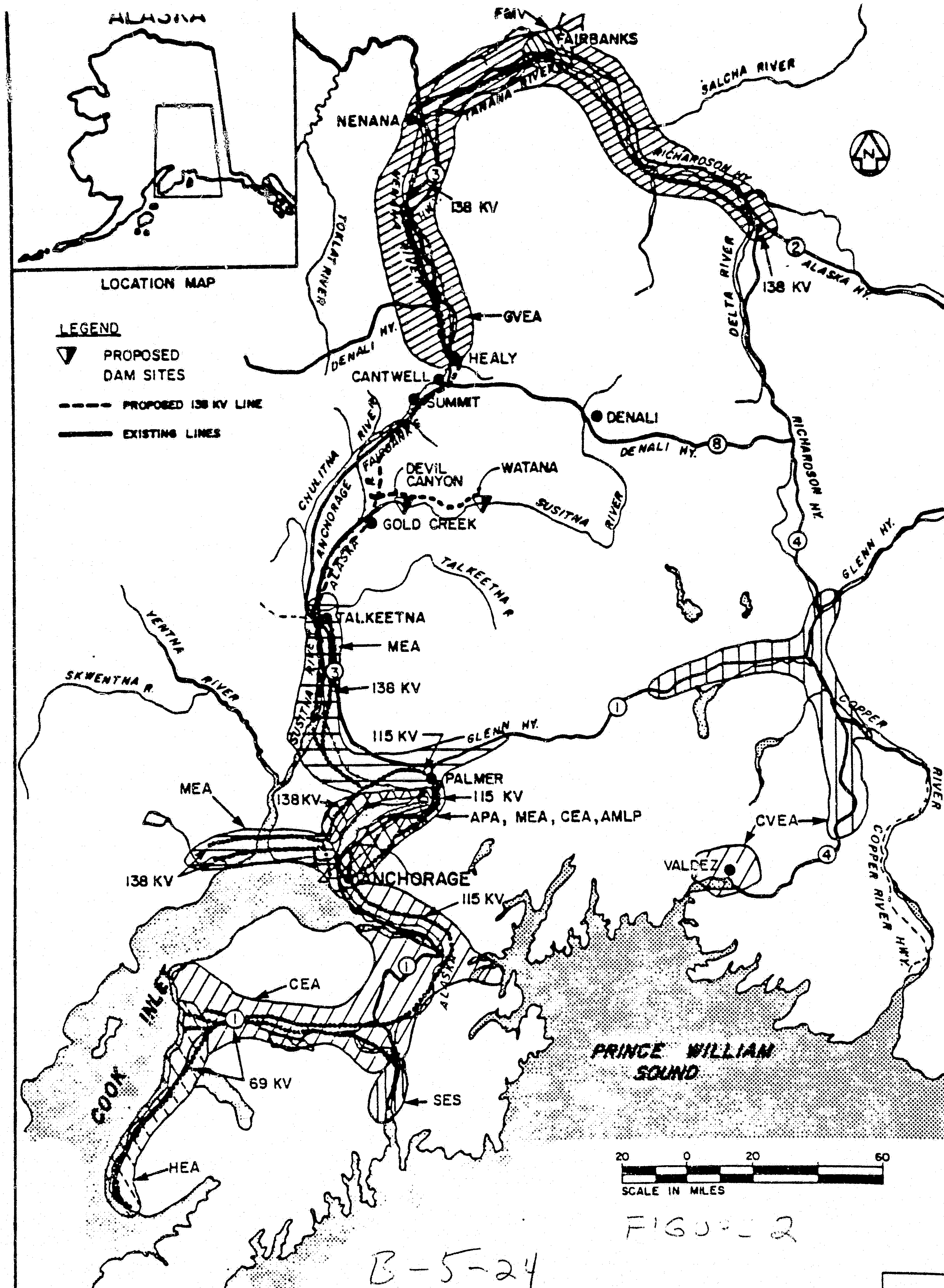

FIGURE 2

B-5-24

APPENDIX 1: EXISTING AND PLANNED CAPACITY DATA

B-5-25

Table A.1 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Alaska Power Administration

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor
EXISTING										
Eklutna	Hydro	---	---	1955	2005	30.0	---	---	0.01	0.95[a/]
PLANNED *										
Bradley Lake	Hydro	---	---	1988	2038	90	---	---	0.01	0.95[b/]

a/ Average annual energy production for Eklutna is approximately 147,875,000 kWh. This is equivalent to an annual lc factor of 0.56.

b/ Average annual energy production from Bradley Lake is expected to be approximately 347,000,000 kWh. Of this total 315,000,000 kWh will be firm energy and 32,000,000 Wh will be secondary. The equivalent annual load factor is 0.4

* The Alaska Power Authority has now assumed responsibility for the development and financing of this project

Table A.2 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Anchorage Municipal Light and Power

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comment
EXISTING											
Station #1											
Unit #1	SCCT	NG/Dist	AGAS/LS	1962	1982	14.0	16.25	14,000	0.10	0.81	Reserv· Peaki
Unit #2	SCCT	NG/Dist	AGAS/LS	1964	1984	14.0	16.25	14,000	0.10	0.81	Reserv· Peaki
Unit #3	SCCT	NG/Dist	AGAS/LS	1968	1988	18.0	18.0	14,000	0.10	0.81	---
Unit #4	SCCT	NG/Dist	AGAS/LS	1972	1992	28.5	32.0	12,500	0.10	0.81	---
Diesel 1 (b)	Diesel	Dist	LS	1962	1982	1.1	1.1	10,500	0.10	0.81	Black Uni
Diesel 2 (b)	Diesel	Dist	LS	1962	1982	1.1	1.1	10,500	0.10	0.81	Black Uni
Station #2											
Unit #5	SCCT	NG/Dist	AGAS/LS	1974	1994	32.3	40.0	12,500	0.10	0.81	---
Unit #6 (c)	CCST	---	---	1979	2009	33.0	33.0	---	0.10	0.81	---
Unit #7	SCCT	NG/Dist	AGAS/LS	1980	2000	73.6	90.0	11,000	0.10	0.81	---
PLANNED											
Station #2											
Unit # 8	SCCT	NG/Dist	AGAS/LS	1982	2002	73.6	90.0	12,500	0.10	0.81	---

a/ All AML&P SCCTs are equipped to burn natural gas or oil. In normal operation they are supplied with natural gas from AGAS. All units have reserve oil storage for operation in the event gas is not available.

b/ These are black-start units only. They are not included in total capacity.

c/ [illegible] combined cycle plant. When operated in this mode, they have a

0 0 2 4 9 9

Table A.3 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Chugach Electric Association

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
ISTING											
luga											
Unit #1	SCCT	NG	Prod.	1968	1988	14.0	16.1	15,000	0.10	0.81	---
Unit #2	SCCT	NG	Prod.	1968	1988	14.0	16.1	15,000	0.10	0.81	---
Unit #3	SCCT	NG	Prod.	1973	1993	51.0	53.0	10,000	0.10	0.81	Jet Engi
Unit #4	SCCT	NG	Prod.	1976	1996	9.3[a]	10.7	15,000	0.10	0.81	---
Unit #5	SCCT	NG	Prod.	1975	1995	60.0	58.0	10,000	0.10	0.81	---
Unit #6	SCCT	NG	Prod.	1976	1996	62.0	68.0	15,000	0.10	0.81	---
Unit #7	SCCT	NG	Prod.	1977	1997	62.0	68.0	15,000	0.10	0.81	---
rnice Lake											
Unit #1	SCCT	---	AGAS	1963	1983	7.5	8.6	23,400	0.10	0.81	---
Unit #2	SCCT	NG	AGAS	1972	1992	16.5	18.9	23,400	0.10	0.81	---
Unit #3	SCCT	NG	AGAS	1978	1998	23.0	26.4	23,400	0.10	0.81	---
oper Lake											
Unit #1,2	Hydro	---	---	1961	2011	16.0	16.0	---	0.05	0.95[b]	---
ternational											
Unit #1	SCCT	NG	AGAS	1964	1984	14.0	14.0	40,000	0.10	0.81	---
Unit #2	SCCT	NG	AGAS	1965	1985	14.0	14.0	40,000	0.10	0.81	---
Unit #3	SCCT	NG	AGAS	1970	1990	17.0	18.0	40,000	0.10	0.81	---

Table A.3 EXISTING AND PLANNED CAPACITY DATA (Cont'd.)

UTILITY: Chugach Electric Association

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
ISTING											
ik Arm (c)											
Unit #1	ST	NG	AGAS	1952	1987	0.5	0.5	---	0.10	0.81	---
Unit #2	ST	NG	AGAS	1952	1987	3.0	3.0	---	0.10	0.81	---
Unit #3	ST	NG	AGAS	1957	1992	3.0	3.0	---	0.10	0.81	---
Unit #4	ST	NG	AGAS	1957	1992	3.0	3.0	---	0.10	0.81	---
Unit #5	ST	NG	AGAS	1957	1992	5.0	5.0	---	0.10	0.81	---
ANNED											
luga Unit 8 (d)	CCST	---	---	1982	2012	54	54	---	---	---	---
rnice Lake #4	SCCT	NG	AGAS	1982	2002	23.0	26.4	12,000	0.10	0.81	---

Beluga Unit #4 is a jet engine used for peaking only. It is not included in total capacity.
Average annual energy production for Cooper Lake is approximately 42,000,000 kWh. This is equivalent to annual load factor of 0.30.
Knik Arm units are old and have higher heat rates. They are not included in total.
Beluga Units #6,7 and 8 will operate as a unit combined-cycle plant in 1982. When operated in this mode, they will have a generating capacity of about 178 MW with a heat rate of 8500 Btu/kWh. Thus, Units #6 and 7 will be retired from "gas turbine operation" and added to "gas combined-cycle operations".

Table A.4 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Homer Electric Association

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
ISTING											
ldovia	Diesel	Dist.	LS	1957	1987	1.50	1.50	10,500	0.10	0.81	Standby
ANNED											
ne											

Table A.5 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Seward Electric Association

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
ISTING											
CO	Diesel	Dist.	LS	1965	1985	3.0	3.0	10,500	0.10	0.81	Standby
D	Diesel	Dist.	LS	1976	1996	2.5	2.5	10,500	0.10	0.81	Standby
ANNED											
ne											

Table A.6 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Military Installations - Anchorage Area

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
ISTING											
mendorf AFB											
Total Diesel	Diesel	Diesel	LS	1952	---	2.1	---	10,500	0.10	0.81	---
Total ST	ST	NG	AGAS	1952	---	31.5	---	12,000	0.10	0.81	---
rt Richardson											
Total Diesel	Diesel	Diesel	LS	1952	---	7.2	---	10,500	0.10	0.81	Cold Sta Units
Total ST	ST	NG	AGAS	1952	---	18.0	---	19,000-20,000	0.10	0.81	Cogenera tion Use For Stea Heating
ANNED											
ne											

Table A.7 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Golden Valley Electric Association

lant nit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
STING											
ly Coal	ST	Coal	NEN	1967	2002	25.0	25.0	13,200	0.01	0.92	—
ly Diesel	Diesel	Dist.	LS	1967	1987	2.75	2.75	10,500	0.01	0.81	Peaking/ Black Start Uni
th Pole											
nit #1	SCCT	Dist.	LS	1976	1996	64.7	65.0	14,000	0.022	0.81	—
nit #2	SCCT	Dist.	LS	1977	1997	64.7	65.0	14,000	0.015	0.81	—
dher											
T 1	SCCT	Dist.	LS	1971	1991	18.4	18.4	15,000	0.10	0.81	—
T 2	SCCT	Dist.	LS	1972	1992	17.4	17.4	15,000	0.10	0.81	—
T 3	SCCT	Dist.	LS	1975	1995	2.8	3.5	15,000	0.10	0.81	—
T 4	SCCT	Dist.	LS	1975	1995	2.8	3.5	15,000	0.10	0.81	—
bined Diesel	Diesel	Dist.	LS	1960-70	1995	21.0	21.0	10,500	0.10	0.81	—
NNED	None										

Table A.8 EXISTING AND PLANNED CAPACITY DATA

UTILITY: University of Alaska - Fairbanks

lant nit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
1	ST	Coal	NEN	---	---	1.50	1.50	12,000	0.10	0.81	---
2	ST	Coal	NEN	1980	---	1.50	1.50	12,000	0.10	0.81	---
3	ST	Coal	NEN	---	---	10.0	10.0	12,000	0.10	0.81	---
1	Diesel	Dist.	LS	--	---	2.75	2.75	10,500	0.10	0.81	---
2	Diesel	Dist.	LS	---	---	2.75	2.75	10,500	0.10	0.81	---

Table A.9 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Fairbanks Municipal Utilities System

lant Init	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comments
STING											
na											
Init #1	ST	Coal	NEN	1954	1989	5.0	5.0	18,000	0.10	0.81	---
Init #2	ST	Coal	NEN	1952	1987	2.0	2.0	22,000	0.10	0.81	---
Init #3	ST	Coal	NEN	1952	1987	1.5	1.5	22,000	0.10	0.81	---
Init #4	SCCT	Dist.	LS	1963	1983	5.25	6.6	15,000	0.10	0.81	---
Init #5	ST	Coal	NEN	1970	2005	20.5	20.5	13,320	0.10	0.81	---
Init #6	SCCT	Dist.	LS	1976	1996	23.1	28.8	15,000	0.10	0.81	---
iesel 1	Diesel	Dist.	LS	1967	1987	2.75	2.75	12,150	0.10	0.81	---
iesel 2	Diesel	Dist.	LS	1968	1988	2.75	2.75	12,150	0.10	0.81	---
iesel 3	Diesel	Dist.	LS	1968	1988	2.75	2.75	12,150	0.10	0.81	---

Table A.10 EXISTING AND PLANNED CAPACITY DATA

UTILITY: Military Installations - Fairbanks

Plant Unit	Prime Mover	Fuel Type	Fuel Supply	Installation Date	Retirement Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Average Annual Heat Rate (Btu/kwh)	Forced Outage Rate	Maximum Annual Capacity Factor	Comme
XISTING											
ielson AFB											
S1,S2	ST	Oil	LS	1953	---	2.50	---	---	0.10	0.81	---
S3,S4	ST	Oil	LS	1953	---	6.25	---	---	0.10	0.81	---
'ort Greeley											
D1,D2,D3	Diesel	Oil	---	---	---	3.0	---	10,500	0.10	0.81	Stan
D4,D5	Diesel	Oil	---	---	---	2.5	---	10,500	0.10	0.81	Stan
't. Wainwright											
S1,S2,S3,S4,ST		Coal	NEN	1953	---	20	---	19,000-20,000	0.10	0.81	Cogene Used Stear Heat
S5	ST	Coal	NEN	1953	---	2	---	---	0.10	0.81	Stan
LANNED	None										

5.2.2 Railbelt Electric Utilities

5.2.2.1 Utility Load Characteristics

This section first presents historical monthly load profiles for each load center. Then daily load curves are discussed, followed by an analysis of load diversity between the two load centers.

(i) Monthly Load Profiles

Table _ shows the historical distribution of monthly loads for each load center. The ratios were derived from the data presented in section 5.2.3. Both regions have winter peaks, occuring in December, January or February . As illustrated in Figures _ and _, the load demand has its minimum during the months of May through August. The ratio of summer to winter peaks varies between 0.55 and 0.65. Also, Table _ shows that the monthly distribution has remained about the same for the period 1976-1982.

(ii) Daily Load Profiles

Table ____ presents typical 1980 weekday and weekend daily load duration data for the months of April, August and December, for the entire Railbelt region.

These data were derived from the Woodward-Clyde study (Woodward-Clyde 1980). Figures ___ and ___ present daily load curves for a week in April, August and December 1982. The data were obtained from Chugach Electric Association and Golden Valley electric Association, which represent about ___percent of the total Railbelt generation.

As shown on Table ___, during the month of April, there is usually a morning peak between 7 and 9 a.m., and an evening peak between 6 and 8 p.m. Between the two peaks, the load demand is more or less constant. The night load is about 70 percent of the daily load. The average daily load factor is about 85 percent.

During the month of August, the load starts to increase at about 7 a.m., but continue to increase slowly until 11-12 a.m., when it decreases slowly. The night load is about 55-60 percent of the daily load. The average daily load factor is about 82 percent.

During the month of December, there is usually a morning peak between 6 and 9 a.m., and an evening peak between 4 and 7 p.m. Between the two peaks, the load is more or less constant. The night load is about 65 percent of the daily load. The average daily load factor is about 85 percent.

(iii) Railbelt Load Diversity

The analysis of system diversity was done for the peak day in Fairbanks which was December 29, 1981 and the peak day in Anchorage of January 6, 1982. The peak coincident and non-coincident loads were collected from all generating sources and diversity was calculated based on the data. Table ___ shows the hourly load demand for these two peak days. The diversity measure in the total Railbelt ranged from 0.97 to 0.99. The basic conclusion of the analysis is that based on the peak demand of individual utilities the total interconnected peak load for the Railbelt would probably be within a few percent of the total non-coincident peak demand.

5.2.2.2 Conservation and Rate Structure Programs

This section presents conservation and rate structure programs initiated by the electric utilities and government agencies. The effects of these existing programs have been incorporated in the forecasting methodology which is described in section 5.3.

The Anchorage Municipal Light and Power (ML&P) Programs

The ML&P program specifically addresses electricity conservation in both residential and institutional settings. It is a formal conservation program as mandated by the Powerplant and Industrial Fuel Use Act of 1978 (FUA). The program of ML&P is designed to achieve a 10% reduction in electricity consumption. To achieve this level of conservation, ML&P provides information on available state and city programs. Additionally, it has programs to:

(1) distribute hot water flow restrictors;

(2) insulate 1000 electric hot water heaters;

(3) heat the city water supply, increasing the temperature by 15°F (decreasing the thermal needs of hot water heaters); and

(4) convert two of its boiler feedwater pumps from electricity to steam.

(5) convert city street lights from mercury vapor lamps to high pressure sodium lamps; and

(6) convert the transmission system from 34.5 KV to 115 KV.

ML&P also supplies educational materials to its customers along with "Forget-me-not" stickers for light switches. It has a full time energy engineer devoted to energy conservation program development.

The projected impacts of specific energy conservation programs are detailed in Table 9 for the period 1981-1987. They are dominated by non-residential public sector programs such as street light conversion, transmission line conversion, and power plant boiler feed pump conversion. The latter programs are expected to provide 25,408 MWh of electricity conservation in 1987, or 72% of the total programmatic energy conservation.

In addition to these conservation programs, ML&P has also projected conservation due to price-induced effects. Table 10 presents the projections. About 60 percent comes from price-induced conservation. After 1983, the rate of increase in conservation declines sharply. The rate of improvement drops sufficiently such that realistic conservation reaches a maximum level by 1983. Beyond that time frame, price-induced conservation may be considered as the overwhelming contributor.

The Golden Valley Electric Association Program

Golden Valley Electric Association, in Fairbanks, provides an education oriented approach to energy conservation programs. To accomplish the education program, GVEA has adapted a plan pursuant to REA regulations. This utility employs an Energy Use Advisor who performs the following tasks:

(1) performs advisory (non-quantitative) audits;

(2) counsels customers on an individual basis on means to conserve electricity;

(3) provides group presentations and panel discussions; and

(4) provides printed material, including press releases and publications.

GVEA also eliminated its special rate for all electric homes, and placed a moratorium on electric home hook-ups in 1977. It has given out flow restrictors. It has prepared displays and presentations for the Fairbanks Home Show and the Tanana Valley State Fair. It coordinates its programs with the state and other programs.

The GVEA budget for conservation activities involves 1.8 man years of effort.

The efforts of GVEA, combined with price increases and other socioeconomic phenomena, produced a conservation effect as shown in Table 13. Although much of the decline in average consumption can be attributed to conversions from electric heat to some other source, part of the reduction is the direct result of conservation. The data show a reduction from 17,332 KWh/house/yr in 1975 to a level of 9,080 KWh/house/yr in 1981. The data in Table 13 also show a moderate upturn in electricity consumption per household in 1982, indicating that the practical limit of conservation may have been reached in the GVEA system. Currently, GVEA's load management program is directed toward commercial consumers. A significant lower rate schedule is available to commercial customers whose demand is maintained at less than 50 kW. Larger power customers are advised on ways to manage their electrical load to minimize demands. In addition, seasonal rates are available to those large consumers who significantly reduce their demand during the winter peak season. A program is underway to identify customers who operate large interruptible loads during periods of system peak demand. Various methods of residential load management are under study, but none appears cost effective at this time other than voluntary consumer response to education programs.

Other Utility Programs

The other utilities have various programs aimed at getting information to the public concerning the dollar savings associated with electricity conservation. The utilities rely on market forces, and aid in consumer recognition of those forces. No specific rate structure programs have been implemented.

Other Conservation Programs

(i) The State Program

The Conservation Section of the Division of Energy and Power Development (DEPD) is responsible for administration of the United States Department of Energy's low-income weatherization program. This program has involved the following activities:

(1) Training of energy auditors;

(2) Performance of residential energy audits, which are physical inspections including measurements of heat loss;

(3) Providing grants of up to $300/household, or loans, for energy conservation improvements based upon the audit;

(4) Providing retrofit (e.g. insulation, weatherization) for low income homes.

The key to the program is the audit, which is performed by private contractors. The forms employed are designed to show savings that can be achieved in the first year, the seventh year, and the tenth year after energy conservation measures have been implemented. The savings demonstrated provide the basis for qualifying for a grant or loan. The audits focus on major conservation opportunities such as insulation and reduction of infiltration (e.g., by weather stripping, caulking, and storm window application).

The DEPD program, overall, achieved a significant level of penetration into the conservation marketplace. Penetration in the state as a whole achieved 24%; and in the combined load centers of Anchorage and Fairbanks it also achieved 24%. It is useful to note that the audit program was more effective in high cost energy areas (e.g., Fairbanks) indicating that public participation was based upon market forces at least to some modest extent.

The DEPD program has achieved a 4.2% savings of energy in Alaska, of which 18% is electricity (House, 1983). Over 80 percent of the energy conserved has been in the area of fossil fuels. This is consistent with the direction of the program towards thermal energy savings (Brewer, 1983).

The DEPD program is currently being phased out, except for low income family assistance, particularly in the Bush Communities (Brewer, 1983). Even in those communities, only 13% of the homes will be treated (at a cost of $2000/house) in the next 3 years (Brewer, 1983). Educational efforts, however, will continue (House, 1983). If programs are constructed for the future, they will be directed at fossil fuel conservation. Particularly in the remote areas (House, 1983).

The City of Anchorage Program

The Anchorage Program is the other non-source-specific conservation program operated by the Energy Coordinator for the City of Anchorage. This program also involves audits, weatherization, and educational efforts. Cursory walk-through audits have been performed on city buildings and schools, and detailed audits have been performed on selected institutional buildings. According to energy coordinator P. Poray, few cost effective conservation measures were uncovered by the audits (Poray, 1983).

The weatherization program is applied in the case of low income personnel, and involves giving grants of up to $1600 for materials and incidental repairs. Labor is supplied from the mprehensive Employment Training Act (CETA) program.

The educational program has involved working with realtors, bankers, contractors and businessmen. It also has involved informal contacts with commercial building maintenance personnel. Finally, it has involved contacts with the general public.

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Table ___

MONTHLY DISTRIBUTION OF PEAK LOAD DEMAND

Anchorage - Cook Inlet Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)
Jan	94.2	76.8	89.2	90.5	89.9	79.1	100.1
Feb	91.2	91.8	85.8	100.0	84.8	84.8	93.3
March	81.7	75.4	77.5	85.9	72.4	73.1	83.0
April	70.9	69.7	70.6	67.8	60.1	69.1	77.4
May	63.9	59.8	62.6	58.9	55.7	61.3	64.3
June	59.9	55.6	59.7	58.5	52.7	61.5	61.8
July	62.3	54.2	59.4	54.9	54.2	63.0	61.6
Aug	70.1	67.5	66.1	61.9	58.3	69.7	73.8
Sept	89.2	78.1	81.5	72.7	69.9	78.7	90.9
Oct	100.0	100.0	100.0	99.0	100.0	100.0	95.6
Nov							
Dec							

Fairbanks - Tanana Valley Area

	1976 (%)	1977 (%)	1978 (%)	1979 (%)	1980 (%)	1981 (%)	1982 (%)
Jan	100.0	74.8	100.0	88.6	99.8	85.7	100.0
Feb	98.6	74.3	98.8	100.0	79.0	94.6	97.0
March	81.0	73.2	85.4	80.7	73.7	73.1	86.8
April	64.2	61.9	83.4	65.1	63.3	70.2	77.1
May	54.3	51.2	60.6	56.1	58.5	69.4	71.0
June	49.2	47.9	60.4	53.5	56.8	63.9	66.6
July	53.6	46.4	57.7	55.4	58.5	62.9	65.4
Aug	52.4	47.3	57.7	56.5	62.3	65.5	68.5
Sept	59.4	55.7	65.5	59.6	63.9	70.8	73.9
Oct	81.3	67.4	75.5	66.3	74.2	77.4	85.8
Nov	83.6	87.1	89.9	71.7	79.2	83.3	94.7
Dec	96.3	100.0	87.2	87.0	100.0	100.0	94.4

HARZA-EBASCO
SUSITNA JOINT VENTURE

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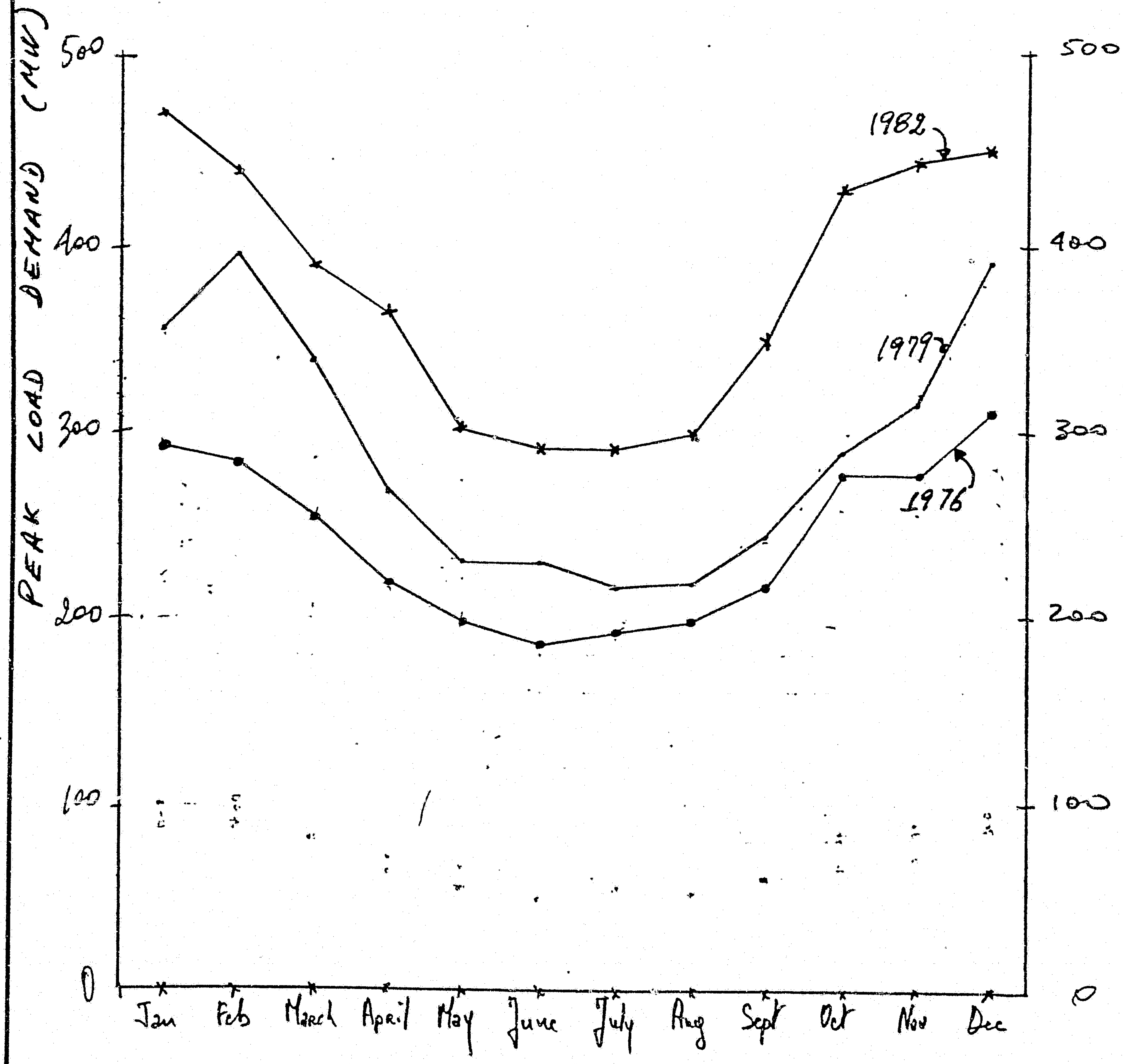
Figure ___

Anchorage - Cook Inlet Area



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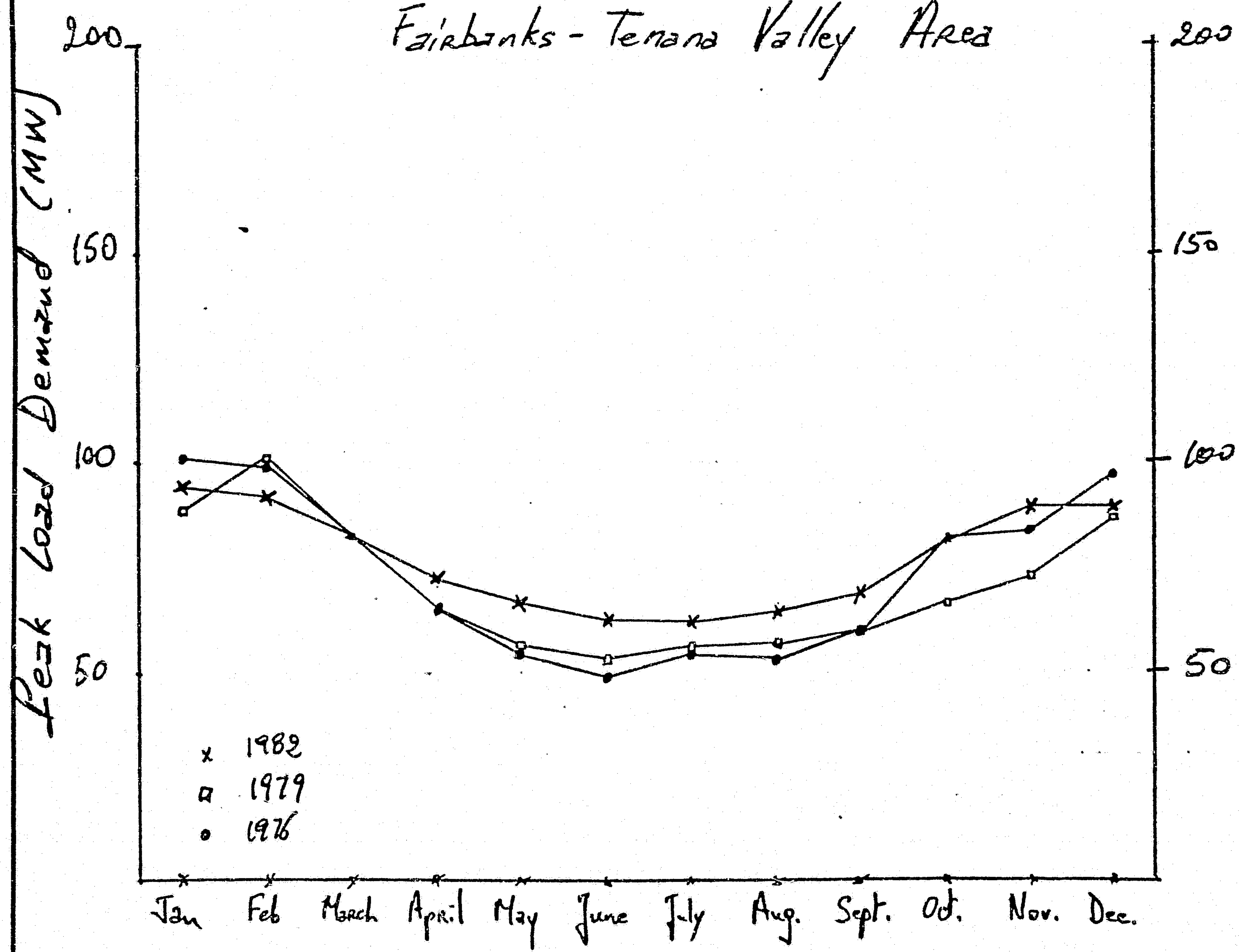


TABLE ____: 1980 TYPICAL DAILY LOAD DURATION

SELECTED MONTHS

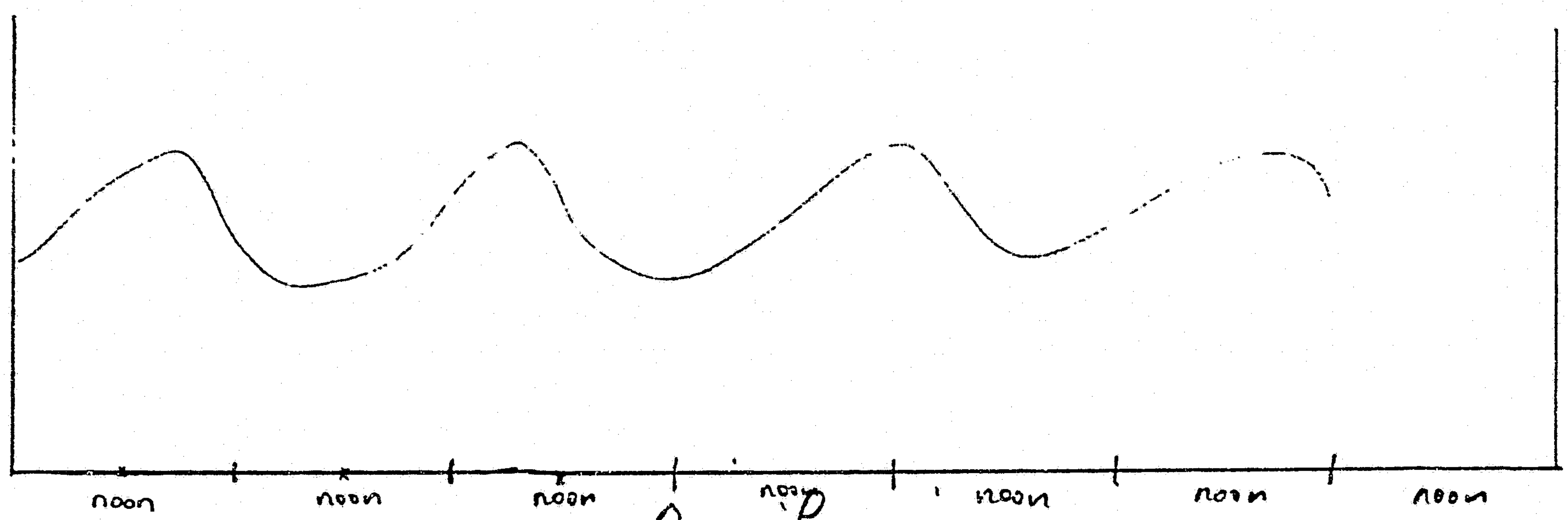
APRIL	AUGUST	DECEMBER	APRIL	AUGUST	DECEMBER
1.000	1.000	1.000	.942	.871	.945
.990	.990	.997	.917	.868	.944
.983	.988	.979	.897	.858	.927
.981	.977	.968	.882	.846	.911
.978	.970	.948	.882	.845	.893
.966	.965	.918	.880	.842	.868
.963	.959	.915	.870	.837	.862
.957	.951	.914	.867	.835	.856
.953	.948	.913	.859	.832	.854
.947	.923	.909	.851	.830	.853
.939	.890	.905	.851	.820	.843
.936	.882	.897	.838	.816	.826
.936	.873	.896	.837	.797	.818
.931	.868	.879	.827	.786	.782
.888	.834	.873	.805	.724	.775
.853	.776	.812	.753	.703	.732
.750	.747	.804	.729	.667	.724
.769	.666	.747	.724	.623	.723
.712	.657	.710	.689	.616	.680
.698	.612	.702	.673	.595	.672
.683	.590	.675	.668	.580	.661
.672	.581	.668	.667	.564	.655
.670	.581	.664	.661	.555	.648
.670	.560 -	.661	.650	.545	.648

Source: Woodward-Clyde, 1980.

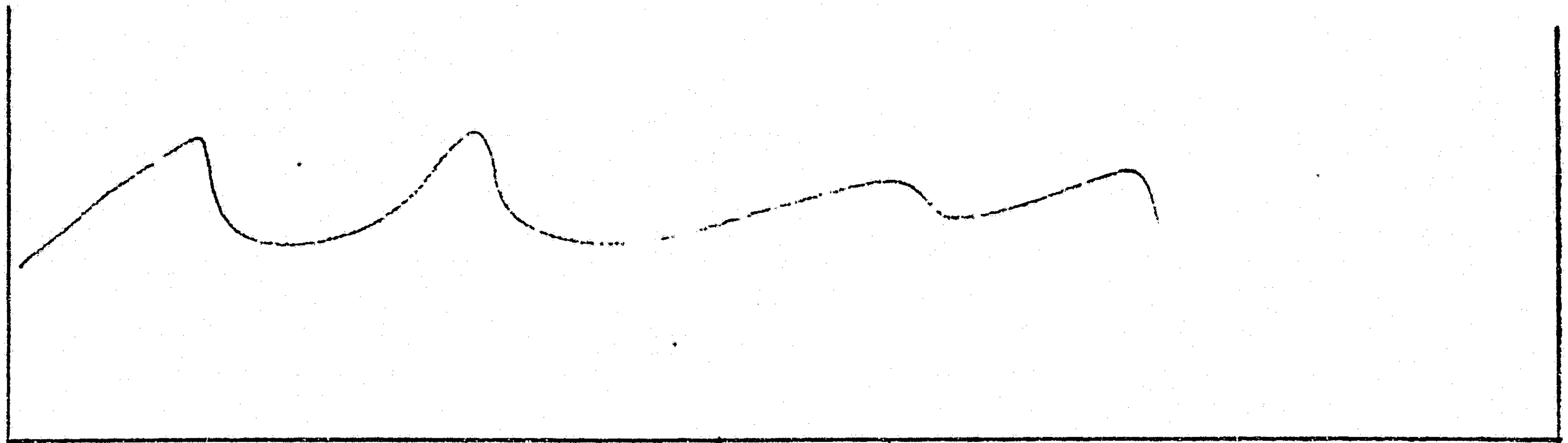
HARZA-EBASCO SUSITNA JOINT VENTURE	SUBJECT ______ COMPUTED ______ CHECKED ______	FILE NO. ______ DATE ______ PAGE ___ OF ___ PAGES

Figure ___

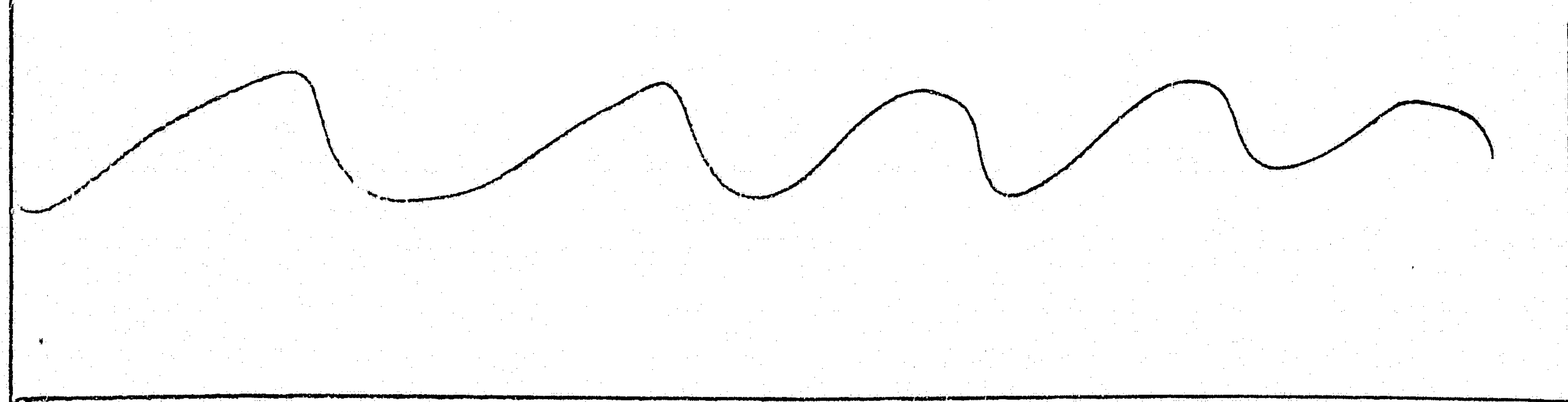
1982 Daily Load Curves
Chugach Electric Association



April



August



12-5-50 December

HARZA-EBASCO
SUSITNA JOINT VENTURE

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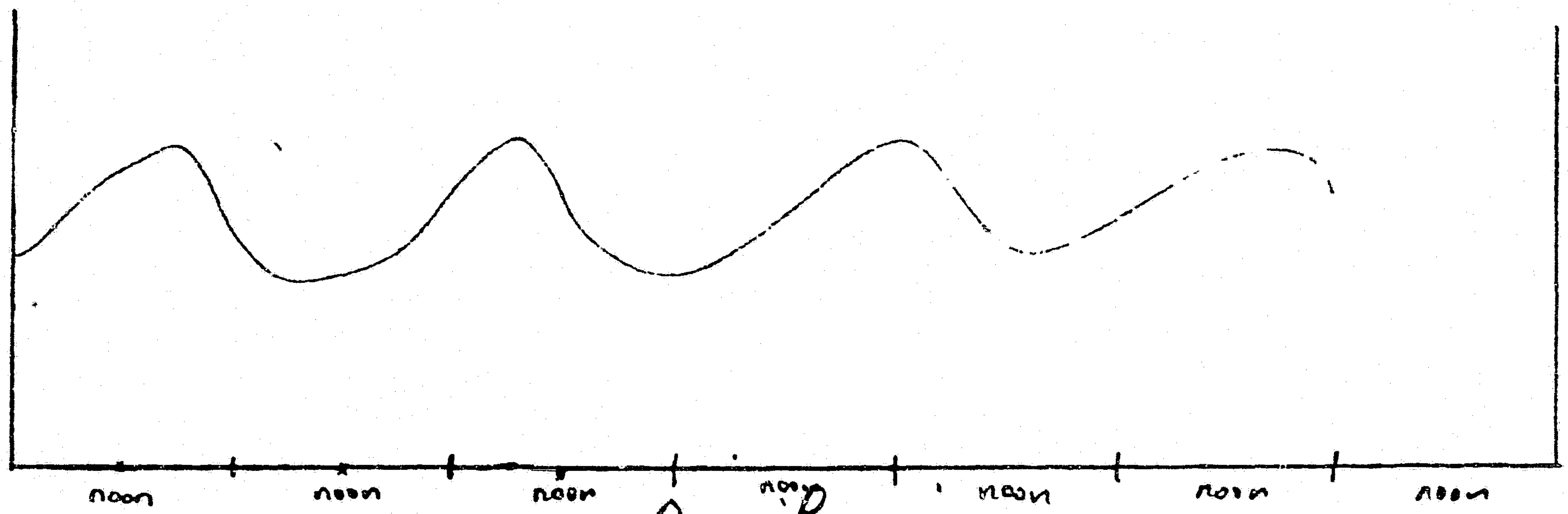
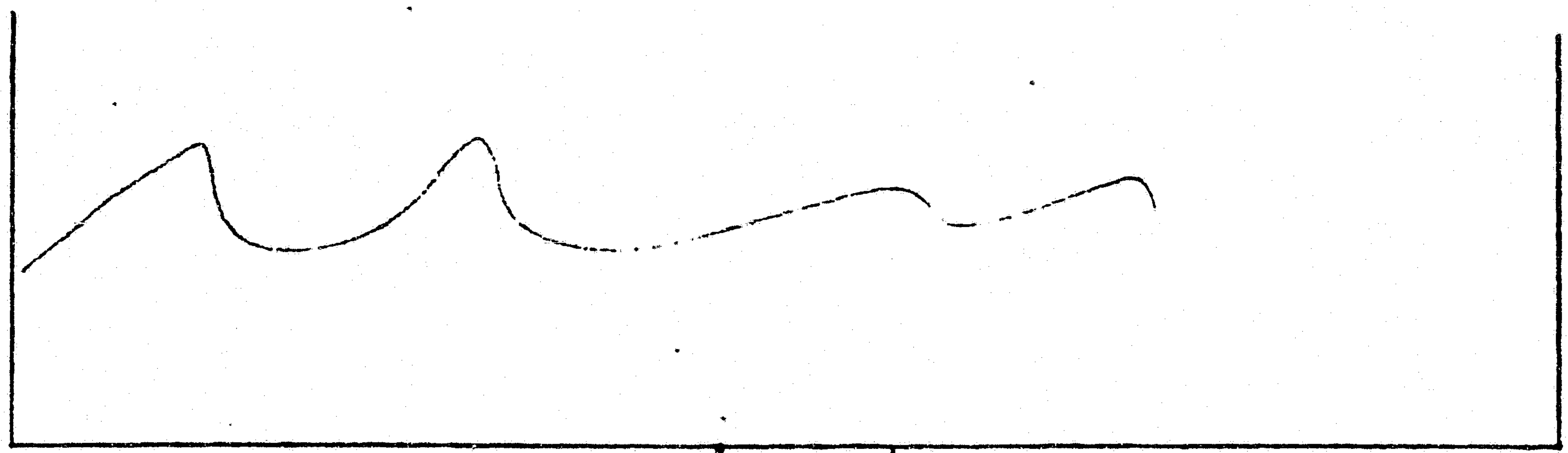
Figure ___

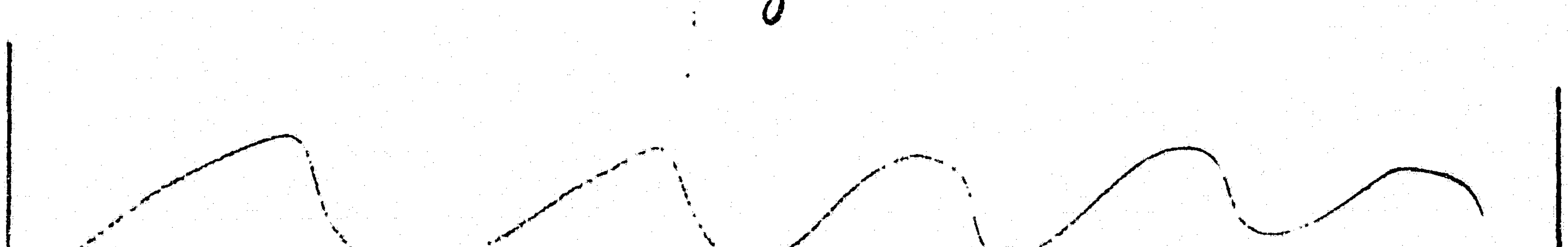
1982 Daily Load Curves
Golden Valley Electric Association



April



August



December

TABLE

RAILBELT LOADS DECEMBER 29, 1981

UTILITY	2PM	3PM	4PM	5PM	6PM	7PM	8PM	Non-Coincident Peak
CEA	168.55	170.7	178.7	179.4	182.1	180.8	173.2	182.1
ML&P	107	111	110	106	104	100	96	111.0
MEA	52.3	51.4	49.5	49.0	52.2	50.1	47.0	52.3
HEA	48.1	48.3	49.7	50.4	49.7	49.0	46.7	50.4
GVEA	71.8	71.8	75.4	69.1	72.9	72.2	73.2	75.4
Ft.WR.	9.5	11.0	11.7	10.2	9.5	8.8	9.5	11.7
EIELSON	10.3	10.3	10.0	10.0	10.0	10.0	10.0	10.3
U. of A.	5.8	5.8	5.6	6.0	4.9	5.3	4.4	6.0
FMUS	27.4	26.7	26.7	25.7	24.0	21.1	18.5	27.4
TOTAL	500.7	507.0	517.3	505.8	509.3	497.3	478.5	526.6

$$\text{Diversity} = \frac{\text{Coincident Peak}}{\text{Non-coincident Peak}} = \frac{517.3}{526.6} = .9823$$

RAILBELT LOADS JANUARY 6, 1982

UTILITY	2PM	3PM	4PM	5PM	6PM	7PM	8PM	Non-Coincident Peak
CEA	175	178	194	202	214	210	203	214
ML&P	109	109	117	115	116	112	107	117
MEA	66	71	71	71	73	74	74	74
HEA	57	56	60	62	62	63	61	63
GVEA	66.5	67.8	69.0	74.6	71.9	74.1	74.2	74.6
Ft.WR.	11.0	11.7	11.7	9.5	9.5	9.5	8.8	11.7
EIELSON	11.0	11.0	11.2	10.9	10.7	10.4	10.4	11.2
U. of A.	6.0	6.2	6.2	6.5	5.7	4.3	5.0	6.5
FMUS	27.4	27.2	29.7	26.2	24.0	23.5	20.4	29.7
TOTAL	528.9	538.3	569.8	577.7	586.8	580.8	563.8	601.7

$$\text{Diversity} = \frac{\text{Coincident Peak}}{\text{Non-coincident Peak}} = \frac{586.8}{601.7} = .9752$$

TABLE 9

CUMULATIVE ENERGY CONSERVATION PROJECTIONS (MWH/YEAR)

ANCHORAGE MUNICIPAL LIGHT AND POWER

Program	Year 1981	1982	1983	1984	1985	1986	1987
Weatherization	586	762	938	1,114	1,290	1,466	1,641
State Programs	879	1,759	2,199	2,683	3,078	3,518	3,737
Water Flow Restrictions	200	464	464	464	464	464	464
Water Heat Injection	3,922	3,922	3,922	3,922	3,922	3,922	3,922
Hot Water Heater Wrap	NA	NA	249	249	249	249	249
Street Light Conversion	0	555	1,859	3,307	4,788	6,306	7,861
Transmission Conversion	0	0	4,119	8,732	9,256	9,811	10,399
Boiler Pump Conversion	7,148	7,148	7,148	7,148	7,148	7,148	7,148
TOTAL	12,735	14,609	20,896	27,619	30,195	32,614	35,421
% Change From Previous Year	NA	14.7	43.0	32.2	9.3	9.8	8.6

Source: AML&P, 1983

TABLE 10

PROGRAMATIC VS MARKET DRIVEN ENERGY CONSERVATION
PROJECTIONS IN THE AML&P SERVICE AREA

Year	Programatic Conservation (MWh)	(%)	Price-Induced Conservation (MWh)	(%)	Total (MWH)	(%)	Increase From Previous Year (%)
1981	12,735	39.5	19,558	60.5	32,294	100	NA
1982	191,609	34.9	27,243	65.1	41,853	100	29.6
1983	20,896	37.1	35,374	62.9	56,289	100	34.4
1984	27,619	41.1	39,560	58.9	67,133	100	19.3
1985	30,195	40.4	44,536	59.6	74,730	100	11.3
1986	32,614	40.6	48,133	59.4	81,015	100	8.4
1987	35,421	41.0	50,940	59.0	86,363	100	6.6

Source: AML&P, 1983

TABLE 13

AVERAGE ANNUAL ELECTRICITY CONSUMPTION PER HOUSEHOLD
ON THE GVEA SYSTEM, 1972-1982

Year	Annual Consumption (kwH)	Monthly Consumption (kwH)	Percent Change
1972	13,919	1,160	+5.6
1973	14,479	1,207	+4.0
1974	15,822	1,319	+9.3
1975	17,332	1,444	+9.5
1976	15,203	1,267	-12.3
1977	14,255	1,188	-6.2
1978	11,574	965	-18.8
1979	10,519	877	-9.1
1980	9,767	814	-7.1
1981	9,080	757	-7.0
1982	9,303	775	+2.5

Source: GVEA (Colonell, 1983)

B-5-55

5.2.3 Historical Data for the Market Area

Available economic and electric power data for the State of Alaska and the Railbelt are summarized in Table 5-A. The table shows the rapid growth that has occurred in the state's and the Railbelt's population, economy, and use of electric power. The growth has been especially rapid during the last decade.

