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HENRY CHEN

BEFORE THE

RGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

SITNA HYDROELECTRIC PROJECT

VOLUME 1

IAL STATEMENT
EXHIBIT A
EXHIBIT C
FEBRUARY 1983

EXHIBIT D
VISED JULY 1983

AL KA OWER AUTHORITY

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FEDERAL ENERGY REGULATORY COMMISSION

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SUSITNA HYDROELECTRIC PROJECT

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INITIAL STATEMENT
EXHIBIT A
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ALASKA POWER AUTHORITY

REVISIONS TO EXHIBIT D

Revised		Renumbered		No Change
Old No.	New No.	Old No.	New No.	
PAGES				
				Table of Cont. pg.1
Table of Cont. pg. 2				
List of Tables pg. i,ii				
List of Figures pg. iii				
				D-1-1 to 10
D-1-11,12				
				D-1-13
D-2-1				
D-3-1 to 3		D-1-4 Deleted		
D-4-1 to 3				
				D-4-4 to 9
D-4-10 to 19	D-4-10 to 22			
		D-4-20	D-4-23	
D-4-21 to 38	D-4-24 to 31			
		D-4-39 - 48	D-4-32 to 41	
D-5-1		D-4-49 to 54 Deleted		
D-6-1 to 3				
TABLES				
D.1				
	D.6 new			D.2 to 5
		D.6,7,8	D.7,8,9	
D.9,10,11	D.10,11,12			
D.12,13	Deleted			
D.14,15,16	D.13,14,15			
		D.17 to 22	D.16 to 21	
D.23 to 27	Deleted			
D.28 to 33	D.22 to 27			
D.34 to 36	Deleted			
D.37	D.28			
		D.38,39	D.29, 30	
D.40	Deleted			
D.41,42	D.31,32			
FIGURES				
				D.1 to 3
D.4 to 6	Deleted			
D.7	D.4			
D.8 and 10	Deleted			
D.9	D.5			
		D.11 to 13	D.6 to 8	
D.14	D.9			
D.15 to 18	Deleted			
D.19	D.10			

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

EXHIBIT D

PROJECT COSTS AND FINANCING

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

(Revised, 7/11/83)

LIST OF TABLES

* Revised 7/11/83
** New 7/11/83
*** Page, figure, or table numbers changed. No revisions in content. 7/11/83

LIST OF TABLES (Continued)

LIST OF FIGURES

EXHIBIT D - PROJECT COSTS AND FINANCING

This exhibit presents the estimated project cost for the Susitna Hydroelectric Project, the market value of project power and a financing plan for the project. Alternative sources of power which were studied are also presented.

1 - ESTIMATES OF COST

This section presents estimates of capital and operating costs for the Susitna Hydroelectric Project, comprising the Watana and Devil Canyon developments and associated transmission and access facilities. The costs of design features and facilities incorporated into the project to mitigate environmental impacts during construction and operation are identified. Cash flow schedules, outlining capital requirements during planning, construction, and start up are presented. The approach to the derivation of the capital and operating costs estimates is described.

The total cost of the Watana and Devil Canyon projects is summarized in Table D.1. A more detailed breakdown of cost for each development is presented in Tables D.2 and D.3.

1.1 - Construction Costs

This section describes the process used for derivation of construction costs and discusses the Code of Accounts established, the basis for the estimates and the various assumptions made in arriving at the estimates. For general consistency with planning studies, all construction costs developed for the project are in January 1982 dollars.

(a) Code of Accounts

Estimates of construction costs were developed using the FERC format as outlined in the Federal Code of Regulations, Title 18 (GPO 1982).

The estimates have been subdivided into the following main cost groupings:

Group	Description
Production Plant	Costs for structures, equipment, and facilities necessary to produce power.

Transmission Plant	Costs for structures, equipment, and facilities necessary to transmit power from the sites to load centers.
General Plant	Costs for equipment and facilities required for the operation and maintenance of the production and transmission plant.
Indirect Costs	Costs that are common to a number of construction activities. For this estimate only camps have been identified in this group. The estimate for camps includes electric power costs. Other indirect costs have been included in the costs under production, transmission, and general plant costs.
Overhead Construction Costs	Costs for engineering and administration.

Further subdivision within these groupings was made on the basis of the various types of work involved, as typically shown in the following example:

- Group:	Production Plant
- Account 332:	Reservoir, Dam, and Waterways
- Main Structure 332.3:	Main Dam
- Element 332.31:	Main Dam Structure
- Work Item 332.311:	Excavation
- Type of Work:	Rock

The detailed schedule of costs using this breakdown is presented in Volume 6 of the Susitna Hydroelectric Project Feasibility Report (Acres 1982a).