Between 1960 and 1982, population in the Railbelt grew from 94,300 to 231,984, an increase of 146 percent, or an average of 4.2 percent per year. The number of households in the Railbelt grew at a faster rate during this period, an average of 4.9 percent per year, reflecting the nationwide trend toward fewer persons per household. Much of the population and economic growth that occurred during this period is attributable to the tremendous increase in state petroleum revenues and general fund expenditures. State petroleum revenues grew from only $4.2 million in 1960 to $3.57 billion in 1982, mainly due to the discovery and development of petroleum on Alaska's North Slope. Between 1960 and 1982 state general fund expenditures rose from less than $100 million per year to $4.6 billion.

Consumption of electric power in the Railbelt has risen significantly faster than the rate of economic growth. Between 1965 and 1982 total energy generation rose from 467 gigawatt hours to 2,934 gigawatt hours, a five-fold increase, or an average of 11.4 percent per year. Peak energy demand has also risen rapidly in recent years, from 412 megawatts in 1976 to 566 megawatts in 1982, an average of 4 percent per year.

Tables 5-B and 5-C present monthly electric power use and peak demand during the period 1976 to 1982 for the Anchorage and Fairbanks load centers. These tables show that while there has been a steady rise in the use of electric power and in peak demand, there has been considerable variation in monthly energy use and peak demand from one year to the next, mostly due to different weather conditions in the Railbelt.

Table 5-D gives the net annual generation of each Railbelt utility between 1976 and 1982. The table shows that Chugach Electric Association, which provides power to numerous other utilities including Homer Electric and Matanuska Electric has generated an excess of 50 percent of the electric energy used in the Railbelt. Anchorage Municipal Light and Power is the second largest generator, having provided nearly 20 percent of the Railbelt's electric energy in 1982.

TABLE 5.A HISTORIC ECONOMIC AND ELECTRIC PO

ITEM	YEAR 1960	1965	1970	197
State Oil and Gas Revenues to General Fund	$ 4.2 million[1]	$ 16.3 million	$ 938.6 million[2]	$ 88.3 ı
State General Fund Expenditures	n.a.	$ 82.7 million	$ 188.6 million	$ 453.3 n
State Population	226,200	265,200	304,700	390,(
State Employment	94,300	110,000	133,400	197,5
Railbelt Population	140,486	n.a.	199,670	n.a
Railbelt Employment[3]	n.a.	74,100	88,500	130,4
Railbelt Households	37,062	n.a.	54,057	n.a
Railbelt Electric Energy Generation				
Anchorage	n.a.	369 GWH	684 GWH	1,270
Fairbanks	n.a.	98 GWH	230 GWH	413
Total	n.a.	467 GWH	914 GWH	1,683
Railbelt Peak Demand[5]	n.a.	n.a.	n.a.	412 l
Railbelt Generation Capacity				

Sources: MAP Model Data Base; Federal Energy Regulatory Commission, Power System Staten Printouts, 1983.

[1] Figure is for 1961.

[2] This figure is unrepresentatively high due to collection of a large petroleum lease bon

[3] Excludes agricultural workers and self-employed.

[4] Figure is for 1976.

[5] Sum of demand in Anchorage and Fairbanks load centers.

TA 5. MONT LOA DATA ANCH GE/ IN ARE

TABLE 5.A HISTORIC ECONOMIC AND ELECTRIC POWER DATA

ITEM	YEAR 1960	1965	1970	1975	1980	1982
State Oil and Gas Revenues to General Fund	$ 4.2 million[1]	$ 16.3 million	$ 938.6 million[2]	$ 88.3 million	$ 2,262.3 million	$ 3,567.3 million
State General Fund Expenditures	n.a.	$ 82.7 million	$ 188.6 million	$ 453.3 million	$ 1,172.8 million	$ 4,601.9 million
State Population	226,200	265,200	304,700	390,000	402,000	437,175
State Employment	94,300	110,000	133,400	197,500	211,200	231,984
Railbelt Population	140,486	n.a.	199,670	n.a.	275,818	307,107
Railbelt Employment[3]	n.a.	74,100	88,500	130,400	132,000	154,033
Railbelt Households	37,062	n.a.	54,057	n.a.	94,210	106,599
Railbelt Electric Energy Generation						
Anchorage	n.a.	369 GWH	684 GWH	1,270 GWH	2,109 GWH	2,443 GWH
Fairbanks	n.a.	98 GWH	230 GWH	413 GWH	443 GWH	491 GWH
Total	n.a.	467 GWH	914 GWH	1,683 GWH	2,552 GWH	2,934 GWH
Railbelt Peak Demand[5]	n.a.	n.a.	n.a.	412 MW[4]	539.8 MW	566.1 MW
Railbelt Generation Capacity						

Sources: MAP Model Data Base; Federal Energy Regulatory Commission, Power System Statement; Alaska Power Administration, Unpublished Printouts, 1983.

1 Figure is for 1961.
2 This figure is unrepresentatively high due to collection of a large petroleum lease bonus.
3 Excludes agricultural workers and self-employed.
4 Figure is for 1976.
5 Sum of demand in Anchorage and Fairbanks load centers.

TABLE 5.B MONTHLY LOAD DATA - ANCHORAGE/COOK INLET AREA 1976-1982

NET ENERGY (MWH)[1/]

MONTH	1976	1977	1978	1979	1980	1981	1982
January	159,858.2	163,954.7	197,400.8	209,892.8	221,441.8	198,497.8	264,468.6
February	151,762.5	143,259.8	167,367.8	209,991.8	181,968.2	186,812.3	219,800.8
March	145,974.8	164,469.6	172,893.1	183,731.1	188,083.2	186,258.4	215,098.6
April	126,643.7	142,019.6	149,718.6	162,344.2	155,413.5	169,546.4	191,709.2
May	117,248.7	131,512.2	140,590.7	145,503.9	150,250.3	152,926.4	175,709.1
June	102,593.1	116,392.9	129,373.5	131,182.0	137,020.4	146,692.3	162,177.2
July	108,065.7	113,375.0	131,730.1	136,025.1	140,791.6	151,730.6	165,315.6
August	110,754.4	121,972.4	131,737.0	137,401.0	143,143.3	157,966.3	168,632.4
September	120,765.2	134,941.0	139,303.2	141,043.1	151,731.5	165,375.5	175,021.4
October	144,349.4	158,473.0	168,690.5	169,443.8	176,803.0	195,024.1	220,744.2
November	153,121.6	194,791.5	191,300.9	179,036.5	202,880.3	216,854.0	234,249.6
December	172,488.7	215,530.2	208,541.0	237,981.0	259,893.3	240,487.8	249,739.9
ANNUAL	1,613,625.9	1,800,691.8	1,928,656.2	2,043,576.2	2,109,420.6	2,168,171.9	2,442,666.7

PEAK DEMAND (MW)

MONTH	1976	1977	1978	1979	1980	1981	1982
January	293.1	288.4	341.3	357.8	399.4	351.8	471.7
February	283.7	269.5	328.6	395.1	337.2	377.0	440.4
March	254.0	283.0	296.6	339.5	321.9	324.9	391.5
April	220.4	261.7	270.3	268.1	266.9	307.3	365.2
May	198.8	224.6	239.8	232.7	247.7	272.5	303.6
June	186.4	208.7	228.6	231.1	234.3	273.4	291.4
July	193.9	203.3	227.4	217.1	224.2	280.1	290.6
August	197.7	216.3	236.6	219.5	240.8	275.9	298.9
September	218.0	253.3	253.1	244.8	259.2	309.7	348.4
October	277.7	293.0	312.1	287.4	310.6	349.9	429.1
November	276.2	344.1	353.2	316.2	349.7	401.3	445.2
December	311.0	375.4	382.8	391.1	444.4	444.7	450.9
ANNUAL	311.0	375.4	382.8	395.1	444.4	444.7	471.7

Source: Alaska Power Administration, unpublished printouts, 1983.

1/ Includes purchases from Alaska Power Administration.

TABLE 5.D NET ELECTRIC POWER GENERATION BY UTILITY
1976-1982
Units -- Gigawatt Hours

UTILITY	YEAR 1976	1977	1978	1979	1980	1981	1982
Anchorage Mun L&P	444.9	420.3	443.1	473.1	486.6	485.3	579.5
Chugach Elec. Assoc.	1,054.5	1,179.7	1,308.6	1,401.0	1,434.1	1,467.7	1,718.4
AK Power Admin.	118.0	203.6	180.1	171.1	184.3	222.7	147.9
Anch Cook Inlet Subtotal[1]	118.0 1,617.4	203.6 1,803.6	180.1 2,931.8	171.1 2,045.2	184.3 2,105.0	222.7 2,175.7	147.9 2,445.8
Fairbanks Mun Util.	123.3	128.5	124.7	124.7	125.6	126.1	140.7
Golden Valley Elec. Assoc.	344.7	353.5	341.5	322.9	317.7	316.9	350.3
Fairbanks Area Sub-total[1]	468.0	481.7	466.2	447.6	443.3	443.0	491.1
Railbelt Total	2,085.04	2,284.3	2,398.0	2,492.8	2,548.3	2,518.7	2,936.9

Source: Alaska Power Administration, Unpublished Printouts, 1983.

[1]Subtotals and total shown may differ from column totals due to rounding.

TABLE 5.C MONTHLY LOAD DATA - FAIRBANKS AREA
1976-1982

MONTH	1976	1977	1978	1979	1980	1981	1982
				YEAR			
				NET ENERGY (MWH)[1/]			
January	55,675.0	47,753.3	52,380.1	49,177.2	50,037.5	42,057.2	53,931.0
February	53,313.3	41,115.2	45,326.6	50,532.3	38,093.0	40,303.0	45,022.0
March	43,844.4	46,759.5	45,014.9	42,322.0	38,220.1	37,927.8	43,698.0
April	34,468.6	37,698.3	36,384.6	35,415.1	32,784.8	35,262.8	38,743.0
May	29,811.4	32,446.1	32,195.9	29,781.9	30,943.3	32,286.2	35,379.0
June	27,063.7	28 787.6	29,783.1	28,091.9	28,015.3	30,163.7	32,428.0
July	28,328.5	28,921.0	30,184.2	29,743.5	30,405.5	30,264.8	34,449.0
August	28,754.2	30,765.5	30,793.2	29,058.6	30,378.0	30,301.7	34,308.0
September	31,311.0	31,474.5	32,455.1	31,404.4	32,232.7	33,661.8	35,637.0
October	40,298.2	41,307.6	40,106.7	36,280.0	36,084.3	39,271.0	42,846.1
November	42,801.7	53,609.9	44,186.7	37,400.1	40,606.1	41,647.1	45,771.0
December	53,334.5	61,015.7	47,394.9	48,370.1	55,500.7	48,820.3	49,885.0
ANNUAL	468,004.3	481,654.2	466,206.0	447,577.1	443,301.3	442,967.3	491,097.0
				PEAK DEMAND (MW)			
January	101.0	87.9	95.8	89.2	95.2	79.8	94.4
February	99.6	87.3	94.7	100.7	75.4	88.1	91.6
March	81.8	86.0	81.8	81.3	70.3	68.1	82.0
April	64.9	72.7	70.9	65.6	60.4	65.4	72.8
May	54.8	60.2	58.1	56.5	55.8	64.6	67.0
June	49.7	56.3	57.9	53.9	54.2	59.5	62.9
July	54.1	54.5	55.3	55.8	55.8	58.6	61.7
August	52.9	55.6	55.3	56.9	59.4	61.0	70.7
September	60.0	65.4	62.8	60.0	61.0	65.9	69.8
October	82.1	79.2	72.3	66.8	70.8	72.1	82.1
November	84.5	102.3	86.1	72.2	75.6	77.6	89.4
December	97.3	117.5	83.5	87.6	95.4	93.1	89.1
ANNUAL	101.0	117.5	95.8	100.7	95.4	93.1	94.4

Source: Alaska Power Administration, unpublished printout, 1983.

1/ Includes purchases from Alaska Power Administration.

5.3 - Forecasting Methodology

The purpose of this section is to present the methodological framework used for the forecasts of economic conditions and electric demand in the Railbelt. The first subsection discusses the main ways that world oil prices can affect the need for power. Next, the models used for forecasting purposes are identified and fully explained. Finally, model validation is discussed for the economic model (MAP) and electric demand model (RED).

5.3.1 The Effect of World Oil Prices on the Need for Power

World oil prices affect the need for electric power in the Railbelt in four basic ways, each of which is explicitly taken into account in forecasting energy and loads.

First, higher world oil prices produce higher levels of petroleum revenues to the State of Alaska, mainly through production taxes and royalty payments that are tied directly to the market price of petroleum. Because of the importance of state revenues and spending to the Alaskan economy, changes in the world price of oil have a significant effect on general economic conditions and the rate of growth in the demand for electric power in the Railbelt as well as the state as a whole. This relationship was considered in the economic analysis and was factored into forecasting demands for electric energy.

Second, world oil prices affect the degree to which oil and other fossil fuels may be substituted for electricity in certain applications. Inter-fuel substitution and its effect on the demand for electricity was explicitly considered in the load forecasting analysis for the Susitna Hydroelectric Project.

The third effect that world oil prices has on the need for power lies in their impact on the cost of power generation. Since much of the electricity used in the Railbelt is generated using fossil fuels, the price of electricity to the consumer will be affected by the world price of oil. As long as fossil fuels fire a substantial portion of the Railbelt's generation facilities, higher world oil prices will lead to higher electricity prices, decreasing the overall demand for electricity. The cost of fossil fuels in generating electricity is a principal factor. It has been considered in the economic and financial analyses associated with determining the most cost-effective system for meeting the Railbelt's future electric power demand, the future cost of electricity to the ultimate consumer and consequently, the demand for electricity.

The fourth effect that world oil prices have on the need for power occurs through the influence that petroleum prices have on the profitability of exploration and development of petroleum reserves in Alaska. Higher world oil prices provide an incentive for higher levels of oil exploration and development, which in turn leads to higher levels of employment and gross output in the petroleum sector as well as support sectors such as transportation, construction, and services. The economic development and population growth associated with such activity increases electric power demands in the Railbelt as well as other parts of Alaska. However, the economic analysis conducted as part of forecasting the demand for electric power relied upon a single set of exploration and development projections because of the uncertainties associated with the discovery of economically developable fields and the lengthy lead time required to develop oil fields in Alaska.

The following sections describe in some detail the ways in which world oil prices were considered in the economic and load forecasting analyses and generation expansion planning.

5.3.2 Forecasting Models

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5.3.2.1. Model Overview

Four computer-based and functionally interrelated models were used in projecting the market for electric power in the Railbelt and evaluating alternative generating plans for meeting electric power demands. First, a model entitled PETREV, operated by the Alaska Department of Revenue, was utilized to project state revenues from petroleum production based on alternative future petroleum prices. The revenue projections from PETREV and numerous other economic and demographic data were then used by the Man-in-the-Arctic Program (MAP) Model to forecast economic conditions, including population, employment, and households, for the Railbelt. The MAP model is operated by the University of Alaska's Institute of Social and Economic Research. The economic projections, along with electric power end use information, electricity demand elasticity functions, and other electric power data then served as input to the Railbelt Electricity Demand (RED) Model to project demand for electric energy and peak loads in the Railbelt by load center. Finally, the Optimized Generation Planning (OGP) model was used to develop the most cost effective generating plans for meeting projected power requirements.

The relationship between the models and their principal input and output data are shown on Figure 1. Figure 1 also shows the role of financial analysis in the selection of the final generation expansion plan.

Figure 1 illustrates the parameters and variables that are common to different models and the interdependency of the models. While the planning process moves generally from the PETREV model through the MAP, RED, and OGP models, there are instances where output from one model is fed back into a previous model. For example, electricity prices are first estimated and used in the RED model to compute electric energy projections. These projections are then used by the OGP model to develop a generation expansion plan and the associated cost of electricity. If there is a significant difference between the estimated and computed data, the models are rerun.

The following sections summarize each of the four principal models, including their respective submodels and modules, key input variables and parameters, and primary output variables. Additional information on the MAP model may be found in Appendix B-3, which presents a detailed description of the model including a complete listing of its equations and input variables and parameters. Appendix B-4 presents similarly detailed documentation of the RED model.

5.3.2.2. PETREV PETROLEUM REVENUE FORECASTING MODEL

State petroleum revenues currently constitute approximately 85 percent of total state revenues. For this reason, and because state revenues and expenditures are important determinants of future state economic conditions, state petroleum revenue projections are generated by a specialized model, PETREV, operated by the Alaska Department of Revenue (DOR). PETREV is structured to take into account the uncertainties associated with forecasting petroleum revenues. Using PETREV, the DOR issues revised petroleum revenue projections on a quarterly basis, using the most current data available on petroleum production, world oil prices, tax rates, regulatory events, natural gas prices, and inflation rates.

PETREV is an economic accounting model that identifies sources of state petroleum revenue, examines the factors that influence revenue levels, projects alternative values for those factors, and relates those factors to the sources of state petroleum revenues from production taxes and royalties. The principal factors influencing the level of petroleum revenues are petroleum production rates, mainly on the North Slope, the market price of petroleum, the costs associated with moving the petroleum from the wellhead to market, petroleum quality differences, tax and royalty rates applicable to the wellhead value of petroleum, and regulatory factors affecting any of the other factors. Wellhead value is estimated by a netback approach whereby the costs of processing and transporting the crude is subtracted from the market value at its destination on the West Coast or Gulf Coast of the United States.

A change in the market price of petroleum of a given percentage has a greater percentage impact on state petroleum revenues. This occurs because the costs of transportation and processing are relatively stable, so the wellhead price, on which state petroleum revenues are based, rises and falls almost dollar for dollar with world oil prices, producing a larger percentage effect on the wellhead value.

Due to the many uncertainties involved in forecasting revenues, the forecasting model projects a range, or frequency distribution, of state petroleum revenues by year, so that for each year a forecasted petroleum revenue figure may be selected based on a given cumulative frequency of occurrence. The model accomplishes this by iteratively selecting a set of input data from among the alternative input variable values and computing a petroleum revenue figure for each time period. Each projection is computed using a set of accounting equations that simulate the generation of petroleum revenues from each state oil and gas lease for each time period. By selecting the average value of all input data the model produces an average petroleum revenue forecast.

- Petroleum Revenue Sensitivity Accounting Model

  Because of the uncertainties in projecting petroleum prices and their importance in developing alternative generation plans and load forecasts, it is necessary to examine the implications of several different world oil price projections in addition to the price projections developed by the DOR. This need is accommodated by DOR through a petroleum revenue sensitivity accounting model. This sensitivity accounting model which is in effect a submodel of the PETREV model, utilizies the accounting equations and average values for all input variables other than world oil prices from PETREV, to compute an adjustment to PETREV's average petroleum revenue forecasts based on different assumed world oil price forecasts. By executing the sensitivity model with the alternative petroleum price projections, alternative petroleum revenue projections are developed for use in the MAP model.

  Most of the petroleum revenues are available for state expenditures for operations and capital construction. Twenty-five percent of state royalties are, by constitutional provision, provided directly to Alaska's permanent fund.

The process of projecting state petroleum revenues and the functions of the PETREV model are presented in some detail in the quarterly report entitled "Petroleum Production Revenue Forecast." (Alaska Department of Revenue, March 1983). The petroleum revenue projections used in preparing the electric power market and economic forecasts are based on the March 1983 average expected values of all factors, including petroleum production, other than petroleum prices.

While production rates can be estimated with reasonable accuracy for the next decade because of the long lead time required to put a field into production in Alaska, higher world petroleum prices could be expected to result in higher levels of exploration and development and, by the 1990's, higher levels of production. Production rates from the North Slope, the source of most state production taxes and royalties, are projected to be approximately 1.6 million barrels per day (MMB/d) in 1983, to peak at nearly 1.8 MMB/d in 1987, and to steadily decline to .7 MMB/d in 1999 (Alaska Department of Revenue March 1983). The petroleum production projections assume continued production from operating fields, production from fields now being developed, and modest levels of production in the 1990's from new fields (Alaska Department of Revenue March 1983). The difference between petroleum revenue projections would be greater if different petroleum production levels were assumed to occur due to higher petroleum prices.

5.3.2.1 Man-in-the-Arctic Program (MAP) Economic Model

The MAP model is a computer-based economic model that simulates the behavior of the economy of the state of Alaska and each of twenty regions of the state corresponding to Bureau of the Census divisions. The Railbelt consists of six of those regions: Anchorage, Fairbanks, Kenai-Cook Inlet, Matanuska-Susitna, Seward, and S.E. Fairbanks. The model, which is in the public domain, was originally developed in 1975 by the Institute of Social and Economic Research of the University of Alaska, under a grant from the National Science Foundation. The model has been continually improved and updated since it was origially written, and has been used in numerous economic analyses such as evaluation of the economic effects of alternative state fiscal policies and assessment of economic effects of development of outer continental shelf petroleum leases. An important application of the MAP model has been in providing economic forecasts in support of electric demand forecasts. It has been used since 1980 in preparing economic forecasts in support of planning and design for the Susitna Hydroelectric Project.

The MAP Model Technical Documentation Report, prepared by the Institute of Social and Economic Research, presents a detailed description of the model, including model logic, the historic economic conditions on which the model is based, the complete economic forecasts used in electric power market forecasting, input variables and parameters, the operation of sub-models, sensitivity tests, model validation, and use of the model. The technical documentation report allows the reader to reproduce the forecasts prepared for the electric power market forecasts and to make certain changes in economic or policy assumptions to determine the effect such changes would have on economic forecasts. However, while the technical documentation report does permit the reader this capability, execution of the model by persons unfamiliar with its logic and specifications would be a tedious task. A more expeditious means for testing the effects of modifying assumptions or input parameters would be to have the model executed by ISER using the user's assumptions. Additional background information on the MAP model may be found in Volume 9 - Alaska Economic Projections for Estimating Electricity Requirements for the Railbelt, the Railbelt, Battelle Pacific Northwest Laboratories, September 1982.

- Map Model Submodels

The MAP model functions in effect as three separate but linked sub-models, as illustrated in Figure 5-2. The scenario generator sub-model enables the user to quantitatively define a scenario of development in exogenous industrial sectors; i.e., sectors whose development is basic to the economy rather than supportive. Examples of such sectors are petroleum production and other mining, the federal government, and tourism. The scenario generator sub-model also enables the user to implement assumptions concerning state revenues from petroleum production.

The statewide economic sub-model develops projections of numerous economic and demographic factors based on quantitative relationships between elements of the Alaskan economy such as employment in basic industries, employment in non-basic industries, state revenues and spending, wages and salaries, gross product, the consumer price index, population, and housing.

The regionalization sub-model enables the user to disaggregate the statewide projections to each of the 20 separate regions of the state, using data on historical and current economic conditions and assumptions concerning basic industrial development.

Each of the three MAP sub-models exists as a computer program, and each program is supported by a set of input variables and parameters. Each of these programs and the supporting input variables and parameters are discussed briefly in the following sections. Detailed information on each sub-model, including a complete listing of the model and the input variables and parameters used in executing the model, is provided in the MAP Model Technical Documentation Report.

Scenario Generator Sub-Model

In order to operate the MAP model, the user must make a number of assumptions concerning the future development of basic industries in the State. Such assumptions are needed because the state economy is driven by interrelated systems of endogenous and exogenous demands for goods and services. Endogenous demands are generated by the resident population and industries that serve that population. Endogenous demands and economic development stemming from such demands are forecasted by measuring and extending the relationships between economic and demographic factors and incorporating discernable trends.

Exogeneous demands originate outside Alaska due to the favorable position of the state to export goods or services to other states or countries. In Alaska, exogenous demands stem from the state's natural resource base, especially petroleum, non-energy minerals, federal property, and tourist attractions. Exogenous demands lead directly to employment in basic sectors such as mining, and indirectly to employment and output in industries such as oil field services that support basic industry and industries such as housing and restaurants that support workers in basic industries and their families.

The scenario generator model permits the user to select, from among a large number of alternative basic industrial cases, those cases that should be assumed for forecasting economic conditions in the state of Alaska and, for purposes of the Susitna Hydroelectric Project, the Railbelt. Cases are in the form of employment projections by sector and region of the state.

The scenario generator model is also used to select the level of state petroleum revenues that should be assumed available to the state's general fund for expenditure on state government operations and capital investment. As indicated above, petroleum revenues constitute a large proportion of total state revenues which provide the basis for state expenditures, an important component of the Alaskan economy.

Output from the scenario generator model for each of the six petroleum price cases is shown in Appendix K of the MAP Model Technical Documentation Report.

Statewide Economic Sub-Model

The statewide economic model is a system of simultaneous equations that individually and collectively define the quantitative relationships between economic and demographic factors in Alaska. The more than 1,000 equations in the model are made up of dependent variables whose values are computed by the model, input data from the scenario generator whose values can be expected to vary from one execution of the model to the next, and parameters, whose values are generally fixed from one model execution to the next. The equations are solved algebraically each time the model is executed to produce a unique set of values for the dependent variables, some of which are computed only incidentally as part of the mathematical process and others of which constitute projections of statewide economic conditions.

While the equations in the statewide economic model are solved as a unit each time the model is executed, they are grouped for organizational and conceptual purposes into four modules: economic module, fiscal module, population module, and household formation module.

The equations in the economic module express relationships between economic factors such as employment in basic industrial sectors and output and employment in support sectors. Important products from the economic module include projections of employment and wages.

The fiscal module computes the contributions that state expenditures are likely to make to the Alaskan economy. A separate module was created for this purpose because of the significance of state expenditures to the state's economy and the model's periodic application in estimating the economic effects of implementing alternative state fiscal policies and assuming various alternative future state revenue levels. This module plays a key role in examining the fiscal and economic effects of different future world petroleum prices and state petroleum revenue levels. Specific assumptions concerning state spending are implemented in the fiscal module as state fiscal policy parameters, which are discussed below.

The population module expresses the relationships between population and economic factors recognized as key determinants of population. Such factors include employment, labor participation rates, fertility and mortality rates, and unemployment and wage rate differentials between Alaska and the rest of the United States.

Equations in the household formation module express the relationship between the formation of households in Alaska and population by age group, sex, and race. Each age-sex cohort has its own propensity to form households which, over the last few years has generally increased. This increase is expected to continue.

Results from the statewide economic model for each of the six petroleum price cases are listed in Appendix M of the MAP Model Technical Documentation Report.

Regionalization Sub-Model

Statewide economic and demographic forecasts are disaggregated by the regionalization model, the third sub-model of the MAP economic model. Disaggregation is accomplished by combining statewide projections with regional industrial development data from the scenario generator model and regional parameters based on historical economic and demographic relationships between each region and the state. This process produces projections by region or region group such as the Anchorage-Cook Inlet and Fairbanks-Tanana Valley regions.

- Input Variables and Parameters

As indicated above, input variables are factors whose values are provided by the user to the model and whose values can be expected to change from one execution of the model to the next. Parameter values are generally fixed during the course of successive model executions.

Input Variables

Sixteen input variables are used by the scenario generator model to define the exogenous economic assumptions for each model execution. Of these 16 variables, listed in Table 5-1, 11 are used to define discrete industrial developments and are therefore region specific.

The remaining five input variables are elements of state revenue forecasts. Estimates of future state petroleum revenue from state petroleum production taxes and royalties are obtained from projections generated by the Alaska Department of Revenue based, for purposes of the Susitna Hydroelectric Project, on alternative projections of world petroleum prices. The Institute of Social and Economic Research provides corresponding estimates of future state lease bonus payments, state petroleum property taxes, and state petroleum corporate taxes.

In addition to factors regarded technically as input variables, several other factors may be varied from one MAP model execution to the next but are generally left constant. These variable parameters include factors such as the U.S. Consumer Price Index and unemployment rate.

Table 5-2 summarizes the principal assumptions behind the selection of basic industry, government employment, and tourism input variables for the base or most likely scenario, as well as key national economic assumptions. Additional information on input variables and assumptions is provided in Appendix K of the MAP Model Technical Documentation Report.

Parameters

The MAP model utilizes three types of parameters: variable state fiscal policy parameters, stochastic parameters, and calculated parameters.

Variable state fiscal policy parameters are used primarily in the fiscal module to represent assumed relationships between variables such as state revenues and expenditures.

These parameters, which may be varied to reflect alternative state fiscal policies or events were left unchanged in preparing the electric power market forecasts for the Susitna Hydroelectric Project. The most important function of these parameters is to quantitatively define state expenditure and revenue policies. In projecting economic conditions for the Susitna Hydroelectric Project, the following assumptions were made:

- state expenditures for operations and capital improvements in 1983 dollars will rise in proportion to state population as long as revenues can support this level of expenditure; this assumption is in accordance with a 1982 amendment to the Alaska State Constitution setting a ceiling on state expenditures;

- when revenues from existing sources cannot support expenditures at the constant real per capita level, earnings from the permanent fund will be made available for operating and capital expenditures; as revenues decline state spending priorities shift from subsidies to capital improvements;

- when revenues from permanent fund earnings and other sources are not sufficient to maintain expenditures at the constant real per capita level, a state personal income tax will be reimposed at its earlier rate;

o when all of these revenue sources are unable to support expenditures at the constant real per capita level, expenditures will be curtailed so that they will not exceed revenues.

Stochastic parameters are coefficients computed using regression analysis. They are used primarily in the economic module of the statewide economic model to express the functional relationships between economic factors such as employment, wages and salaries, wage rates, gross product, and other national and regional economic factors such as unemployment and consumer price indices. Stochastic parameters are also used in the population module to express the relationship between population migration into and out of Alaska and wage rate and unemployment level differentials. Stochastic parameters are used where relationsips between variables can be defined with only a limited degree of certainty that a presumed relationship exists.

Calculated parameters are generally calculated rates or other quotients, and are used primarily in the population and household formation modules and the regionalization model. Calculated parameters include factors such as percent population by age group and sex, persons per household, and percent heads of household by age and sex. Calculated parameters used in the regionalization model include factors such as percent of state population, employment, and housing by region. Complete listings of model parameters are provided in Appendices G, H, and I of the Map Model Technical Documentation Report.

MAP Model Output

Six sets of economic forecasts through the year 2010 were generated based on the six petroleum price and state petroleum revenue cases and other input variables and parameters described above. For purposes of generating economic projections in years after 1999, the last year for which petroleum revenue projections are available from the Alaska Department of Revenue, petroleum revenue forecasts were extrapolated to the year 2010 using rates of change observed during the latter 1990's.

Specific factors used directly as input to the Railbelt Electricity Demand (RED) Model are the following:

- o population by load center, Greater Anchorage and Greater Fairbanks, by year 1981 through 2010;
- o total employment by load center by year;
- o total households in the state by age group of head of household - 24 and under years of age, 25-29, 30-54, and over 55 - by year;

o total households by load center by year;

A complete set of these projections, along with Railbelt population and employment totals, state population and employment totals, state petroleum revenues, and general fund expenditures for each of the six petroleum price cases by year is provided in Appendix N of the MAP Model Technical Documentation Report. Projections of additional related economic factors are also included in Appendix N.

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5.3.2.4 - Railbelt Elctricity Demand (RED) Model

The Railbelt Electricity Demand (RED) Model is a econometric-end use model that projects both electric energy and peak losf demand in the Anchorage-Cook Inlet and Fairbanks-Tanana Valley load centers of the Railbelt for the period 1980-2010. The model was originally written by the Institute of Economic and Social Research (ISER) of the University of Alaska in _____ for the Office of the Governor of Alaska. It was later modified and expanded by Battelle Pacific Northwest Laboratories.

Submodels of the RED Model

The RED Model is made up of seven separate for interrelated modules, each of which has a discrete computing function within the model. They are the uncertainty, housing, residential consumption, business consumption, program-induced conservation, miscellaneous consumption, and peak demand modules. Figure ___ shows the basic relationship among the seven modules.

The model may be operated probabilistically, whereby the model produces a frequency distribution of projections where each projection is based on a different, randomly selected set of input parameters. The model may also be operated probabilistically, whereby only one set of forecasts is produced based on a single set of input variables. When operated probabilistically, the RED model begins by creating the Uncertainty Module, which selects a trial set of model parameters to be used by other modules. These parameters include price elasticities, appliance saturations, and regional load factors. Exogenous forecasts of population, economic activity, and retail prices for fuel oil, gas and economic activity, and retail prices for fuel oil, gas, and electricity are used with the trial parameters by the Residential Consumption and Business Consumption Modules to produce forecasts of electricity consumption. These forecasts, along with the additional trial parameters, are used in the Program-Induced Conservation Module to simulate the effects of government programs that subsidize or mandate the market penetration of certain technologies that reduce the need for power. This policy-induced component of conservation is in addition to those savings that would be achieved through normal consumer reaction to energy prices. The revised consumption forecasts of residential and business (commercial, small industrial, and government) consumption are used to estimate future miscellaneous consumption and total sales of electricity. These forecasts and separate assumptions regarding future major industrial loads are used along with a trial system load factor to estimate peak demand.

After a complete set of projections is prepared, the model begins preparing another set by returning to the Uncertainty Module to select a new set of trial parameters. After several sets of projections have been prepared, they are formed into a frequency distribution to allow the user to determine the probability of occurrence of any given laod forecast. When only a single set of projections is needed, the model is run in certainty-equivalent mode whereby, a specific default set of parameters is used and only one trial is run.

The RED model produces projections of electricity consumption by load center, sector, and 5-year interval. A linear interpolation is performed to obtain yearly data. This information may then be used by the Optimized Generation Planning Model to plan and dispatch electric generating capacity for each year. The remainder of this section presents brief descriptions of each module in the RED model.

Uncertainty Module. The purpose of the Uncertainty Module is to randomly select values for individual model parameters that are considered most subject to forecasting uncertainty. These parameters include the market saturations for major appliances in the residential sector; the price elasticity and substitute energy forms and cross-price elasticities of demand for electricity in the residential and business sectors; the intensity of electricity use per square foot of floor space in the business sector; and the electric system load factors for each load center.

These parameters are generated by a Monte Carlo routine, which uses information on the distribution of each parameter (such as its expected value and range) and the computer's random number generator to produce sets of parameter values. Each set of generated parameters represents a "trial". By runing each successive trial set of generated parameters through the rest of the modules, the model builds disstributions of annual electricity consumption and peak demand. The end points of each distributions reflect the probable range of annual electric consumption and peak demand, given the level of uncertainty.

The Uncertainty Module need not be run every time RED is run. The parameter file contains "default" values of the parameters that may be used to conserve computation time. However, the forecast of electric power requirements for the Susitna Hydroelectic Project was done using the certainty equivalent option.

The Housing Module. The Housing Module calculates the number of households and the stock of housing by dwelling type in each load center. Formerly, using exogenous state-wide forecasts of the number of households, household headship rates by age, the age distribution of Alaska's population, and regional forecasts of total population, the housing stock module first derived a forecast of the number of households in each load center. Now the MAP model produces estimates of the number of households by census area so the RED model has been modified to directly accept the MAP regional forecast of the number of households. The Housing Module then estimates the distribution of households by age of head and size of household in each load center. Finally, it forecasts the demand for four types of housing stock: single family, mobile homes, duplexes, and multifamily units.

The supply of housing is calculated in two steps. First, the supply of each type of housing from the previous period is adjusted for demolition and compared to the demand. If demand exceeds supply, construction of additional housing begins immediately. If excess supply of a given type of housing exists, the model examines the vacancy rate in all types of houses. Each type is assumed to have a maximum vacancy rate. If this rate is exceeded, demand is first reallocated from the closest substitute housing type, then from other types. The end result is a forecast of occupied housing stock for each load center for each housing type in each forecast year. This forecast is passed to the Residential Consumption Module.

Residential Consumption Module. The Residential Consumption Module forecasts the annual consumption of electricity in the residential sector. The Residential Consumption Module employs an end-use approach that recognizes nine major end uses of electricity, and a "small appliances" category that encompasses a large group of other end uses.

For a given forecast of occupied housing, the Residential Consumption Module first adjusts the housing stock to net out housing units not served by an electric utility for each type. It then forecasts the residential appliance stock and the portion using electricity, stratified by the type of dwelling and vintage of the appliance. Applicance efficiency standards and average electric consumption rates are applied to that portion of the stock of each appliance using electricity and the corresponding consumption rate to derive a preliminary consumption forecast for the residential sector. Finally, the Residential Consumption Module receives exogenous forecasts of residential fuel oil, natural gas, and electricity prices, along with "trial" values of price elasticities and cross-price elasticities of demand from the Uncertainty Module. It adjusts the preliminary consumption forecast for both short- and long-run price effects on appliance use and fuel switching. The adjusted forecast is passed to the Program-Induced Conservation and Peak Demand Modules.

Business Consumption Module. The Business Consumption Module forecasts the consumption of electricity by load center for each forecast year. Because the end uses of electricity in the commercial, small industrial, and government sectors are more diverse and less known than in the residential sector, the Business Consumption Module forecasts electrical use on an aggregate basis rather than by end use.

RED uses a proxy (the stock of commercial and industrial floor space) for the stock of capital equipment to forecast the derived demand for electricity. Using employment projections and a trend in square feet of commercial (and light industrial) floor space per employee, the module forecasts the regional stock of floor space. Next, econometric equations are used to predict the intensity of electricity use of a given level of floor space in the absence of any relative price changes. Finally, a price adjustment similar to that in the Residential Consumption Module is applied to derive a forecast of business electricity consumption, excluding large industrial demand, which is exogenously determined. The Business Consumption Module forecasts are passed to the Program-Induced Conservation and Peak Demand modules.

Program-Induced Conservation Module. Because of the potential importance of government subsidized programs in the market place to encourage conservation of energy and substitution of other forms of energy for electricity, the RED model includes a module that permits explicit treatment of government programs to foster additional market penetration of technologies and programs that reduce the demand for utility-generated electricity. The module structure is designed to incorporate assumptions on the technical performance, costs, and market penetration of electricity-saving innovations in each end use, load center, and forecast year. The module forecasts the additioal electricity savings by end use that would be produced by government programs beyond that which would be induced by market forces alone, the costs associated with these savings, and adjusted consumption in the residential and business sectors.

Miscellaneous Consumption Module. The Miscellaneous Consumption Module forecasts total miscellaneous consumption for second (recreation) homes, vacant houses, and other miscellaneous uses such as street lighting. The module uses the forecast of residential consumption to predict electricity demand in second homes and vacant housing units. The sum of residential and business consumption is used to forecast street lighting requirements.

Peak Demand Module. The Peak Demand Module forecasts the annual peak demand for electricity. The annual peak load factors were based on historical Railbelt load patterns.[4/] A two-stage approach using load factors is used. The unadjusted residential and business consumption, miscellaneous consumption, and load factors generated by the Uncertainty Module are first used to forecast preliminary peak demand. Next, displaced consumption (electricity savings) calculated by the Program-Induced Conservation Module is multiplied by a peak correction factor supplied by the Uncertainty Module to allocate a portion of electricity savings from conservation to peak demand periods. The allocated consumption savings are then multiplied by the load factor to forecast peak demand savings, and savings are subtracted from peak demand to forecast revised peak demand. Separate estimates of peak demand for major industrial loads are then added to compute annual peak demand for each load center.

Input Data. There are five input data files to the RED model. The RDDATA file contains output data of the MAP model, including load center population, households, and employment and state household by age group, and the real prices of fuel oil and natural gas, by load center and end-use sector.

The RATE DAT file contains the real prices of electricity by load center and ened-use sector. These prices are derived from the OGP results.

The PARAMETER file contains the numerical values that describe the distributions of the parameters varied in the Uncertainty module. These variables are: housing demand coefficients; saturation rate of electrical applicances, floor space elasticities; short-term and long-term own-price and cross-price elasticities for electricity, fuel oil, and natural gas; and annual laod factors.

The EXTRA DAT file contain s information on the annual electrical consumption and peak demand of large industrial projects.

4/ Two sources were utilized in this effort. The first was Woodward Clyde Consultant's 1980 study Forecasting Peak Electrical Demand for Alaska's Railbelt (Final Report), prepared for Acres American, Inc. The second was statistical series from 1970 through 1981 load factors by month for the Anchorage-Cook Inlet and Fairbanks-Tanana Valley load centers.

The CONSER DAT file contains information on the technical a·' narket characteristics of conservation options, both for subsidized and non-subsidized options. Up to 10 residential conservation options may be specified. Business sector conservation is handled as a single unit.

- Output Data The RED output report contains various tables generated by the program. The main tables are the following:

- Number of households for each load center, forecast year (1980, 1985, --- 2010), and type of housing (single family, multifamily, duplex, and mobile homes);
- Residential appliance saturations for each load center, forecast year, and type of housing;
- Residential use per household without price elasticity adjustments for each load center, forecast year, and appliance category (small appliance, large appliance, and space heat);
- Business use per employee with price elasticity adjustments for each load center, and forecast year;
- Electric energy requirements for each load center, year, and category of consumption (residential, business, miscellaneous, incremental conservation savings, and total which includes large industrial projects);
- Peak electric requirements for each load center and year.

Additionally, more detailed information about the RED Model is available in Battelle Pacific Northwest Laboratories 1982, and . . .

5.3.2.5 - Optimized Generation Planning

The OGP model was developed by General Electric Company (GE). The following description of the model was extracted from the GE descriptive handbook.[3] The model combines the three elements of generation expansion planning system reliability, operating and investment costs and generation addition analysis. Figure 4 outlines the procedure used by OGP to determine an optimum generation expansion plan. The following paragraphs describe the reliability evaluation, the optimization procedure, and the production costing simulation. A description of the input and output files is also provided.

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[3] General Electric Company, Descriptive Handbook, Optimized Generation Planning Program, March 1983.

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- o Residential use per household without price elasticity adjustments for each load center, forecast year, and appliance category (small appliance, large appliance, and space heat);
- o Business use per employee with price elasticity adjustments for each load center, and forecast year;
- o Electric energy requirements for each load center, year, and category of consumption (residential, business, miscellaneous, incremental conservation savings, and total which includes large industrial projects);
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3/ General Electric Company, Descriptive Handbook, Optimized Generation Planning Program, March 1983.

Reliability Evaluation. The user can specify one of three possible reliability criteria: daily or hourly loss-of-load probability (LOLP), and percent reserve margin. A LOLP of 1 day for 10 years was used.

Generation Expansion and Production Costing Simulation. In OGP, the fuel and related operating and maintenance costs are determined by an hourly simulation of the system's operation. The basic sequential functions of the operational strategy are outlined in the followig six steps:

- Determine load modification based on recognition of contractual purchases and sales (i.e., reflect firm contracts).
- Schedule conventional hydro.
- Schedule monthly thermal unit maintenance based on planned outage rates or specific maintenance periods.
- Schedule pumped storage hydro or other types of energy storage.
- Commit thermal generating units to serve the remaining loads based on economics or environmental factors, spinning reserve rules, and unit cycling capabilities.
- Dispatch the generation based on relative production costs and environmental emissions specified by the user.

The production simulation performed is for a total utility system or pool commitment and dispatch assumed to have an unlimited power transfer capability between areas or companies internal to the pool represented. The following paragraphs describe how OGP follows the six steps outlined above to determine production costs. It also discusses the commitment and dispatch of units with fuel or energy limits.

The hourly loads are initially modified by OGP to consider the firm purchases and sales that exist between the area being studied and entities outside that area.

The power and energy available from any conventional hydroelectric project used in the simulation is divided into two types: base load and peak load. The base load energy that must be produced is accounted for by subtracting a constant capacity from every hourly load in the month as shown on Figure 6. This capacity value is referred to as the plant minimum rating. After this base load energy is used, any remaining energy available is used for peak shaving. In such situations, the program uses the remaining capacity and energy of the hydro unit to reduce the peak loads as much as possible. If any excess energy exists at the end of a month, a user-specified maximum storage amount can be carried forward into the next month.

Maintenance schedules designed to account for planned downtime, due to activities such as repairs or refueling, are developed by OGP for each generating unit based on user-specified planned outage rates. The peak loads are examined throughout the year, and individual generating units are scheduled in an attempt to levelize the peak load plus capacity on maintenance throughout the year.

The system operating conditions involved when pump-storage hydro or other energy storage devices are available must also be considered. Energy storage scheduling algorithms have been included in production costing programs for some time. Although usually referred to as pumped-storage hydroalgorithms, they have been utilized to study other energy storage devices on electric utility systems such as batteries and thermal storage.

After modifications for contracts, hydro, and energy storage operations have been made, the remaining loads must be served by the thermal units on the system. The cost characteristics of thermal generating units are modeled using a single incremental heat rate. Specific unit operating costs are determined by the fuel input curve, fuel cost, and variable O&M cost. Specific unit operating costs are determined by the fuel input curve, fuel cost and variable O&M cost. In order to minimize the thermal generating unit operating expense of a power system, two fundamental objectives must be met: (1) the number of units committed each hour should be minimized, subject to the commitment policy and operating constraints of the power system, and (2) the generating units in each commitment, as determined for the first objective, should be dispatched on an equal incremental cost basis.

The dispatching function loads the incremental sections of the committed units in order to serve the demand at minimum system fuel cost. This dispatch technique is referred to as the equal incremental cost approach (or minimum incremental cost approach). The incremental loading sections are dispatched beginning with the least expensive unit. When enough incremental loading sections have been scheduled so the load is served, the remaining unloaded incremental sections will be the most expensive. Thus, the system spinning reserve margin is allocated to the generating units so system fuel costs are minimized. At this point, loading level established, the hourly energy disposition is scheduled, and the hourly production cost is determined for each unit.

- <u>Input Data</u> There are two major input files to OGP: the Generation file and the Load file. The Generation file model is created for use as a data base representing the in-service and on-order generating units. For each unit, the following characteristics are described:

- o Type of generator
- o Unit sizes and earliest service year allowable
- o Unit costs
- o Fuel types and costs
- o Operation and maintenance costs
- o Heat rates
- o Commitment minimum uptime rule
- o Forced outage rates
- o Planned outage rates

The Load file is specified by the user to represent peak and shape characteristics which are projected to occur for the years included in the OGP study. The user supplies the following load shape data:

- o Annual peak and energy demand
- o Month/annual ratios
- o The 0%, 20%, 40%, and 100% points on the peak load duration curve, by month
- o Typical weekday and weekend-day hourly ratios by month

- <u>Output Data</u> Output options have been designed and included in OGP to provide the user with flexibility in the level of detail and volume of documentation received. Complete batch output reports as well as summary outputs are available.

The output available from the OGP program includes the following information:

- Listing of the input data.
- Standard tables, as defined by the user, for various unit characteristics.
- Listing of the unit types and sizes available for optimization and their characteristics.
- Listing of the Load file for the study period.
- Listing of the generating units on the system and their characteristics.
- Year-by-year summary of the firm contracts input by the user.
- Production simulation summaries, listing all of the generating units of the system with their energy output, fuel and O&M costs, fuel consumption, and environmental emissions. These summaries can be obtained on a monthly or annual basis, for all the decision passes or just the optimum system.
- Summary of all the expansion alternatives, with their associated costs and reliability measures, evaluated during the optimization.
- Summaries of the final system expansion through time and the associated costs.

(c) Development of Alternative Planning Scenarios

The purpose of this section is to trace the alternative assumptions of key variables and particularly the effect of those concerning world oil prices through the model presented in Section 1 and the process outlined on Figure 2. The variables discussed in this section are identified by a letter in parenthesis. These letters correspond to those shown on Figure 2. Figure 2 is a network diagram which identifies the flow of world oil price scenarios through the planning process indicating branches where other parameters are varied.

World Oil Price

The most significant variable affecting the power market forecasts and the economic and financial feasibility of the Susitna Project is the world oil price (A). The base year world oil price in 1983 is taken at about $29/bbl but several different oil price paths are assumed over the period 1983 through 2010 depending on the forecast adopted. The overall escalation rates for each of the forecasts identified in Section (b) are as follows:

Source	1983-2010 Escalation Rate (%)
SHCA-base case	3.65
SHCA-NSD	2.01
FERC +2	2.0
FERC 0	0
FERC -1	-1.0
FERC -2	-2.0

All six forecasts will be carried through the planning process to the output of the RED model. Because of the many variables and alternatives which are examined at various stages during the planning process, it has been decided to limit the number of assumed world price of oil projections from six to one for the OGP model and the financial analysis, specifically, SHCA's oil price projection has been adopted.

PETREV and MAP Models

In general, the future movement of world oil prices would affect the development of new fields and production rates, and DOR has considered this relationship in their model. Therefore, petroleum production variables (B) corresponding to each world oil price assumption case are considered although the impact on petroleum production might be insignificant in terms of the PETREV projections.

5.3.3 MODEL VALIDATION

Both the MAP and RED models are used to simulate future conditions based on alternative assumptions concerning world and state economic conditions and electricity demand in the Railbelt. Measures that have been taken to ensure that both models simulate economic and electricity utilization conditions and relationships as accurately as possible are summrized below.

5.3.3.1 MAP MODEL VALIDATION

- MAP Model

Validation of the MAP Model has been accomplished using two separate but interrelated techniques. First, a standard set of statistics was computed for each of the stochastic parameters used in the MAP model equations. These statistics provide information on the expected accuracy of each coefficient and the probability that each coefficient expresses the correct relationship between variables. Second, the MAP model was tested to determine the accuracy with which it could simulate observed historical conditions.

Stochastic Parameter Tests

Stochastic parameters are, as indicated above, coefficients computed using regression analysis, a statistical procedure whereby the quantitative relationship between variables is estimated by one or more computed coefficients. Most of the equations in the economic module of the statewide economic model are computed using regression analysis.

In estimating coefficients using regression analysis a number of statistics are computed that indicate the accuracy of the coefficient and the overall efficiency of the equation in estimating the true value of the dependent variable. Among these statistics are t-values and correlation coefficients. They are used both in selecting the best independent variables for estimating a given dependent variable and in determining the expected accuracy of the final equation.

Correlation coefficients, t-values, and several other statistics have been computed for each stochastic equation used in the MAP model. In each equation efforts have been made to obtain the highest possible values for these statistics in order to ensure that the model reflects actual economic relationships as accurately as possible. As a result of this effort all the coefficients used in the MAP model have a relatively high level of statistical significance. Statistics are listed by equation in the MAP Model Technical Documentation Report Appendix H.

Simulation of Historical Economic Conditions

Although the MAP model has been in use since 1975, analyses conducted for the Susitna Hydroelectric Project were the first applications of the model in long range projection of economic conditions. Previous applications of the model had been in analysis of economic effects of alternative state policies. It is not possible, therefore, to test the model's projection accuracy using old forecasts. However, the model's accuracy was tested by simulating historcal economic conditions by executing the model utilizing historical data and input variables. Table 5-6 summarizes the results of simulation of selected historical conditions. The table shows that the MAP model reproduces historical conditions with reasonable accuracy. More complete results of this test are shown in appendices B and C of the MAP Model Technical Documentation Report.

TABLE 5-6

SIMULATION OF HISTORICAL ECONOMIC CONDITIONS

Factor					
Non-Agriculatural Wage and Salary Employment	1965	70,529	70,406	-123	-.174
	1970	92,465	88,837	-3,628	-3.924
	1975	161,315	154,893	-6,422	-3.981
	1980	169,609	166,281	-3,328	-1.962
Wages and Salaries In Alaska - $million - nominal	1965	721	757	36	4.9
	1970	1,203	1,134	-69	-5.7
	1975	3,413	3,408	-5	-0.1
	1980	4,220	4,083	-182	-4.3
Personal Income In Alaska - $million - nominal	1965	827	861	34	4.1
	1970	1,388	1,309	-79	-5.7
	1975	3,455	3,372	-83	-2.4
	1980	5,030	4,972	-58	-1.2

Results based on February 1983 execution of MAP Model.

5.3.3.2 RED MODEL VALIDATION

To be completed

Figure 1

RELATIONSHIP OF PLANNING MODELS
AND INPUT DATA

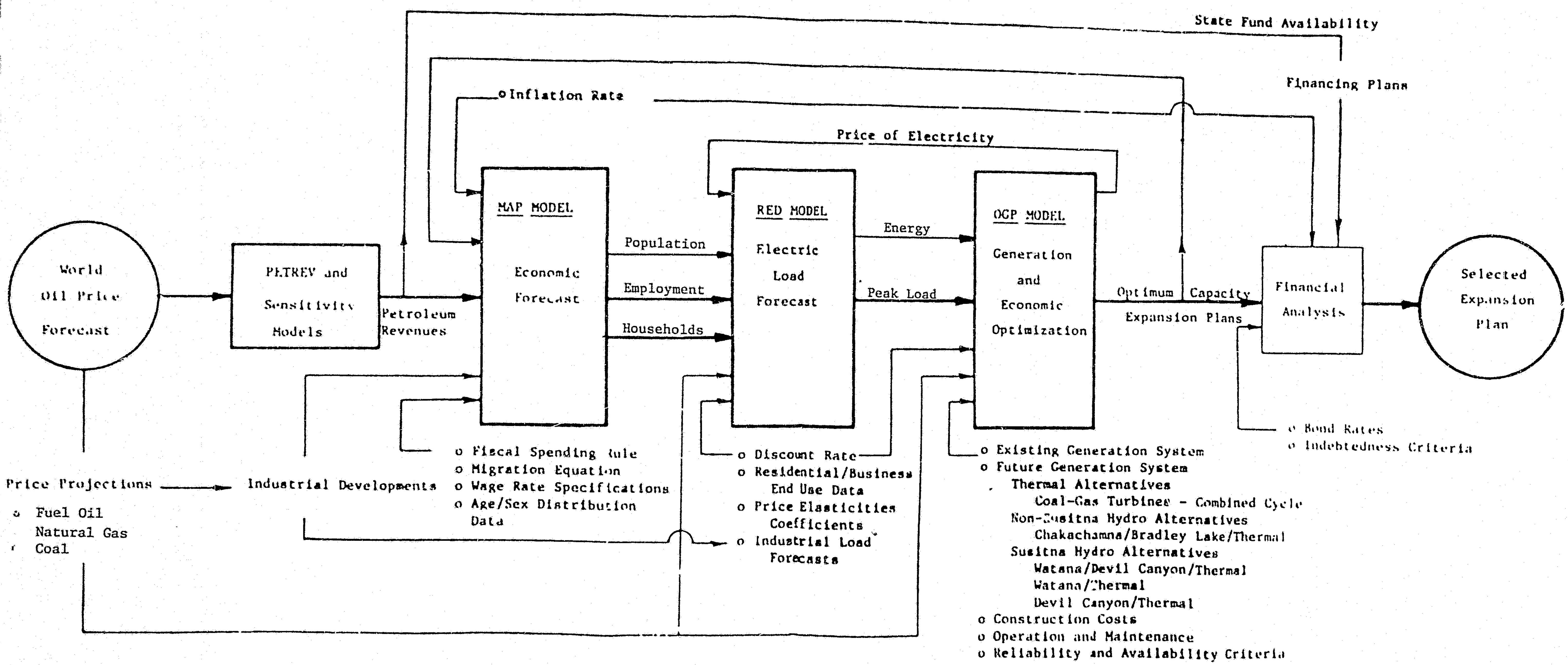


Figure 1

RELATIONSHIP OF PLANNING MODELS
AND INPUT DATA

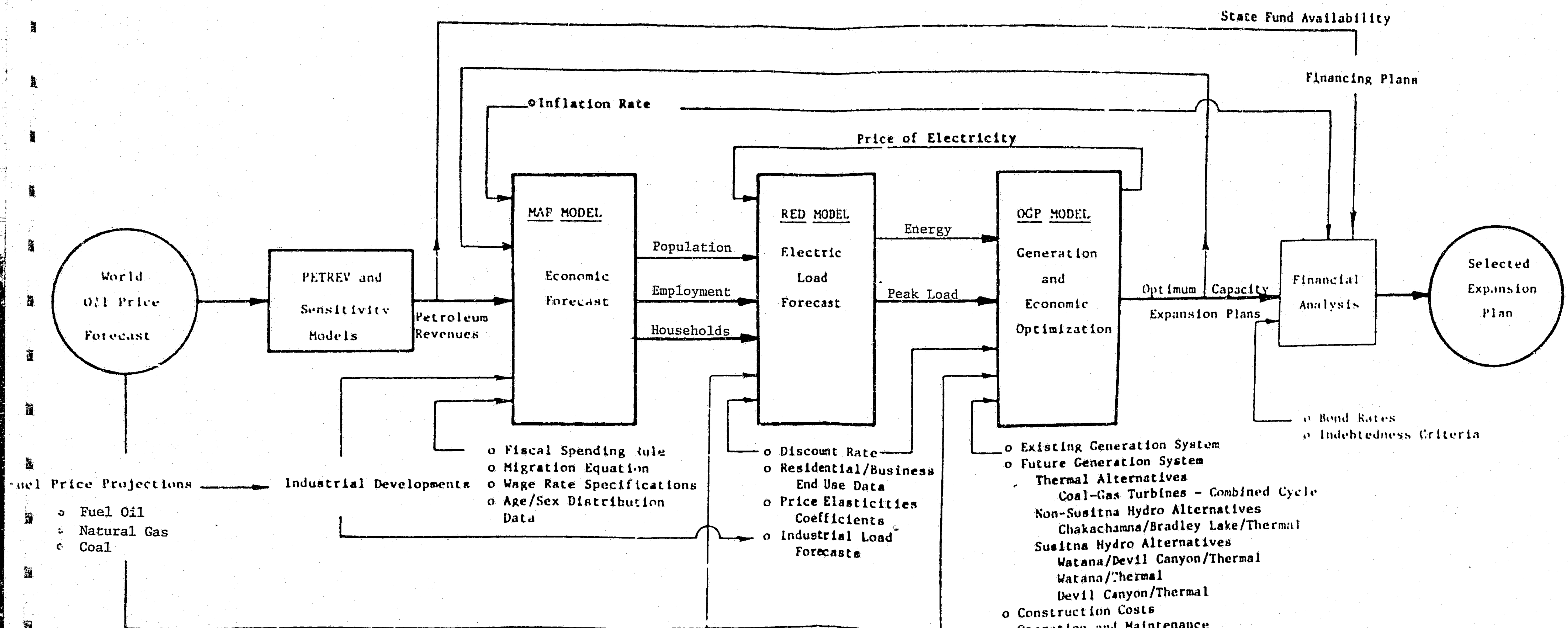


TABLE 5-1

LIST OF MAP-MODEL INPUT VARIABLES

Employment in Basic (Exogenous) Industrial Sectors:
- Agriculture
- Mining
- High Wage Exogenous Construction (e.g. enclave type pipeline construction)
- Low Wage Exogenous Construction (e.g. office building construction)
- High Wage Exogenous Manufacturing (e.g. new oil refinery operation)
- Sectoral Average Wage Exogenous Manufacturing (all current manufacturing)
- Exogenous Transportation (e.g. pipeline maintenance)
- Fish Harvesting

Tourism
- Number of Tourists Annually

State Petroleum Revenues
- State Petroleum Production Tax Revenues
- State Petroleum Royalty Revenues
- State Petroleum Lease Bonus Payments
- State Petroleum Property Tax Revenues
- State Petroleum Corporate Tax Revenues

TABLE 5-32

SUMMARY OF EXOGENOUS ECONOMIC ASSUMPTIONS

Exogenous Employment Assumptions

Trans-Alaska Oil Pipeline System	Operating employment remains constant at 1,500 through 2010.
Prudhoe Bay Field Employment	Construction employment developing Prudhoe Bay and Kuparuk fields peaks at 2,400 in 1983 and 1986. Operating employment remains at 2,502 through 2010 for overall North Slope production.
Upper Cook Inlet Petroleum Production	Employment declines gradually beginning in 1983 so as to reach 50 percent of the 1982 level (778) by 2010.
Tertiary Recovery of North Slope Oil	Tertiary oil recovery project utilizing North Slope natural gas occurs in early 1990s with a peak annual employment of 2,000.
OCS Exploration and Development	The current OCS five-year leasing schedule calls for 16 OCS lease sales subsequent to October 1982, including the Beaufort, Norton, and St. George Sales, which have already taken place (Sales 71, 57, and 70). Development is assumed to occur only in the Navarin Basin (1.4 billion barrels of oil) and the Beaufort Sea (6.1 billion barrels of oil). All other sales are assumed to result in exploration employment only.
Anchorage Oil Headquarters	Several oil companies establish regional headquarters in Alaska in mid-1980s.
Beluga Chuitna Coal Production	Development of 4.4 million ton/year mine for export beginning in 1994 provides total total employment of 524.
Hydroelectric Projects	Employment peaks at 725 in 1990 for construction of several state-funded hydroelectric projects around the state.

TABLE 5-2 (Continued)

SUMMARY OF EXOGENOUS ECONOMIC ASSUMPTIONS

Exogenous Employment Assumptions

U.S. Borax Mine	The U.S. Borax mine near Ketchikan is brought into production with operating employment of 790 by 1988.
Greens Creek Mine	Production from the Greens Creek Mine on Admiralty Island results in employment of 315 people from 1986 through 1996.
Red Dog Mine	The Red Dog Mine in the Western Brooks Range reaches full production with operating employment of 448 by 1988.
Other Mining Activity	Employment increases from a 1982 level of 5,267 at 1 percent annually.
Agriculture	Moderate state support results in expansion of agriculture to employment of 508 in 2000.
Forest and Lumber Products	Employment expands to over 3,200 by 1990 before beginning to decline gradually after 2000 to about 2,800 by 2010.
Pulp Mills	Employment declines at a rate of 1 percent per year after 1983.
Commercial Fishing-Nonbottomfish	Employment levels in fishing and fish processing remain constant at 6,323 and 7,123 respectively.
Commercial Fishing-Bottomfish	The total U.S. bottomfish catch expands at a constant rate to allowable catch in 2000, with Alaska resident harvesting employment rising to 733. Onshore processing capacity expands in the Aleutians and Kodiak census divisions to provide total resident employment of 971 by 2000.

SUMMARY OF EXOGENOUS ECONOMIC ASSUMPTIONS

Exogenous Employment Assumptions	
Federal Military Employment	Employment remains constant at 23,323.
Federal Civilian Employment	Rises at 0.5 percent annual rate from 17,900 in 1982 to 20,583 by 2010.
Tourism Assumptions	Number of visitors to Alaska increases by 50,000 per year from 680,000 in 1982 to over 2 million by 2010.
National Variables Assumptions	
U.S. Inflation Rate	Consumer prices rise at 6.5 percent annually after 1985.
Real Average Weekly Earnings	Growth in real average weekly earnings averages 1 percent annually.
Real Per Capita Income	Growth in real per capita income averages 1.5 percent annually after 1984.
Unemployment Rate	Long-run rate of 6 percent.

FIGURE 5-2

MAP MODEL SYSTEM FLOWCHART

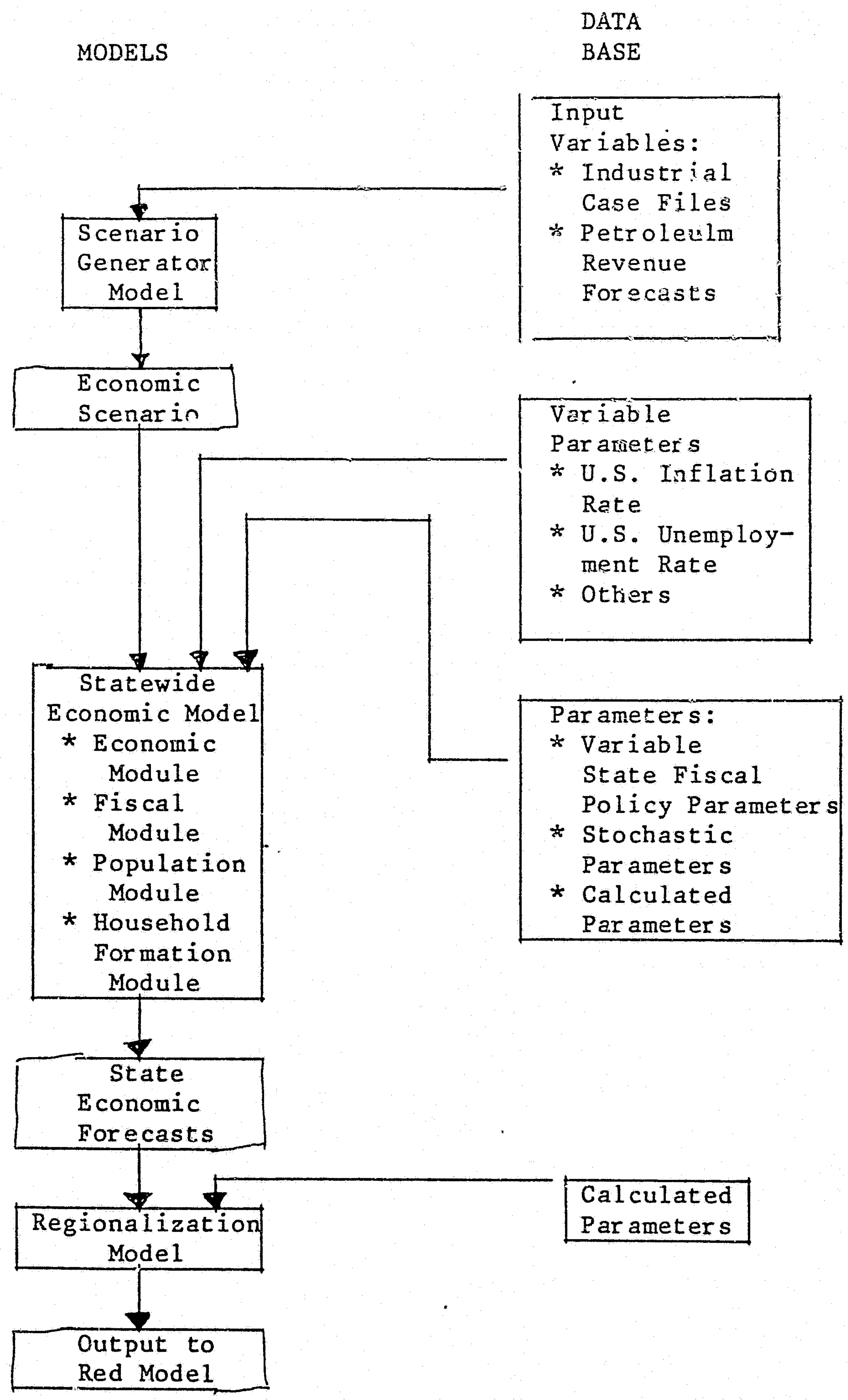
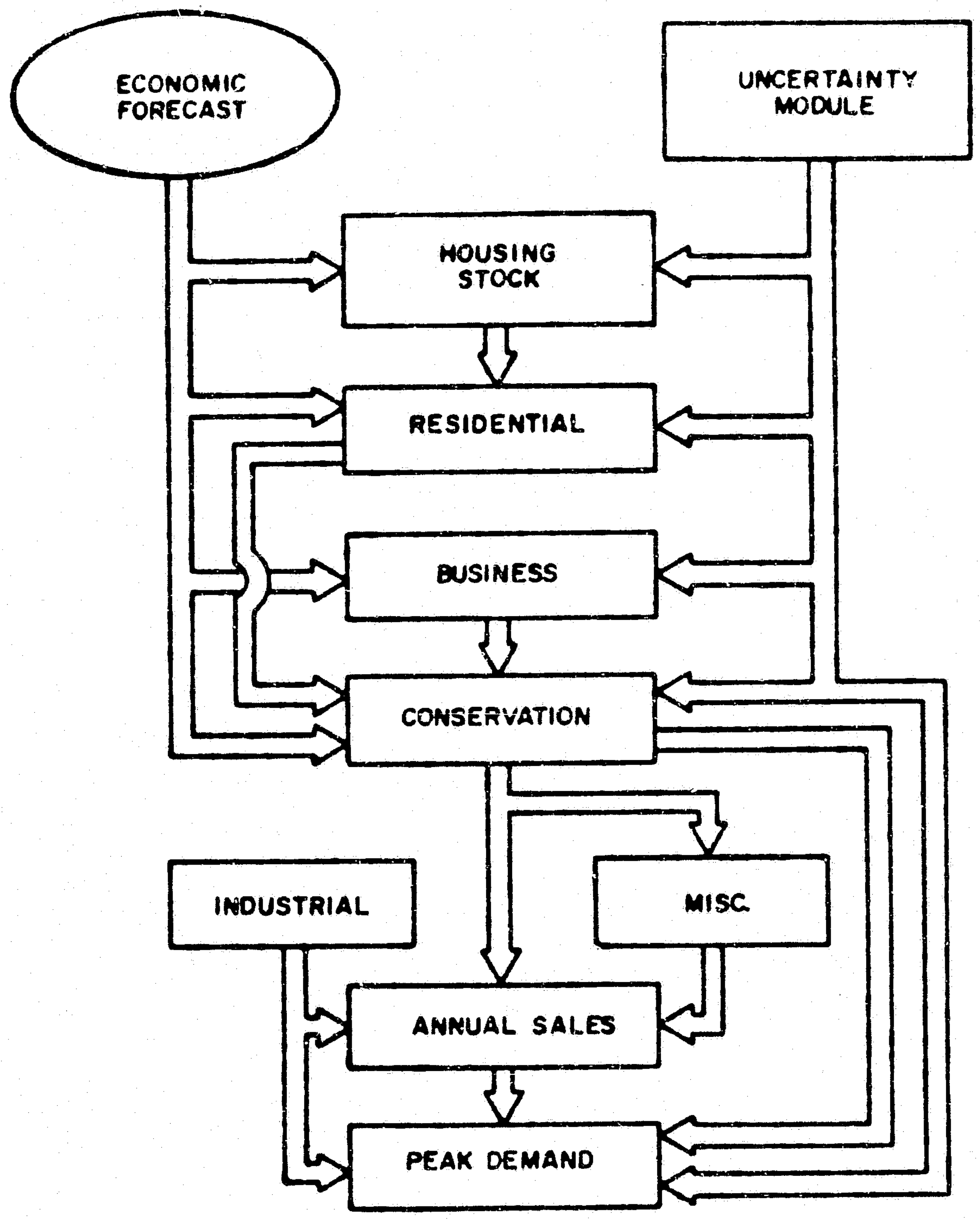


EXHIBIT 4

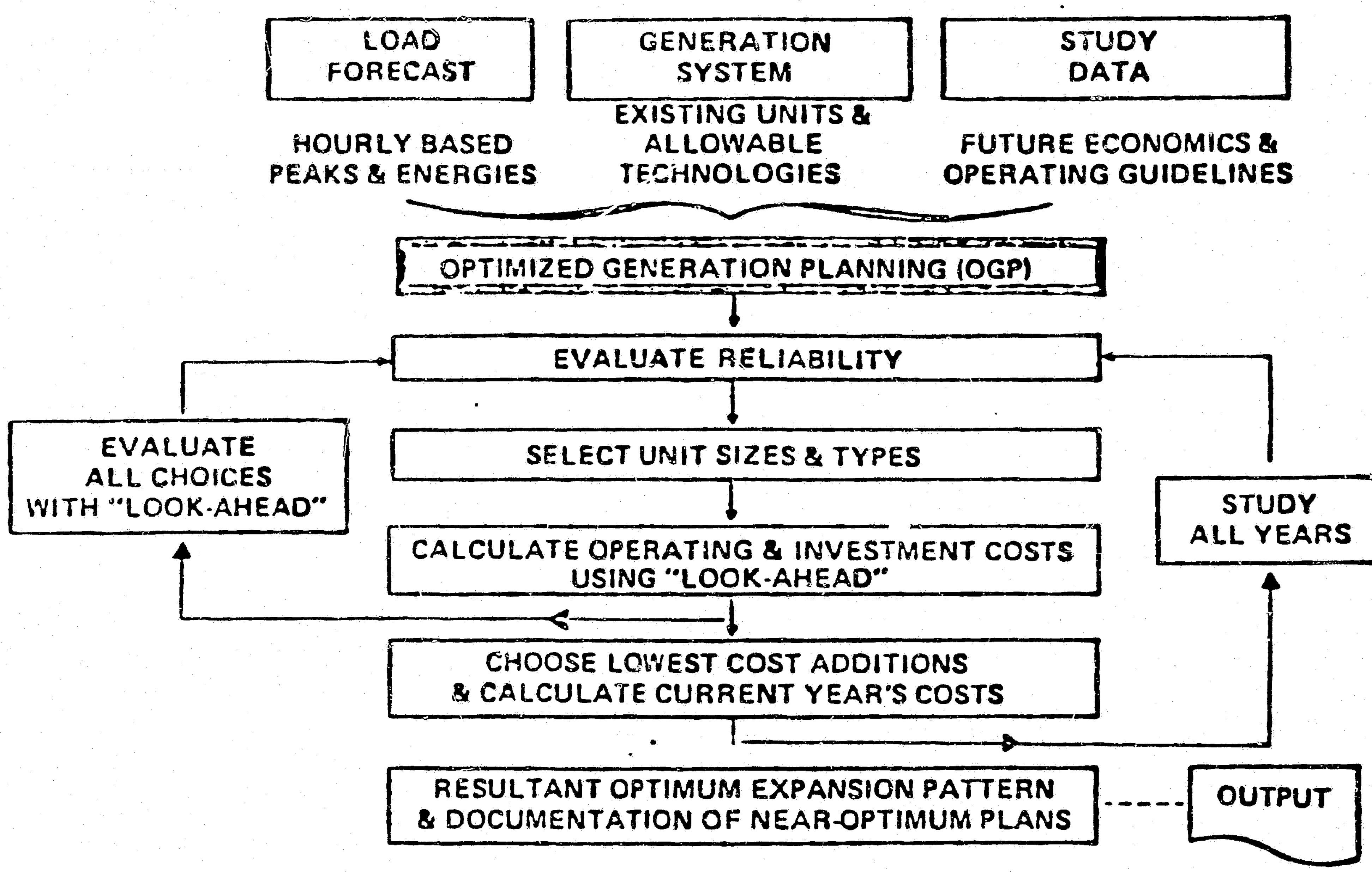


RAILBELT ELECTRICITY DEMAND (RED)
MODEL INFORMATION FLOWS

5.3.2.4

B-5-10

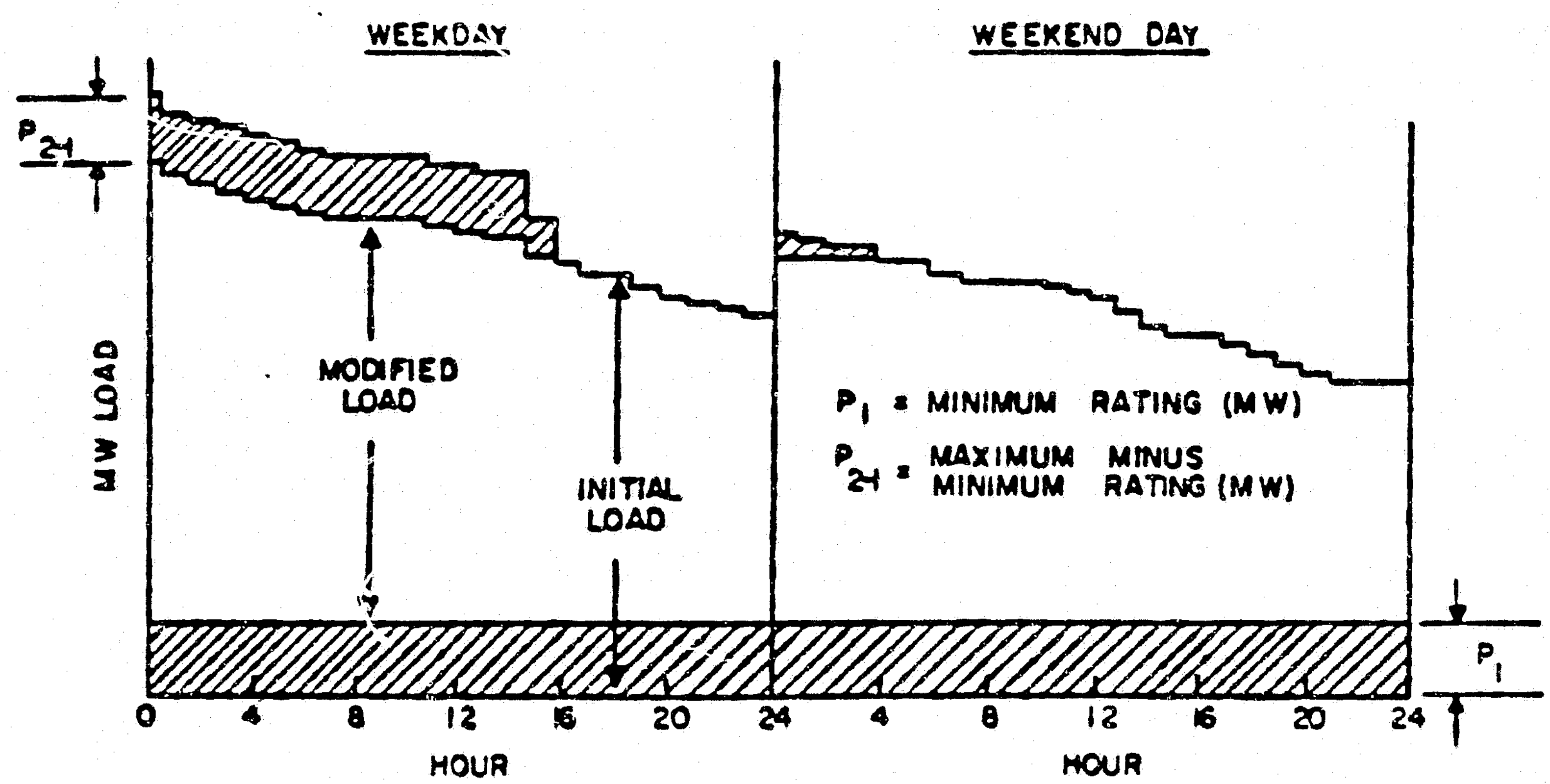
EXHIBIT 5



OPTIMIZED GENERATION PLANNING (OGP)
MODEL INFORMATION FLOWS

B-5

EXHIBIT 6



EXAMPLE OF CONVENTIONAL
HYDRO OPERATIONS

5/5/83

5.4 Forecast of Electric Power Demand

5.4.1 Oil Price Forecasts

Forecasting the future world price of oil is uncertain and most previous forecasts have been lacking in accuracy particularly over the last ten years when oil markets received radical upward price shocks. Some forecasts can be considered to be better than others, however, largely because of the methodology used, the experience level of the forecasters, and the reasoning behind the forecasts. This category includes Sherman Clark Associates, Data Resources Inc., and the Energy Modeling Forum.

The forecasts by these entities as well as the forecasts by the Alaska Department of Revenue are presented and discussed in the following sections. It should be noted that all prices referred to are in 1983 dollars per barrel and all forecasts are assumed to start from a base price of $28,95/bbl in that year.

5.4.1.1 Sherman Clark Associates

Sherman Clark has over thirty-five years of experience in the field of energy including twenty years with Stanford Research

Institute as Director of Energy and Resource Economics. Sherman Clark Associates (SCA) prepares annually a detailed 25 - 30 year forecast of the supply and demand for energy and resulting, estimated prices. Table 2 shows SCA's forecasts of crude oil and fuel oil in 1982 dollars. The SCA forecast prices for oil and coal prsently are for three scenarios to which probabilitites of occurrence have been assigned. SCA's latest scenarios are:

Base Case. In this scenario, oil prices decrease from the existing 1983 price of $29.00/bbl to $26.30/bbl in 1983 dollars and remain at that level until 1989 when SCA has assumed a severe supply disruption will occur, causing prices to jump to $40.00. Prices will remain at $40/bbl until 1990. After 1990 the price would increase as follows:

Period	Real Price Increase ($/yr)	Price in Last Year of Period 1983/bbl)
1990-2000	3.0	53.76
2000-2010	3.5	75.75
2010-2020	1.5	87.80
2020-2030	0	0
2030-2040	0	0

- 2

The severe supply disruption would be an overthrow of the Saudi Arabian government by a radical element that would severely cut back on oil production or a war ivolving Saudi Arabia in which the ability to produce oil was severely damaged. SCA has assigned a 40% probability of occurrence to this scenario.

No Supply Disruption Case. This case is similar to the Base Case, but no severe supply disruption occurs. In addition, there is an assumption that more Non-OPEC crude will be found and produced. Estimated prices drop to $26.30/bbl and remain there until 1989 when they rise at a real rate of 3%/yr to 2010, or a price of $50.39/bbl. After 2010 the price would increase as follows:

Period	Real Increase (%/yr)	Price in Last Year of Period (1983/bbl)
2010-2020	2.5	64.48
2020-2030	1.5	74.84
2030-2040	1.0	82.66

SCA has assigned a 35% probability of occurrence to this scenario.

Zero Economic Growth Case. This scenario assumes that there will be no economic growth until 1990. Consequently, prices drop to $17.00/bbl in 1985 and remain at that level until 1990 at which time they begin to rise at a real rate of 5%/yr to year 2010. SCA has not extended this forecast beyond 2010. SCA has assigned a 25% probability to this scenario.

5.4.1.2. Data Resources Incorporated (DRI)

DRI is a well-known forecasting organization which provides forecasts of GNP, economic indicators, and commodity prices including prices for oil and coal. Extensive use is made of economic and other computer models including special energy forecasting models such as the DRI Drilling Model, DRI Coal Model and the DRI Energy Model. Worldwide supply and demand for oil are estimated to arrive at a forecast price for oil. DRI's spring 1983 forecast shows:

Period	Real Price Increase (%)	Price in Last Year of Period (1983 $/yr)
1983-1984	-13.1	25.17
1984-1985	7.4	27.02
1985-1990	6.5	36.99
1995-2000	4.4	45.85
2000-2005	3.1	53.43
2000-2005	1.1	56.54

DRI has not extended their forecast beyond 2005 nor have they formulated other scenarios nor assigned a probability to its forcast. It therefore is assumed that its single forecast is the likely or most probable outcome.

5.4.1.3. Energy Modeling Forum (EMF)

The EMF was created by the Electric Research Institute (EPRI) to improve the use and usefulness of energy models. The EMF is administered by the Stanford Institute for Energy Studies which is in the Department of Engineering - Economic Systems and the Department of Operations Research. The EMF operates through ad hoc working groups of energy model developers and users. Each group is organized around a single topic to which existing models can be applied.

One of the groups, with members from around the world, addressed issues relating to oil price, availability, and security of supply. The results of their study were reported in an EPRI publication entitled, World Oil.1/ The objective of the study was to analyze world oil issues through the application of 10 prominent world models to twelve

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1/EPRI, World Oil, prepared by Stanford University Energy Modeling Forum, Principal Investigator, J.S. Sweeney, EA-2447-SY, Summary Report, June 1982.

scenarios designed to bound the range of likely future world oil market conditions. The ten models used are listed in Table 3.

The twelve scenarios include a reference or base case which is not necessarily EMF's most likely case but rather is a plausible mean case which can be considered as representative of the general trends that can be expected.

In general, EMF expects a soft oil market for the 1980's with little or no real price increase until 1990 unless there is a supply disruption. Beginning in 1990, real prices will increase over the next several decades in either steady upward movememts or in sudden price jumps followed by gradual declines. EMF's reference case shows the following median real price increases:

Period	Real Price Increase (%/yr)	Price in Last Year of Price (1983 $/bbl
1983-1985	2.0	30.11
1985-1990	6.0	40.29
1990-2000	4.0	59.64

EMF does not extend their forecast beyond 2000.

The results using the ten models in the twelve scenarios are a clustering in year 2000 of world oil price in the range of $50 - 80/bbl, which brackets the EMF reference case.

5.4.1.4. Alaska Department of Revenue (DOR)

The Alaska DOR prepared forecasts of world oil prices to use as an input to their revenue model.

The revenue model provides an estimate of the quantity of revenue from oil and gas royalties and other sources that the state can expect co receive annually through 1999. The DOR's oil price and revenue forecasts are updated quarterly, with March 1983 as the current forecast. The DOR arrives at its forecast of oil prices through the "Delphi" method which consists of questioning persons knowledgable in the area of energy and oil and attempting to arrive at some sort of consensus of future oil prices.

The DOR March 1983 mean forecast projects the price of oil decreasing from $28.95/bbl in 1983 to $21.95/bbl in 1987, then gradually increasing at an average rate of 1.3 percent per yer to a 1999 value of $25.60/bbl.

5.4.1.5. Selection of Oil Price Forecast

The six (SCA(3), DRI(1), EMF (1), and DOR (1)) all price forecasts described above are shown on Table 1 and presented graphically on Figure 1. Also shown on Table 1 and Figure 1 are four other oil price forecasts which show real growth rates from an 1983 base price of $28,95/bbl of +2, 0, -1, and -2 percent per year, these forecasts are included as they will be used to develop power market forecast, described in Section 5.4.4 which will be used in economic sensitivity analyses presented in Exhibit D.

The Sherman Clark Associates, Data Resources Inc., and Energy Modeling Forum forecasts are based on detailed analyses of the supply of and demand for oil. All of these forecasts reflect the existing soft market for oil that may continue for several years. However the forecasts also reflect the high probability of a world economic recovery from the 1981 - 1982 recession and the resulting increased demand for oil. In addition, the forecasts reflect the fact that oil is a depletable resource and although there are some substitutes, eventually the dwindling world supply should result in higher real prices barring some dramatic technological breakthrough.

The DOR forecast of oil is developed by the "Delphi" method, i.e. by questioning various knowledgable persons in the energy field and then using the predominate thinking of the group questioned to develop a forecast. This method depends heavily on the particular persons questioned and may be overly influenced by particular influential individuals in Alaska who believe in the imminent breakup of OPEC as the controlling force for the world price of oil. While OPEC appears to have lost some power in the last year, as evidenced by the drop in the official price of oil from $34/bbl to $29/bbl, an accord between the OPEC members seems to have been reached concerning the quantities of oil produced so that the price appears likely to hold at $29/bbl. The economic recovery that is currently underway in the U.S., which will undoubtedly be followed by the rest of the free industrial world, should support the benchmark price eventually allow OPEC to increase the price as demand for oil increases. A zero or negative economic growth oil price scenario therefore seems unlikely and comparing the false starts in economic recovery of 1979 and 1981 when inflation was high and unemployment low with the current situation in which inflation is low and unemployment high would appear be erroneous.

The most likely future oil price scenario should therefore lie somewhere within the forecasts of DRI, EMF, and SCA Base and no supply disruption cases. As can be seen on Figure 1, the DRI, EMF and SCA base case forecasts are similar through the years 2000.

For the purpose of evaluating the economic attractiveness of the Project, a somewhat more conservative forecast should be chosen as the base case. According to SCA the NSD has a probability of occurance of 75 percent. The SCA No Supply Disruption (NSD) case was therefore selected as the base case. The SCA base case would be used in sensitivity analyses to cover the higher range of forecasts such as the DRI and EMF forecasts. The +2, 0, -1 and -2 percent per year forecasts would be used to cover a range of oil price forecasts below the SCA-NSD forecast including the DOR forecast.

Table 2 shows the base case and five sensitivity oil price forecasts for which power market and economic studies will be performed.

5.4.2 Other Key Variables and Assumptions

Many variables and assumptions beside world oil prices are used in the models described in Section 5-3. Table ___ lists these variables by symbol and name. Also listed on Table ___ are the base case value of the variable and its source.

Of these variables and assumptions, some have a greater influence on the power market forecasts than others. The following have been identified as key variables and assumptions other than world oil price:

Model	Key Variable or Assumption
PETREV	None
MAP	State Mining Employment State Active Duty Military Employment Tourists Visiting Alaska U. S. Real Wage Growth Rate Price Level Growth Rate

3-5-121

Model	Key Variable or Assumption
RED	Regional Population[1/]
	Regional Households[1/]
	Appliance Saturations
	Energy Consumption of Appliance
	Growth Rate of Appliance Consumption
	Own-price Elasticity
	Cross-price Elasticity
	Regional Employment[1/]

[1/] Output from MAP model, petroleum price dependent variables

Model	Key Variable or Assumption
RED	Electric Cons. Floor Space Elasticity
	Regional Load Factor
OGP	Fuel Costs[1/]
	Fuel Escalation Rates[1/]
	Thermal Plant Cost
	Hydro Plant Cost
	Discount Rate

These variables and assumptions are discussed in the appendix which describes each model. The sensitivity of the base case forecast to changes in these values is shown for each of

5.4.3 Base Case Forecast - Model Output

The base case oil price forecast SCA's NSD forecast, was run through the series of forecasting models described in section 5.3. Table ____ shows the output of the models for the following key variables:

- World Oil Price
- Energy Price
  - Fuel Oil
  - Natural Gas
  - Electricity
- State Petroleum Revenues
  - Production Taxes
  - Royalty Taxes
- State General Fund Expenditures
- State Population
- State Employment
- Railbelt Population
- Railbelt Employment
- Railbelt Total Number of Households
- Railbelt Electrical Energy Demand
- Railbelt Peak Demand (MW)

A comparison of this forecast to previous forecasts is presented in Section 5.5.

5.4.4 SENSITIVITY FORECASTS - MODEL OUTPUT

The output of the models for the five (SCA Base and +2, 0, -1, and -2 percent) sensitivity forecasts are shown on Tables ___ through ___, respectively.

A comparison of this forecast to previous forecasts is presented in Section 5.5.

5.4.4 SENSITIVITY FORECASTS - MODEL OUTPUT

The output of the models for the five (SCA Base and +2, 0, -1, and -2 percent) sensitivity forecasts are shown on Tables ___ through ___, respectively.

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol	Variable: Name		Base Case Value	Sensitivity Value	Source
MAP MODEL					
EMAGRI	State Agricultural Employment	1983	203		
		2010	740		
EMP9	State Mining Employment	1983	9,387		
		2010	16,282		
EMCNX1	State High Wage Exog.Const.Exp	1983	3,261		
		2010	1,056		
EMCNX2	State Low Wage Exog.Const.Exp.	1983	290		
		2010	0		
EMT9X	State Exog.Transportation Exp.	1983	1,552		
		2010	3,279		
EMMX1	State High Wage Manufac. Emp.	1983	0		
		2010	0		
EMMX2	State Low Wage Manufac. Emp.	1983	10,433		
		2010	11,617		
EMFISH	State Fish Harvesting Emp.	1983	6,421		
		2010	7,096		
EMGM	State Active Duty Military Emp.	1983	23,323		
		2010	23,323		
EMGC	State Civilian Federal Emp.	1983	17,989		
		2010	20,583		

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol	Variable: Name		Base Case Value	Sensitivity Value	Source
MAP MODEL					
TOURIST	Tourists Visiting Alaska	1983	730,000		
		2010	2,080,000		
RPTS	State Petroleum Production Tax Revenue	1983	1,480 MM		
		2010	699 MM		
RPRY	State Petroleum Royalty Revenue	1983	1,430 MM		
		2010	1,592 MM		
RPBS	State Bonus Payment Revenue	1983	26 MM		
		2010	0		
RPPS	State Petroleum Property Tax Revenue	1983	149 MM		
		2010	564 MM		
RTCSPX	State Petroleum Corporate Tax Revenue	1983	235 MM		
		2010	1,601 MM		
GGRWEVS	U. S. Real Wage Growth/Year		.01		
UUS	U. S. Unemployment Rate		.06		
GRDIRPU	U. S. Real Income Growth/Year		.015		
GRUSCPI	Price Level Growth/Year		.065		
LFPART	Labor Free Participation Rate		.9338		

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TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol	Variable: Name	Base Case Value	Sensitivity Value	Source
RED Model				
UNCERTAINTY MODULE				
N	Number of Values to be Generated			
HOUSING MODULE				
POP	Regional Population Forecast			
HH_{Ata}	Regional Households			
b, c, d	Housing Demand Coefficients			
AHS	Average Household Size			
BHH	Military Households Residing on Base			
P	Regional Household Size Probability			
R	Ratio of Regional to State Relative Frequency of Age of Household Head			
HS_{TY}	Railbelt Household Stock by Type			
r	Period Specific Removal Rate			
V	Normal Vacancy Rate			

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol	Variable: Name	Base Case Value	Sensitivity Value	Source
RED Model				
RESIDENTIAL CONSUMPTION MODULE				
HD_{TY}	Occupied Households by Type of Dwelling			Housing Module
SAT	Appliance Saturations by Type of Dwelling			Uncertainty Module
SE	Percent of Households served by Electric Utilities			
AS	Initial Stock of Appliances			
d	Vintage Specific Survival Rates			
AC	Average KWh Consumption of Appliances			
Z	Length of forecast periods			
g	Growth Rate of KWh Consumption of Appliances			
cs	Conservation Standards Target Consumption Reduction			
E	Own-price Elasticity			Uncertainty Module
CE	Cross-price Elasticity			Uncertainty Module

VARIABLES AND ASSUMPTIONS

Variable: Symbol	Variable: Name	Base Case Value	Sensitivity Value	Source
RED Model				
	BUSINESS CONSUMPTION MODULE			
TEMP	Total Regional Employment			
POP	Regional Population			
CPI	Consumer Price Index, Anchorage			
KIR99	Statewide Average Wage Rate			
BBETA	Electricity Consumption Floor Space Elasticity			Uncertainty Module
E	Own-price Elasticity			Uncertainty Module
CE	Cross-price Elasticity			Uncertainty Module
	CONSERVATION MODULE			
THHS	Total households served			Residential Module
TECH	Technical Energy Savings			
COSTI	Instllation and Purchase Cost of the Residential Conservation Device			
COSTO	Operation and Maintenance costs of the Residential Conservation Device			
RCSAT	Residential saturation of the device (with and without government intervention)			
ESAT	Residential electric use saturation			
PRES	Expected residential electricity price			
RESCON	Price-adjusted residential consumption			
CF	Peak Correction Factor			

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol	Variable: Name	Base Case Value	Sensitivity Value	Source
RED Model				
CONSERVATION MODULE (cont'd)				
PPES	Potential proportion of electricity saved in business in new and retrofit uses			
BCSAT	Business conservation saturation rate (with and without government intervention)			
COST	Cost per megawatt hour saved in business			
BUSCON	Business price-adjusted consumption			Business Module
MISCELLANEOUS MODULE				
ADBUSCON	Adjusted Business Requirements			Conservation Module
ADRESCON	Adjusted Residential Requirements			Conservation Module
VACHG	Vacant Housing			Housing Module
Sl	Street Lighting			
sh	Proportion of households having a second home			
shkWh	Per unit second-home consumption			
Vh	Consumption in vacant housing			

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol	Variable: Name	Base Case Value	Sensitivity Value	Source
RED Model				
PEAK DEMAND MODULE				
LF	Regional load factor			Uncertainty Module
RESCON	Residential electricity sales before adjustment for subsidized conservation			Residential Consumption Module
BUSCON	Business requirements prior to adjustment for subsidized conservation			Business Consumption Module
ADRESCON	Subsidized conservation-adjusted residential requirements			Conservation Module
ADBUSCON	Business requirements adjusted for subsidized conservation			Conservation Module
ACF	Aggregate peak correction factor			Conservation Module

B - [illegible]

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol OGP Model	Variable: Name		Base Case Value	Sensitivity Value	Source
FUCOST	Base Price of Fuel in 1983, $/MMBtu	Nat Gas	2.38		
		Diesel Oil	5.58		
		Nenana Coal	1.72		
		Beluga Coal	1.86		
PATFC	Pattern of fuel cost escalation rates				
PLCDKW	Plant cost, in $/kW, of thermal units				
CAPDB	Capacity of thermal units, MW				
INSTDB	Year of installation, default month is January				
KRETDB	Year of retirement; defaults to N years after INSTDB, where N is specified plant life.				