(b) Approach to Cost Estimating

The estimating process used generally included the following steps:

- Collection and assembly of detailed cost data for labor, material, and equipment as well as information on productivity, climatic conditions, and other related items;

- Review of engineering drawings and technical information with regard to construction methodology and feasibility;
- Production of detailed quantity takeoffs from drawings in accordance with the previously developed Code of Accounts and item listing;
- Determination of direct unit costs for each major type of work by development of labor, material, and equipment requirements; development of other costs by use of estimating guides, quotations from vendors, and other information as appropriate;
- Development of construction indirect costs by review of labor, material, equipment, supporting facilities, and overheads; and
- Development of construction camp size and support requirements from the labor demand generated by the construction direct and indirect costs.

(c) Cost Data

Cost information was obtained from standard estimating sources, from sources in Alaska, from quotes by major equipment suppliers and vendors, and from representative recent hydroelectric projects. Labor and equipment costs for 1982 were developed from a number of sources (State of Alaska 1982; Caterpillar Tractor Co. 1981) and from an analysis of costs for recent projects performed in the Alaska environment.

It has been assumed that most contractors will work an average of two 10-hour shifts per day, six days per week. Due to the severe compression of construction activities in 1985-86, it has been assumed that most work in this period will be on two 12-hour shifts, seven days per week.

The 10-hour work shift assumption provides for high utilization of construction equipment and reasonable levels of overtime earnings to attract workers. The two-shift basis generally achieves the most economical balance between labor and camp costs.

Construction equipment costs were obtained from vendors on an FOB Anchorage basis with an appropriate allowance included for transportation to site. A representative list of construction equipment required for the project was assembled as a basis for the estimate. It has been assumed that most equipment would be fully depreciated over the life of the project. For some activities such as construction of the Watana main dam, an allowance for major overhaul was included rather than fleet replacement. Equipment operating costs were estimated from industry source data, with appropriate modifications for the remote nature and extreme climatic environment of the site. Alaskan labor rates were used for equipment maintenance and repair. Fuel and oil prices have been based upon FOB site prices.

Information for permanent mechanical and electrical equipment was obtained from vendors and manufacturers who provided guideline costs on major power plant equipment.

The costs of materials required for site construction were estimated on the basis of suppliers' quotations with allowances for shipping to site.

(d) Seasonal Influences on Productivity

A review of climatic conditions together with an analysis of experience in Alaska and in northern Canada on large construction projects was undertaken to determine the average duration for various key activities. It has been projected that most above-ground activities will either stop or be curtailed during December and January because of the extreme cold weather and the associated lower productivity. For the main dam construction activities, the following seasons have been used:

- Watana dam fill - 6-month season
- Devil Canyon arch dam - 8-month season.

Other above-ground activities are assumed to extend up to 11 months depending on the type of work and the criticality of the schedule. Underground activities are generally not affected by climate and should continue throughout the year.

Studies by others (Roberts 1976) have indicated a 60 percent or greater decrease in efficiency in construction operations under adverse winter conditions. Therefore, it is expected that most contractors would attempt to schedule outside work over a period of between six to ten months.

Studies performed as part of this work program indicate that the general construction activity at the Susitna damsite during the months of April through September would be comparable with that in the northern sections of the western United States. Rainfall in the general region of the site is moderate between mid-April and mid-October, ranging from a low of 0.75 inches precipitation in April to a high of 5.33 inches in August. Temperatures in this period range from 33°F to 66°F for a twenty-year average. In the five-month period from November through March, the temperature ranges from 9.4°F to 20.3°F, with snowfall of 10 inches per month.

(e) Construction Methods

The construction methods assumed for development of the estimate and construction schedule are generally considered normal to the industry, in line with the available level of technical information. A conservative approach has been taken in those areas where more detailed information will be developed during subsequent investigation and engineering programs. For example, normal drilling, blasting, and mucking methods have been assumed for all underground excavation. Conventional equipment has also been considered for major fill and concrete work.

(f) Quantity Takeoffs

Detailed quantity takeoffs were produced from the engineering drawings using methods normal to the industry. The quantities developed are listed in the detailed summary estimates in the Susitna Hydroelectric Feasibility Report (Acres 1982a, Vol. 6).