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TABLE ___

VARIABLE AND ASSUMPTIONS

Variable		Base Case Value	Sensitivity Value	Source
Symbol OGP Model	Name			
PLCHYD	Plant cost, $/kW of hydro units			
INSTDB	Same as for thermal			
KRETDB				
GMINDB	Hydro capacity to be base loaded, MW by month			
GMAXDB	Maximum hydro capacity; (GMAXDB-GMINDB) loaded on peak or intermediate; MW by month			
ENGYDB	Average monthly hydro generation, GWh			
RELENG	Reliability energy (firm energy) from hydro, used in generation addition analyses.			

TABLE ___

VARIABLE AND ASSUMPTIONS

Variable: Symbol OGP Model	Variable: Name	Base Case Value	Sensitivity Value	Source
FIXCHG, HYDFCR	Fixed carrying charge rates for thermal and hydro units, %			
OMDKW, OMHYD	Fixed O&M costs, $/kW for thermal and hydro units			
OMDHR, OMVHYD	Variable O&M costs, ¢/kWh, for thermal and hydro units			
FORATE	Fixed outage rate, % of time for thermal units			
PORATE	Planned outage rate, % of time, for thermal units.			
PWRATE	Present worth discount rate, %			
SPRES	Spinning reserve capacity required. Either in MW or as percent of peak demand.			

SUMMARY OF INPUT ANI

Reference[1]/	Item Description	1983
A	World Oil Price (1983$/barrel)	
	Energy Price (1983$)	
	Fuel Oil ($/MMBTU)	
	Natural Gas ($/MMBTU)	
	Coal ($/MMBTU)	
	Electricity ($/KWh)	
	State Petroleum Revenues (Nominal $)	
	Production Taxes	
	Royalty Taxes	
	State General Fund Expenditures (Nominal $)	
	State Population	
	State Employment	
	Railbelt Population	
	Railbelt Employment	
	Railbelt Total Number of Households	
	Railbelt Electricity Demand (GWh)	
	Anchorage	
	Fairbanks	
	Total	
	Railbelt Peak Demand (MW)	

1/ Refer to the reference letter of Figure ______

____________________ SCENARIO

SUMMARY OF INPUT AND OUTPUT DATA

Reference[1]/	Item Description	1983	1985	1990	1995	2000	2005	2010
A	World Oil Price (1983$/barrel)							
	Energy Price (1983$)							
	Fuel Oil ($/MMBTU)							
	Natural Gas ($/MMBTU)							
	Coal ($/MMBTU)							
	Electricity ($/KWh)							
	State Petroleum Revenues (Nominal $)							
	Production Taxes							
	Royalty Taxes							
	State General Fund Expenditures (Nominal $)							
	State Population							
	State Employment							
	Railbelt Population							
	Railbelt Employment							
	Railbelt Total Number of Households							
	Railbelt Electricity Demand (GWh)							
	Anchorage							
	Fairbanks							
	Total							
	Railbelt Peak Demand (MW)							

1/ Refer to the reference letter of Figure ______

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5.5 Evaluation of Electric Power Market Forecasts

5.5.1 Comparison With Previous Forecasts

Two sets of previous forecasts have been used in Susitna Hydroelectric Project studies in addition to the power market forecasts presented in detail in this section. In 1980, the Institute for Social and Economic Research (ISER) prepared economic and accompanying end-use electric energy demand projections for the Railbelt. The end-use forecasts were further refined as part of the Susitna Hydroelectric Project feasibility study to estimate capacity demands and demand patterns. Also estimated was the potential impact on these forecasts of additional load management and energy conservation efforts. These forecasts were used in several portions of the feasibility study, including the development selection study and initial economic and financial analyses described in Section 1 of this Exhibit B.

In 1981 and 1982, Battelle Pacific Northwest Laboratories produced a series of load forecasts for the Railbelt. These forecasts were developed as a part of the Railbelt Alternatives Study completed by Battelle under contract to the State of Alaska. Battelle's forecasts were based on updated economic projections prepared by ISER and some revised end-use models developed by Battelle which took into account price sensitivity and several other factors not included in the 1980 projections. The December 1981 Battelle forecasts were used in the optimization studies for the Watana and Devil Canyon developments completed early in 1982 and described in Subsection ____ of this Exhibit B. Battelle also produced power market forecast in December 1982 based on a reduced projection of world oil prices. That forecast was produced too late for the preparation of the FERC License Application filed in February 1983.

These previous forecasts were made for three electric load centers: the Anchorage-Cook Inlet area; the Fairbanks-Tanana Valley area; and the Glennallen-Valdez area. When these studies were undertaken, it was not decided whether the Glennallen-Valdez area would be included in the intertied Railbelt electrical system. The decision was subsequently made, based on economics, that the Glennallen-Valdez area will not be included in the interconnected area. Therefore, the updated electric load forecasts presented herein do not consider the power requirements of this load center.

Both ISER and Battelle produced high, medium and low forecasts for use in Susitna planning studies. The medium forecast was used for determining base generation plans, with the high and low forecasts used in sensitivity analyses.

In addition to the ISER and Battelle forecasts performed for the purpose of planning the Susitna Hydroelectric Project, the Railbelt utilities annually produce forecasts for their own respective markets. The bases for these forecasts are not readily available.

Table ____ provides a summary comparison of these previous power market forecasts under the medium scenario. While these forecasts are not precisely consistent in the definitions of the market area or in the assumptions relating to the current base scenario, the comparison does provide an insight in the change in perception of future growth rates during the time that the various sets of forecasts were developed.

The energy demand forecast of the updated base case scenario is about ____ percent lower than the December 1981 Battelle forecast, for the year 2010. The Sherman Clark Base Case projection for year 2010 is about 6 percent greater, and the FERC 0 percent case is about ___ percent lower. The utility forecasts are the highest, although the 1983 forecast is about 20 percent lower than the 1982 forecast for year 2000.

LIST OF PREVIOUS

RAILBELT PEAK AND ENERGY DEMAND FORECASTS

(MEDIUM SCENARIO)

YEAR	ISER 1980 Forecast		Battelle 1981 Forecast		Battelle 1982 Forecast Plan 1A (w/o Susitna)		Battelle 1982 Forecast Plan 1B (w/ Susitna		Battelle Revised 1982 Forecast Plan 1A		Utility 1982 Forecast		Utility 1983 Forecast	
	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)	PEAK DEMAND (MW)	ENERGY DEMAND (GWh)
1980	510	2790	----	----	521	2551	521	2551	521	2551	----	----	----	----
1981	----	----	574	2893	----	----	----	----	----	----	----	----	----	----
1982	650	3570	687	3431	643	3136	647	3160	615	3000	769	3697	716	3531
1990	735	4030	892	4456	880	4256	924	4482	701	3391	1126	5305	940	4678
1995	934	5170	983	4922	993	4875	996	4894	791	3884	1626	7098	1167	5884
2000	1175	6430	1084	5469	1017	5033	995	4728	810	4010	2375	9067	1420	7335
2005	1380	7530	1270	6428	1092	5421	1073	5327	870	4319	NA	NA	NA	NA
2010	1635	8940	1537	7791	1259	6258	1347	6686	1003	4986	NA	NA	NA	NA

1/Table 5.6 - Acres Feasibility Report - Volume 1 or Table B.70 - Exhibit B of License. Includes 30% of military loads, and excludes industrial self-supplied electricity.

2/Table 5.7 - Acres Feasibility Report - Volume 1 or Table B.71 - Exhibit B of License. Excludes military and industrial self-supplied electricity.

3/Table B.12 and B.13 of Battelle Volume 1. Excludes military and industrial self-supplied electricity.

4/Page xv of Battelle Volume 1. Excludes military and industrial self-supplied electricity.

5/At plant net generation.

Note: The Battelle forecasts are for end-use demand, and should be increased by approximately 8 percent for actual at plant net generation.

3/5

5.5 - Evaluation of Electric Power Market Forecasts

5.5.2 Impact of Oil Prices on Forecasts

The previous section (5.4) presented forecasts of oil prices and electric demand in the Railbelt and detailed discussion of the results. The electric demand forecasts contained in that section reflect the impact of oil prices based on separate world price of oil scenarios. The purpose of this section is to summarize the impact of oil prices.

An overall assessment of the impact that changes in the price of oil have on the demand for electricty can be obtained by measuring the relationship between the rate of growth of oil prices and the rate of growth in the demand for electric energy. Table _ compares these growth rates for the relevant world price of oil cases.

TABLE B._

Comparison of Electric Demand
and Oil Price Growth Rates
(1982-2010)

Scenario	Oil Price Growth Rate (%)	Electric Demand Growth Rate (%)
Sherman Clark (Base)	3.6	3.6
FERC	2	3.19
FERC	0	2.9
FERC	-1	2.73
FERC	-2	2.67

A regression analysis was performed to relate the electric demand growth rates associated with the forecasts in section 5.4 to their corresponding world price of oil growth rates. The estimated relationship is as follows:

$$y = 2.25 + 0.25\,x$$

where y = electric demand growth rate

x = world oil price growth rate

The slope of the line provides a measure of the responsiveness of electric demand to oil prices over the planning period (1983-2010). The value of this coefficient (0.25) denotes that expected oil prices changes would have an impact on the growth in demand for electricity but not a significant impact. The responsiveness of electric demand to oil prices is ________ based on our results. If we assume that the growth rate of oil prices increases from one percent to four percent per annum, electric demand growth would increase by only one percentage point.

5.5.3 Sensitivity to Other Key Variables and Assumptions

Sensitivity analyses were conducted in order to determine the extent to which forecasts were affected by varying the values of selected input variables and parameters, other than world oil prices. The other key variables and assumptions which were tested in the sensitivity analyses are listed in Section 5-4.2 For the MAP Model, input variables tested included ten industrial development factors, tourism in Alaska, and four national economic variable parameters. The results of the sensitivity analyses, which were conducted in February 1983, are summarized in Table A. The table shows that of the variables tested, projections of households are most sensitive to mining employment, which includes petroleum production, military employment, tourism, growth in real wages, and growth in the consumer price index. Sensitivity tests were also conducted using selected economic model parameters, including those relating to labor force participation rates, Federal tax rates, and population migration. Results of these tests are shown in Appendix J of the MAP Model Technical Documentation Report.

- Electric Power Load Sensitivity Tests

Sensitivity analyses for the RED Model were conducted for the key variables which were not petroleum price dependent. These variables are appliance saturations, energy consumption by appliance, growth rate of appliance consumption, own price elasticity, and cross price elasticity. The sensitivity analyses were carried out for the base case oil price forecast. The results are shown on Table B.

Sensitivity tests were also conducted for the OGP Model. The key variables other than petroleum price dependent variable which were tested are thermal plant cost, hydro plant cost and discount rate. The sensitivity analyses are described in Exhibit D.

TABLE A

RESULTS OF MAP MODEL SENSITIVITY TESTS[1]

Factor	Value in Year 2000 Low	Value in Year 2000 High	Projected Statewide Households in Year 2000 Low	Projected Statewide Households in Year 2000 High	% Difference
State Agricult. Employment	160	2,000	215,436	217,352	.9
State Mining Emp.[2]	3,990	19,107	200,458	229,782	14.6
State High Wage Exog. Constr. Emp.	0	2,000	212,523	217,971	2.6
State Low Wage Exog. Constr. Emp.	0	1,000	215,119	217,579	1.1
State Exog. Trans. Emp.	1,100	2,968	214,306	217,223	1.4
State High Wage Manu. Emp.	0	486	215,824	216,610	.4
State Low Wage Manu. Emp.	8,205	16,000	210,106	220,833	5.1
State Fish Harvesting Emp.	4,536	9,192	213,557	217,744	2.0
State Active Duty Military Emp.[2]	16,892	33,000	209,936	224,575	7.0
State Civil Fed. Emp..[2]	17,800	21,719	212,372	217,962	2.6
Tourists Visiting AK	1,066,000	2,566,000	209,936	224,575	7.0
U.S. Real Wage Growth/Year[2]	.005	.015	211,335	223,723	5.9
U.S. Unemp. Rate	.05	.075	211,161	222,178	5.2
U.S. Real Income Growth/Year	.005	.025	215,493	216,272	.4
U.S. Price Level Growth/Year[2]	.09	.05	205,924	222,305	8.0

[1]Results based on February 1983 execution of MAP Model.

[2]Key Variable

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TABLE B

RED MODEL SENSITIVITY TESTS

Variable	Base Case Value	Sensitivity Values High	Sensitivity Values Low	Railbelt Elec Energy Demand in 2010, ??? Base	Railbelt Elec Energy Demand in 2010, ??? High	Railbelt Elec Energy Demand in 2010, ??? Low	Percentage Base Case High	Percentage Base Case Low
Appliance Saturation								
Appliance Energy Consumption								
Growth Rate of Appliance Consumption								
Own Price Elasticity								
Cross Price Elasticity								

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SECTION 5.6 - PROJECT UTILIZATION

The purpose of this section is to describe how the power generated by the Susitna Project will be utilized in the interconnected railbelt system. The discussion that follows is based on the Project's operation under the base case power market forecast.

The characteristics of the combined railbelt load are discussed in Subsection 5.2.2 Load duration curves are also presented in that subsection as Figure ___.

The operation of the Susitna Project as stated in Section 3.7 of this Exhibit will be as follows: the Watana development will operate as a base load project until the Devil Canyon Development enters operation at which time the Devil Canyon development will operate on peak and reserve. The dependable capacity and energy production from Watana opeating alone and with Devil Canyon are presented in Section 4.3 of this Exhibit. The firm and average annual energy production, and maximum dependable capacity and the year in which it is achieved for the Susitna Project under the base case flow regime, Regime C, are as follows:

Utility	Percentage of Railbelt Energy Sales (1982)
Chugach Electric Association	20
Anchorage Municipal Light & Power	40
Golden Valley Electric Association	10
Matanuska Electric Association	10
Fairbanks Municipality Utilities System	5
Homer Electric Association)	15
Seward Light Department)	
Total	100

APPENDIX B-2

FUELS PRICING STUDIES

Introduction

There are thermal alternatives to the Susitna Hydroelectric generating facility which would provide the same capacity and generation as Susitna through the use of a fuel or fuels such as natural gas or coal. The economic viability of these alternatives and their competiveness with the Susitna Project depend heavily on the future availability and price of the required fuels.

The availability and price of fuels to provide Railbelt generation needs through the year 2040 are analyzed in this appendix. The primary fuels that are analyzed are natural gas, coal, and distillate fuel oil. There are other potential fuels such as peat and wood but these are not discussed due to the findings of previous studies that these fuels are not economically competitive when compared to natural gas and coal. Multiple data sources were employed including previous studies by consultants, information from state and federal agencies, and data, plans and other information from electric and gas utilities in the Railbelt Area. Projections of future natural gas and distillate fuel prices were tied to the future, world price of oil. Projections of future world oil prices were obtained from several sources and from these projections, Harza-Ebasco used its judgment in selecting the most likely projected prices.

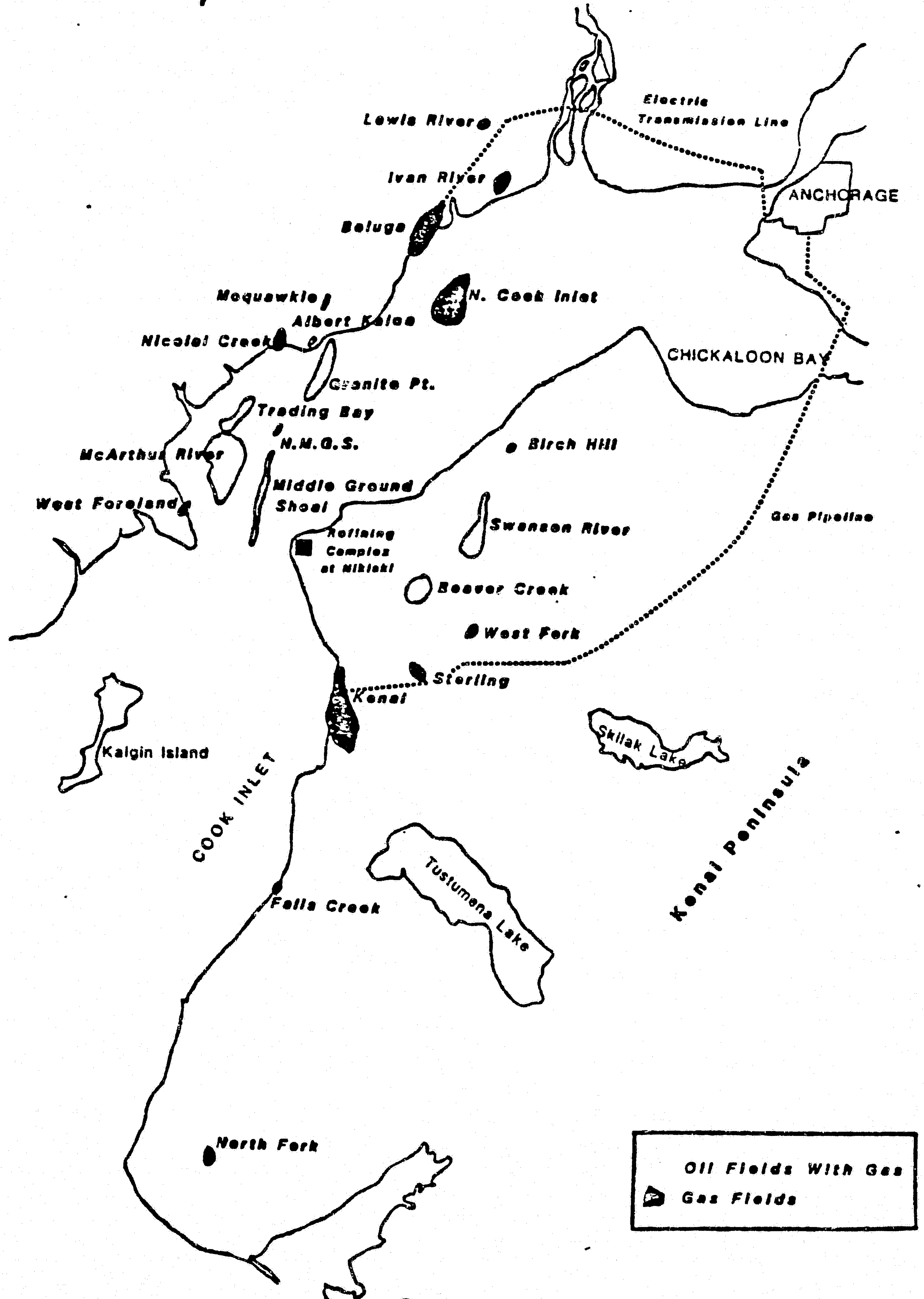
Results concerning the availability and price of fuels were used as inputs into the Alaska Department of Revenue forecasting model and the Institute of Social and Economic Research's econometric forecasting model. In addition, the results were used as input parameters in the determination of the cost of thermal generating alternatives.

Part I - Natural Gas

Resources and Reserves

Known recoverable reserves of natural gas are located in the Cook Inlet area near Anchorage and on Alaska's North Slope at Prudhoe Bay. Gas is presently being produced from the Cook Inlet area. Some of the gas is committed under firm contract and some is for all practical purposes committed, but not by contract. Considerable quantities of gas remain uncommitted and could be used for power generation. There are substantial recoverable reserves on the North Slope that could be used for power generation, but until a pipeline or electrical transmission line is constructed, the gas cannot be utilized. Undiscovered gas resources are believed to exist in the Cook Inlet area and also in the Gulf of Alaska where no gas has been found to date.

Figure 1 - COOK INLET REGION Gas Fields



Source: NERA, "An Economic Analysis of the Proposed Extension of the Phillips - Marathon LNG Contract With Tokyo Gas & Tokyo Electric", May 1982.

Estimates of potential gas resources in these areas have been made by the United States Geological Survey and the Alaska Department of Natural Resources. The quantities of proven and potential undiscovered gas from these areas are discussed below.

Cook Inlet Proven Reserves

The locations of the Cook Inlet gas fields are shown in Figure 1. Estimated recoverable reserves from the Cook Inlet fields and the commitment status of those reserves are shown in Exhibit 1. This table is essentially Table 2.2 from the Battelle Study(1) but, updated and rearranged to reflect current conditions. Recoverable reserves are from the Alaska Oil & Gas Conservation Commission's latest estimate.(2)

New contracts between Enstar and Shell & Marathon are shown(3) in Exhibit 1 as well as the five-year extension of the Phillip/s Marathon LNG contract with Tokyo Gas and Tokyo Electric Companies.(4) Reserves that were formerly committed to Pacific Alaska Liquified Natural Gas (PALNG) Company* are shown for reference purposes, but are included as uncommitted reserves since PALNG's contracts for the gas expired in 1980.(5) All of the proven gas is not presently under contract as is shown in Exhibit 1 where 1,654 Bcf of proven reserves is presently uncommitted.

*See subsequent section entitled; Competition For Gas.

Exhibit 1 Estimated Cook Inlet Natural Gas Recoverable Reserve[5] and Commitment Status as of January 1, 1982

	Recoverable Reserves 1	Enstar	Chugach Electric Assoc.	AMP&L	Collier Carbon & Chemical	Phillips/ Marathon LNG	SOCAL ARCO Rental	Uncommitted Reserves	Pacific Alaska LNG Assoc.
Beaver Creek	240	250[2]	--	--	--	--	--	0	--
Beluga River	742	220	285	--	--	--	--	237	404
Birch Hill	11	--	--	--	--	--	--	11	--
Cannery Loop	N/A	--	--	--	--	--	N/A		(3)
Falls Creek	13	--	--	--	--	--	--	13	--
Ivan River	26	--	--	--	--	--	--	26	106[4]
Kaldachabuna	N/A	--	--	--	--	--	N/A		--
Kenai	1,109	256	--	(5)	377	250	106	120	--
Lewis River	22	--	--	--	--	--	--	22	99[4]
McArthur River	90	--	--	--	--	--	--	90	--
Nicolai Creek	17	--	--	--	--	--	--	17	--
North Cook Inlet	951	27[6]	--	--	--	110[7]	--	814	--
North Fork	12	--	--	--	--	--	--	12	--
N. Middle Ground	N/A	--	--	--	--	--	N/A		--
Sterling	23	--	--	--	--	--	--	23	--
Stump Lake	N/A	--	--	--	--	--	N/A		(1)
Swanson River		--	--	--	--	--	--	259	--
Trail Ridge	N/A	--	--	--	--	--	N/A		--
Tyonek	N/A	--	--	--	--	--	0		--
West Foreland	20	--	--	--	--	--	--	20	--
Total	3,541	759	285	--	377	360	106	1,654	760[8,9]

Notes

1. Alaska Oil and Gas Conservation Commission.
2. Part of gas will be taken from Kenai Field.
3. Participant in exploration underway in 1980.
4. Based on DeGolyer and MacNoughten reserve estimate in 1975.
5. Uncertain royalty status.
6. Royalty gas.
7. This figure assumes that Tokyo Gas Co. and Tokyo Electric Co. contracts will be met by gas from the Cook Inlet Field. In actuality, a significant portion is supplied by the Kenai Field.
8. Estimate of gas available on blowdown.
9. PALNG's latest estimate of their previously committed reserve is 980 Bcf less the 220 lost to Enstar. This 760 Bcf is 151 greater than the sum of quantities from the individual fields. It is not known from which fields the additional 151 Bcf would come.

In addition to proven recoverable reserves in the Cook Inlet area, there is the possibility of additional supplies in the form of undiscovered gas.

Cook Inlet Undiscovered Gas

Earlier estimates of additional natural gas resources in the Cook Inlet area ranged from 6.7 TCF to 29.2 TCF.[6] These estimates may be high since subsequent drilling by Mobil and Arco in Lower Cook Inlet has resulted in nothing but dry holes.

A recent study by the State of Alaska, Department of Natural Resources presents estimates of undiscovered gas and oil versus the probability of finding those quantities.[7] Summaries of the estimates are presented in Table 1 and show that there is a probability of 75% that at least about 2.0 TCF of undiscovered gas remains in the Cook Inlet area.

The Department also estimated "economically recoverable" resources by assuming a recovery factor of 0.9 and a minimum commercial deposit size of 200 BCF. These are also presented in Table 1 and show that there is a probability of 75% that at least about 1.0 TCF of economically recoverable gas remains in the Cook Inlet Area.

TABLE 1

Preliminary Estimates of Undiscovered Gas Resources In Place & Economically Recoverable Gas Resources For the Cook Inlet Basin[1]

Probability - %[2]	Quantity of Gas - TCF In Place	Economically Recoverable
99	0.47	0.00
95	0.93	0.22
90	1.24	0.43
75	1.98	0.93
50	3.07	1.76
25	4.38	2.78
10	5.84	4.04
5	6.93	4.90
1	9.06	6.83

1. Data from letter to Mr. Eric P. Yould, Executive Director, APA from Ron G. Schaff, State Geologist, State of Alaska, Department of Natural Resources, Division of Geological and Geophysical Surveys, dated February 1, 1983.

2. Probability that quantity is at least the given value. Mean or as expected value for Economically Recoverable gas is approximately 2.0 TCF due to skewed distribution.

North Slope Gas

Estimated recoverable natural gas reserves from the North Slope are about 29 trillion cubic feet (TCF) for the Sodlerochit Reservoir at Prudhoe Bay. Additional gas from the North Slope is estimated to be 4.5 TCF.[8] The State of Alaska royalty share of Prudhoe Bay reserves is 12.5% or 3.6 TCF. North Slope gas is currently either shut-in or reinjected into reservoirs to maintain pressure for oil extraction since there is no pipeline to areas where the gas can be burned or otherwise utilized.

Gulf of Alaska Gas

The Gulf of Alaska lies to the east of the Kenai Peninsula and Anchorage and is close enough to the Railbelt area to be considered as a potential source of gas for Railbelt electric generation (see Figure 2). To date, no oil or gas has been discovered in the Gulf of Alaska. The United States Geological Survey (U.S.G.S.) has, however, developed estimates of the quantities of gas that might exist in the Gulf.

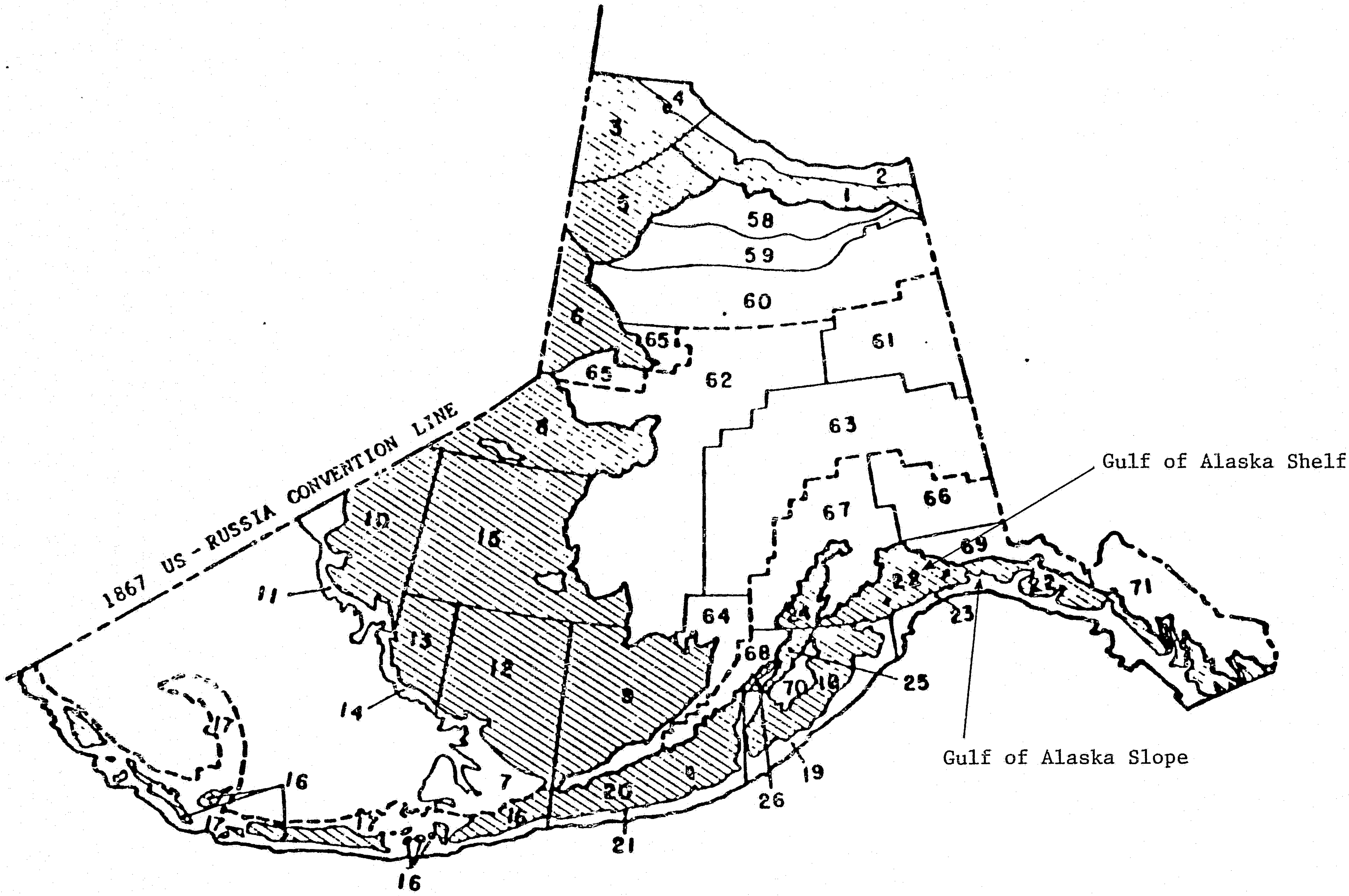


FIGURE 2 - Areas of Alaska Assessed by the U.S.G.S. For Undiscovered Resources. Shading Denotes Offshore Shelf Areas.

Source: U.S. Department of the Interior Geological Survey, Open-File Report 82-666A, 1981.

The U.S.G.S. presents its estimates of undiscovered gas in terms of the probability of finding "economically recoverable" gas. Economically recoverable resources are those that can be economically extracted under price-cost relationships and technological trends prevailing at the time of the assessment.[9] For their low estimate, there is a probability of 95% that the estimated value will be exceeded. For the high estimate, there is a 5% probability that the estimated value will be exceeded. The U.S.G.S. analysis can also be interpreted as having a probability of 90% that the amount of undiscovered gas will be between the low and high estimates. In addition to low and high estimates, the U.S.G.S. also provides a mean value as the quantity of gas most likely to be found. The U.S.G.S. estimates for the Gulf of Alaska Shelf (to a depth of 200 meters) are:[10]

Low	0.46 TCF
High	9.24 TCF
Mean	3.14 TCF

The estimate for the Gulf of Alaska Slope which is those Gulf areas with a water depth from 200 meters to 2,400 meters is:

Low	0.36 TCF
High	3.70 TCF
Mean	1.53 TCF

These estimates show that additional gas might, in the future become available from the Gulf for Railbelt electrical generation.

Production and Use of Natural Gas

Natural gas is produced and used in Alaska for heating, electrical generation, liquified natural gas (LNG) export and the manufacture of ammonia/urea. Most of the production and use (other than reinjection) currently takes place in the Cook Inlet area but the large proven quantities located on the North Slope and undiscovered potential in the Gulf of Alaska make these areas worthy of consideration for future use. Current and potential production from the three areas is discussed below.

Cook Inlet Current Production and Use

The production and use of Cook Inlet gas for the past five years is shown in Table 2. Gas that has been injected (or actually reinjected) was not consumed and is still available for heating, electrical generation, or other uses. The use of gas in field operations depends on oil production and has been fairly constant over the last five years.

LNG sales are for export to Japan and the manufactured ammonia/urea is exported to the lower forty eight states. Both uses of gas have been fairly constant and are expected to remain so in future years.

TABLE 2

Historical and Current Production and
Use of Cook Inlet Natural Gas

USE	QUANTITY - BCF 1978	1979	1980	1981	1982
Injection	114.1	119.8	115.4	100.4	103.1
Field Operations:					
Vented, Used on lease, shrinkage	23.5	17.5	28.0	20.6	21.3
Sales:					
LNG	60.9	64.1	55.3	68.8	62.9
Ammonia/Urea	48.9	51.7	47.6	53.7	55.3
Power Generation:					
Utilities	24.6	28.2	28.7	29.1	30.5
Military	5.1	5.0	4.8	4.6	4.7
Gas Utilities	13.5	14.0	15.5	16.2	17.7
Other	3.3	4.8	5.1	5.7	9.5
Total Sales	156.3	167.8	157.0	178.1	180.6
Total	293.9	305.1	300.4	299.1	305.0

Source: "Historical and Projected Oil and Gas Consumption, Jan. 1983", State of Alaska, Dept. of Natural Resources, Division of Mineral and Energy Management, Table 2.8.

Natural gas is used for electrical generation by Chugach Electric Association and Anchorage Municipal Light and Power. The use of gas by both of these utilities has been increasing to meet increases in electrical load and to replace oil-fired generation. The military bases in the Anchorage area, Elmendorf AFB and Fort Richardson, use gas to generate electricity and to provide steam for heating. The military gas use has been fairly constant in the past and is expected to remain so in the future.

The gas utility sales shown are made principally by Enstar Corporation and are for space and water heating and other uses by residential, commercial, and industrial customers. These sales grow with increases in population and increased use by existing consumers. The growth is expected to continue in the future and will be increased further when Enstar begins gas service to the Matanuska Valley.

Other sales consist principally of [finish after talking to Alaska Dept. of Natural Resources.]

Cook Inlet Future Use

The future consumption of Cook Inlet gas depends on the gas needs of the major users and their abillity to contract for needed supplies. The major existing users are Phillips/Marathon for LNG export, Collier for manufacture of ammonia/urea, Enstar for retail sales, sales to electric utilities and the military, and Chugach Electric Assoc., and Anchorage Municipal Light d Power for electrical generation. Since there is a limited quantity of proven gas and estimated undiscovered reserves in the Cook Inlet area, reserves will be exhausted at some time in the future. In addition, there may not be sufficient gas for electrical generation beyond some point because of higher priorities accorded other uses, either through contract or by order of regulatory agencies such as the Alaska Public Utilities Comission. To estimate the quantity of Cook Inlet gas available for electrical generation, the requirements and priorities of the major users are discussed below.

Phillips/Marathon currently has 360 BCF of gas under contract (Exhibit 1) and it is highly probable that it will obtain enough of the uncommitted gas in Exhibit 1 to meet its needs through 2010. Collier Chemical currently has 377 BCF committed and will probably also be able to obtain sufficient gas to meet its needs through 2010. Both of these entities are established, economically viable facilities, owned by Cook Inlet gas producers who control part of the uncommited reserves. Phillip and Collier are estimated to consume 62 BCF and 55 BCF respectively per year from 1982 through 2010.

Enstar presently has enough gas under contract to serve its retail customers until after the year 2000 but since Enstar also sells gas to the military (for electric generation) and to Chugach and Anchorage Municipal Light and Power for electric generation, it may have to seek additional reserves in order to meet the needs of those customers. It is assumed, however, that Enstar will be able to acquire sufficient gas to meet the needs of its retail customers (including the Matanuska Valley customers) and that those customers' needs will have priority over the use of gas for electrical generation. Retail use is estimated to increase from about 18 BCF in 1982 to 52 BCF in 2010.

Gas used in field operations and other sales of gas vary from year to year but together are estimated to average about 25 BCF/yr over the period 1982 to 2010.

After satisfying all of the forementioned needs, there is still a considerable amount of gas remaining that could be used for electrical generation, at least for a number of years. Chugach Electric Association has 285 BCF committed through contract (see Exhibit 1) and Enstar has 759 Bcf contracted, some of which will be sold to Anchorage Municipal Power and Light and Chugach for electrical generation. Assuming that the Anchorage/Fairbanks intertie is completed in ~~1990~~ 1984-85, ~~1995~~, the electircal requirements of both cities and smaller towns in between could be met with generation using Cook Inlet gas.

The quanities of gas required to meet all Railbelt electrical requirements were calculated using the estimated load and energy forecast (H/E 1983 SCA base case) for the Railbelt area. Estimated generation from the existing Eklutna and Cooper Lake and the proposed

Bradley Lake hydro units was subtracted as well as generation from the existing Healy coal-fired unit. Average heat rates for the gas-fired units were assumed to be 15,000 Btu/Kwh until 1995 where the heat rate would decrease to 8500 Btu/Kwh to reflect the installation of high efficiency, combined cycle units to meet base and swingload operations. The estimated annual gas requirements increase from 35 Bcf in 1983 to 54 Bcf in 2010.

The annual and cumulative use of gas for each of the major users and the total use of gas for the Railbelt is shown in Table 3. The remaining proven and undiscovered (mean or expected quantity) gas resources are also shown and as can be seen, proven reserves will be exhausted by about 1998, and expected undiscovered resources by about 2007. The estimated use of Cook Inlet proven reserves and undiscovered resources is graphically illustrated in Figure 3. Cumulative uses for the major users were taken from Table 3. The major users, Phillips/Marathon for LNG, Collier for Ammonia/Urea and Enstar for gas sales to retail customers are shown as first or priority users. Electrical generation needs for the Railbelt Area using the Harza/Ebasco SCA 1983 base case are plotted on top of those priority users.

The data from Table 3 indicates that relying on all gas-fired electrical generation to provide the Railbelts' needs past the year 2000 is somewhat risky. However, if it was decided that the Railbelt's

Year End Remaining Reserves	
?roven[6]	Proven Plus Mean Undiscovered[7]
3341.6	5381.6
3138.6	5178.1
3931.4	4971.4
2721.4	4761.4
2507.5	4547.5
2291.1	4331.1
2077.5	4117.5
1861.3	3901.3
1642.6	3682.6
1421.3	3461.3
1197.4	3237.4
970.8	3010.8
741.5	2781.5
532.9	2572.9
322.1	2362.1
107.9	2147.9
(107.6)	1932.4
	1714.6
	1494.5
	1271.9
	1046.7
	818.6
	586.8
	352.3
	113.2
	(129.3)

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Enstar estimates.

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. 1982-1985 and 8,500

evenues from Table 1.

TABLE 3

Estimated Use of Cook Inlet Natural Gas By User - All Volumes in BCF

Year	Phillips/Marathon LNG/Plant[1]	Collier Ammonia/Urea[1]	Enstar Retail Sales[2]	Field Operations & Other Sales[3]	Electric Generation: Military[4]	Electric Generation: All Others[5]	Total Gas Use	Total Cumulative Gas Use	Year End Remaining Reserves: Proven[6]	Year End Remaining Reserves: Proven Plus Mean Undiscovered[7]
1982	62	55	17.7	25	5	34.7	199.4	199.4	3341.6	5381.6
1983	62	55	19.2	25	5	37.3	203.5	402.9	3138.6	5178.1
1984	62	55	19.8	25	5	39.9	206.7	609.6	3931.4	4971.4
1985	62	55	20.5	25	5	42.5	210.0	819.6	2721.4	4761.4
1986	62	55	22.8	25	5	44.1	213.9	1033.5	2507.5	4547.5
1987	62	55	23.6	25	5	45.8	216.4	1249.9	2291.1	4331.1
1988	62	55	24.4	25	5	42.2	223.6	1463.5	2077.5	4117.5
1989	62	55	25.3	25	5	43.9	216.2	1679.7	1861.3	3901.3
1990	62	55	26.1	25	5	45.6	218.7	1898.4	1642.6	3682.6
1991	62	55	27.1	25	5	47.2	221.3	2119.7	1421.3	3461.3
1992	62	55	28.0	25	5	48.9	223.9	2343.6	1197.4	3237.4
1993	62	55	29.0	25	5	50.6	226.6	2570.2	970.8	3010.8
1994	62	55	30.1	25	5	52.2	229.3	2799.5	741.5	2781.5
1995	62	55	31.1	25	5	30.5	208.6	3008.1	532.9	2572.9
1996	62	55	32.2	25	5	31.6	210.6	3218.9	322.1	2362.1
1997	62	55	34.4	25	5	32.8	214.2	3433.1	107.9	2147.9
1998	62	55	34.6	25	5	33.9	215.5	3648.6	(107.6)	1932.4
1999	62	55	35.8	25	5	35.0	217.8	3866.4		1714.6
2000	62	55	37.0	25	5	36.1	220.1	4086.5		1494.5
2001	62	55	38.3	25	5	37.3	222.6	4309.1		1271.9
2002	62	55	39.7	25	5	38.5	225.2	4534.3		1046.7
2003	62	55	40.1	25	5	41.0	228.1	4762.4		818.6
2004	62	55	[illegible].6	25	5	42.2	231.8	4994.2		586.8
2005	62	55	4[illegible].1	25	5	43.4	234.5	5228.7		352.3
2006	62	55	45.6	25	5	46.5	239.1	5467.8		113.2
2007	62	55	47.2	25	5	48.3	242.5	5710.3		(129.3)
2008	62	55	48.9	25	5	50.1	246.0	5956.3		
2009	62	55	50.6	25	5	52.0	249.0	6205.9		
2010	62	55	52.4	25	5	53.8	253.2	6459.1		

[1]Based on historical use from Table 2 and telephone conversations with Mr. Jim Settle of Phillips Petroleum Co. and Mr. George Ford of Collier Chemical.

[2]Estimate provided by Mr. Harold Schmidt, UP Enstar Co., Feb. 14, 1983. Includes sales to Matanuska Valley customers beginning in 1986. Consumption from 1991-2010 projected by Harza/Ebasco at average growth rates in Enstar estimates.

[3]Estimate based on historic use shown in Table 2.

[4]Estimate based on historic use shown in Table 2.

[5]Calculated based on SCA/Basecase load and energy forecast; inclusion of generation from Eklutna, Cooper Lake and Bradley Lake hydro units and Healy coal unit; and assumed average Railbelt heat rates of 15,000 Btu/kWh from 1982-1985 and 8,500 Btu/kWh from 1986-2010.

[6]Proven reserves of 3,541 Bcf on Jan 1, 1982. See Exhibit 1.

[7]Includes proven revenues of 3,541 Bcf plus expected value for undiscovered economically recoverable revenues from Table 1.

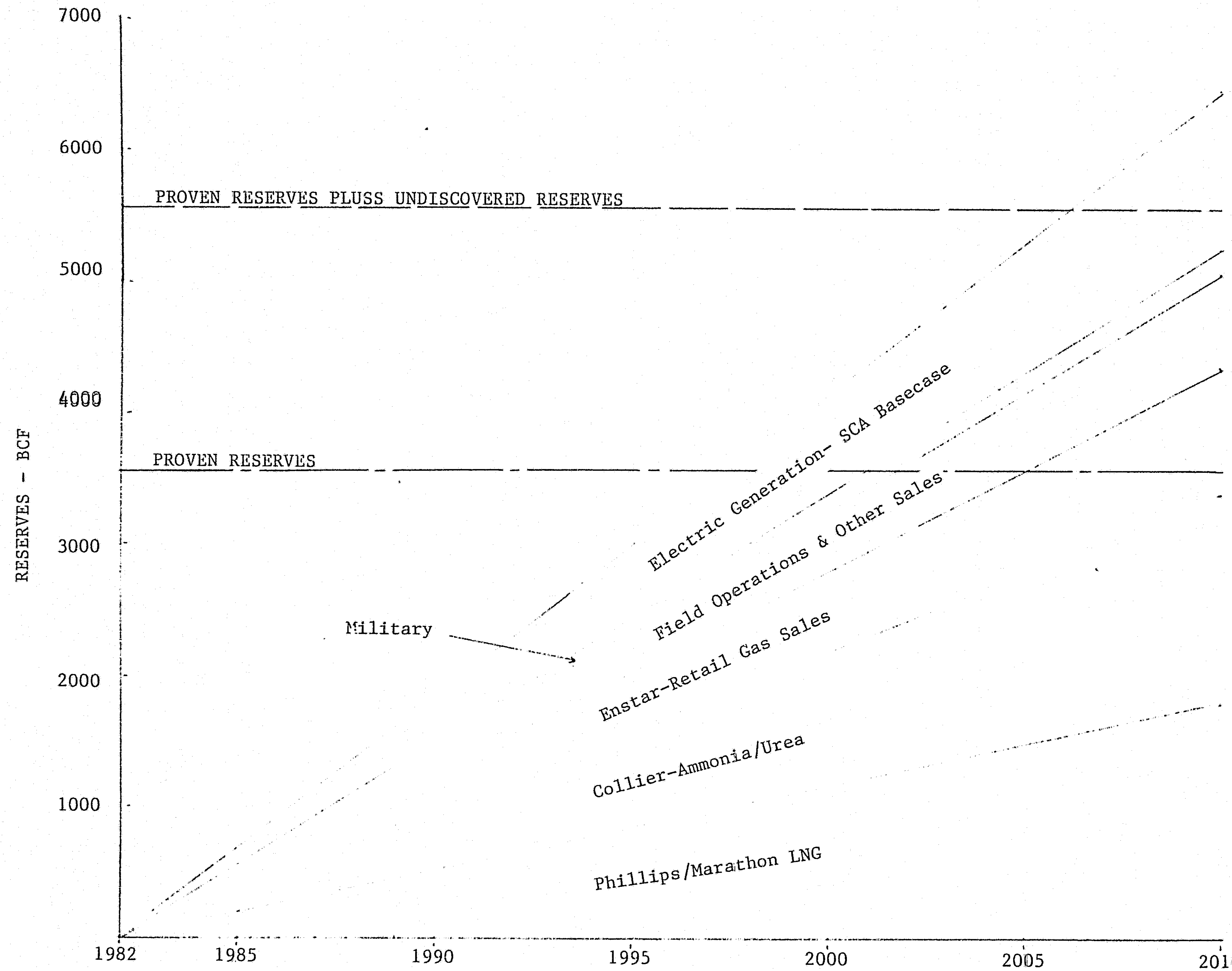

FIGURE 3 - Cook Inlet Natural Gas Reserves and Estimated Cumulative Consumption

needs should be met with thermal generation, it is likely that at least one and probably more 200 MW coal-fired generating units would be constructed. These units would be base loaded and would considerably reduce the use of gas for electrical generation and thereby prolong the availability of Cook Inlet reserves.

There is also the possibility that the uncommitted, proven reserves and any undiscovered resources could be acquired by entities not shown in Table 3, thus reducing or eliminating the availability of Cook Inlet gas for electric generation. This possibility is discussed next.

Competition For Cook Inlet Gas

Known potential purchasers for the uncomitted, recoverable and undiscovered Cook Inlet gas reserves in addition to those shown in Table 3 are Pacific Alaska LNG Associates and the parties who would own and operate the proposed Trans-Alaska Gas System (TAGS).

The proposed Pacific Alaska LNG (PALNG) project was initiated about ten years ago, but has been repeatedly delayed due to difficulties in obtaining regulatory approval for a terminal in California. The project has also had difficulty in contracting for sufficient gas reserves in order to obtain Federal Energy Regulatory Commission (FERC) approval of the project. At one time, Pacific Alaska had 980 BCF of recoverable reserves under contract. The contracts expired in 1980, but producers did not give written notice of termination so the contracts have been in limbo. Recently, however, Shell Oil Co. sold 220 BCF of gas that was formerly committed to PALNG to Enstar Natural Gas Company.[11] This reduced PALNG'S semi-committed reserves to 760 BCF (see Exhibit 1).

The FERC has approved the PALNG project, but with the condition that PALNG obtain 1.6 TCF of reserves for Phase I of the project and 2.6 TCF before Phase II is commenced.[12] Pacific Gas and Electric Co., one of the PALNG partners, has ceased accruing an allowance for funds used during construction (AFUDC) on funds already expended. In addition, PG&E does not plan to put any more money into the project and has filed with the California Public Utilities Commission (CPUC) for permission to place the expended funds into its "Plant Held for Future Use" account which will enable the utility to get the funds into its rate base and thus earn a return on them.[13] PALNG also claims it requires additional equity partners to make the project viable, but, to date, has found none. Although PALNG is still searching for additional gas reserves, there is little chance that the project would begin construction prior to the early 1990s.[14] Implementation of the project would depend primarily on the availability and price of alternative sources of natural gas for the Lower Forty Eight market and particularly for the California market. According to one expert, there are sufficient proven and probable reserves of conventional gas in the Lower Forty

Eight states to last fifteen to twenty years.(15) When all of these factors are considered, it does not appear that the PALNG project will be implemented, at least not until 1995 or after. The recoverable reserves originally committed to PALNG can, therefore, probably be acquired by other purchasers such as Chugach Electric Association and Enstar.

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.(16)

If the project were implemented, Cook Inlet gas producers might be able to sell their gas to TAGS for liquefaction and sale to Asia. Sale would depend on the capacity of the liquefaction plant and the market for LNG. The price that could be 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 shorter transmission and gathering lines would probably be required). Any estimate of the probability of whether TAGS will be implemented is difficult at this time, since the report on the project has just been published and there has not been sufficient time for the proposal to be analyzed by many concerned and interested parties. We have, however, attempted to estimate the maximum price that TAGS would probably be willing to pay Cook Inlet producers for gas delivered to the TAGS liquifacation plant (see the following section entitled, Current Prices).

North Slope Gas

Over ninety percent of the North Slope gas is currently reinjected. Some is used in field operations and a small amount is sold to the TAPS, used by Prudhoe Bay refineries and for North Slope local electrical generation. A small quantity from the South Barrow field is also used to meet residential heating needs. Table 4 shows North Slope production and use for 1982.

The problem in using North Slope gas for Railbelt electrical generation is that a pipeline must be constructed to bring the gas to where its needed, i.e. Fairbanks or Anchorage or an electrical transmission line must be built so that power generated on the North Slope can be brought to load centers. The major proposals for utilization of North Slope gas are discussed below.

Alaska Natural Gas Transportation System (ANGTS): This plan would construct a pipeline from the North Slope via Fairbanks and through Canada to the Lower Forty Eight. The project has been temporarily shelved due to a high estimated delivered price and the resulting difficulty in obtaining financing. The project will ~~propbably~~ probably not be operational before the early to mid-1990s, if ever, so North Slope gas

Table 4

Current Production and Use of
North Slope Gas For 1982

Use	Quanity - BCF
Injection	671.0
Field Operations:	
Vented, Used on ,	
shrinkage	50.2
Sales	
Power generation (civilian)	0.4
Gas utilities (residential)	0.5
Other sales	
Refineries	0.5
TAPS	11.9
Misc.	0.2
Total	734.7

Source: "Historical and Projected Oil and Gas Consumption Jan. 1983", State of Alaska, Dept. of Natural Resources, Division of Minerals and Energy Management, Table 2.7.

from this method can not be counted on to provide Railbelt electrical generation.

Trans Alaska Gas System (TAGS): This alternative was recently proposed by the Governor's Economic Committee on North Slope Natural Gas and would construct a pipeline from Prudhoe Bay to the Kenai Peninsula where the gas would be liquified and sold to Japan and other Asian countries.[17] Some of the gas could be utilized for power generation at Kenai (or conceivably from a tap at Fairbanks although an additional processing plant would have to be installed since the gas is to be piped in an unprocessed state). Implementation of the TAGS is highly uncertain at this time and therefore cannot be counted on to provide gas for electric generation.

Pipeline to Fairbanks: In this plan, the North Slope gas would be piped to Fairbanks via a small diameter pipeline where it would be used to generate electricity for the Railbelt Area and also to meet residential and commercial heating needs in Fairbanks. Cost studies have shown that this method is economically inferior to other proposed methods for utilization of North Slope gas and will therefore probably not be implemented.

North Slope Generation: This proposed plan is an alternative to transporting the gas by some means, for the gas would be utilized in combustion turbines located on the North Slope and the electricity transmitted to the Railbelt Area. Cost studies have been developed, but there do not appear to be any serious proponents of this method.

Gulf of Alaska Gas

To date, there have been no discoveries of gas in the Gulf of Alaska. This potential source of gas for Railbelt electrical generation is therefore too speculative at this time to incorporate its use into the future Railbelt generation alternatives.

Current Prices of Natural Gas

There is no single market price of gas in Alaska since a well developed market does not exist. In addition, the price of gas is affected by regulation via the Natural Gas Policies Act of 1978 (NGPA) which specifies maximum wellhead prices that producers can charge for various categories of gas (some categories will be deregulated in 1985). There are some existing contracts for the sale/purchase of Cook Inlet gas which specify wellhead prices but since there are no existing contracts for the sale of North Slope gas, the wellhead price can only be estimated based on an estimated final sales price and the estimated costs to deliver the gas to market. The current wellhead prices of natural gas for the Cook Inlet area and the North Slope are discussed below.

Cook Inlet

Currently there are four contracts for the sale/purchase of Cook Inlet gas where the contracts were negotiated at arms length and the contracts are public documents. These are:

(1) Chugach Electric Assn./Chevron, ARCO, Shell contract for purchase of gas from the Beluga River Field.[18]

(2) Enstar/Union, Marathon, ARCO, Chevron contract for purchase of gas from the Kenai Field.[19]

(3) Enstar/Shell contract for purchase of gas from the Beluga Field.[20]

(4) Enstar/Marathon contract for purchase of gas from the Kenai & Beaver Creek Fields.[20]

The Chugach contract current price is about $0.28/MCF and under the terms of the contract is estimated to increase to about $0.38/MCF in 1983 dollars by 1995. The contract will not be deregulated in 1985 by Subtitle B, Section 121 of the NGPA. The contract terminates in 1998 or whenever the contracted quantity of gas has been taken. At the maximum annual take of 21.9 BCF/yr., the contract will terminate in 1995 since 285 BCF remained under the contract on January 1, 1982 (See Exhibit 1).

The Enstar/Union contract current wellhead price is about $0.27/Mcf and becomes about $0.64/Mcf when delivered to Anchorage because of the addition of transmission costs. The wellhead price remains at $0.27/Mcf until 1986 where the price becomes the average price that Union/Marathon receives from new sales to third parties. If there are no new sales, the price will remain at $0.27/Mcf until contracted reserves are taken (estimated to be 1990 by Battelle) or the contract expires which is in 1992. Like the Chugach contract, this gas will not be deregulated by the NGPA in 1985.

The Enstar/Shell and Enstar/Marathon contracts were both signed in December 1982 and are essentially the same in that they have a base wellhead price of $2.32/Mcf in 1983 with an additional demand charge of $0.35/Mcf beginning in 1986. The base price and the demand charge are to be adjusted annually based on the price of No. 2 fuel oil at the Tesoro Refinery, Nikiski, Alaska. The contracts terminate in 1997 or whenever the contracted quantity of gas has been taken. The wellhead price of the gas under these contracts will probably not be deregulated in 1985 by the NGPA since the No. 2 fuel oil price adjustment mechanism is classified as an "Indefinate Price Escalator" and contracts containing these are specifically excluded under Section 121 (e) of the NGPA (see discussion under Deregulation section).

The Phillips/Marathon LNG gas is not regulated and appears to have a wellhead price that fluctuates with the delivered price of LNG in

Japan which is tied to the world price of oil. Sources have quoted the wellhead price as $2.07/Mcf in 1980[21] and $2.02/Mcf in 1982.[22]

Estimated Price For New Purchases: If current and future Railbelt electrical requirements are to be met with gas generation, new purchases of uncommitted Cook Inlet gas will be required. The price that will have to be paid for the additional gas is important in the evaluation of thermal alternatives versus the Susitna hydroelectric alternative.

Previous contracts for gas such as the Chugach/Chevron and Enstar/Union agreements are not indicative of the price that would have to be paid today for uncommitted gas since these contracts were entered into long ago and their current prices are substantially below any energy equivalency with oil or coal. Although low price gas from these contracts will be used for future electrical generation, the contracts expire in the 1990 - 1995 period and thus are not important in the Susitna vs. gas-fired unit alternative analysis which covers the period 1993-2040.

The price for new purchases would seem to depend heavily on whether the Cook inlet gas can be economically exported as LNG. With the postponement or demise of PALNG this possibility seems somewhat remote at the present time. Assuming therefore, that there is no competition from LNG exporters, the gas and electric utilities in the area would be the primary, remaining potential purchasers. The actual price that would be agreed upon between producers and the utilities is impossible to predict but an indication is provided by the Enstar/Shell and Enstar/Marathon contracts described above.

The wellhead price agreed on in the Enstar contracts was $2.32/Mcf with an additional demand charge of $0.35/Mcf beginning in 1986. The demand charge of $0.35/Mcf on the Enstar/Marathon contract applies to all gas taken under the contract from January 1, 1986 to contract expiration. Under the Enstar/Shell contract, the demand charge of $0.35/Mcf applies only if daily gas take is in excess of a designated maximum take. Enstar expects they will incur the demand charge because of electric utility requirements that increase the daily take.[23] Severance taxes of $0.06/Mcf and a fixed pipeline charge of $0.30 for pipeline delivery from Beluga to Anchorage are additional costs. Future prices (Jan. 1, 1984 and on) are to be determined by escalating the wellhead price plus the demand charge based on the price of #2 fuel oil in the year of escalation versus the price on January 1, 1983. If it were assumed that the generating units were located at the source of gas, the pipeline charge would be eliminated giving a Jan. 1, 1983 price of $2.38/Mcf. (See Table 5)

The price in Table 5 seems to represent the best estimate currently available for the cost of Cook Inlet gas for electrical

TABLE 5

Estimated Base Prices for New
Purchases of Uncommitted & Undiscovered
Cook Inlet Gas

Without LNG Export Opportunities

	1983-1986	1986-1997
Wellhead Price	$2.32/Mcf	$2.32/Mcf
Additional demand charge(1)	0.0	0.35
Severance tax	0.06	0.06
Total (unescalated)(2)	$2.38/Mcf	$2.73/Mcf
Transmission charge(3)	0.30	0.30
Delivered to Anchorage	$2.68/Mcf	$3.03/Mcf

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[1] Demand charge of $0.35 on Enstar/Marathon contract applies from January 1, 1986 on while demand of $0.35 on Enstar/Shell contract applies only if daily gas take is in excess of a designated maximum take.

[2] Prices are escalated based on the price of No. 2 fuel oil at the Tesoro Refinery, Nikiski, Alaska beginning Jan. 1, 1984.

[3] Estimated transmission charges would be about $0.30/Mcf. Per telephone conversation with Mr. Harold Schmidt, VP Enstar.

generation. Therefore this price was used as the cost of fuel for gas-fired generation in the thermal alternative to Susitna over the period 1993-2040. Since the price is tied to the future price of oil, it was escalated based on the estimated future price of oil to obtain prices for 1993 to 2040 (See Projected Gas Prices Section).

Although the possibility of uncommitted Cook Inlet reserves being purchased for LNG export seems to be remote at the present time, it is interesting to speculate as to what price producers might be able to obtain if LNG export opportunities existed. 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 subtract shipping, liquifaction, conditioning, and transmission costs to arrive at the maximum wellhead price.

Asian countries are probably the primary market for Alaska LNG, specifically Japan and Korea. LNG would compete with imported oil in those markets and its price would therefore be dependent upon the world price of oil. An example of this LNG/oil price competitivenesss is the existing contract between Phillips/Marathon and the Tokyo Gas and Toyko Electric Companies where the delivered price of gas is equal to the weighted average price of oil imported to Japan.[24] For an imported oil price of $34/bbl, the equivalent LNG price would be about $5.85/Mcf (1000 Btu/Ft^3 gas) and for an oil price of $29/bbl, $5.00/Mcf.

Conditioning, liquefaction, and shipping cost estimates were recently developed by the Governor's Economic Committee in their study of a Trans Alaska Gas System (TAGS) which would transport North Slope gas to the Kenai Peninsula via pipeline, then liquefy and ship the LNG to Japan.[25] These estimated costs are based on the large volumes of gas available from the North Slope. An LNG facillity for Cook Inlet gas only would be considerably smaller and there might be some economies of scale in going from a small to a large facility. These economies are not believed to be large however. In addition, its just as likely that TAGS will be implemented as a Cook Inlet only LNG facility and producers might therefore have the opportunity to sell their gas to either facility. The estimated costs for conditioning, liquefaction, and shipping of $2.00/Mcf from the TAGS study are therefore believed to be representative for estimating the wellhead price of Cook Inlet gas where LNG export opportunities exist.

The estimated, netback, wellhead price of Cook Inlet gas for LNG export is shown in Table 6. The price would vary depending on the average price of oil delivered to Japan so prices based on $34/bbl and $29/bbl oil are shown. The maximum price that could be paid to producers is $3.00-$3.85/Mcf and these prices are higher than the estimated prices with no LNG export opportunities shown in Table 5. Therefore, if LNG opportunities did exist, the price of Cook Inlet gas for electrical generation would be higher than the price we have adopted (Table 5) since the utilities would have to outbid potential LNG exporters.

TABLE 6

Estimated 1983 Base Prices for New Purchases of Uncommitted & Undiscovered Cook Inlet Gas

With LNG Export Opportunities

LNG Price - Japan(1)	$5.85/Mcf	$5.00/Mcf
Less:(2)		
Conditioning	0.34	0.34
Liquefaction	0.95	0.95
Shipping	0.71	0.71
Subtotal	2.00	2.00
Maximun Price to Producer(3)	$3.85/Mcf	$3.00/Mcf

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1 Based on oil prices of $34/bbl and $29/bbl.

2 Based on implementation of the Trans-Alaska Gas System (TAGS) total System, lower tariff. Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas, Report by the Governor's Economic Committee on North Slope Natural Gas, January 1983. See Reference 14, Exhibits C1, C2 and page 18 and 46 of the Marketing Study Section. (Costs shown in the report were stated in 1988 dollars and were converted to 1983 dollars using the reports' assumed inflation rate of 7%/yr.)

3 Delivered to LNG liquefaction facility. Transmission costs assumed to be negligible.

North Slope

The relevant price of North Slope gas for use in Railbelt electrical generation is the "delivered price", that is, the price of gas delivered to generating units located near the electric load centers or if generation were to take place on the North Slope, the equivalent price for electricity delivered to the load centers.

The delivered price is dependent upon the wellhead price that must be paid the North Slope producers and the cost of delivering the gas (or electricity) to the Railbelt load centers. The price that producers would accept is unknown but it is evident that they don't have a large number of alternatives to utilize the gas. They can shut the gas in or reinject as they are presently doing or sell to some entity that will transport the gas (or electricity) to market. There is a maximum price that the producers can charge since the gas is regulated by the Natural Gas Policy Act of 1978 but the only minimum would seem to be the value obtained from reinjection.

One method of estimating a North Slope wellhead price is to begin with a known or estimated price that the gas would bring in a given market and subtract the estimated costs to deliver the gas to that market. Since the sales price depends on the market to which the gas is delivered and the costs depend on the distance and method of delivery, it is best to discuss the North Slope wellhead price and the cost of using the North Slope gas for electrical generation by the transportation method employed. This is done below for those transportation methods described under the section, "Production and Use of Natural Gas".

Alaska Natural Gas Transportation System (ANGTS): The ANGTS propos~~ed~~al was to deliver North Slope gas to the Lower Forty Eight but the line passes close enough to Fairbanks ~~such~~ so that some gas could be used there for electric generation (and heating). Battelle estimated the transportation costs to be about \$3.80/MMBtu.[26] Even at a zero wellhead price, the gas cost for electrical generation would be well above the cost of Cook Inlet gas and at the maximum wellhead price of 2.30/MMBtu (~~April~~ June 1983) the delivered price would be 6.10 /MMBtu. Because implementation of this project is doubtful, its estimated gas costs are not considered to be reasonable prices to use as imputs to the thermal alternatives.

Trans Alaska Gas System (TAGS): The TAGS proposes to deliver gas to the Kenai Peninsula for liquefaction and export as LNG. Some of the gas could undoubtedly be used for electric generation at Kenai and the costs that electric utilities would have to pay to buy the gas can be estimated from information in the TAGS report. This information is presented in Table 7 for the total TAGS system and Phase I of the system. A low tariff which would provide a 30% after tax return to equity investors and a high tariff which would provide 40% are shown for both the total system and Phase I.

TABLE 7

Estimated Cost of North Slope Natural
Gas for Electric Generation at Kenai
Assuming Implementation of the Trans
Alaska Gas System (TAGS)

	Total System				Phase I System			
	Low Tariff		High Tariff		Low Tariff		High Tariff	
Estimated 1983 LNG Price per MM Btu (1)	$5.85	$5.00	$5.85	$5.00	$5.85	$5.00	$5.85	$5.00
Less Costs: (2)								
Shipping	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
Liquefaction	0.95	0.95	1.18	1.18	1.00	1.00	1.26	1.26
Subtotal	$1.66	$1.66	$1.89	$1.89	$1.71	$1.71	$1.97	$1.97
Minimum 1983 price (3)	$4.19	$3.34	$3.96	$3.11	$4.14	$3.29	$3.88	$3.03
Conditioning Costs	0.34	0.34	0.42	0.42	0.42	0.52	0.51	0.51
Pipeline Costs (4)	2.04	2.04	2.79	2.82	2.82	3.86	3.86	3.86
Wellhead Price (5)	1.81	0.96	0.75	(0.10)	0.90	0.05	(0.49)	(1.34)

down 35¢s.

(1) LNG prices are delivered prices to Japan and are equivalent to $34/bbl oil for the $5.85/MMBtu price and $29/bbl oil for the $5.00/MMBtu price.
(2) Costs in the report are shown in nominal 1988 dollars which were converted to 1983 dollars using the study's inflation rate of 7%.
(3) Minimum price TAGS would accept from utilities for purchase of gas at LNG gas conditioning facility.
(4) For pipeline from North Slope to Kenai Peninsula.
(5) Maximum price that TAGS would be able to pay North Slope producers.

Source: Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas, Report by the Governor's Economic Committee on North Slope Gas, January, 1983. See Exhibits C1 and C2 and pgs 18 and 46 of the Marketing Study Sections.

The price that electric utilites would have to pay is dependent upon the LNG sales price in Japan so prices of $5.85/MBtu and $5.00/MMBtu have been shown. These correspond to oil prices in Japan of $34/~~661~~bbl and $29/~~661~~bbl respectively.

Using the netback approach, shipping and liquefaction costs are subtracted from the sales prices for these would be avoided by TAGS if the gas was sold to electric utilities at the LNG plant. As can be seen, prices vary from $3.03/MMBtu to $4.19/MMBtu but the lower prices may not be realistic since they may result in low or negative wellhead prices to the producers. In addition, at an estimated sales price of $5.00/MMBtu the TAGS would probably not be implemented.

Subtraction of gas conditioning costs and pipeline transmission costs gives the wellhead price which varies from a negative $1.34 to $1.81/MMBtu depending on the system, tariff, and sales price assumed.

If it is assumed that TAGS would be implemented only at an LNG sales price of $5.85/MMBtu or above, that the total system would be constructed and that some point between the low and high tariff was acceptable to investors and North Slope producers, then the price of gas to electric utilities at Kenai would be $3.96-$4.19/MMBtu.* These

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*This would provide investors an after-tax return on equity between 30 and 40% and North Slope producers a wellhead price between $0.75 and $1.81/MCF.

assumptions seem to be reasonable and a 1983 cost of North Slope gas of $4.00/MMBtu for electric generation will therefore be assumed.

Pipeline to Fairbaks: Transportation costs of a small diameter pipeline to Fairbanks have been estimated to be about $4.80/MMBtu for electrical generation.[27] Using the average of the reasonable TAGS wellhead prices discussed above of $1.28/MMBtu (ave. of $0.75 and $1.81/MMBtu) provides a delivered cost in Fairbanks of $6.00/MMBtu. This cost is considerably higher than the estimated cost from TAGS and was therefore not used in the analysis of thermal alternatives.

North Slope Generation: This alternative uses the North Slope gas without incurring transportation costs for the gas. However, the generated electricity must be transmitted to the Fairbanks load center thereby requiring the construction of an electrical transmission line. The capital costs and O&M costs of this line have also been estimated and they are about 80% of the gas transmission lines.[28] Based on this, an equivalent "gas" transportation cost would be $3.89/MMBtu (0.8 x $4.8/MMBtu) which when added to a wellhead price of $1.28/MMBtu would result in an "equivalent delivered" cost of gas of $5.12/MMBtu. This is less than the small diameter pipeline alternative but still considerably more than the TAGS delivered cost. This price was therefore not used in the analysis of thermal generation alternatives.

The estimated delivered cost of gas to Railbelt load centers based on transportation costs and assumed wellhead prices are shown in Table 8. The only cost used as an input to the thermal alternatives analysis, however, is the cost derived from the TAGS study which was found to be about $4.00/MMBtu in 1983 dollars.

TABLE 8

Estimated 1982 Delivered Cost of North
Slope Natural Gas For Railbelt Electrical Generation

Delivery Method	Estimated Cost $/MMBtu	Value Used $/MMBtu
ANGTS [1]	4.03-5.30	
TAGS [2]	3.96-4.19	4.00
Pipeline to Fairbanks [3]	4.80-6.08	
North Slope Generation [4]	3.84-5.12	

spread out

[1] Cost of $3.80/MMBtu in 1982$ ~~and~~ assuming a zero wellhead cost was estimated by Battelle. This was adjusted to 1983$ to provide the $4.03/MMBtu. The $5.30/MMBtu includes an assumed wellhead cost of $1.28/MMBtu.

[2] Costs estimated using a "netback" approach. See Table 7. Value of $4.00/MMBtu selected as reasonable value for thermal generation alternatives analysis.

[3] Costs estimated using capital and O&M costs from Reference 27. The cost of $4.80/MMBtu assumes a wellhead price of zero while the $6.08/MMBtu price assumes a wellhead price of $1.28/MMBtu.

[4] Costs estimated using capital and O&M costs from Reference 27. These costs are "equivalent" costs for the gas would be burned on the North Slope and the electricity delivered to Railbelt load centers via an electric transmission line. The "equivalent" costs were determined by comparing the costs of the electric transmission line with the costs of the gas pipeline to Fairbanks. The $3.84/MMBtu assumes a wellhead price of zero and the $5.12/MMBtu a wellhead price of $1.28/MMTbu.

TABLE 8

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North Slope Generation[4]	3.84-5.12	

spread out

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[1] Cost of $3.80/MMBtu in 1982$ ~~and~~ assuming a zero wellhead cost was estimated by Battelle. This was adjusted to 1983$ to provide the $4.03/MMBtu. The $5.30/MMBtu includes an assumed wellhead cost of $1.28/MMBtu.

[2] Costs estimated using a "netback" approach. See Table 7. Value of $4.00/MMBtu selected as reasonable value for thermal generation alternatives analysis.

[3] Costs estimated using capital and O&M costs from Reference 27. The cost of $4.80/MMBtu assumes a wellhead price of zero while the $6.08/MMBtu price assumes a wellhead price of $1.28/MMBtu.

[4] Costs estimated using capital and O&M costs from Reference 27. These costs are "equivalent" costs for the gas would be burned on the North Slope and the electricity delivered to Railbelt load centers via an electric transmission line. The "equivalent" costs were determined by comparing the costs of the electric transmission line with the costs of the gas pipeline to Fairbanks. The $3.84/MMBtu assumes a wellhead price of zero and the $5.12/MMBtu a wellhead price of $1.28/MMTbu.

on transportation costs and assumed wellhead prices are shown in Table 8. The only cost used as an input to the thermal alternative analysis, however, is the cost derived from the TAGS study and found to be about $4.00/MMBTU in 1983 dollors.

Projected Gas Prices

The estimated 1983 costs of Cook Inlet and North Slope gas were developed in the previous sections. Since the analysis of thermal alternatives covers the period 1983-2040, a method for projecting the 1983 price must be utilized.

The method selected is to tie the price of natural gas to the world price of oil since the two fuels can be substituted in many cases and particularly since the recent Enstar gas pruchase contract price is tied to the price of oil. The Enstar price was used as the 1983 estimated price of gas for the Cook Inlet area and it is assumed to be representative of future contracts for Cook Inlet uncommitted and undiscovered gas.

If North Slope gas is sold as LNG to Japan or Korea, the delivered price will probably be tied to the world price of oil in the same manner as the existing Phillips/Marathon LNG contract. Electric utilities who purchase gas from the LNG exporters will probably also have to pay a price which is adjusted to the world oil price (see Table 7). Therefore, it is assumed that future prices of North Slope gas for electrical generation will also fluctuate with the world price of oil.

The oil price forecast that is selected to project future Cook Inlet and North Slope gas prices is therefore critical in the analysis of thermal generation alternatives. The following sections review a range of forecasts.

Oil Price Forecasts

Forecasting the future world price of oil is a perilous task at best and most previous forecasts have been lacking in accuracy particularly over the last ten years when oil markets received radical upward price shocks. Some forecasts can be considered to be better than others, however, largely because of the methodology used, the experience level of the forecast~~o~~ers, and the reasoning behind the forecasts. In this category, we would include Sherman Clark Associates, Data Resources Inc., and the Energy Modeling Forum.

We have reviewed the forecasts by these entities as well as the forecasts by the Alaska Department of Revenue. The forecasts are presented and discussed in the following sections.

Sherman Clark Associates

Sherman Clark has over thirty-five years of experience in the field of energy including twenty years with Stanford Research Institute as Director of Energy and Resource Economics. Sherman Clark Associates (SCA) prepares annually a detailed 25 - 30 year forecast of the supply and demand for energy and resulting, estimated prices. The SCA forecast prices for oil and coal presently are for three scenarios to which probabilities of occurrence have been assigned. SCA's latest scenarics are:

Base Case. In this scenario, oil prices decrease from the existing 1983 price of $29.00/bbl to $26.30/bbl in 1983 dollars and remain at that level until 1989 where SCA has assumed a severe supply description will occur, causing prices to jump to $40.00. Prices will remain at $40/bbl until 1990 where they will increase at a real rate of 3% until 2000 and then at a 3.5% real rate until 2010. The severe supply description envisioned would be an overthrow of the Saudi Arabian government by a radical element that would severely cut back on oil production or a war involving Saudi Arabia where the ability to produce oil was severely damaged. SCA has assigned a 40% probability of occurrence to this scenario. From 2010 to 2020 SCA estimates a real rate of increase of 1.5%/yr. and from 2020 to 2040 a real rate of 0%.

No Supply Description Case. This case is similar to the Base Case, but no severe supply description occurs. In addition, there is an assumption that more Non-OPEC crude will be found and produced.

Estimated prices drop to $26.30/bbl and remain there until 1989 where they rise at a real rate of 3%/yr. to 2010. SCA has assigned a 35% probability of occurrence to this scenario. For 2010 to 2020 SCA estimates a real rate of 2.5%; 2020 to 2030 a rate 1.5%; and 2030 to 2040 a rate of 1.0%

Zero Economic Growth Case. This scenario assumes that there will be no economic growth until 1990. Consequently, prices drop to $17.00/bbl until 1990 where they begin to rise at a real rate of 5%/yr to year 2010. SCA has assigned a 25% probability to this scenario. SCA has made no estimated projections past 2010 for this case.

Data Resources Incorporated (DRI).

DRI is a well-known forecasting organization which provides forecasts of GNP, economic indicators, and commodity prices including prices for oil, gas and coal. Extensive use is made of econometric and other computer models including special energy forecasting models such as the DRI Drilling Model, DRI Coal Model and the DRI Energy Model. Worldwide supply and demand for oil are estimated to arrive at a forecast price for oil. DRI's spring 1983 base case forecast shows a negative 13% real change for 1984, a 7.4% real change from 1984-1985, about a 6.5%/yr. real increase from 1985-1990, a 4.4%/yr. real increase from 1990 to 1995 a 3.1%/yr. real increase from 1995-2000, and a 1.1%/yr real increase from 2000-2005. Assuming a 1983 price of

$28.95/bbl, the price in 2000 would be about $53/bbl and if the 1.1%/yr. rate of price increase was assumed to continue until 2010, the price at that point in time would be about $60/bbl in 1983 dollars. DRI has also formulated low and high price scenarios but has not assigned a probability to any of the forecasts. It therefore is assumed that its base case forecast is the likely or most probable outcome.

Energy Modeling Forum (EMF).

The EMF was created by the Electric Power Research Institute (EPRI) to improve the use and usefulness of energy models. The EMF is administered by the Stanford Institute for Energy Studies which is in the Dept. of Engineering - Economic Systems and the Dept. of Operations Research. The EMF operates through ad hoc working groups of energy model developers and users. Each group is organized around a single topic to which existing models can be applied.

One of the groups, with members from around the world, addressed issues relating to oil price, availability, and security of supply. The results of their study were reported in an EPRI publication entitled, World Oil.[29] The objective of the study was to analyze world oil issues through the application of 10 prominent world oil models to twelve scenarios designed to bound the range of likely future world oil market conditions. The ten models used are listed in Table 9.

The twelve scenarios include a reference or base case which is not necessarily EMF's most likely case but rather is a plausible mean case which can be considered as representative of the general trends that can be expected. The twelve scenarios are listed in Table 10.

In general, EMF expects a soft oil market for the 1980's with little or no real price increase until 1990 unless there is a supply disruption.

Beginning in 1990, real prices will increase over the next several decades in either steady upward movements or in sudden price jumps followed by gradual declines. EM's reference case shows median real price increases of 2% annually between 1980 and 1985, 6% annually for 1985 to 1990 and 4% for 1990 to 2000. Starting from a 1983 price level of $28.95/bbl, this results in a price of $30/bbl in 1985, $40/bbl in 1990, and $60/bbl in the year 2000. If the 4%/yr. real increase continued to the year 2010, the price would be about $88/bbl in 1983 dollars.

EMF's other eleven scenarios result, of course, in prices different from the reference case. The relative outcome of the other eleven scenarios is illustrated in Figure 4 which shows the estimated world oil price in the year 2000 for all ten models for each of the

TABLE 9

Models Used in the World Oil Study

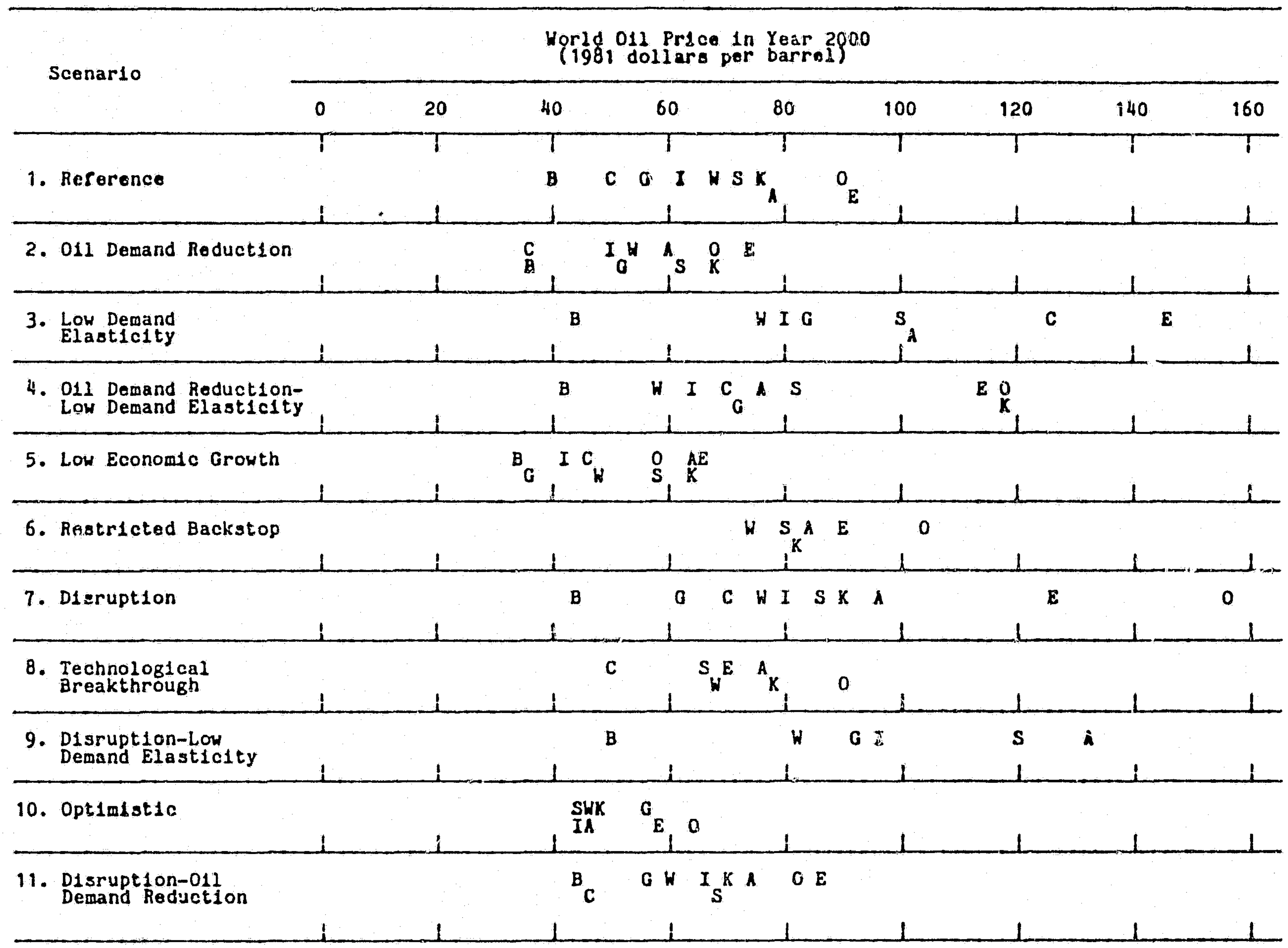
Model	Organization(s)
Gately-Kyle-Fischer	New York University Imperial Oil Ltd.
IEES-OMS (International Energy Evaluation System-Oil Market Simulation)	U.S. Department of Energy
IPE (International Petroleum Exchange)	Massachusetts Institute of Technology
Salant-ICF	U.S. Federal Trade Commission ICF, Incorporated
ETA-MACRO	Stanford University
WOIL	U.S. Department of Energy/ Energy and Environmental Analysis, Incorporated
Kennedy-Nehring	University of Texas Rand Corporation
OILTANK	Chr. Michelsen Institute
Opeconomics	British Petroleum Co. Ltd.
OILMAR	Energy and Power Subcommittee, U.S. House of Representatives

TABLE 10

Scenario Descriptions

Scenario	Description
1. Reference Case	base case for analysis
2. Oil Demand Reduction	agressive import reduction program in the OECD
3. Low Demand Elasticity	reduction in demand elasticities to 5/8 of reference case
4. Oil Demand Reduction-Low Demand Elasticity	agressive import reduction program in low elasticity world
5. Low Economic Growth	reduced GNP growth rates throughout the world
6. Restricted BAckstop	50% reduction in availability continuing 10 MMBD reduction in OPEC capacity
7. Disruption	in 1985 sudden and indefinitely continuing 10 MMBD reduction in OPEC capacity
8. Technological Breakthrough	rrduced cost and increased availability of nonconventional energy
9. Disruption-Low Demand Elasticity	10 MMBD OPEC capacity reduction in low elasticity world
10. Optimistic	aggressive import reduction program; more availability of nonconventional energy; increased OPEC capacity
11. Disruption-Oil Demand	10 MMBD OPEC capacity reduction in presence of agressive import reduction program
12. High Oil Price	oil price 50% higher than values determined in reference case

002|49



Models: G = Gately, I = IEES-OMS, C = IPE, A = ETA-MACRO, K = Kennedy-Nehring, O = OILMAR, E = OILTANK, W = WOIL, S = Salant-ICF, B = Opeconomics

Note: For all models other than IEES-OMS and IPE, the average of prices between 1995 and 2005 is given. For IEES-OMS, the 1995 price is presented; for IPE, averages between 1995 and 2000 are presented. Several projections are higher than \$160/bbl and thus do not appear above. These include: for the low demand elasticity scenario, Kennedy-Nehring (\$175) and OILMAR (\$177); for the disruption-low demand elasticity scenario, OILTANK (\$184), IPE (\$198), Kennedy-Nehring (\$217), and OILMAR (\$417).

FIGURE 4 - World Oil Price Forecasts For Eleven Scenarios Using Ten Different Energy Forecasting Models

twelve scenarios. The price is shown in 1981 dollars, and if converted to 1983 dollars would be about 10% higher. (The director of EMF has indicated, however, that if the estimates were redone in 1983 they would be 10 - 15% lower.)

The significance of Figure 4 is that the results using the ten models in the twelve scenarios are a clustering in year 2000 of world oil price in the range of $50 - 80/bbl.

Alaska Department of Revenue (DOR).

The Alaska DOR prepares forecasts of world oil prices to use as an input to their revenue model. The revenue model provides an estimate of the quantity of revenue from oil and gas royalties and other sources that the state can expect to receive annually through 1999. The DOR's oil price and revenue forecasts are updated quarterly.

The Alaska DOR arrives at its forecast of oil prices through the "Delphi" method which consists of questioning persons knowledgable in the area of energy and oil and attempting to arrive at some sort of consensus as to what future oil prices will be. The DOR forecast results in the lowest oil prices by the year 2010 although the SCA Zero Economic Growth estimate has lower forecast prices from 1983 - 1998. The DOR's forecast oil prices decrease from $28.95/bbl in 1983 to a low of $22/bbl in 1987 and then increase at an average real rate of about

1.3%/yr. from 1988 - 1999 resulting in a price of about $26/bbl in 1999. If the 1999 DOR price is escalated to 2010 at the same 1.3%/yr. rate, the price becomes about $30/bbl.

Discussion and Recommendation.

The Sherman Clark Associates, Data Resources Inc., and Energy Modeling Forum forecasts seem to be based on detailed analyses of the supply of and demand for oil over the forecasting period. All of these forecasts reflect the existing soft market for oil that may continue for several years. However the forecasts also reflect the high probability of a world economic recovery from the 1981 - 1982 recession and the resulting increased demand for oil. In addition, the forecasts reflect the fact that oil is a depletable resource and although there are some substitutes, eventually the dwindling world supply should result in higher real prices barring some dramatic technological break through.

The DOR forecast of oil is developed by the "Delphi" method, i.e. by questioning various knowledgeable persons in the energy field and then using the predominate thinking of the group questioned to develop a forecast. This method depends heavily on the particular persons questioned and may be overly influenced by particular influential individuals in Alaska who believe in the imminent breakup of OPEC as the controlling force for the world price of oil. While OPEC appears to have lost some power in the last year, as evidenced by the drop in the official price of oil from $34/bbl to $29/bbl, an accord between the OPEC members seems to have been reached concerning the quantities of oil produced so that the price seems likely to hold at $29/bbl in nominal terms. The relatively strong economic recovery that is currently underway in the U.S. will undoubtedly be followed by the rest of the free industrial world and should support the benchmark price and eventually allow OPEC to increase the price as demand for oil increases. A zero economic growth oil price scenario therefore seems unlikely and comparing the false starts in economic recovery of 1979 & 1981 where inflation was high and unemployment low with the current situation where inflation is low and unemployment high would appear to involve specious reasoning.

We believe that the most likely future oil price scenario should therefore lie somewhere within the forecasts of DRI, EMF, and Sherman Clark Associates. Ignoring the Sherman Clark ZEG scenario which we believe to have a probability considerably less than 25%, the future price of oil in the year 2010 should fall somewhere between $50 and $75/bbl. This price range would seem to be substantiated by the twelve scenarios run by the EMF (see Figure 1) which show the prices in the year 2000 to be grouping in the range of $40 to $80/bbl.

Taking the approximate middle of these estimates would seem to be a reasonable approach to obtaining an estimate of future oil prices. This would equate to a constant price of $28.95/bbl from 1983 through 1986, a real rate of increase of 2.9%/yr. from 1987 through 1998, and a

3.0%/yr. real rate of increase from 1999 to the year 2000. This forecast translates into an oil price of about $44/bbl in the year 2000 and $58/bbl by 2010. This forecast, entitled the "reference case", and the other scenarios discussed above are shown in Table 11 and are graphed in Figure 5.

Forecasts Past Year 2010

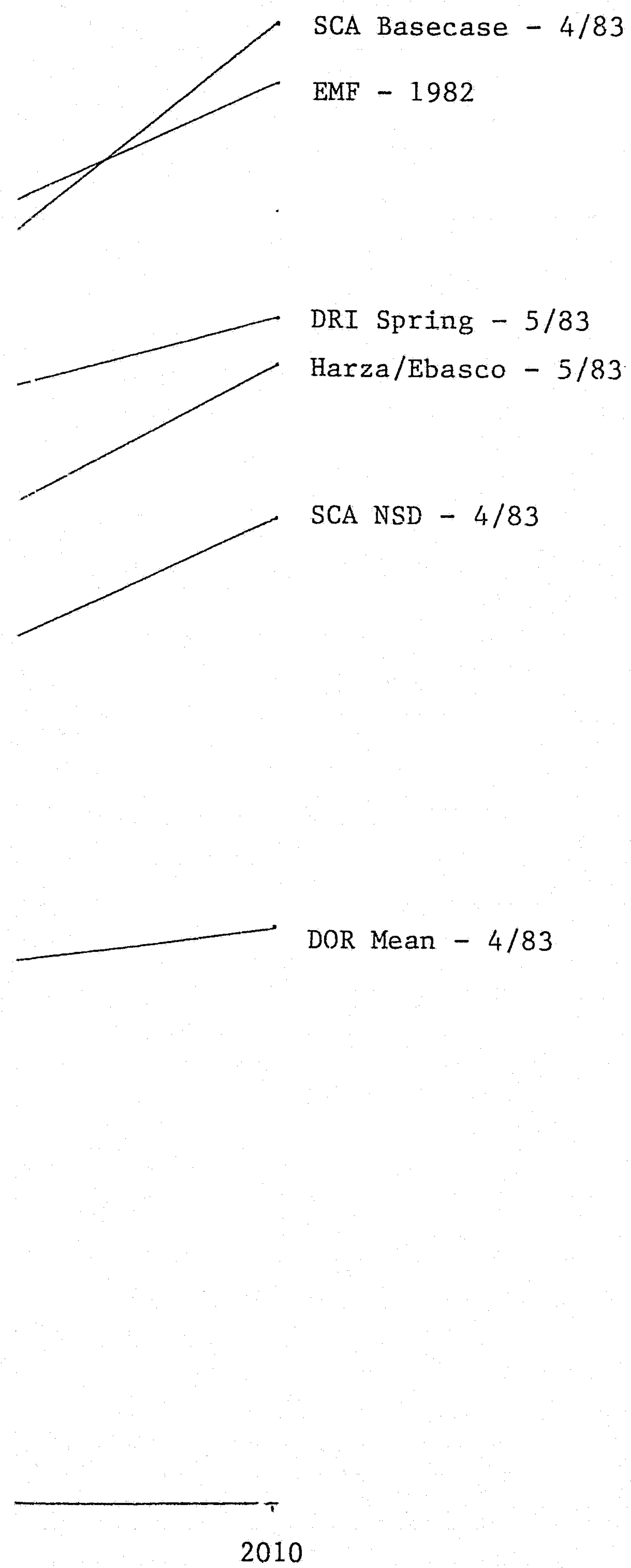
The evaluation of thermal alternatives relative to Susitna require that an economic evaluation period over the estimated life of the longest lived alternative be used. The alternative with the longest life is Susitna which is conservatively estimated to be 50 years. Assuming Susitna was on-line in 1993, the economic evalution period would end in year 2043. Therefore, fuel prices for the thermal alternatives must also be provided for the years 2010-2043.

SCA is the only forecaster who has forecast oil prices past the year 2010. Attempts to forecast that far into the future are probably not much better than guesses. It is generally accepted wisdom, however, that as the price of oil increases in real terms, alternatives become economically competitive. Thus oil and gas from coal will probaly become competitive at an oil price of $70-$80/bbl (1983$). Heavy oil, oil from tar sands, oil from shale, and gas and oil from unconventional deposits such as gas from geopressurized wells and low-permeability reservoir gas will probably be available at real

TABLE 11
ALTERNATIVE PETROLEUM PRICE PROJECTIONS 1983 - 2010
1983 DOLLARS

	Sherman Clark Base Case		Sherman Clark NSD Case		DRI Spring 1983		Harza/Ebasco Reference Case		Energy Modeling Forum		Department of Revenue Mean	
	$/bbl	%Chg.	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg
1983	28.95	-4.6	28.95	-4.6	28.95	-13.1	28.95	0.0	28.95	2.0	28.95	-17.2
4	27.61	-4.7	27.61	-4.7	25.17	7.4	28.95	0.0	29.53	2.0	23.96	- 5.4
5	26.30	0.0	26.30	0.0	27.02	6.5	28.95	0.0	30.11	6.0	22.67	- 1.4
6	26.30	0.0	26.30	0.0	28.77	6.5	28.95	2.9	31.94	6.0	22.35	- 1.8
7	26.30	0.0	26.30	0.0	30.64	6.5	29.79	2.9	33.82	6.0	21.95	1.3
8	26.30	52.1	26.30	3.0	32.62	6.5	30.65	2.9	35.85	6.0	22.15	1.3
9	40.00	0.0	27.09	3.0	34.74	6.5	31.54	2.9	38.02	6.0	22.34	1.3
1990	40.00	3.0	27.90	3.0	36.99	~~6.5~~ 4.4	32.46	2.9	40.29	4.0	22.55	1.3
1	41.20	3.0	28.74	3.0	38.61	4.4	33.40	2.9	41.88	4.0	22.79	1.3
2	42.44	3.0	29.60	3.0	40.31	4.4	34.37	2.9	43.57	4.0	23.04	1.3
3	43.71	3.0	30.49	3.0	42.08	4.4	35.36	2.9	45.29	4.0	23.32	1.3
4	45.02	3.0	31.40	3.0	43.92	4.4	36.39	2.9	47.14	4.0	23.63	1.3
5	46.38	3.0	32.34	3.0	45.85	4.4	37.44	2.9	49.02	4.0	23.96	1.3
6	47.77	3.0	33.31	3.0	47.27	3.1	38.53	2.9	51.00	4.0	24.31	1.3
7	49.20	3.0	34.31	3.0	48.74	3.1	39.65	2.9	53.03	4.0	24.71	1.3
8	50.68	3.0	35.34	3 0	50.26	3.1	40.80	3.0	55.15	4.0	25.14	1.3
9	52.20	3.0	36.40	3.0	51.82	3.1	42.02	3.0	57.37	4.0	25.60	1.3
2000	53.76	3.~~0~~5	37.50	3.0	53 ~~58~~.43	~~3.1~~ 1.14	43.28	3.0	59.64	2.0	25.93	1.3
1	55.64	3.5	38.63	3.0	54.04	1.14	44.58	3.0	60.84	2.0	26.27	1.3
2	57.58	3.5	39.78	3.0	54.65	1.14	45.92	3.0	62.05	2.0	26.61	1.3
3	59.58	3.5	40.98	3.0	55.27	1.14	47.30	3.0	63.30	2.0	29.96	1.3
4	61.66	3.5	42.21	3.0	55.90	1.14	48.71	3.0	64.56	2.0	27.31	1.3
5	63.81	3.5	43.47	3.0	56.54	1.14	50.18	3.0	65.86	2.0	27.66	1.3
6	66.04	3.5	44.78	3.0	57.33	1.14	51.68	3.0	67.18	2.0	28.02	1.3
7	68.34	3.5	46.12	3.0	58.13	1.14	53.23	3.0	68.52	2.0	28.39	1.3
8	70.73	3.5	47.50	3.0	58.95	1.14	54.83	3.0	69.89	2.0	28.76	1.3
9	73.20	3.5	48.93	3.0	59.77	1.14	56.47	3.0	71.29	2.0	29.13	1.3
2010	75.75	3.5	50.39	3.0	60.61	1.14	58.17	3.0	72.71	2.0	29.51	1.3

*EMF and DOR forecasts extrapolated by H/E after 2000 & 1999 respectively.


SCA Basecase - 4/83
EMF - 1982
DRI Spring - 5/83
Harza/Ebasco - 5/83
SCA NSD - 4/83
DOR Mean - 4/83
2010

$)

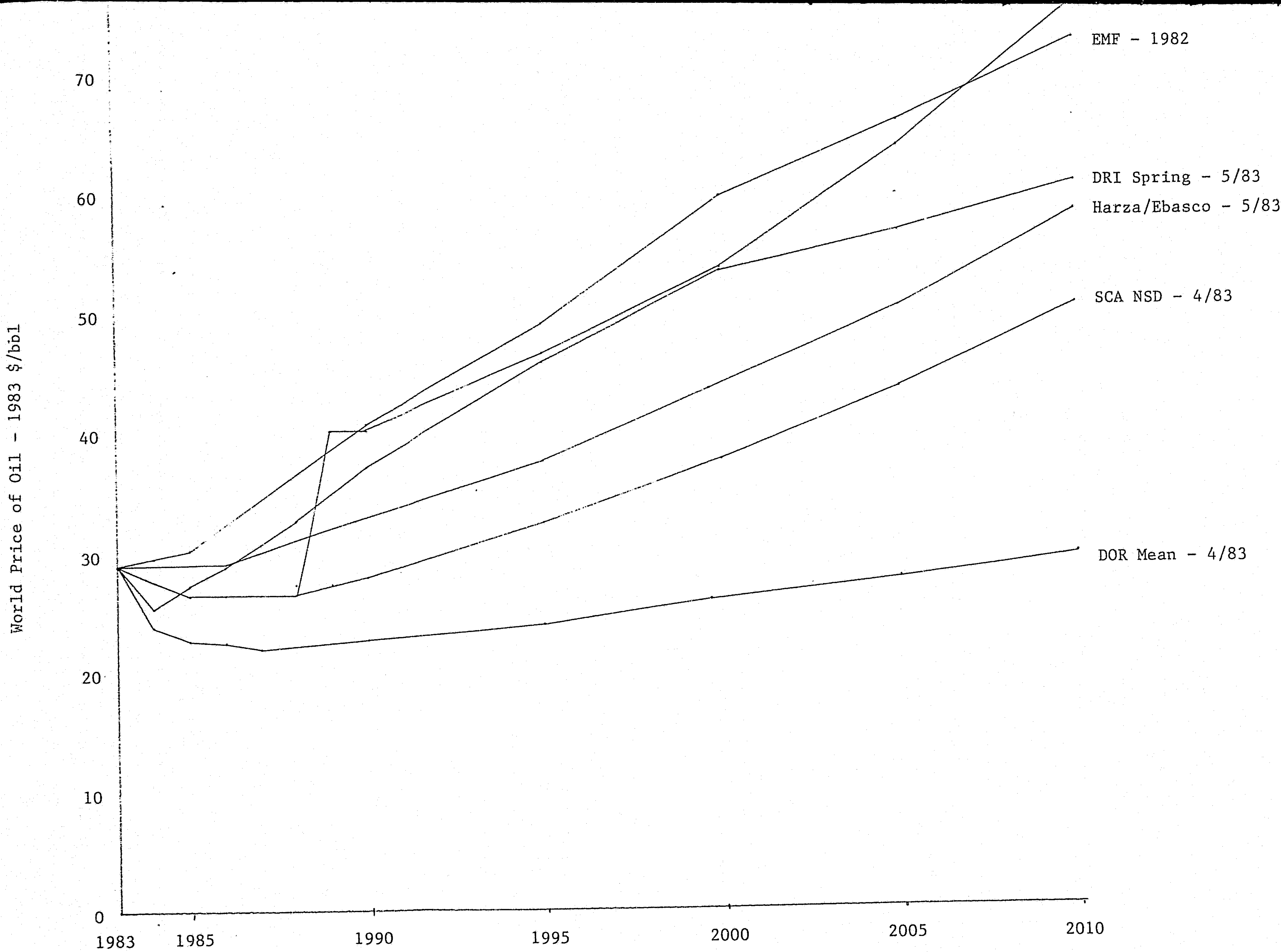


FIGURE 5 - Alternative Oil Price Projections - $/bbl (1983 $)

prices above $80/bbl. In addition, electrical energy from fusion may become economically available as well as energy from unforseen new technologies. Who, for example, foresaw the potential contribution of nuclear power to present world energy requirements in 1935? The period 1935-1983 covers forty eight years which is a shorter period than that covered by the present forecast, 1983-2043.

Since the factors of oil substitutability and new technological developments in energy, will probably tend to mitigate future, continuing real increases in the price of oil and natural gas, we recommend tapering real rates of increase in the world price of oil according to the following schedule:

Period	Real Oil Price Increase
2010-2020	2%/yr.
2021-2030	1%/yr.
2031-2043	0%/yr.

Table 12 shows the SCA forecasts from 2010-2040 and the other forecasts which have been extended using the real increases presented above or the last escalation rate used by the estimator.

TABLE [illegible]

ALTERNATIVE OIL PRICE PROJECTIONS 2010 - 2040

1983 DOLLARS

	Sherman Clark [1] Base Case		Sherman Clark [1] NSD Case		DRI [2] Spring 1983		Harza/Ebasco [3] Reference Case		Energy Modeling Forum [4]		Department of Revenue Mean [5]	
	$/bb	%Chg.	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg	$/bbl	%Chg
2010	75.75	1.5	50.39	2.5	60.61	1.1	58.17	2.0	72.71	2.0	29.51	1.3
1	76.89	1.5	51.65	2.5	61.28	1.1	59.33	2.0	74.16	2.0	29.89	
2	78.04	1.5	52.94	2.5	61.95	1.1	60.52	2.0	75.65	2.0	30.28	
3	79.21	1.5	54.26	2.5	62.63	1.1	61.73	2,0	77.16	2.0	30.68	
4	80.40	1.5	55.61	2.5	63.32	1.1	62.97	2.0	78.70	2.0	31.07	
2015	81.60	1.5	57.00	2.5	64.02	1.1	64.22	2.0	80.28	2.0	31.48	
6	82.83	1.5	58.42	2.5	64.72	1.1	65.51	2.0	81.88	2.0	31.89	
7	84.07	1.5	59.88	2.5	65.43	1.1	66.82	2.0	83.52	2.0	32.30	
8	85.33	1.5	61.38	2.5	66.15	1.1	68.16	2.0	85.19	2.0	32.72	
9	86.61	1.5	62.91	2.5	66.88	1.1	69.52	2.0	86.90	2.0	33.15	
2020	87.80	~~1.5~~ 0.0	64.48	1.5	67.62	1.1	70.91	1.0	88.63	1.0	33.58	
1	87.80	0.0	65.45	1.5	68.36	1.1	71.62	1.0	89.52	1.0	34.02	
2	87.80	0.0	66.43	1.5	69.11	1.1	72.34	1.0	90.41	1.0	34.46	
3	87.80	0.0	67.43	1.5	69.87	1.1	73.06	1.0	91.32	1.0	34.91	
4	87.80	0.0	68.44	1.5	70.64	1.1	73.79	1.0	92.23	1.0	35.36	
2025	87.80	0.0	69.47	1.5	71.42	1.1	74.53	1.0	93.15	1.0	35.82	
6	87.80	0.0	70.51	1.5	72.20	1.1	75.27	1.0	94.08	1.0	36.76	
7	87.80	0.0	71.57	1.5	73.00	1.1	76.03	1.0	95.02	1.0	36.23	
8	87.80	0.0	72.64	1.5	73.80	1.1	76.79	1.0	95.97	1.0	37.72	
9	87.80	0.0	73.73	1.5	74.61	1.1	77.55	1.0	96.93	1.0	38.21	
2030	87.80	0.0	74.84	1.0	75.43	1.1	78.33	0.0	97.90	0.0	38.71	
1	87.80	0.0	75.59	1.0	76.26	1.1	78.33	0.0	97.90	0.0	39.21	
2	87.80	0.0	76.34	1.0	77.10	1.1	78.33	0.0	97.90	0.0	39.72	
3	87.80	0.0	77.10	1.0	77.95	1.1	78.33	0.0	97.90	0.0	40.23	
4	87.80	0.0	77.88	1.0	78.81	1.1	78.33	0.0	97.90	0.0	40.76	
2035	87.80	0.0	78.65	1.0	79.68	1.1	78.33	0.0	97.90	0.0	41.29	
6	87.80	0.0	79.44	1.0	80.55	1.1	78.33	0.0	97.90	0.0	41.82	
7	87.80	0.0	80.23	1.0	81.44	1.1	78.33	0.0	97.90	0.0	42.36	
8	87.80	0.0	81.03	1.0	82.33	1.1	78.33	0.0	97.90	0.0	42.37	
9	87 80	0.0	81.84	1.0	83.24	1.1	78.33	0.0	97.90	0.0	42.92	
2040	87.80	0.0	82.66	1.0	84.15	1.1	78.33	0.0	97.90	0.0	42.48	1.3

1/ Sherman Clark's own estimates.

2/ DRI projected at last DRI projection rate of 1.1%/yr.

3/ H/E estimated rates. See text for discussion.

4/ EMF projected using H/E estimated rates. EMF estimate made in 1982 and EMF indicat~~or~~es if estimate was made in 1983 it would be lower (approx. 10-15%). This would give a 2040 price of $83-88/bbl.

5/ DOR projected using last DOR projection rate of ~~1~~%/year.
1.3

World Price Projections

Gas prices are projected from 1983-2043 using selected oil price scenarios. The base prices of gas for 1983 are $2.38.MCF for Cook Inlet gas (Table 5) and $4.00 for North Slope gas (Table 8). The oil price snenarios selected from Table 11 and 12 were the SCA base case and the SCA no scenarios disruption (NSO) case. These scenarios were selected because they are the only forecasts where the forecaster extended his forecast to 2043 and in addition, the two scenarios bracket a wide range of plausible future oil prices. In addition, the DRI, DOR & forecast scenarios of 4%, 0%, -1%, and -2.0% real rates per year were also employed to illustrate a wide range of possible future oil prices and resulting projected Cook Inlet and North Slope gas prices.

The projected gas prices are shown in Tables 13 and 14 and were used as gas price imports to the thermal generation analysis.

Effect of Gas Price Deregulation (under development)

E 1

PROJECTED COOK INLET WELLHEAD GAS PRICES 1983 - 2040

1983 DOLLARS

Insert A

	Sherman Clark Base Case	Sherman Clark NSD Case	Reference Case +2%/yr.	Reference Case 0%/yr.	Reference Case -1.0%/yr	Referenc Case e -2.0%/yr
1983	2.38	2.38	2.38	2.38	2.38	2.38
4	2.27	2.27	2.43	2.38	2.36	2.33
5	2.16	2.16	2.48	2.38	2.33	2.29
6	2.51	2.51	2.88	2.73	2.66	2.58
7	2.51	2.51	2.94	2.73	2.63	2.53
8	2.51	2.59	3.00	2.73	2.60	2.48
9	3.82	2.66	3.06	2.73	2.58	2.43
1990	3.82	2.74	3.12	2.73	2.55	2.38
1	3.93	2.83		2.73		
2	4.05	2.91		2.73		
3	4.17	3.00		2.73		
4	4.30	3.09		2.73		
5	4.43	3.18	3.45	2.73	2.43	2.15
6	4.56	3.27		2.73		
7	4.709	3.37		2.73		
8	4.84	3.47		2.73		
9	4.98	3.58		2.73		
2000	5.13	3.69	3.80	2.73	2.31	1.95
1	5.31	3.80		2.73		
2	5.50	3.91		2.73		
3	5.69	4.03		2.73		
4	5.89	4.15		2.73		
5	6.09	4.27	4.20	2.73	2.10	1.76
6	6.31	4.40		2.73		
7	6.53	4.53		2.73		
8	6.76	4.67		2.73		
9	6.99	4.81		2.73		
2010	7.24	4.95	4.64	2.73	2.09	1.59
1	7.34	5.08		2.73		
2	7.46	5.20		2.73		
3	6.68	5.33		2.73		
4	7.80	5.47		2.73		
5	7.91	5.60	5.12	2.73	1.98	1.44
6	8.03	5.74		2.73		
7	8.15	5.89		2.73		
8	8.27	6.04		2.73		
9	8.40	6.19		2.73		
0	8.40	6.34	5.65	2.73	1.89	1.30
1	8.40	6.44				
2	8.40	6.53				
3	8.40	6.63				

TABLE 13(cont'd)
PROJECTED COOK INLET WELLHEAD GAS PRICES 1983-2040
1983 DOLLARS

Insert A

	Sherman Clark Base Case	Sherman Clark NSD Case	Reference Case +2%/hr.		Reference Case 0%/yr.	Reference Case -1.0%/yr.	Reference Case -2.0%/yr.
2024	8.40	6.73	~~2.73~~		2.73	1.79	
5	8.40	6.83	~~2.73~~	6.24	~~1.79~~	~~1.17~~	1.17
6	8.40	6.93	~~2.73~~				
7	8.40	7.04	~~2.73~~				
8	8.40	7.14	~~2.73~~				
9	8.40	7.25	~~2.73~~			1.71	
2030	8.40	7.36	~~2.73~~	6.89	~~1.71~~	~~1.06~~	1.06
1	8.40	7.43	~~2.73~~				
2	8.40	7.51	~~2.73~~				
3	8.40	7.58	~~2.73~~				
4	8.40	7.66	~~2.73~~			1.62	
2035	8.40	7.73	~~2.73~~	7.61	~~1.62~~	~~0.96~~	0.96
6	8.40	7.81	~~2.73~~				
7	8.40	7.89	~~2.73~~				
8	8.40	7.97	~~2.73~~				
9	8.40	8.05	~~2.73~~			1.54	
2040	8.40	8.13	~~2.73~~	8.40	~~1.54~~	~~0.87~~	0.87
					2.73		

(1) Estimated 1983 price of Cook Inlet gas from Table 5.
(2) Additional demand charge of $0.35/MMBtu applies from 1986 forward and is escalated by price of oil change.

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Insert A (to table 13)

Year		DRI Spring 1983	DOR Mean
1983		2.38	2.38
4		2.07	1.97
1985		2.22	1.86
6	+0.35	2.74	2.18
7		2.92	2.14
8		3.11	2.17
9		3.31	2.20
1990		3.52	2.23
1		3.68	
2		3.84	
3		4.01	
4		4.19	
1995		4.37	2.38
6		4.50	
7		4.64	
8		4.79	
9		4.94	
2000		5.09	2.54
1		5.15	
2		5.20	
3		5.26	
4		5.32	
2005		5.38	2.71
6		5.44	
7		5.50	
8		5.56	
9		5.62	
2010		5.68	2.89
1		5.74	
2		5.81	
3		5.87	
4		5.93	
2015		6.00	3.08
6		6.07	
7		6.13	
8		6.20	
9		6.27	
2020		6.34	3.28
1		6.41	
2		6.48	
3		6.55	

TABLE 14

Projected North Slope Delivered Gas Prices
In 1983 dollars per MMBtu

Insert B

YEAR	Sherman Clark Base Case	Sherman Clark NSD	Reference Case +2/yr	Reference Case 0%/yr.	Reference Case -1.0/yr.	Reference Case -2.0%/y
1983	4.00	4.00	4.00	4.00	4.00	4.00
1984	3.82	3.82	4.08	4.00	3.96	3.92
1985	3.64	3.64	4.16	4.00	3.92	3.84
1986	3.64	3.64		4.00		
1987	3.64	3.64		4.00		
1988	3.64	3.75		4.00		
1989	5.53	3.86		4.00		
1990	5.53	3.98	4.59	4.00	3.73	3.47
1991	5.69			4.00		
1992	5.86			4.00		
1993	6.04			4.00		
1994	6.22			4.00		
1995	6.41	4.61	5.07	4.00	3.55	3.14
1996				4.00		
1997				4.00		
1998				4.00		
1999				4.00		
2000	7.43	5.35	5.60	4.00	3.37	2.84
2001				4.00		
2002				4.00		
2003				4.00		
2004				4.00		
2005	8.82	6.20	6.18	4.00	3.21	2.56
2006				4.00		
2007				4.00		
2008				4.00		
2009				4.00		
2010	10.48	7.18	6.83	4.00	3.05	2.32
2011				4.00		
2012				4.00		
2013				4.00		
2014				4.00		
2015	11.29	8.13	7.54	4.00	2.90	2.10
2016				4.00		
2017				4.00		
2018				4.00		
2019				4.00		
2020	12.16	9.20	8.32	4.00	2.76	1.89
2021	12.16			4.00		
2022	12.16			4.00		
2023	12.16			4.00		
2024	12.16			4.00		
2025		9.91	9.19	4.00	2.62	1.71

TABLE 14 (continued)

Projected North Slope Delivered Gas Prices
In 1983 dollars per MMBtu

Insert B

YEAR	Sherman Clark Base Case	Sherman Clark NSD	Reference Case +2/yr	Reference Case 0%/yr.	Reference Case 1.0/yr.	Reference Case -2.0%/y
2026	12.16			4.00		
2027	12.16			4.00		
2028	12.16			4.00		
2029	12.16			4.00		
2030	12.16	10.67		4.00	2.49	1.55
2031	12.16		10.15	4.00	2.49	1.55
2032	12.16			4.00		
2033	12.16			4.00		
2034	12.16			4.00		
2035	12.16	11.22	11.20	4.00	2.37	1.40
2036	12.16			4.00		
2037	12.16			4.00		
2038	12.16			4.00		
2039	12.16			4.00		
2040	12.16	11.79	12.37	4.00	2.26	1.26

1) Estimated 1983 price of North Slope gas from Table 8.

Insert B (to Table 14)
(North Slope)

Year	DRI Spring 1983	DOR Mean		
1983	4.00	4.00		

WILSON JONES COMPANY G7504 GREEN

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18. Battelle, Op. Cit. p.A.2

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20. See Reference 3.

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22. Reference 8, p.A.3.

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24. Anchorage Daily Times, January 4, 1983.

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Part II - COAL

This analysis of coal availability and cost in Alaska has been developed to provide the basis for evaluating a thermal alternative to the Susitna Hydroelectric Project. This assessment has been developed by a careful review of available literature plus contacts with Alaskan coal developers and exporters. Critical literature included the Bechtel (1980) report executive summary, selected Battelle reports (e.g., Secrest and Swift, 1982); Swift, Haskins, and Scott, (1980) and the U.S. Department of Energy (1980) study on transportation and marketing of Alaskan coal. Numerous other reports were used for data confirmation. The most current data were obtained by contacts with the following individuals: Mr. Joseph Usibelli, Usibelli Coal Co.; Mr. Robert Styles, Diamond Alaska Coal Co.; Mr. C. E. McFarland, Placer Amex, Inc.; Mr. William Noll, Suneel Alaska, Inc.; Mr. W. Baker, Golden Valley Electric Association; and Mr. Keith Sworts, Fairbanks Municipal Utility Systems.

Resources and Reserves

Alaska has three major coal fields: Nenana, Beluga, and Kukpowruk (see Figure 1). It also has lesser deposits on the Kenai Peninsula and in the Matanuska Valley. Alaska deposits, in total, contain some 130 billion tons of resources (Averitt, 1973), and 6 billion tons of reserves as is shown in Table 1. The Nenana and Beluga fields are the most economically promising Alaska deposits as they are very large and have favorable mining conditions. The Kukpowruk deposits cannot be mined economically, and also face substantial environmental problems (Kaiser Engineers, 1977). The Kenai and Matanuska fields are small and present additional mining difficulties (Battelle, 1980).

The Nenana Field, located in central Alaska, contains a reserve base of 457 million tons and a total resource of nearly 7 billion tons as is shown in Table 2. Its subbituminous coal ranges in quality from 7400-8200 Btu/lb, is high in moisture content, is low in sulfur content and is very reactive (see Table 3). Some 84% of this coal is contained in seams greater than 10 ft. in thickness, and stripping ratios of 4:1 are commonly encountered (Energy Resources Co., 1980).

The Beluga Field contains identified resources of 1.8 billion tons (Department of Energy, 1980) to 2.4 billion tons

(Energy Resources Co., 1980). The quality of this sub-bituminous coal varies according to report. Several analyses are shown in Table 4. Beluga deposits typically are in seams greater than 10 ft in thickness (Energy Resources Co., 1980) (Styles, 1983), and may be up to 50 ft. thick in places (Barnes, 1966). Stripping ratios from 2.2 to 6 are commonly found.

Present and Potential Alaskan Coal Production

Currently, there is only one significant producing mine in Alaska, the Usibelli Coal Co. mine located in the Nenana Field. This unit produces 830 thousand tons of coal/yr for use by local utilities, military establishments, and the University of Alaska-Fairbanks. These users operate 87 Megawatts (MW) of electrical generation capacity, as shown in Table 5, and plans exist at Fairbanks Municipal Utility System (FMUS) to increase the total coal-fired electric generating capacity to 108 MW (Sworts, 1983). The FMUS capacity shown in Table 5 also serves the Fairbanks district heating system.

To produce the 830 thousand tons/yr., Usibelli Coal Co. employs a 33 yd^3 dragline and a front end loader-truck system. This mine, with its existing equipment, has a production capacity of 1.7-2.0 million tons/yr. (Usibelli, 1983). Much of that capacity would be employed if, and when, the Suneel Alaska Co. export contract for 880 thousand tons (800 thousand metric tons)/yr becomes fully operational. That contract calls for full-scale shipments, as identified above, to the Korean Electric Power Co. beginning in 1986 (Noll, 1983).

Production at the Usibelli mine ultimately could be increased to 4 million tons/yr (Department of Energy, 1980; Battelle, 1982; Usibelli, 1983). The mine, which has been in operation since 1943, has 300 years of reserves remaining at current rates of production (Usibelli, 1983). Thus, at 4 million tons of production, mine life would exceed 70 years. This production, which may not be able to be used at the mine mouth for environmental reasons (Ebasco, 1982) due to proximity to the Denali National Park, may be shipped to various locations via the Alaska Railroad.

The Beluga Field, which totally lacks infrastructure, currently is not producing coal; however, several developers have plans to produce in that region. These developers include the Diamond Alaska Coal Co., a joint venture of Diamond Shamrock and the Hunt Estates; and Placer Amex Co. Involved in their plans are such infrastructural requirements as the construction of a town, transportation facilities to move the coal to tidewater, roads, and other related systems. These are necessary if one or more mines are to be made operational.

Diamond Alaska Coal Co. holds leases on 20 thousand acres of land (subleasing from the Hunt-Bass-Wilson Group), with 1 billion tons of subbituminous resources. Engineering has been performed for a 10 million ton/yr mine designed to serve export markets on the Pacific Rim; and the engineering has involved a mine, a 12 mile overland conveyor to Granite Point, shiploading facilities at Granite Point, town facilities, and power generation facilities (Styles, 1983). The mine intself involves two draglines plus power shovels and trucks. The target timeframe for production is 1988-1991 (Styles, 1983). Placer-Amex plans involve a 5 million ton/yr mine in the Beluga field, also serving the export market (Department of Energy, 1980).

As can be seen, the primary plans for the Beluga Field are for exporting of coal to the Pacific Rim. The proponents of exports believe that Alaskan coal can compete on a cost basis with Austrailian coal (Styles, 1983), that Alaskan coal is more competitive than lower 48 U.S. coal (Swift, Haskins, and Scott, 1980), and that policy decisions in Japan and Korea favor the exporting of Alaskan coal (Swift, Haskins, and Scott, 1980).

There are reasons to believe that exporting may be difficult to accomplish, however. Alaskan coal is of relatively low quality for the export market (Noll, 1983) and does not meet the Japanese coal specifications (Swift, Hasins, and Scott, 1980). The world recession dampened the need for coal on the Pacific Rim and set back the export development timetable (Noll, 1983). The stabilization and decline in the world price of oil has reduced the incentive for converting from oil to coal in the Pacific Rim countries (McFarland, 1983).

It is feasible to develop the Beluga Field at a smaller scale for local needs, however. This potential is recognized, inferrentially, by Olsen, et. al. (1979) of Battelle and supported explicitly by Usibelli (1983) and Placer-Amex (McFarland, 1983). Diamond Alaska Coal Co. currently is performing detailed engineering studies on a 1-3 milion ton/yr mine in this field (Styles, 1983). As a consequence, it is reasonable to conclude that production in both the Nenana and Beluga fields could be used to support new coal fired power generation in Alaska.

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Current Alaskan Coal Prices

The issue of coal prices can be addressed either from a production cost perspective or a market value perspective, or from a combination of the two. The production cost perspective is particularly appropriate if electric utilities serve as the primary market, since their contracts with coal suppliers typically are based upon providing the coal operator with coverage of operating costs plus a fair return on investment (typically treated as 15 percent. See Bechtel, 1980; Stanford Research Institute, 1974; and other reports for use of this 15% ROI). The market value perspective is particularly appropriate when exports become the dominant market. These concepts are employed separately for Nenana and Beluga coal.

Nenana Coal Prices

Coal pricing data exist for Usibelli coal, and these data provide a basis for estimating the cost of coal at future power generation facilities.

Currently, Usibelli coal is being sold to the Golden Valley Electric Association (GVEA) Healy generating station under longterm contract at a price of $1.16/million Btu (Baker, 1983), and to FMUS at a mine-mouth price of $1.35/ million Btu (Sworts, 1983). The current average tipple price for Usibelli coal is $23.38/ton of 7800 Btu/lb coal, or $1.50/million Btu (Usibelli, 1983). This value is based, to a large extent, on labor productivity of 50 tons/man day as reported by Usibelli (1983). That is a slight decline in productivity, as Usibelli had achieved 60 tons/man day (Usibelli, 1983), a value confirmed by the National Coal Association (1980).

The $1.50/million Btu reflects the price of coal from the Usibelli mine operating at about 50 percent of capacity. Usibelli (1983) estimates that if production were increased to 1.6 million tons/yr, coal prices would decline to $20/ton ($1.28/million Btu). Usibelli (1983) also estimates, however, that an immediate 10% increase in all coal prices associated with that mine can be expected in order to comply with new land reclaimation regulations. As a consequence, the marginal cost of Usibelli coal can be calculated (in 1983 dollars) as:

$20/ton x 1.1 x ton/15.6 million Btu = $1.40/million Btu

The Usibelli mine could be expanded to 4 million tons/yr., given the reserve base available. At such production levels, Usibelli (1983) states that the additional 2 million tons of production would exhibit the same prices as the current mine when operating at full capacity.

The pricing perspective of Usibelli, however, is not universally shared. The Department of Energy coal transportation study (USDOE, 1980), estimates that coal from the additional 2 million tons/yr. will cost $1.88-$2.03/million Btu in January 1983 dollars ($1.62-$1.75/million BTu in 1980 dollars).

Because there is an apparent disagreement on coal prices from a second unit of production, and because the Suneel contract is not yet in place ,the $1.40/million Btu is used as a conservative base price for Nenana Field coal at the mine mouth; however, such coal must be transported to market by railroad. FMUS, for example, pays $0.50/million Btu for rail shipment of Usibelli coal (Sworts, 1983). Battelle (1982) developed railroad cost functions for coal transport and, on this basis, the following charges should be added to Usibelli coal (Secrest and Swift, 1982):

Destination	Charge (1983 $/million Btu)
Nenana	0.32
Willow	0.51
Matanuska	0.60
Anchorage	0.70
Seward	0.78

Therefore, the delivered price of coal to a new power plant is estimated to be $1.72-$2.18 depending upon location. On this basis it is likely that new power plants fueled by Usibelli coal would be in the communities of Nenana or Willow [Ebasco (1982) projected a Nenana location]. These are the appropriate base prices for use in power plant analysis.

Beluga Coal Prices

The approach of the price of coal from the Beluga field depends, in large measure, on whether or not the export market for Alaskan coal develops in the Pacific Rim. If that market exists, then both marketing and production cost analyses apply. In the absence of that market, production costs must be estimated for smaller mines.

The qualitative arguments for and against projecting an export market for Alaskan coal have been previously discussed. In this section the existence of the export market is assumed. Estimates of the magnitude of that potential market have been developed by Sherman H. Clark and Associates (Clark, 1983), and by Mitsubishi Research Institute (MRI, 1983). The Sherman H. Clark values are shown in Figure 2 for Japan and Korea. As this figure illustrates, the projected total market in Japan alone could exceed 100 million metric tons by the end of this decade. The data from MRI are shown in Figures 3 and 4, with particular emphasis on the use of coal in electric utilities. MRI forecasts a smaller total coal market in Japan in 1990, some 72.7 million tons (vs. Sherman H. Clark's 108.1 million tons). MRI estimates that the U.S. share of that Japanese market is 11.1 million tons, as is shown in Table 6.

Regardless of whether the Japanese market will be 73 or 108 million metric tons in 1990, these forecasts do illustrate that a large potential market exists. In that they are consistent with the date from Swift, Haskins, and Scott (1980). This market is potentially highly available to the Alaskan mines due to transportation cost differentials (Swift, Haskins, and Scott, 1980). Transportation cost differentials are based upon the distance to market, as illustrated in Figure 5. Levy (1982) argues this point most strongly when he states that Alaskan coal exports will "dwarf current production" in Alaska by the 1990's, and states that most western coal that is exported will come from the Alaskan fields, notably Beluga.

Because of this strong evidence for an export market, particularly in Japan (MRI, 1982), it is essential to place a market value on the Alaskan coal. Various "shadow pricing" or "net back" approaches have been used previously to achieve this value (see, for example, Secrest and Swift, 1982). The approach taken here is quite similar. The value of coal in Japan is based upon the FOB price of coal at ports in the competing nations of Australia, Canada, and South Africa obtained from Clark (1983), and the transportation charges associated with that coal as obtained from Diamond Shamrock Corp. (1983). The value of coal in Japan, therefore, is \$2.40-\$2.50/ million Btu as is shown in Table 7. Deductions are taken from this value to reflect the lower quality of Alaskan coal, and to reflect the transportation costs from Alaska to Japan. The market value of Alaskan coal FOB Granite Point is \$1.81-\$1.95/million Btu, as is shown in Table 8.

Frequently it is argued that the market value FOB mine is substantially lower than the market value FOB Port. In arguing this case, all capital and operating charges associated with transporting the coal from mine to tidewater have to be deducted from the $1.81-$1.95/million Btu. However if the market value of coal assumes exports, then it necessarily assumes that the coal transport facilities are in place. The assumption of such transport facilities being in existence means that all capital costs must be treated as sunk costs, and that the only charges to be netted out are incremental O&M costs associated with whether the specific coal is or is not moved to tidewater. These charges would be minimal assuming the operation of the export system. As a consequence the values of $1.81-$1.95/million Btu are assumed to hold.

Production cost estimates for Beluga coal also have been developed. They are based upon large mines (5-10 million tons/yr) producing coal for export, and smaller mines (1-3 million tons/yr) serving only the power plant market (200-600 MW).

Production cost estimates have been made for large mines serving the export market, and these are reported in Table 9. The lower bound values range from $1.16/million Btu to $1.27/million Btu and the higher bound values range from $1.65/million Btu to $1.74/million Btu. The average of these estimates, taken as a group, is $1.45/million Btu.

For the purposes of deriving a coal cost estimate assuming exports, the difference between the market value and the production cost value must be addressed. Battelle approached reconciliation by simple averaging (Secrest and Swift, 1982). That approach is shown here as well, with the average of the market values ($1.88/million Btu) being averaged with the production cost of $1.45/million Btu to achieve a price of $1.67/million Btu.

While this provides one basis for analysis, it appears that the market value is a more meaningful number to use. If a coal operator could sell coal at $1.88/million Btu FOB Port, and if there were few cost savings to be achieved by not transporting the coal to tidewater, then there would be no reason to sell at some average price. Rather, assuming the export of 5-10 million tons/yr at 7200-7800 Btu/lb coal, such a practice would result in decreased revenues to the coal operation of $15.1-$32.8 million per year. These decreased revenues graphically display the concept of opportunity cost. For this reason the market value of coal 's assumed.

The Beluga mines as currently projected have largely been considered as sources of coal to be exported to Pacific Rim countries such as Japan, Korea, and Taiwan. Certainly, there has been substantial optimism expressed for such marketing (see Beluga Coal Company and Diamond Alaska Coal Company, 1982; Styles, 1983; Swift, Haskins, and Scott, 1980). Further, there is a substantial constituancy promoting such exports (see Resource development Council of Alaska, 1983). Whether or not this market develops, however, is still a matter of uncertainty.

In the absence of strong export markets, production costs for smaller mines have to be considered. Production costs for smaller mines have been reported by varius potential vendors, at \$1.50/million Btu (Diamond Alaska Coal Co. value quoted by Griffith 1983 to \$2.00/million Btu (Placer-Amex value quoted by McFarland, 1983). Initial order-of-magnitude values have been developed based upon the coal mine costing model of the McLean Research Center (1980) and the pricing formula of Kaiser Engineers (1977). These values are \$1.65/million Btu to \$1.80/million Btu, not including infrastructural costs, and are shown in Table 10. These values are within the range cited by the vendors.

Production cost numbers have been derived independently by Paul Wier and Associates (Schaible, 1983). These costs assume that a 3-seam operation would be developed at 1 million tons/yr. and at 3 million tons/yr. In both cases, the coal would be mined by truck and shovel technology rather than dragline technology. It would be crushed and delivered to the power plant. At the one million ton/yr size, transport to powerplant would be accomplished by trucks and at the three million ton/yr size it would be accomplished by conveyor belt. In both cases town development costs would be shared between the coal mine and the power plant, and the coal mine portion would be capitalized with the mine. Using a 100% equity assumption and a 17% Return on Investment (ROI) due to risk, they estimate the cost of coal from small mines in the Beluga field at -----

Coal prices in Alaska, then, are assumed to be \$1.72 - \$1.91/million Btu for Nenana coal delivered either to the town of Nenana or the town of Willow; and \$1.88/million Btu for Beluga coal if exported. If coal is produced for domestic purposes only the expected price is \$____________/million Btu.

Real Coal Price Escalation

Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually long term contracts which include a base price for the coal and a method of escalation to provide prices in future years. The base price provides for recovery of the capital investment, profit, and operating and maintenance costs at the level in existence when the contract was entered into. The intent of the escalation mechanism is to recover actual increases in labor and material costs from operation and maintenance of the mine. Typically the escalation mechanism consists of an index or combination of indexes such as the producer price index, various commodity and labor indexes, the consumer price index which applied to operating and maintenance expenses, and or regulation related indices. The original capital investment is not escalated, so the price of coal to the utility tends to increase with general inflation, but at a real rate of increase of 0%/yr.

The free market price of coal, however, could increase or decrease at a rate above or below the general rate of inflation because of demand/supply relationships in the relevant coal market. The utility with an existing contract tied to a cost reflective index would not experience these real changes until the existing contract expired and was renegotiated, or a contract for new or additional quantities of coal was executed.

Several escalation rates have been estimated for utility coal in Alaska and in the lower 48 states, and they range from 2.0-3.0%/year (real) as is shown in Table 11. Several more generic rates have also been developed by Sherman H. Clark and Associates and by DRI, and these are shown in Table 12.

These rates can be compared to the real rate of increase experienced by Golden Valley Electric Association, calculated to be 2.3% since 1974 (Diener, 1981). It is difficult to use that historical GVEA rate, however, for the following reasons: (1) the rate relates to an existing contract, and (2) the rate covers a period of time when the provisions of the Coal Mine Safety Act of 1969 were being incorporated into the price of coal.

The generic estimates of Sherman H. Clark and DRI appear to be based more upon supply-demand analyses than upon extrapolations of historical data. Consequently there are distinctions in coal quality, as shown in Figure 6, taken from Sherman Clark and Associates.

Because the forecasts of DRI and Sherman H. Clark are based upon supply-demand factors, they are used here and are to be applied to the base contract price of coal. The 2.6% real rate of increase is applied to the mine-mouth price of Nenana Field (Usibelli) coal as this mine is used principally to supply domestic markets. It should be noted, however, that this is the price before transport. Transportation costs over time are shown in Table 13. For the Beluga Field there is sufficient evidence to support the use of an export market driven value that a base price of $1.88 is used. Because this is used the export-specific escalator of 1.6% is applied. The resulting fuel prices are shown in Table 14. As a consequence of these calculations the real escalation rates for the delivered base price of coal experienced by utilities at various locations are as follows:

Utility Location	Coal Field	Escalation Rate
Nenana	Nenana	2.3
Willow	Nenana	2.2
Beluga	Beluga	1.6

It is also useful to note that the export market could fail to develop. In such a case the Beluga Field coal would esclate at a rate more comparable to the Nenana Field coal, since the mine would be geared to serving the same market. In this case, base coal costs would be as follows:

Year	Coal Cost ($/Million Btu)			
1983 (base)	1.75	1.80	1.85	1.90
1990	2.09	2.15	2.21	2.27
2000	2.71	2.78	2.86	2.93
2010	3.50	3.60	3.69	3.79

While there is some correlation between export coal prices and world oil prices such a correlation is tenuous, at best, with respect to utility coal contracts. Technical correlations must accommodate differences which exist between coal and oil fired units in the areas of capital costs ($/kW), operating costs, and fuel purchasing agreements. Further such correlations must accommodate significant differences in market flexibility and market opportunity between coal and oil suppliers. For these reasons it is necessry to treat coal prices as being independent of world oil prices.

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Table 1. Demonstrated Rese[illegible] Base in Alaska and the U.S. by Type of Coal.

(values in millions of short tons)

Type of Coal	Alaska	Total U.S.
Anthracite	--	7341.7
Bituminous	697.5	239,272.9
Subbituminous	5,443.0	182,035.0
Lignite	14.0	44,063.9
Total	6,154.5	472,713.6
Percent of Total	1.3%	100%

Source: Demonstrated Reserve Base of Coal in the United States on January 1, 1980.

Table 2. Reserves and Resources of the Nenana Field.

Reserve/Resource Type	Quantity (tons x 10^6)
Reserve Base	457
Resources	
Measured	862
Indicated	2,700
Inferred	3,377
Total	6,938[a]

[a] Totals do not add due to rounding on measured and inferred.

Source: Energy Resources Co., 1980.

Table 3. Proximate and Ultimate Analysis of Nenana Field Coal

Proximate Analysis	Weight Percent
Moisure	26.1
Ash	6.4
Volatile Matter	36.3
Fixed Carbon	31.2
As Received Ultimate Analysis (wt %)	
Hydrogen	3.6
Carbon	47.2
Oxygen	15.5
Nitrogen	1.05
Sulfur	0.12
Chlorine	---
Moisture	26.1
Ash	6.4
Higher Heating Value (Btu/lb)	7,950

Source: Hazen Laboratory Analyses for Fairbanks Municipal System.

Table 4. Ultimate Analyses of Beluga Coal

Value (wt %)	Analyses		
	Stanford[a] Research Inst.	Battelle[b] (Waterfall Seam)	Diamond[c] Alaska Coal Co.
Carbon	44.7	---	45.4
Hydrogen	3.8	---	2.9
Nitrogen	0.7	---	0.7
Oxygen	15.8	---	14.4
Sulfur	0.2	0.18	0.14
Ash	9.9	16.0	7.9
Moisture	24.9	21.0	28.0
Higher Heating	7200	7536	7800

a/Stanford Research Institute, 1974

b/Swift, Haskins, and Scott, 1980

c/Diamond Shamrock Corporation, 1983

Table 5. Coal Fired Capacity in Alaska.

Owner	Location	Heat Rate (Btu/kWh)	Capacity (MW)
Golden Valley Electric Assn.	Healy	13,200	25
University of Alaska	Fairbanks	12,000	13
U.S. Air Force Ft. Wainwright	Fairbanks	20,000	20
Fairbanks Municipal Utility System	Fairbanks	13,300-22,000	29
Total	N/A	13,000-22,000	87

Source: Battelle, Vol VI, 1982.

Table 6. Projected National Shares of Japanese Coal Market For Imports in the Year 1990[a]

Nation	Market Share Percentage	Million Tons
Australia	41.8	30.4
Canada	11.9	8.7
United States	15.3	11.1
China	16.0	11.6
USSR	5.6	4.1
South Africa	4.2	3.0
All Others	5.2	3.8
Total	100.0	72.7

Source: MRI, 1982

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a/ Includes steam coal and metallurgical coal.

Table 7. The Value of Coal Delivered in Japan By Coal Origin (Jan, 1983 Dollars)

Nation of Coal Origination	Value of Coal (FOB Port)	Shipping Cost ($/ton)	Value of Coal ($/ton(	$/million Btu)
Australia	$45.00	10.50	$55.50	$2.49
South Africa	37.50	15.30	52.80	2.37
Canada	45.00	10.35	55.35	2.48

a/From Sherman H. Clark and Associates, 1983

b/From Diamone Shamrock Corp., 1983

c/Assumes 11,160 Btu/lb per Japanese Specification in Swift, Haskins, and Scott, 1980.

Table 8: The Market Value of Coal FOB Granite Point, Alaska (Jan 1983 Dollars)

	Value of Coal ($/Million Btu)	
	Low	High
The Value of Coal in Japan[a]/	$2.40	$2.50
Price Discount Based upon the impact of lower quality on plant capital costs (1.6%)[b]/	$0.04	$0.04
Net Value of Coal in Japan	$2.36	$2.46
Cost to Transport Coal[c]/	$0.55	$0.51
Net Value of Coal at Granite Point	$1.81	$1.95

[a]/From Table 7

[b]/See Swift, Haskins, and Scott (1980) analysis on Waterfall Seam Coal, pp. 7-5-7-6.

[c]/Cost is $8.00/ton. Low value column reflects 7200 Btu/lb coal and high value column reflects 7800 Btu/lb coal (see Table 4).

Order-of-Magnitude

Table 10. Production Cost Estimates For a 2 Million ton/yr Mine in the Beluga Coal Field (1983 Dollars, Jan 1.)*

Parameter	Cost
Initial Capital Investment	\$73,315,000[a]
Deferred Capital Investment	\$22,470,000[b]
Total Capital Investment	\$95,785,000
Annual O&M, Costs	\$38,349,000[c]
Cost Per Ton @ 15% ROI	\$27.72[d]
Cost Per Million Btu (7200-7800 Btu/lb)	\$1.65-\$1.80[e]

*Not including infrastructive.

NOTES TO PRODUCTION COST TABLE

a/Equation is

$C_I = 4.391\ RT + 3.259T$

C_I = Initial Capital Investment (Lower 48, 1980\$ x 10^6)
R = Stripping Ratio (Taken at 4.4)
T = Annual Production (Million tons)

Alaska Factor For Capital = 1.4
Escalator = 1.094 x 1.06 = 1.5964

$C_I = (4.391 \times 4.4 \times 2 + 3.259 \times 2) \times 1 \times 10^6 \times 1.4 \times 1.5964 =$
\$73,315,131 (Say \$73,315,000)

b/ Equation is

$C_D = ,1712\ RT + 8.268T^{20.577}$

$C_D = (0.1712 \times 4.4 \times 2 + 8.268 \times 2^{20.577}) \times 1.4 \times 1.15964 \times 1 \times 10^6$
=22,469,671 (Say \$22,470,000)

c/ Equation is

$C_A = 9.262 = 4.555T$

Alaska Factor = 1.8

$C_A = (9.262 + 4.555 \times 2) \times 1 \times 10^6 \times 1.8 \times 1.15964 =$
38,348,830 (Say \$38,349,000)

Equations From: McLean Research Center, 1980
Alaska Factors From: Usibelli, 1983

NOTES TO PRODUCTION COST TABLE - 2

d/ Equations are

$$S = \frac{1}{.875} \left(C_A + 1.33 \frac{(C_I + C_D - D)}{PWF}\right)$$

$D = 0.1\ (C_I + C_D - D)$ depreciation

PWF = 6.566 @ 15% ROI

S/T = $/Ton

$$S = \frac{1}{.0875} \left(38{,}439{,}000 + 1.33 \left(\frac{95{,}785{,}000}{6.566} - 9{,}579{,}000\right)\right)$$

S= $51,441,000

$/ton = $51,441,000/2,000,000 = $25.72

e/ 25.72/15.6 = $1.65(@ 7800 Btu/lb coal)

25.72/14.4 = $1.79(@ 7200 Btu/lb coal)

Equations For Annuity Coal Pricing
From Kaiser Engineers 1977

Coal Heat Contents: Diamond Alaska Coal, 1983
Stanford Research
Institute, 1974

Table 11. Some Protected Escalation Rates for Coal Prices.

Forecastor	Coal	Real Escalation Rate (%) to 2010
Battelle (1982)[a]	Beluga	2.1
	Nenana	2.0
Acres (1981)[b]	Beluga	2.6
	Nenana	2.3
Acres (1982)[c]	Beluga	2.5
	Nenana	2.7

a/ Secrest and Swift, 1982.

b/ Diener, 1981.

c/ Diener, 1982.

Table 12. Coal Price Real escalation Rates

Author	Coal Types	Long Term Real Escalation Rate
DRI	New Coal Contracts	2.6%
Sherman H. Clark	New Coal Contracts and Spot Market Coal	
	West Coal	2.9%
	Lignite	2.3%
	Coal Exports	1.6%

Sources: DRI, 1983; Clark, 1983.

Table 13. Nenana Coal Transportation Costs - 1983
From Healy to Plant Location ($/MMBtu)

Year	Plant Location Nenana	Willow	Matanuska	Anchorage	Seward
1983	0.32	0.51	0.60	0.70	0.78
1984	0.30	0.48	0.57	0.67	0.74
1985	0.30	0.48	0.57	0.67	0.75
1986	0.32	0.49	0.58	0.67	0.76
1987	0.33	0.50	0.58	0.68	0.77
1988	0.33	0.50	0.59	0.69	0.78
1989	0.34	0.51	0.60	0.70	0.79
1990	0.34	0.52	0.61	0.71	0.80
1991	0.35	0.52	0.62	0.72	0.81
1992	0.35	0.53	0.63	0.73	0.82
1993	0.36	0.54	0.64	0.74	0.84
1994	0.36	0.54	0.64	0.75	0.84
1995	0.36	0.55	0.64	0.75	0.85
1996	0.37	0.55	0.65	0.76	0.86
1997	0.37	0.55	0.65	0.76	0.86
1998	0.37	0.56	0.66	0.77	0.87
1999	0.37	0.56	0.66	0.78	0.88
2000	0.38	0.57	0.67	0.78	0.88
2001	0.38	0.57	0.67	0.79	0.89
2002	0.38	0.57	0.68	0.79	0.90
2003	0.39	0.58	0.68	0.80	0.90
2004	0.39	0.58	0.69	0.81	0.91
2005	0.39	0.59	0.69	0.81	0.92
2006	0.40	0.59	0.70	0.82	0.92
2007	0.40	0.60	0.70	0.83	0.93
2008	0.40	0.60	0.71	0.83	0.04
2009	0.41	0.61	0.72	0.84	0.95
2010	0.41	0.61	0.72	0.85	0.95

Notes:

Transportation cost equations: (1983)
Healy to:

Nanana = $0.23 + 0.09 (oil escalation rates)
Willow = 0.36 + 0.15 (oil escalation rates)
Matanuska = 0.42 + 0.18 (oil escalation rates)
Anchorage = 0.49 + 0.21 (oil escalation rates)
Seward = 0.55 + 0.23 (oil escalation rates)

Table 14. Estimated Delivered Base Prices of Coal in Alaska by Year (in 1983 $/Btu x10^6

Year	Nenana Field Coal Delivered to			Beluga Field Coal
	Mine Mouth	Nenana	Willow	Mine Mouth
1983	1.40	1.72	1.91	1.88
1984	1.44	1.74	1.92	1.91
1985	1.47	1.77	1.95	1.94
1986	1.51	1.83	2.00	1.97
1987	1.55	1.88	2.05	2.00
1988	1.59	1.92	2.09	2.04
1989	1.63	1.97	2.14	2.07
1990	1.68	2.02	2.20	2.10
1991	1.72	2.07	2.24	2.13
1992	1.76	2.11	2.29	2.17
1993	1.81	2.17	2.35	2.20
1994	1.86	2.22	2.40	2.24
1995	1.91	2.27	2.46	2.27
1996	1.85	2.32	2.50	2.31
1997	2.01	2.38	2.56	2.35
1998	2.06	2.43	2.62	2.39
1999	2.11	2.48	2.67	2.42
2000	2.17	2.55	2.74	2.46
2001	2.22	2.60	2.79	2.50
2002	2.28	2.66	2.85	2.54
2003	2.34	2.73	2.92	2.58
2004	2.40	2.79	2.98	2.62
2005	2.46	2.85	3.05	2.67
2006	2.53	2.93	3.12	2.71
2007	2.59	2.99	3.19	2.75
2008	2.66	3.06	3.26	2.80
2009	2.73	3.14	3.34	2.84
2010	2.80	3.21	3.41	2.89

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		DATE
	COMPUTED CHECKED	PAGE OF PAGES

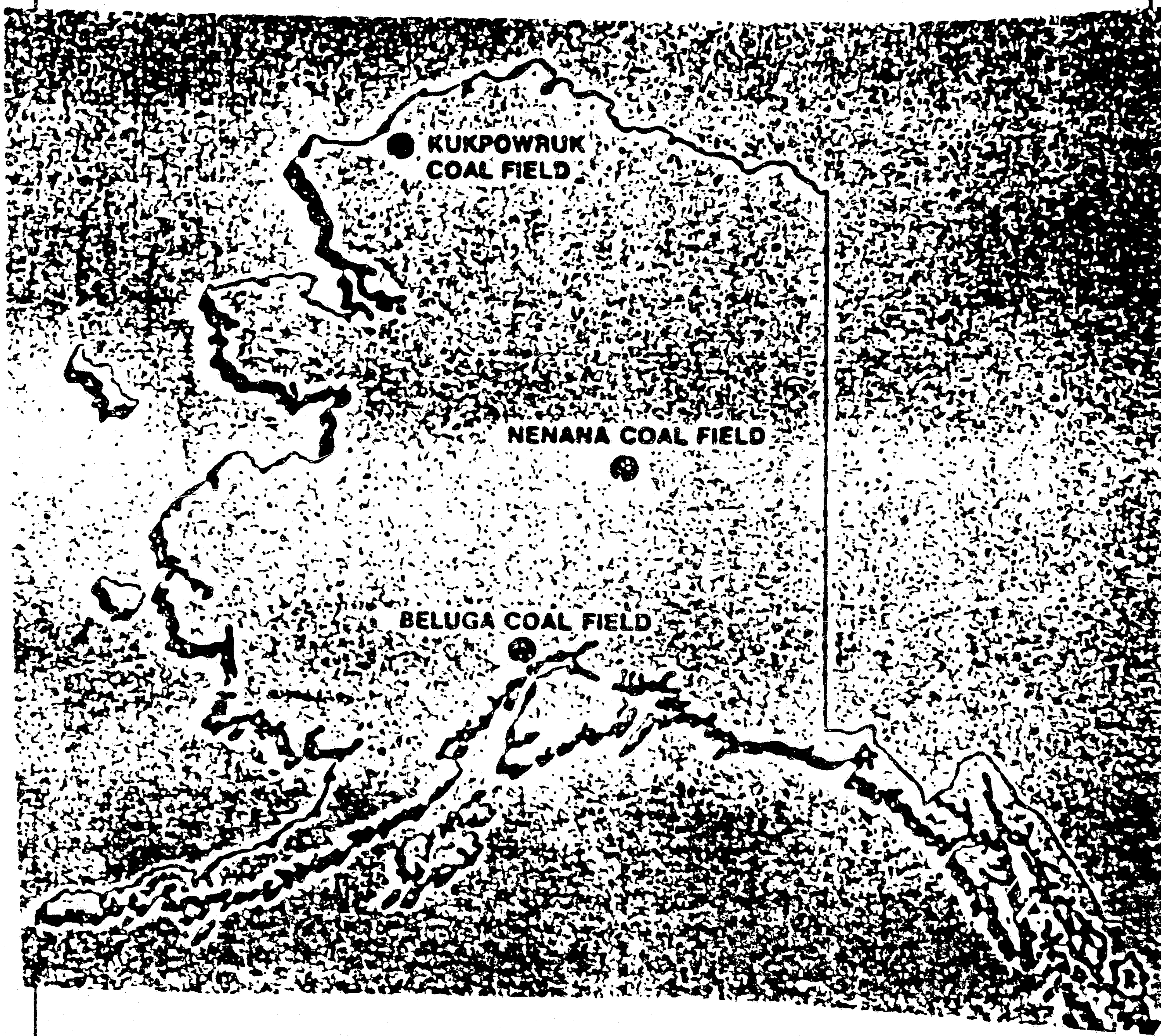

FIG 1. MAJOR COAL FIELDS IN ALASKA

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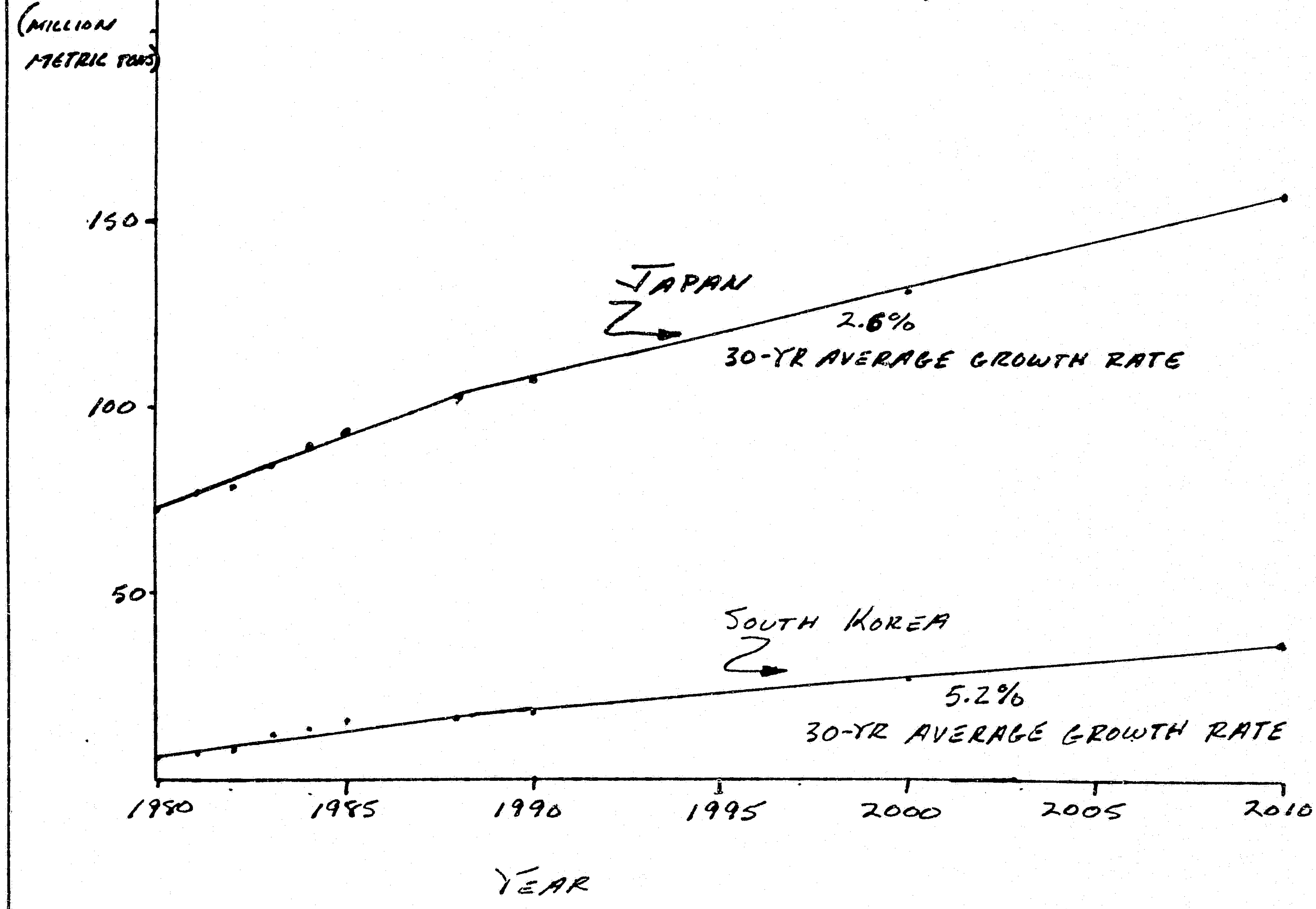
Fig 2. PRESENT AND PROTECTED COAL IMPORTS IN JAPAN AND SOUTH KOREA, 1980-2010



SOURCE: SHERMAN CLARK ASSOCIATES, 1983

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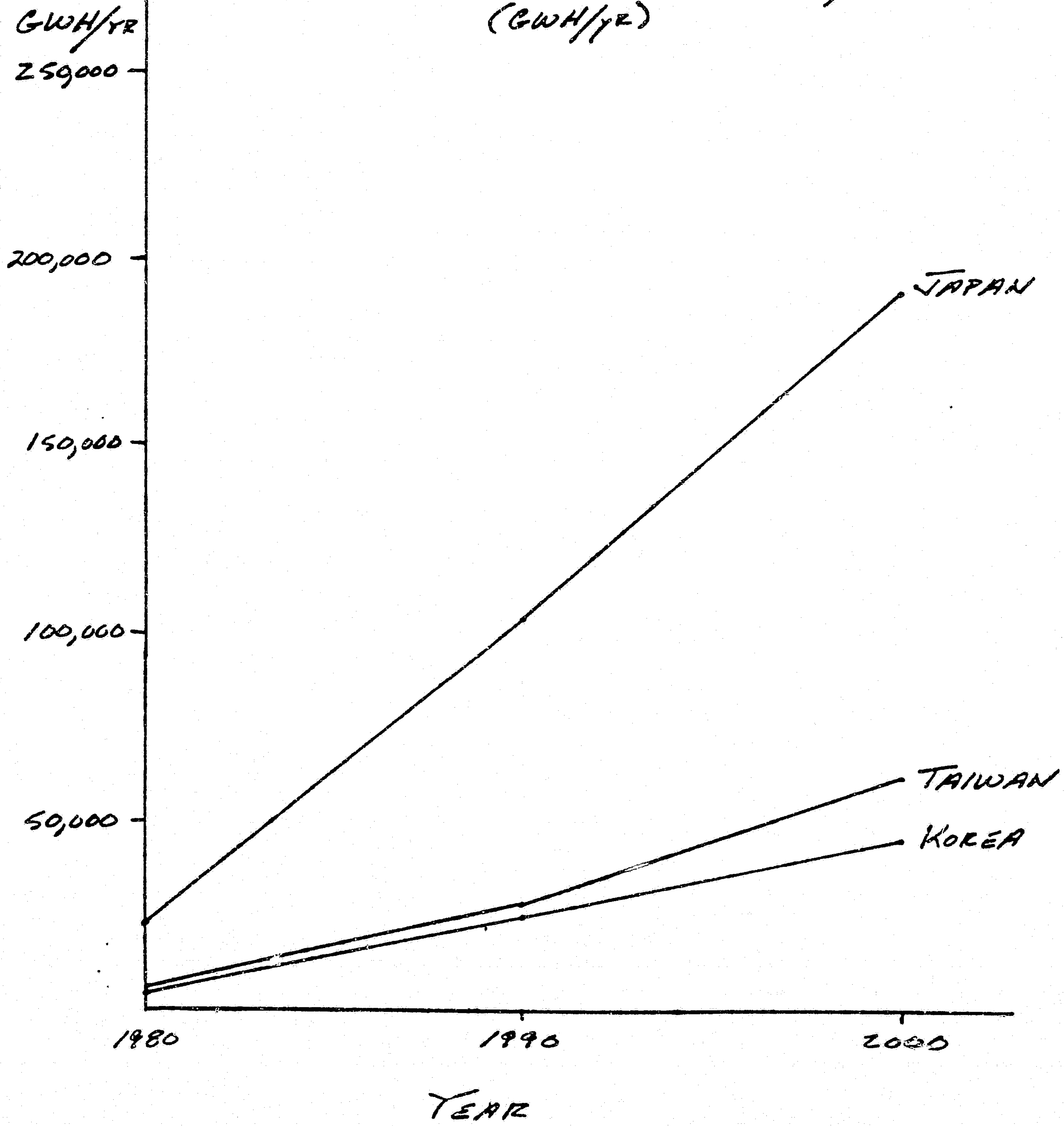
Fig 3. PROJECTED COAL FIRED ELECTRICITY GENERATION IN PACIFIC RIM COUNTRIES, 1980-2000 (GWH/YR)



SOURCE: MRI, 1982

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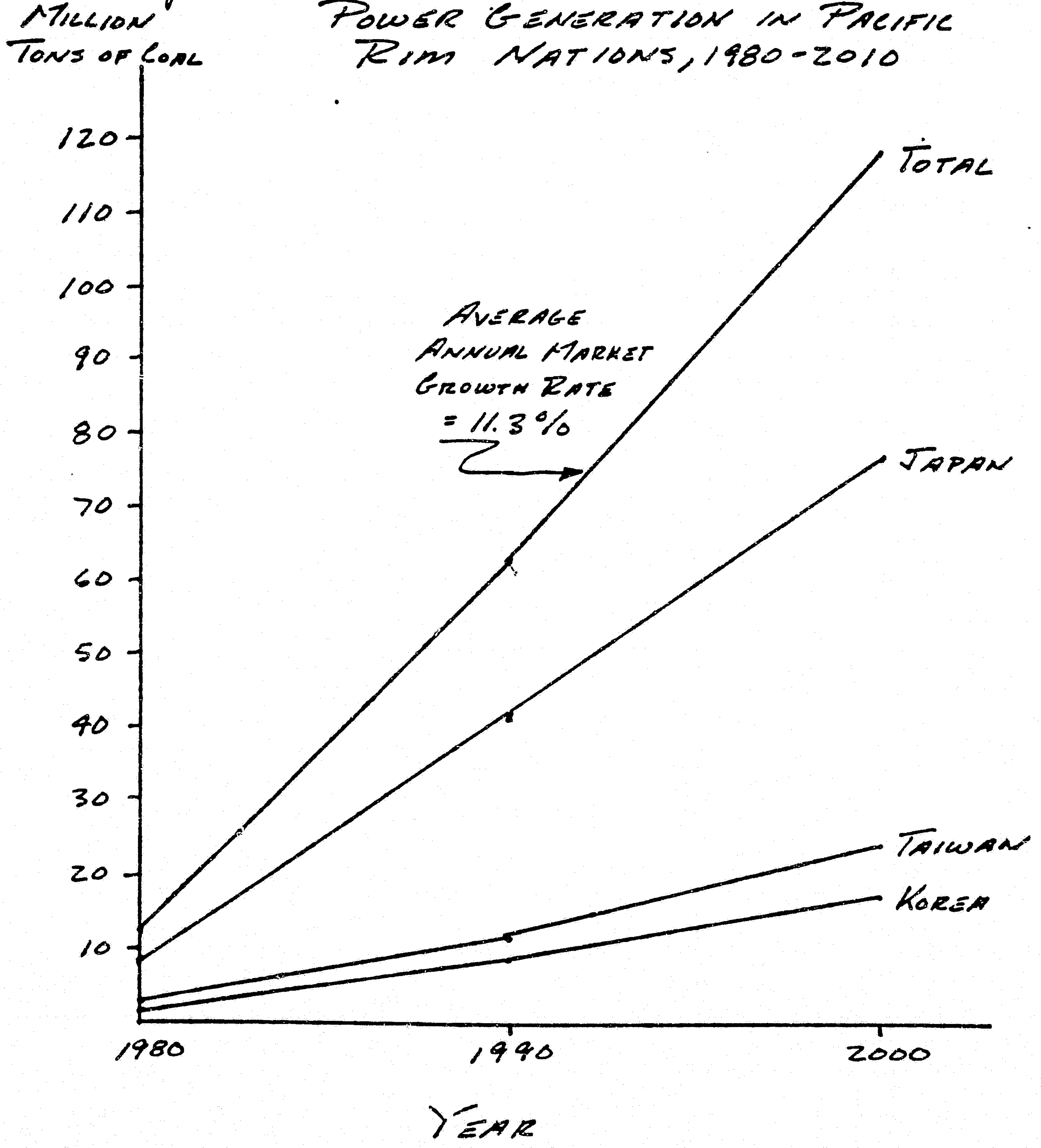
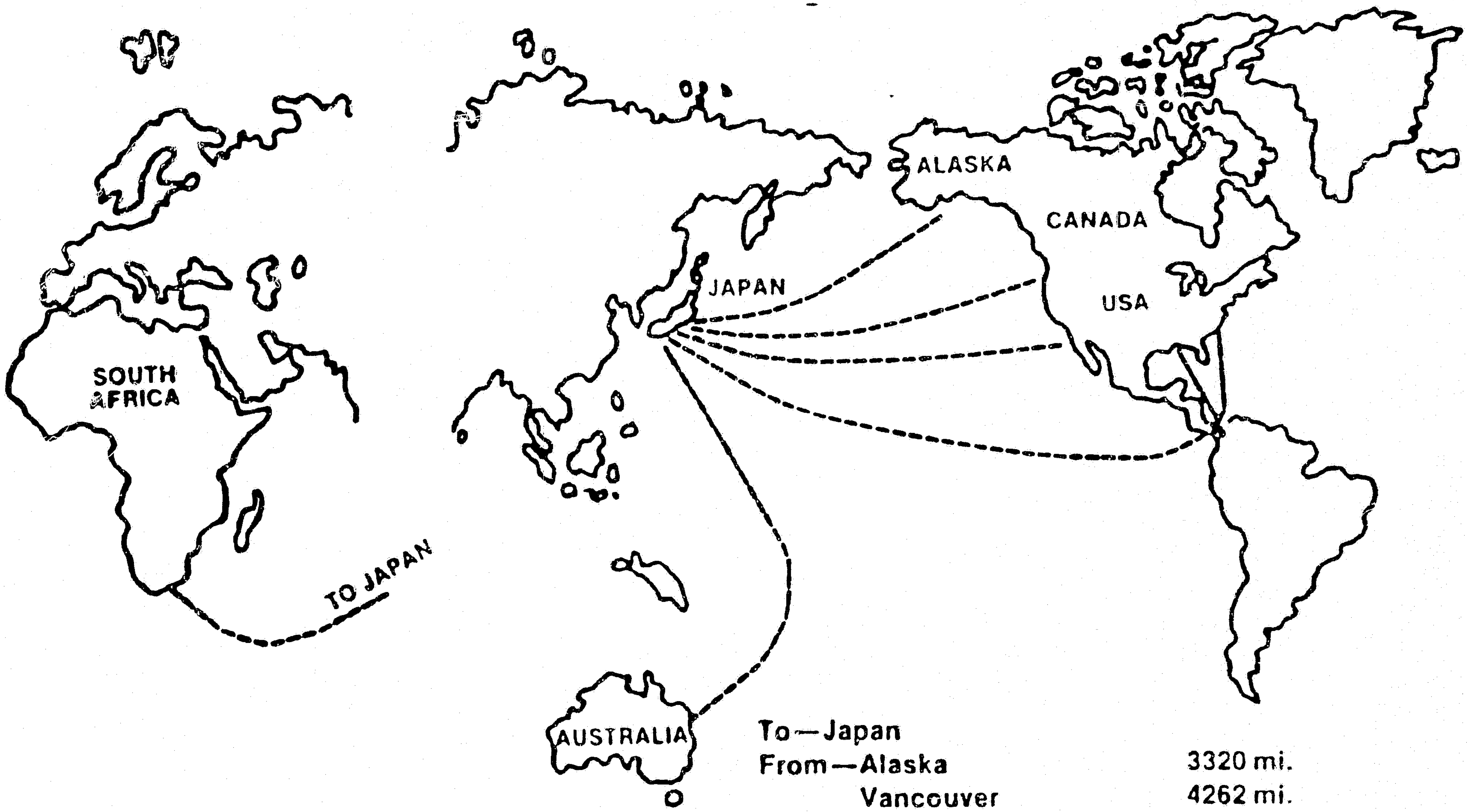
Fig 4. TOTAL COAL NEEDS FOR ELECTRIC POWER GENERATION IN PACIFIC RIM NATIONS, 1980-2010



SOURCE: MRI, 1982

581/8-81

FIG. 5. DISTANCES FROM COAL PORTS TO JAPAN



To—Japan	
From—Alaska	3320 mi.
Vancouver	4262 mi.
U.S. West Coast	4839 mi.
Australia	4265 mi.
South Africa	7291 mi.
U.S. Gulf Coast	9095 mi.
U.S. Atlantic Coast (Panama Canal)	9504 mi.

SOURCE:
DIAMOND SHAMROCK
CORP., 1983

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SUSITNA JOINT VENTURE

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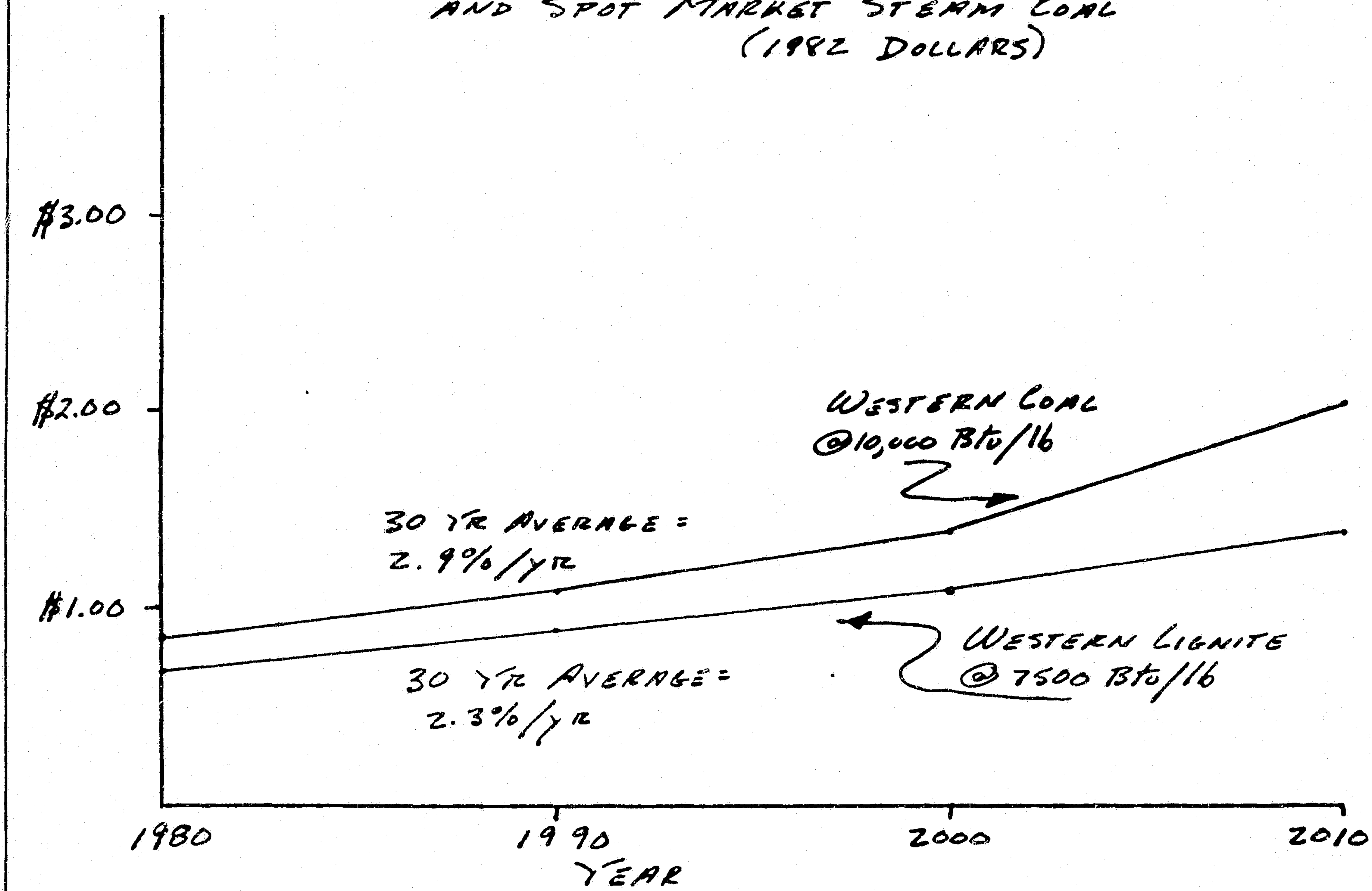
Fig 6. FORECAST REAL COAL PRICES FOR WESTERN COAL AND LIGNITE, 1980-2010; NEW CONTRACT AND SPOT MARKET STEAM COAL (1982 DOLLARS)



SOURCE: SHERMAN H. CLARK & ASSOCIATES, 1983

Part III - Distillate Oil

Distillate oil, i.e. oil fuel used in diesel engine and gas turbine generating units is not a significant factor in the analysis of Railbelt generation alternatives for the years 1993 to 2040. With an electric transmission tieline between Anchorage + Fairbanks, generation with diesel engines will be eliminated except for small isolated communities. Both thermal and hydroelectric alternatives will ~~will~~ utilize gas or coal for required thermal generation. Any generation provided by oil-fired units will either be the same for all alternatives or the difference will be so small that they can be ignored in the economic comparison of the alternatives. However, to provide a complete picture for fuels actually used in the Railbelt for electrical generation the following information on distillate oil availability + price is presented

<u>Availability</u>

The availability of distillate oil over the forecast period does not appear to present any problems.[1] Although part of the distillate oil used in Alaska is imported, this fact alone will not seem to affect its availability. We have assumed that distillate oil in the required quantities will be available from somewhere, either from refineries within Alaska, or imported from the lower forty eight states over the economic analysis period 1993 - 2040

<u>Price</u>

The average current price for medium distillate fuels in Anchorage + Fairbanks is shown in table 1. These prices will change with the world market price for oil, so to obtain future prices, the estimated price changes for several scenarios of ~~so~~ future world oil prices have been applied to the 1983 price to obtain the prices in table 2 over the period 1983 - 2040.

Bibliography
Part III - Distillate Oil

1. Battelle Pacific Northwest Laboratories. Railbelt Electric Power Alternative Study: Fossil Fuel Availability and Price Forecasts, Volume VII, March 1982, p. 8.1.

HARZA-EBASCO SUSITNA JOINT VENTURE

MEMORANDUM

LOCATION Anchorage

DATE June 6, 1983

TO I. Robinson

NUMBER 6.2.4.1

FROM N. M. Hernandez

SUBJECT FERC Responses to Schedule A

Attached for H-E Internal review is the response to the query No 1 in Schedule A. Unfortunately Acres did not perform the studies necessary to answer the deficiencies relative to the spillway fuse plugs and the Devil Canyon arch dam thrust block on the right bank.

A complete answer for the former will require computer analyses which have been initiated. The results are expected by June 13. In the latter, manual computation have been initiated and are slated for completion during this week.

N. M. Hernandez

NMH/ml

SCHEDULE A

FERC RESPONSE

EXHIBIT F

QUERY NO. 1

Stability and Stress Analyses

Provide summaries of stability and stress analyses for the following structures; Watana Dam, Devil Canyon Arch Dam and trhust block abutements, Devil Canyon Saddle dam, Watana and Devil Canyon main spillway gate structure, and the Watana and Devil Canyon emergency spillway fuse plugs.

Given the different structures to which this question applies the response will be in two parts. Part 1 will cover the embankment structures of Watana Dam, Devil Canyon Saddle dam and the Watana and Devil Canyon emergency spillway fuse plugs. Part 2 will cover the concrete structures of the Devil Canyon Arch Dam, its' thrust blocks at the abutments, and spillway gate structures, and the Watana main spillway gate structure.

Part I

To comply with the deficiencies to the material to be covered in this part, it is suggested that an Appendix be incorporated in the Exhibit F. Attached is a draft of the appendix. You will note that paragraphs 1.3 a and b dealing with the spillway fuse plugs is incomplete. This deficient work, which was not included in the original submittal to FERC, is now being made in Harza's Chicago office. The results of these studies will be available for inclusion in the appendix during the week of 13 June 83.

APPENDIX FB

APPENDIX FB - WATNA AND DEVIL CANYON EMBANKMENT STABILITY ANALYSES

1 - Preliminary Design

1.1 General

Early stage stability analysis for the Watana Main Dam and the Devil Canyon Saddle Dam embankments have been conducted in sufficient detail to satisfy project feasibility. The following paragraphs summarize these evaluations along with subsequent studies of the spillway fuse plug embankments for both dams.

1.2 - Watana Main Dam and Devil Canyon Saddle Dam

Although the Watana main dam maximum cross-section has been analyzed, the safety factors also apply to the Devil Canyon Saddle Dam, which has a much lower height. The embankment design (cross-section and foundation treatment) is identical for both embankments (Plates 1 and 2). It should be recognized that the quoted safety factors derived from the ±830 foot high main dam are conservative for the ±150 high saddle dam.

a. Static Analysis

Loading Conditions and Factors of Safety

The following conditions were analyzed:

Case	Required Minimum Factor of Safety (3)	Calculated Factor of Safety U/S Slope	Calculated Factor of Safety D/S Slope
Construction	1.3	2.0	1.7
Normal Maximum Operating	1.5	2.0	1.7
Maximum Reservoir Drawdown	1.0	1.8	1.7
Maximum Reservoir Level During PMF	1.3	2.0	1.7

The calculated factors of safety as shown in the above table indicate no general slope stability problems under static loading.

b. Seismic Stability Evaluation

The safety factor evaluation of the embankment seismic stability was based on a comparison of available shear strength to the earthquake induced shear stresses. A shear stress exceedance ratio was utilized to represent an indication of the stability of the embankment slopes. Based on this comparison, a ratio less than 1.0 indicates an ample margin of safety.

Results

Figures 4, 5, 6 and 7 are plots of the drained shear stress exceedance and undrained shear stress exceedance for the soft and stiff core, respectively. These plots show zones of shear stress exceedance on the surfaces of the embankment, however, the overall stability of the embankment is apparent.

Conclusions

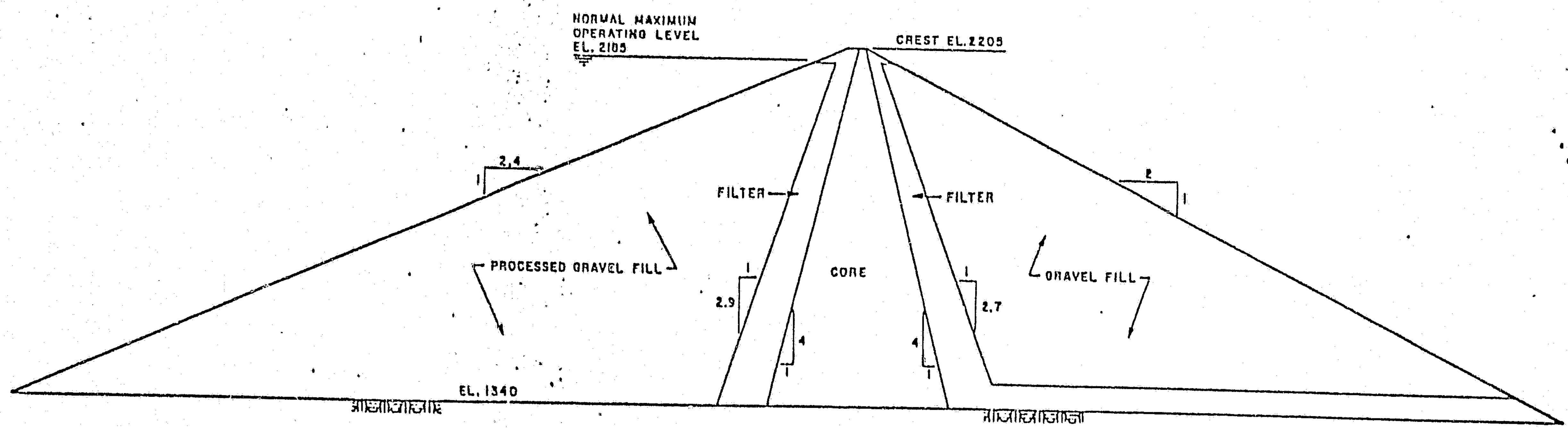
The above results indicate limited zones of shear stress exceedance adjacent to the toe of the upstream shell, near the upstream crest, and in the surface layer of the downstream shell. Since they are localized zones not extending into the embankment, the overall embankment will be stable under seismic loading.

1.3 Spillway Fuse Plug Embankments

The emergency spillway fuse plug embankments utilize exterior slopes and fill materials similar to the dam embankments (Plates 2 & 3). It should be emphasized that although the fuse plug dike will co-exist with a reservoir operating pool, it is designed to breach and wash out when overtopped by pools exceeding the maximum operating level.

(a) Static Analysis

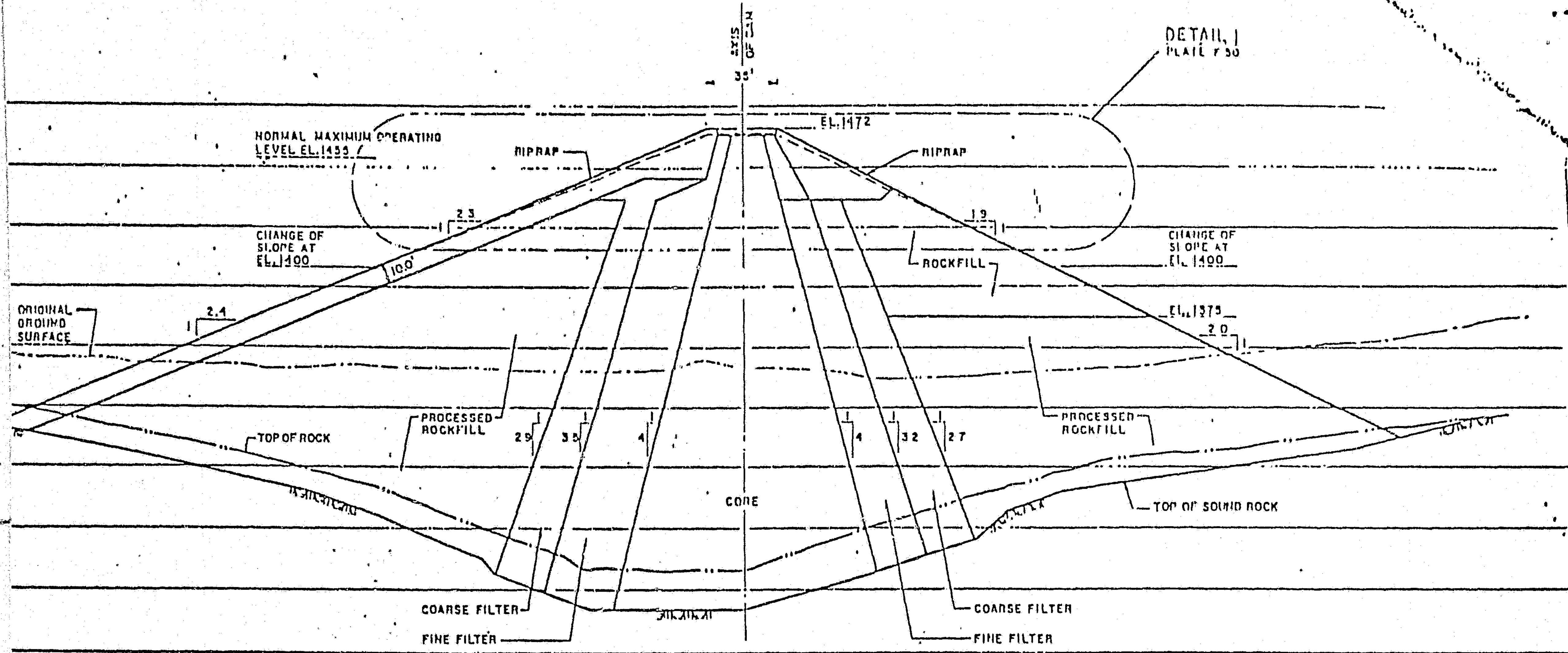
(b) Seismic Evaluation



NOTE:
FOR DETAILED CROSS SECTION SEE PLATE 9
IN VOLUME 3 OF FEASIBILITY REPORT.

WATANA DAM
MAXIMUM CROSS SECTION

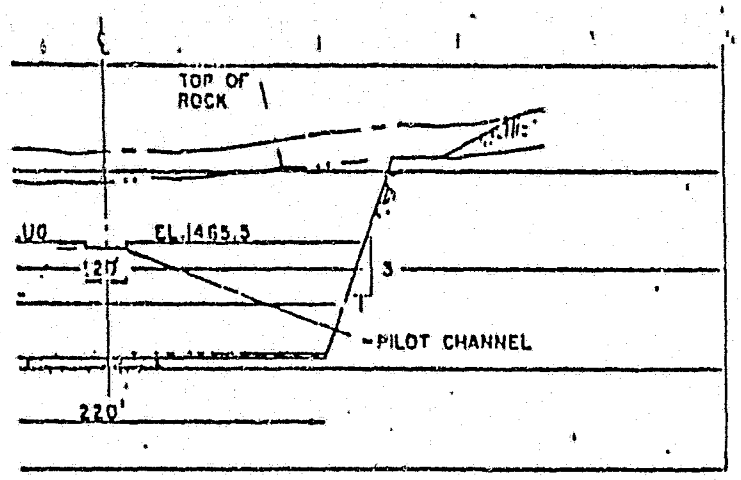
PLATE 1



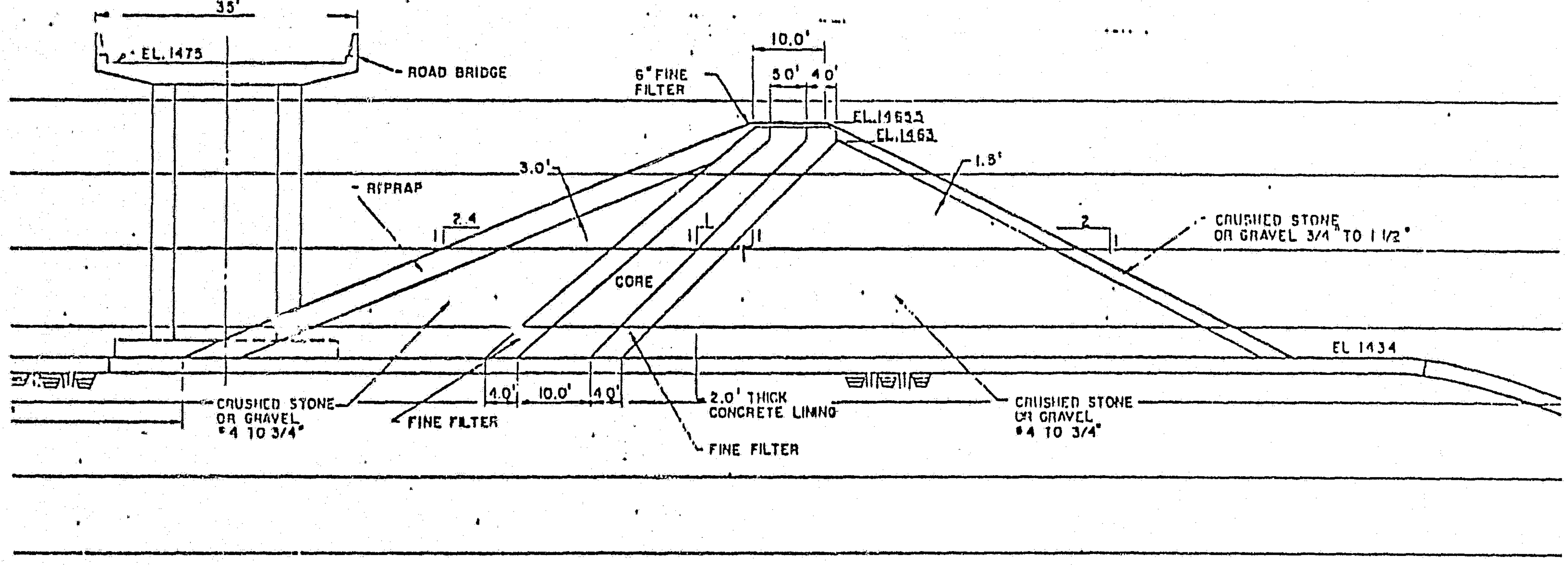
SECTION THROUGH SADDLE DAM
AT MAXIMUM HEIGHT

SCALE 0 30 60 FEET (1 INCH = 30 FEET)

ALASKA POWER AUTHORITY	
SUSITNA HYDROELECTRIC PROJECT	
DEVIL CANYON SADDLE DAM SECTION	
EXHIBIT F	PLATE 2



SECTION A-A (PLATE F57)
SCALE A



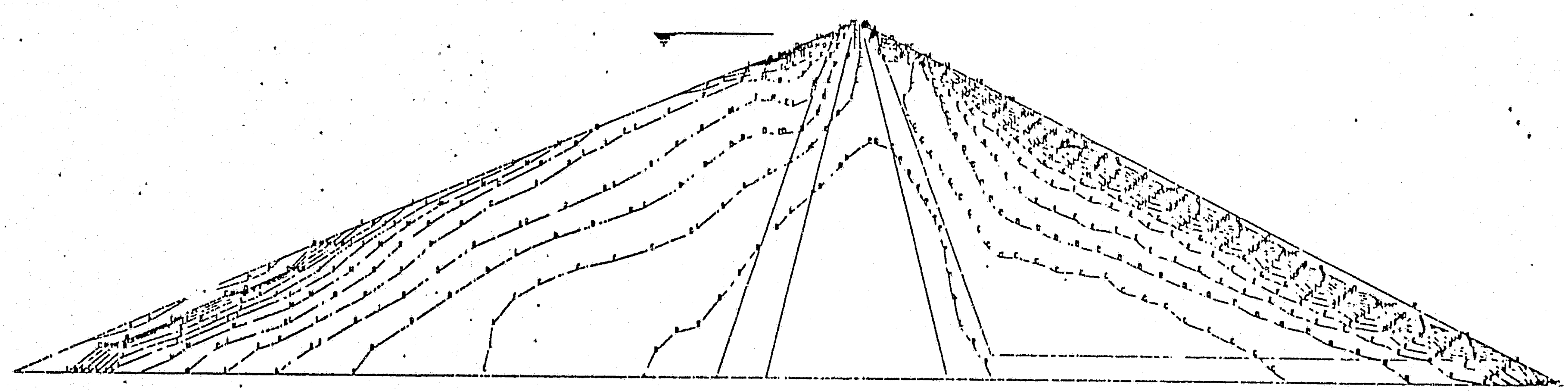
SECTION THROUGH FUSE PLUG (PLATE F57)
SCALE B

SCALE B 0 10 20 FEET (1 INCH = 10 FEET)

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

DEVIL CANYON
EMERGENCY SPILLWAY
SECTIONS

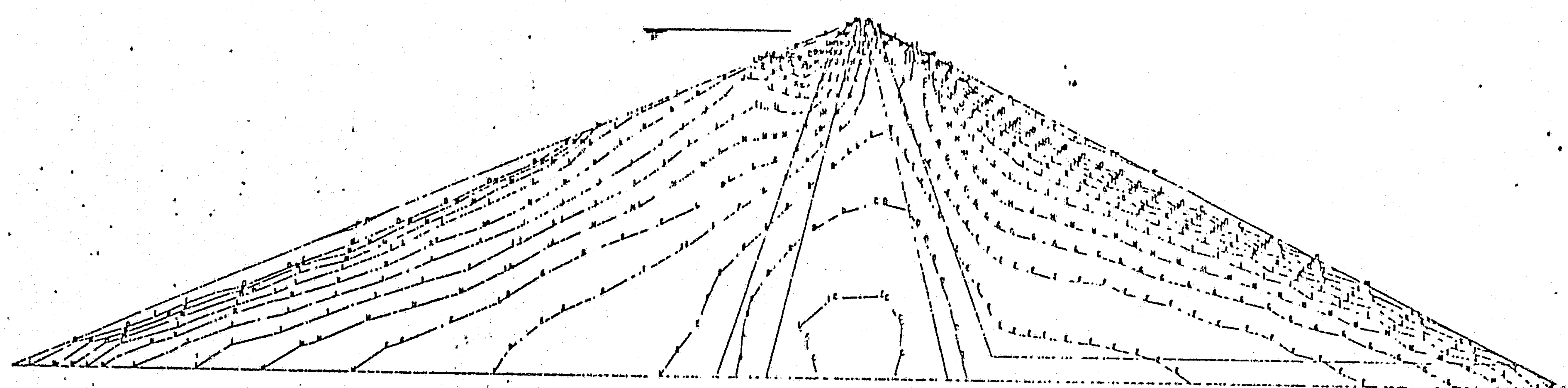
EXHIBIT F	PLATE 3



SYMBOL	A	B	C	D	E	F	G	H	I	J
VALUE	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
SYMBOL	K	L	M	N	O	P	Q	R	S	
VALUE	1.1	1.2	1.3	1.4	1.5	2.0	4.0	6.0	8.0	

DYNAMIC RUN SOFT CORE

DRAINED SHEAR STRESS EXCEEDANCE (TAUdell/TAUfd)



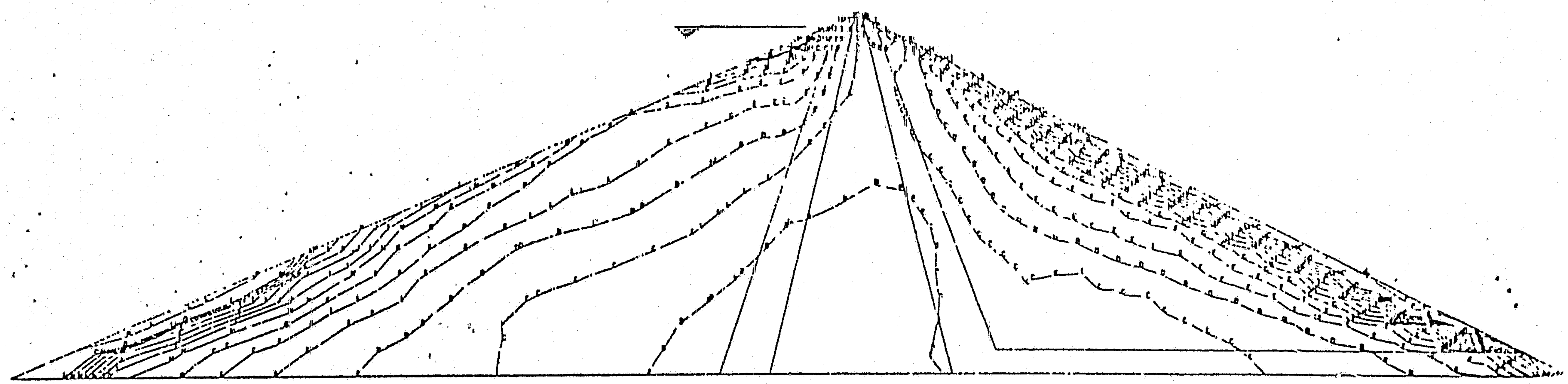
SYMBOL	A	B	C	D	E	F	G	H	I	J
VALUE	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
SYMBOL	K	L	M	N	O	P	Q	R	S	
VALUE	1.1	1.2	1.3	1.4	1.5	2.0	4.0	6.0	8.0	

DYNAMIC RUN SOFT CORE

UNDRAINED SHEAR STRESS EXCEEDANCE (TAU dmax / TAUc)

PLATE 5

AGRIS

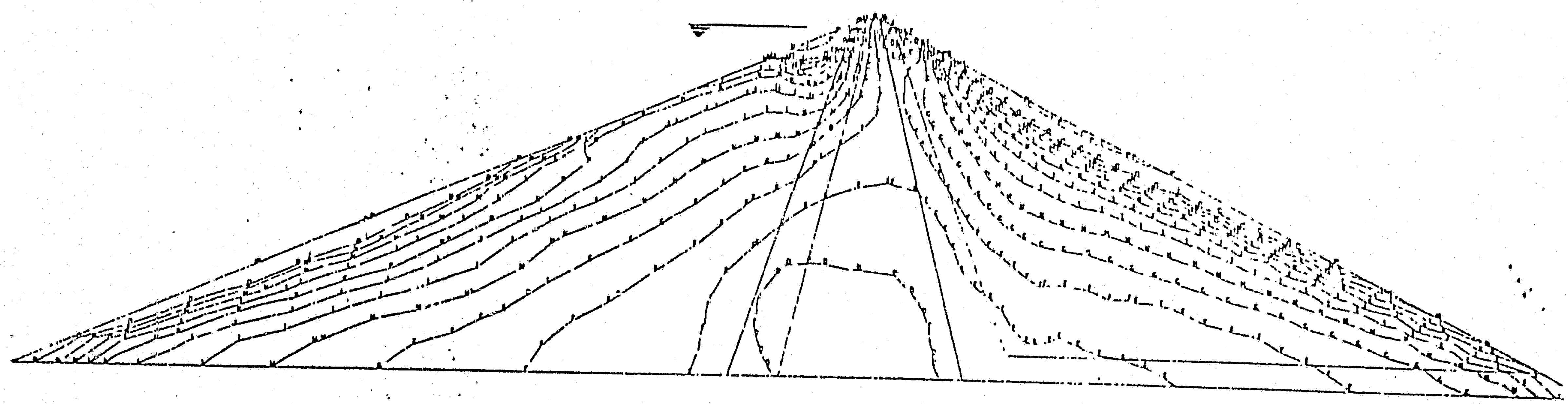


SYMBOL	A	B	C	D	E	F	G	H	I	J
VALUE	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
SYMBOL	K	L	M	N	O	P	Q	R	S	
VALUE	1.1	1.2	1.3	1.4	1.5	2.0	4.0	6.0	8.0	

DYNAMIC RUN STIFF CORE

DRAINED SHEAR STRESS EXCEEDANCE (TAUdeff/TAUfd)

PLATE 6



SYMBOL	A	B	C	D	E	F	G	H	I	J
VALUE	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0
SYMBOL	K	L	M	N	O	P	Q	R	S	
VALUE	1.1	1.2	1.3	1.4	1.5	2.0	4.0	6.0	8.0	

DYNAMIC RUN STIFF CORE

UNDRAINED SHEAR STRESS EXCEEDANCE (TAUdmax/TAUc)

PLATE 7

Exhibit F
Query No. 1

a) DEVIL CANYON ARCH DAM

In compliance with this portion of the non conforming item it is suggested that Section 4.2(e) (iii) of the Supporting Design Report be corrected to read as follows:

(iii) Stability Analysis
See Reference No. 2 Appendix B5
The arch dam has . . . . . .

also diagrams indicating the stresses at nodal points for the loading cases will be incorporated in PLATE F45 of Exhibit F, see attachment.

Part 2

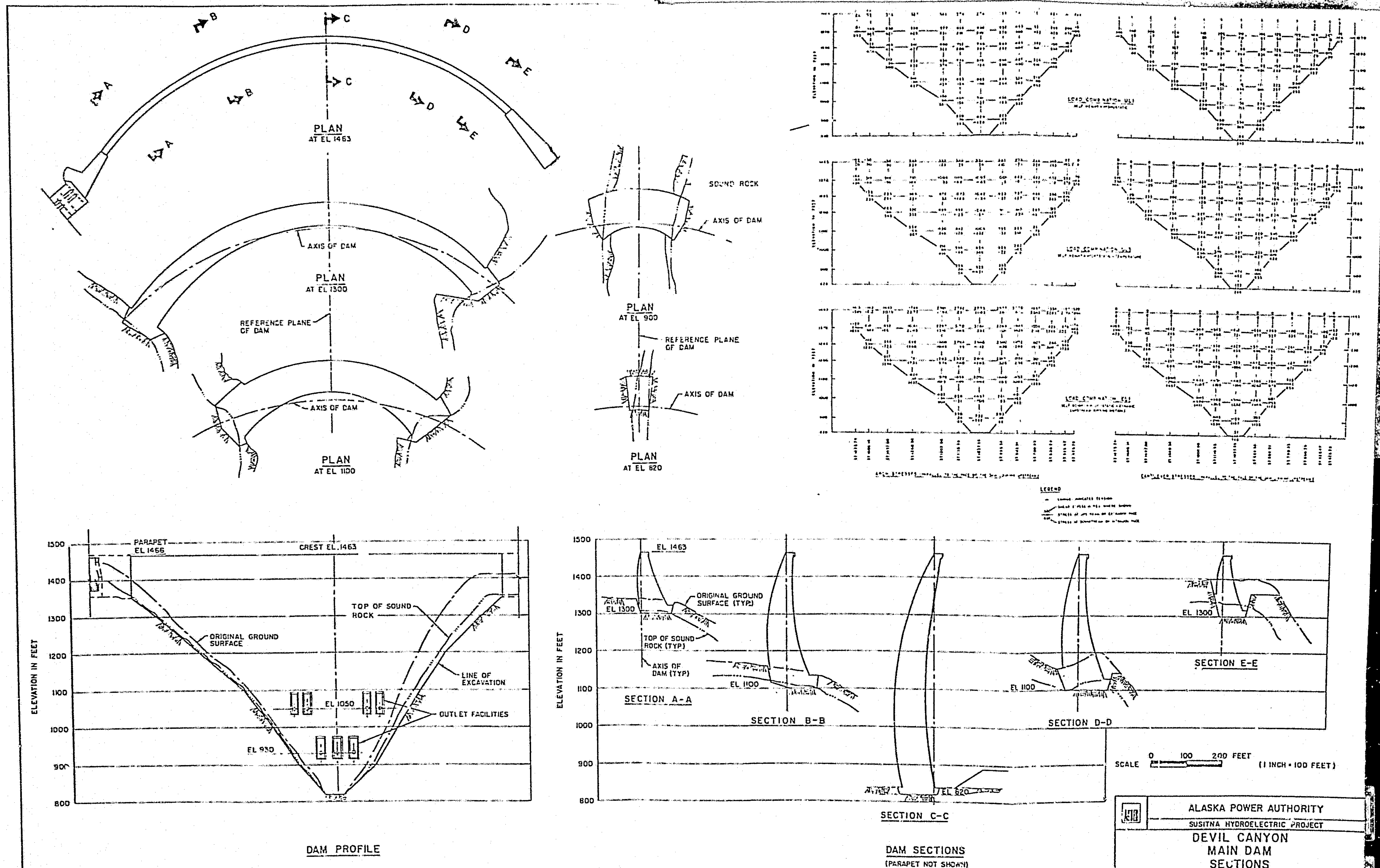
The following pages present proposals for addressing the deficiencies posed for the following concrete structures:

a) Devil Canyon Arch Dam

b) Devil Canyon Arch Dam Thrust Block Abutments

c) Devil Canyon Arch Dam Spillway Gate Structure

d) Watana Dam Spillway Gate Structure



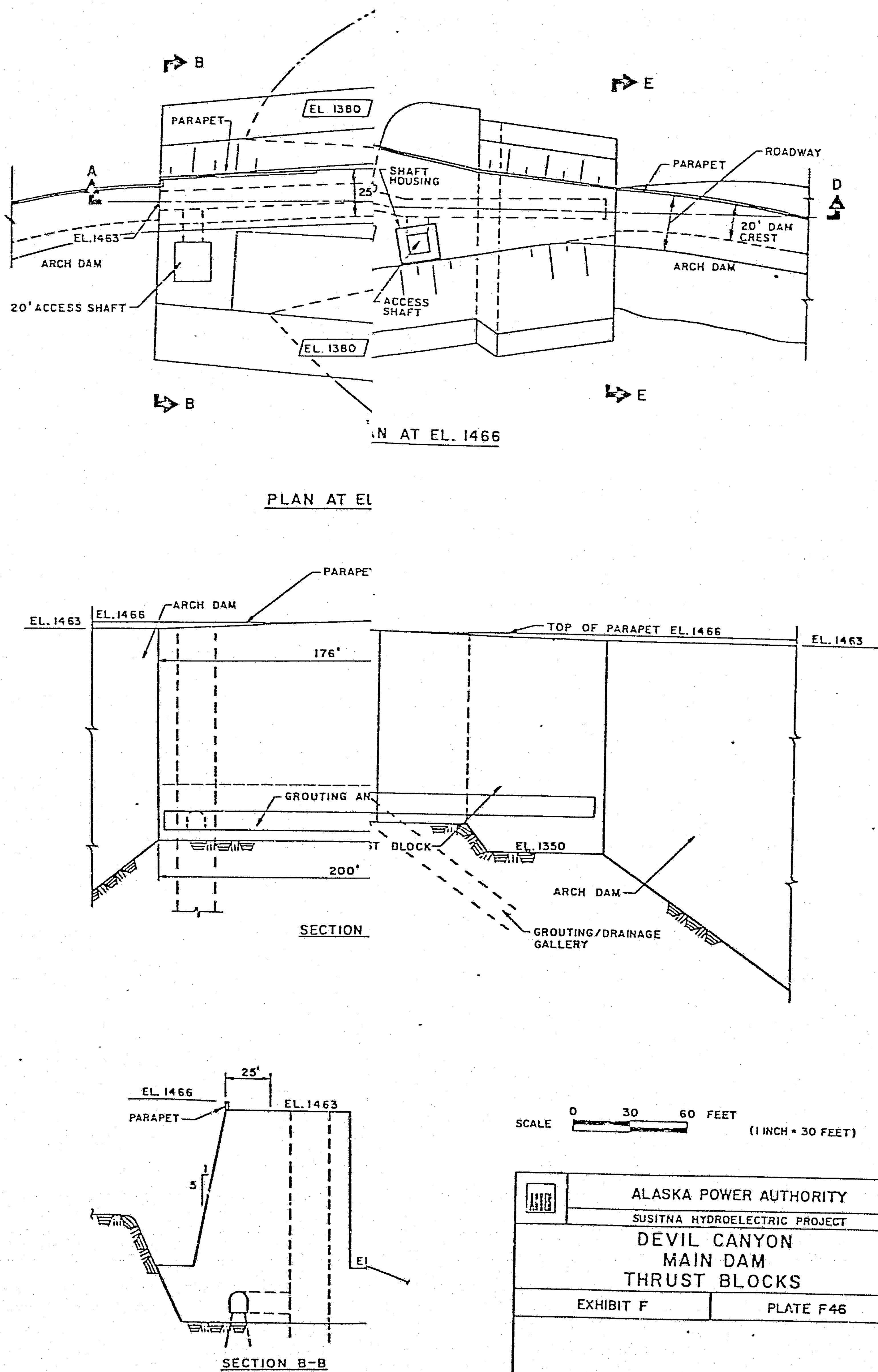
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

DEVIL CANYON
MAIN DAM
SECTIONS

EXHIBIT F	PLATE F45

b.) DEVIL CANYON ARCH DAM THRUST BLOCK ABUTMENTS

In compliance with this portion of the non conforming item we suggest the incorporation of a table, summarizing factors of safety for the loading cases, on PLATE F46 of Exhibit F, see attachment.

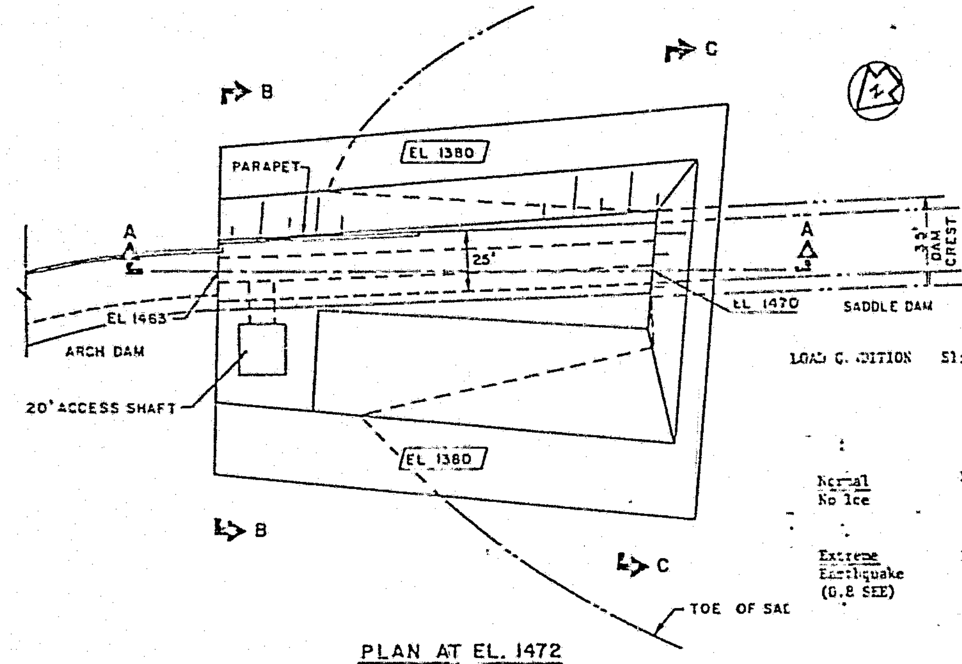


ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

DEVIL CANYON
MAIN DAM
THRUST BLOCKS

EXHIBIT F	PLATE F46



PLAN AT EL. 1472

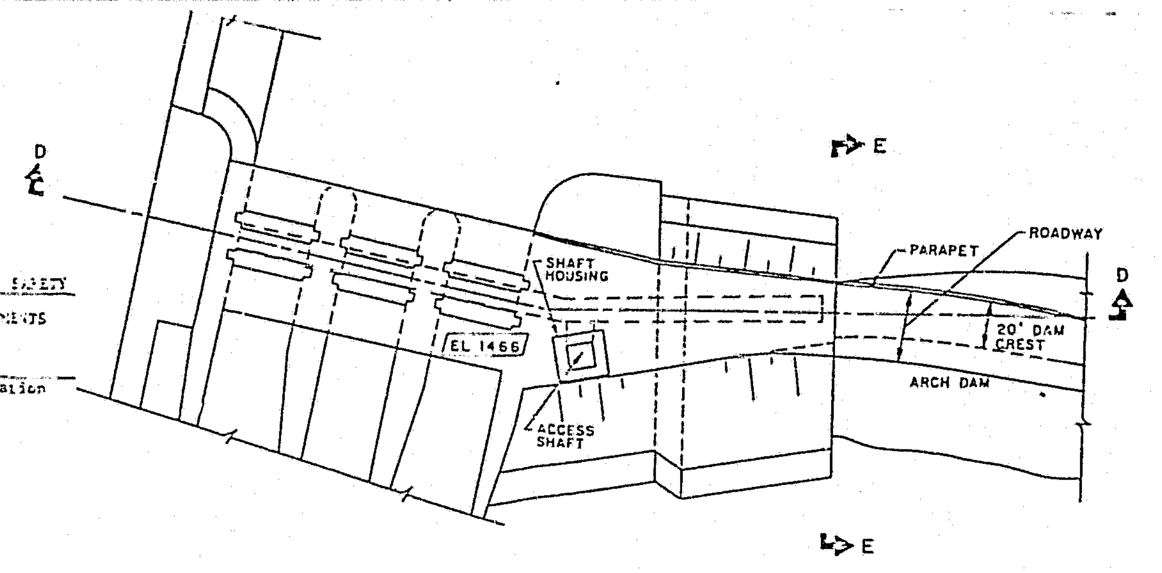
SUMMARY of STABILITY ANALYSES FACTORS of SAFETY

DEVIL CANYON ARCH DAM THRUST BLOCK ABUTMENTS

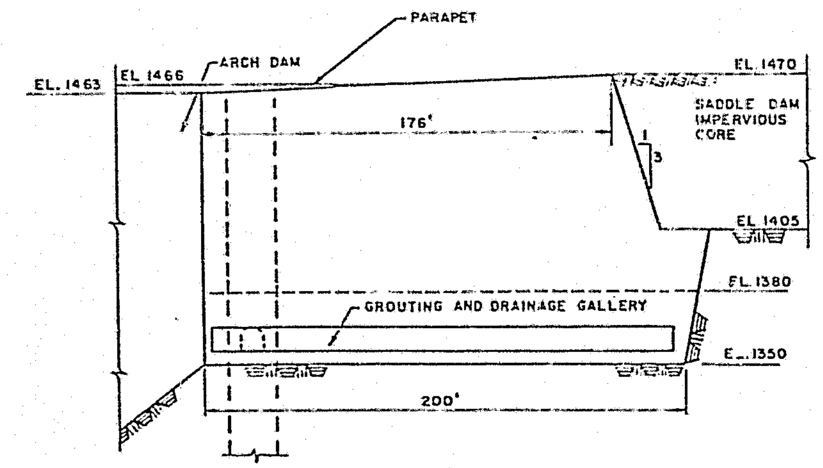
LOAD CONDITION	LEFT Sliding	LEFT Shear Friction	LEFT Floatation	RIGHT Sliding	RIGHT Shear Friction	RIGHT Floatation
Normal No Ice	N.A.	4.54	6.37	N.A.		
Extreme Earthquake (0.8 SEE)	N.A.	1.04	6.45	N.A.		

Physical parameters

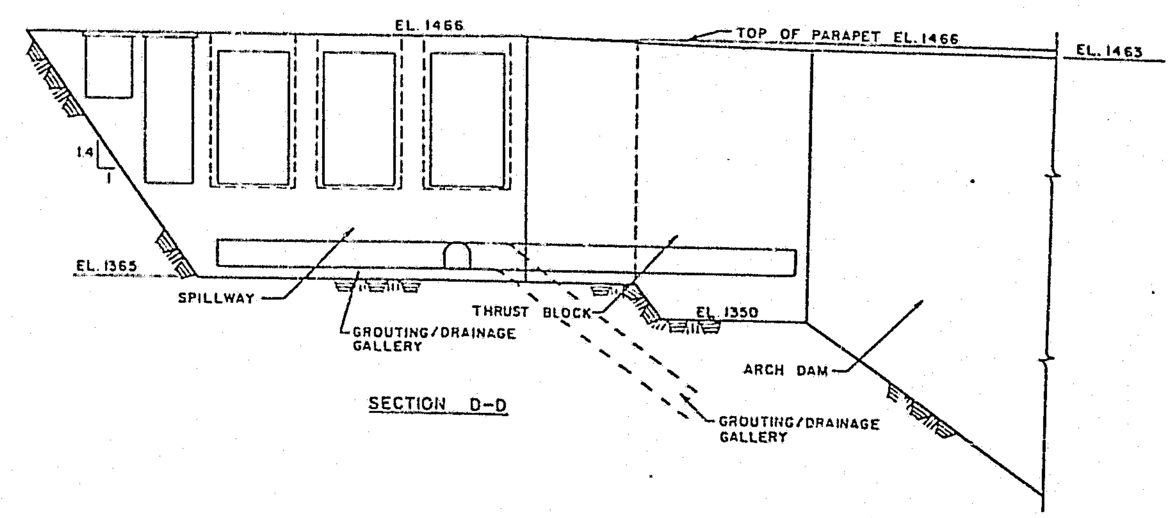
Tanϕ = .613, c = 200 psi | Tanϕ, c =



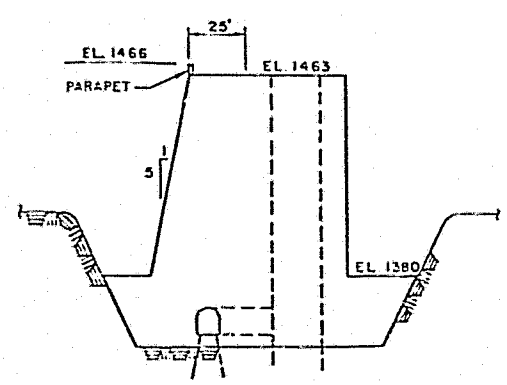
PLAN AT EL. 1466



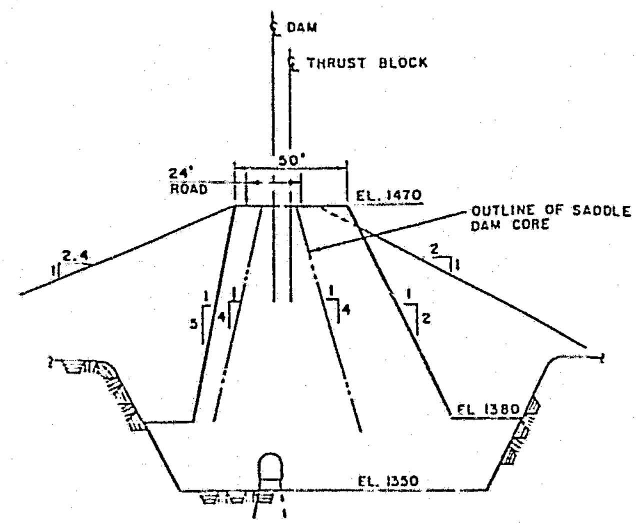
SECTION A–A



SECTION D–D

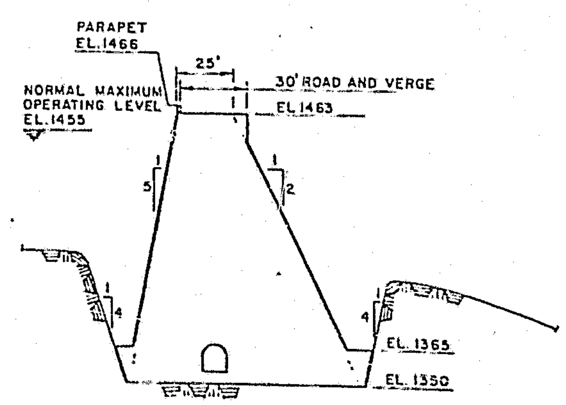


SECTION B–B



SECTION C–C

LEFT ABUTMENT THRUST BLOCK



SECTION E–E

RIGHT ABUTMENT THRUST BLOCK

SCALE 0 30 60 FEET (1 INCH = 30 FEET)

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
DEVIL CANYON MAIN DAM THRUST BLOCKS

EXHIBIT F	PLATE F46

c.) DEVIL CANYON MAIN SPILLWAY GATE STRUCTURE.

In compliance with this portion of the non conforming item it is suggested that the follwoing tables summarizing the stresses and factors of safety for the loading cases, be incorporated in PLATE F55 of Exhibit F.

DEVIL CANYON ARCH DAM SPILLWAY GATE STRUCTURE

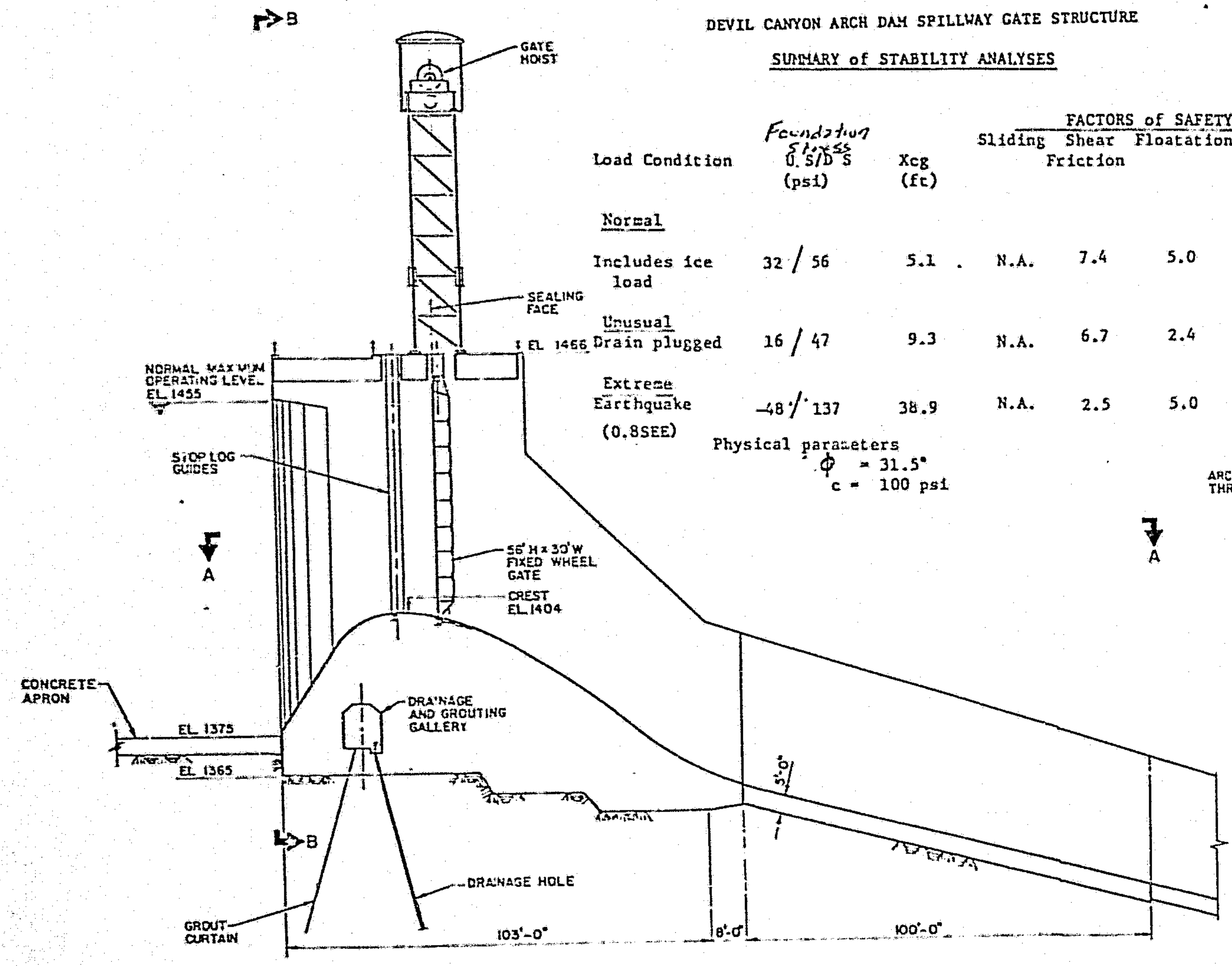
SUMMARY of STABILITY ANALYSES

Load Condition	Foundation Stress U.S/D.S (psi)	Xcg (ft)	FACTORS of SAFETY Sliding	Shear Friction	Floatation	Overturning
Normal						
Includes ice load	32 / 56	5.1	N.A.	7.4	5.0	2.5
Unusual Drain plugged	16 / 47	9.3	N.A.	6.7	2.4	1.7
Extreme Earthquake (0.8SEE)	-48 / 137	38.9	N.A.	2.5	5.0	1.2

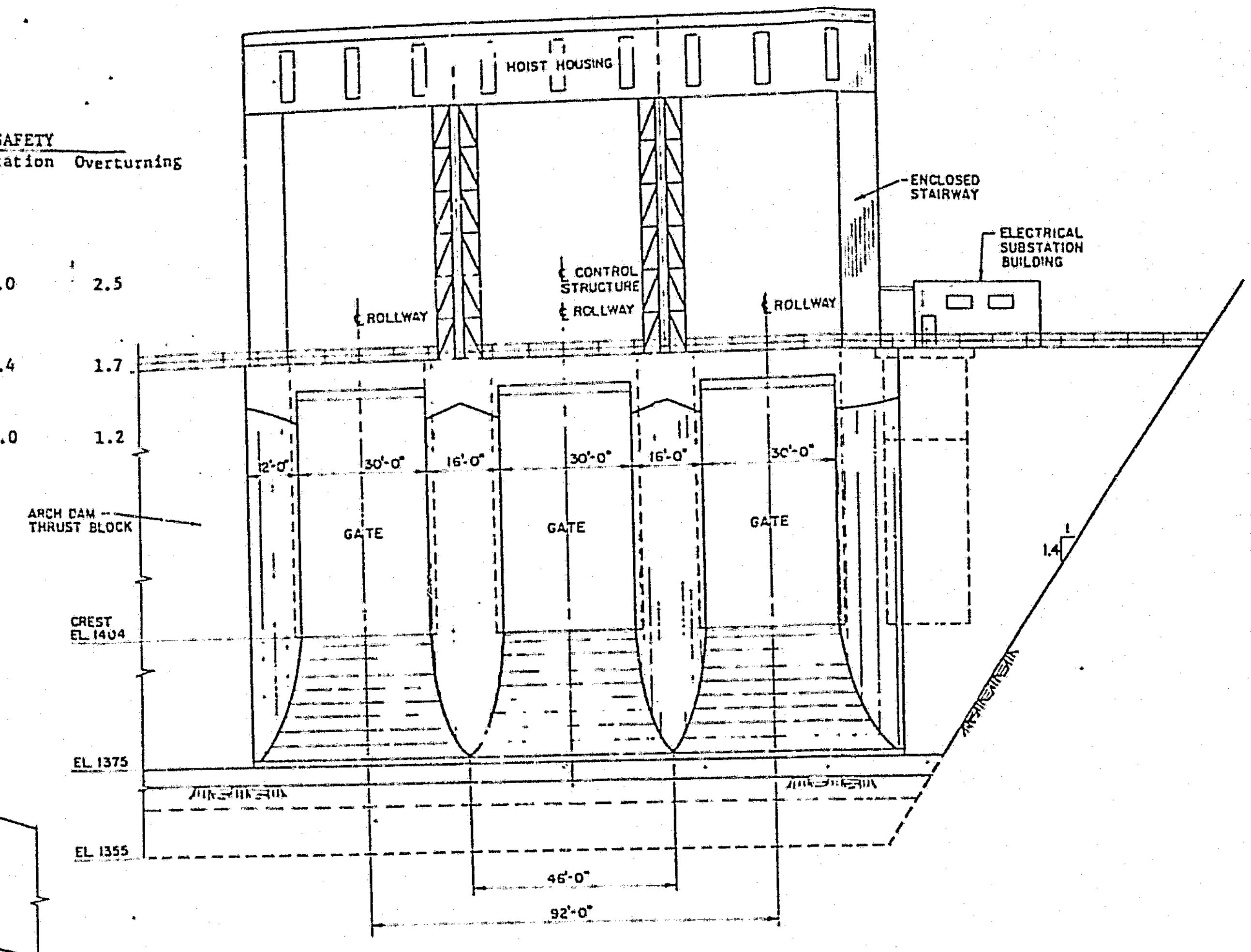
Physical parameters

$\phi = 31.5°$

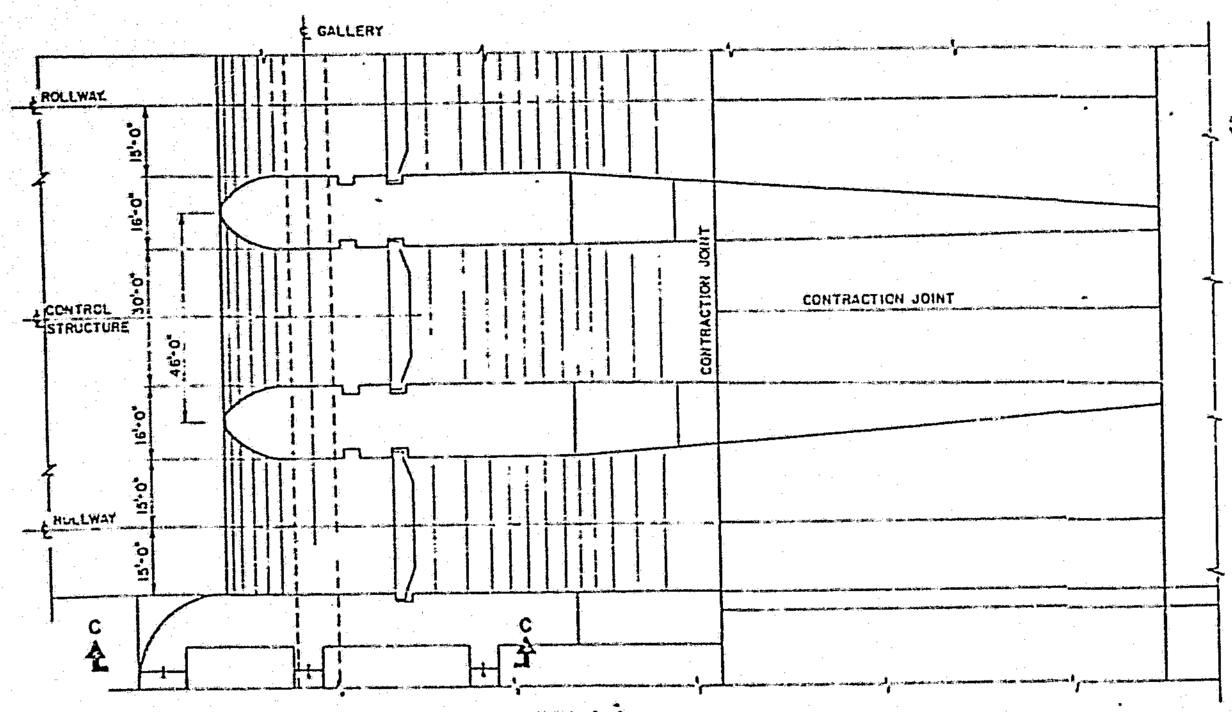
$c = 100$ psi



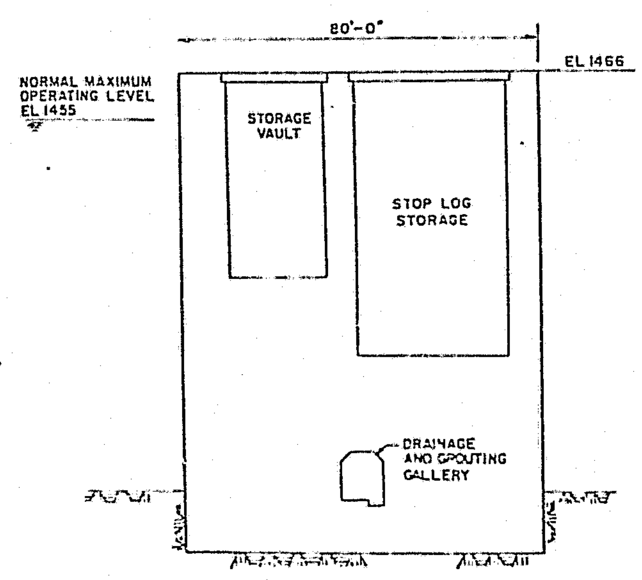
TYPICAL SECTION THRU CENTERLINE OF ROLLWAY



ELEVATION B-B



SECTION A-A



SECTION C-C

SCALE 0 16 32 FEET (1/16 INCH = 1 FEET)

ALASKA POWER AUTHORITY

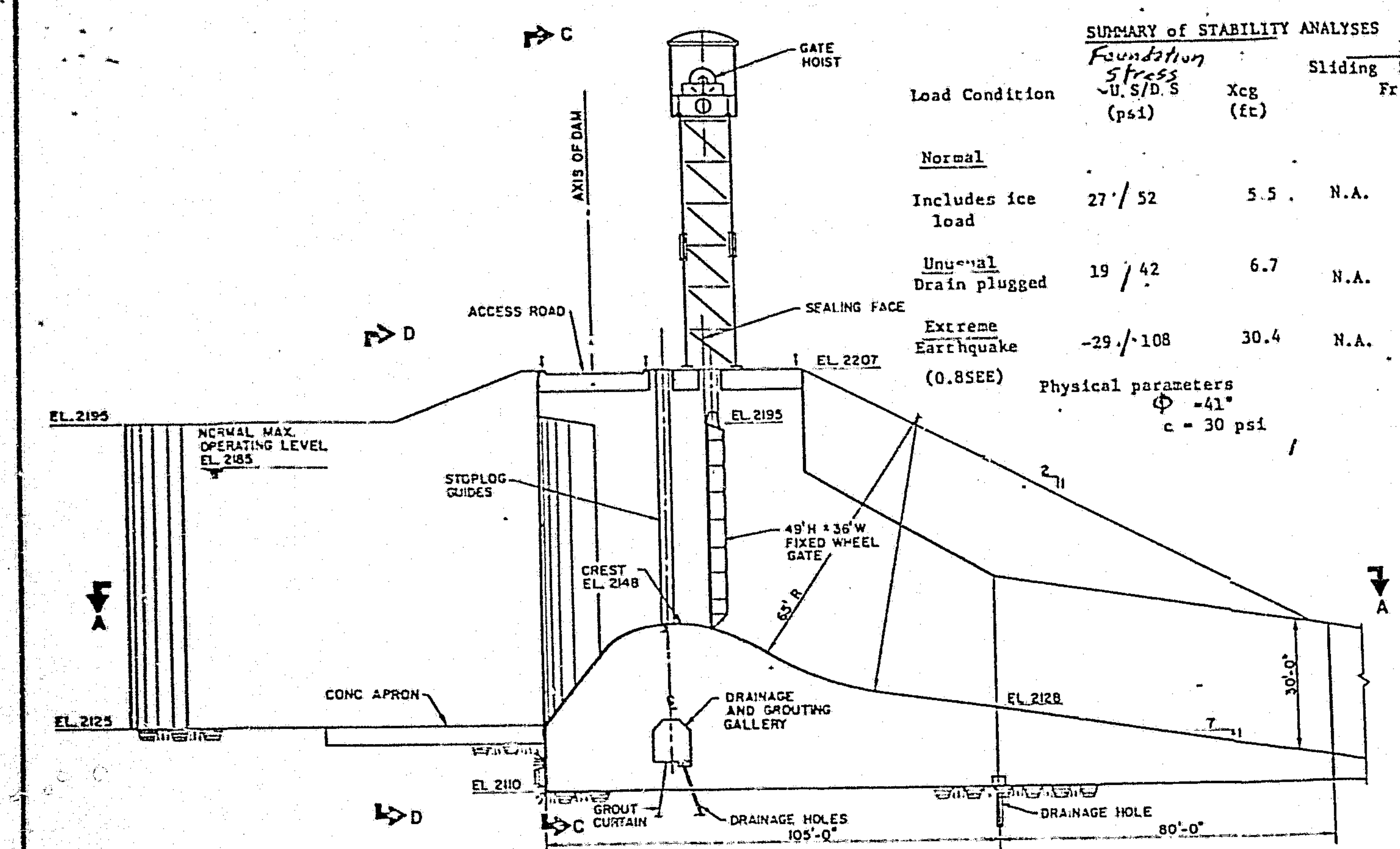
SUSITNA HYDROELECTRIC PROJECT

DEVIL CANYON
MAIN SPILLWAY
CONTROL STRUCTURE

EXHIBIT F	PLATE F55

d.) WATANA MAIN SPILLWAY GATE STRUCTURE

In compliance with this portion of the non conforming item it is suggested; that a table summarizing the stresses and factors of safety for the loading cases, be incorporated in PLATE F13 of Exhibit F, see attachment.



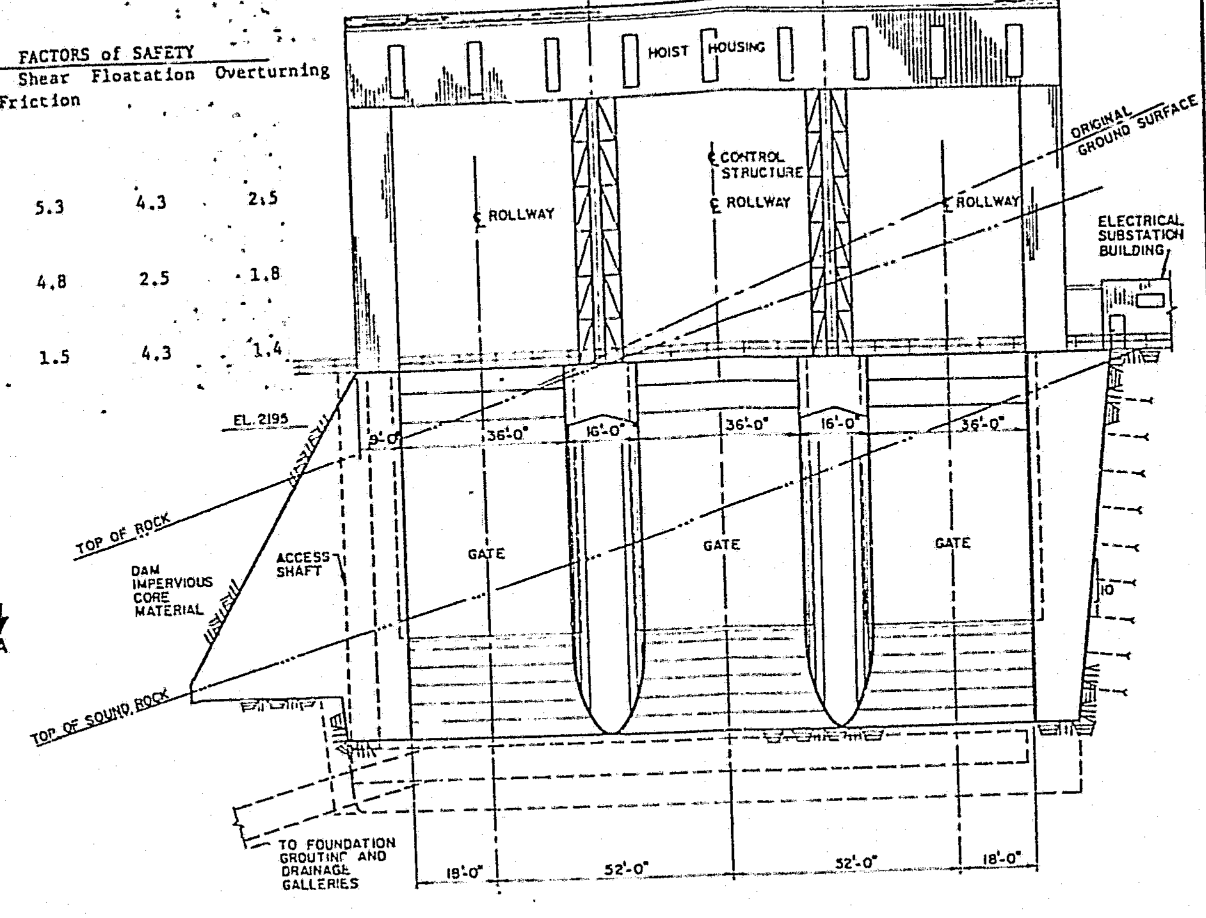
SECTION B-B

WATANA DAM SPILLWAY GATE STRUCTURE

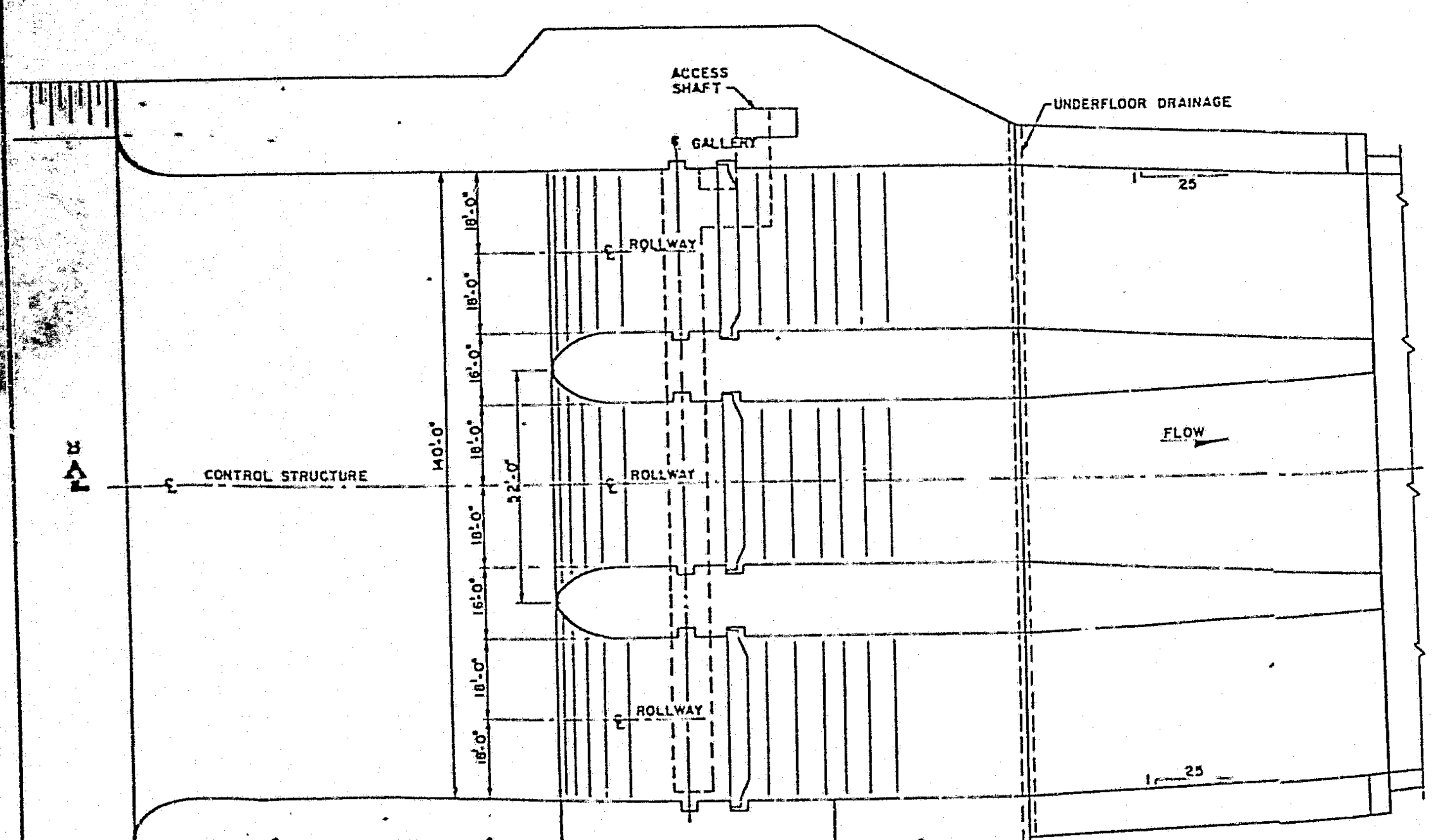
SUMMARY of STABILITY ANALYSES

Load Condition	Foundation Stress ~U.S/D.S (psi)	Xcg (ft)	FACTORS of SAFETY: Sliding	Shear Friction	Floatation	Overturning
Normal — Includes ice load	27 / 52	5.5	N.A.	5.3	4.3	2.5
Unusual — Drain plugged	19 / 42	6.7	N.A.	4.8	2.5	1.8
Extreme — Earthquake (0.8SEE)	-29 / -108	30.4	N.A.	1.5	4.3	1.4

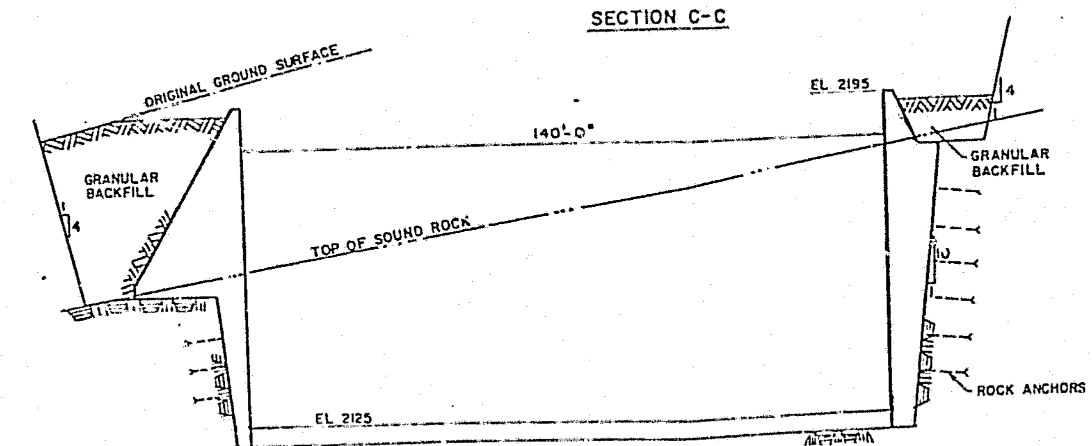
Physical parameters
$\phi = 41°$
$c = 30$ psi



SECTION C-C



SECTION A-A



SECTION D-D

SCALE 0 16 32 FEET (1/16 INCH = 1 FEET)

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
WATANA
MAIN SPILLWAY
CONTROL STRUCTURE

EXHIBIT F	PLATE F13

FOLD LENGTH
— 12
— 11
— 8.5
— 8

AUTO
MANUAL
FEED