(g) Indirect Construction Costs

Indirect construction costs were estimated in detail for the civil construction activities. A more general evaluation was used for the mechanical and electrical work.

Indirect costs included the following:

- Mobilization
- Technical and supervisory personnel above the level of trades foremen
- All vehicle costs for supervisory personnel
- Fixed offices, mobile offices, workshops, storage facilities, and laydown areas, including all services
- General transportation for workmen on site and off site

- Yard cranes and floats
- Utilities including electrical power, heat, water, and compressed air
- Small tools
- Safety program and equipment
- Financing
- Bonds and securities
- Insurance
- Taxes
- Permits
- Head office overhead
- Contingency allowance
- Profit.

In developing contractor's indirect costs, the following assumptions have been made:

- Mobilization costs have generally been spread over construction items;
- No escalation allowances have been made, and therefore any risks associated with escalation are not included. These have been addressed in both the economic and financial studies;
- Financing of progress payments has been estimated for 45 days, the average time between expenditure and reimbursement;
- Holdback would be limited to a nominal amount;
- Project all-risk insurance has been estimated as a contractor's indirect cost for this estimate, but it is expected that this insurance would be carried by the owner; and
- Contract packaging would provide for the supply of major materials to contractors at site at cost. These include fuel, electric power, cement, and reinforcing steel.

1.2 - Mitigation Costs

The project arrangement includes a number of features designed to mitigate potential impacts on the natural environment and on residents and communities in the vicinity of the project. In addition, a number of measures are planned during the construction of the project to reduce similar impacts caused by construction activites. These measures and facilities represent additional costs to the project than would otherwise be required for safe and efficient operation of a hydroelectric development. These mitigation costs have been estimated at $153 million and have been summarized in Table D.4. In addition, the cost of full reservoir clearing at both sites has been estimated at $85 million. Although full clearing is considered good engineering practice, it is not essential to the operation of the power facilities. These costs include direct and indirect costs, engineering, administration, and contingencies.

A number of mitigation costs are associated with facilities, improvements or other programs not directly related to the project or located outside the project boundaries. These would include the following items:

- Caribou barriers
- Raptor nesting platforms
- Fish channels
- Fish hatcheries
- Stream improvements
- Salt licks
- Habitat management for moose
- Fish stocking program in reservoirs

A detailed discussion of the mitigation programs required for the project is included in Exhibit E along with tables listing detailed costs. The costs of these programs including contingency have been estimated as follows and listed under project indirects in the capital cost estimate.

Watana	$32 million (Approximately)
Devil Canyon	5 million (Approximately)
Total Project	$37 million

A number of studies and programs will be required to monitor the impacts of the project on the environment and to develop and record various data during project construction and operation. These include:

- Archaeological studies

- Fisheries and wildlife studies

- Right-of-way studies; and

- Socioeconomic planning studies.

The costs for the above work have been included under project overheads and have been estimated at approximately $20 million.

1.3 Engineering and Administration Costs

Engineering has been subdivided into the following accounts for the purposes of the cost estimates:

- Account 71

  . Engineering and Project Management
  . Construction Management
  . Procurement

- Account 76

  . Owner's Costs

The total cost of engineering and administrative activities has been estimated at 12.5 percent of the total construction costs, including contingencies. A detailed breakdown of these costs is dependent on the organizational structure established to undertake design and management of the project, as well as more definitive data relating to the scope and nature of the various project components. However, the main elements of cost included are as follows:

(a) Engineering and Project Management Costs

These costs include allowances for:

- Feasibility studies, including site surveys and investigations and logistics support;

- Preparation of the license application to the FERC;

- Technical and administrative input for other federal, state and local permit and license applications;

- Overall coordination and administration of engineering, con struction management, and procurement activities;

- Overall planning, coordination, and monitoring activities related to cost and schedule of the project;

- Coordination with and reporting to the Power Authority regarding all aspects of the project;

- Preliminary and detailed design;

- Technical input to procurement of construction services, support services, and equipment;

- Monitoring of construction to ensure conformance to design requirements;

- Preparation of start up and acceptance test procedures; and

- Preparation of project operating and maintenance manuals.

(b) Construction Management Costs

Construction management costs have been assumed to include:

- Initial planning and scheduling and establishment of project procedures and organization;

- Coordination of on site contractors and construction management activities;

- Administration of on site contractors to ensure harmony of trades, compliance with applicable regulations, and maintenance of adequate site security and safety requirements;

- Development, coordination, and monitoring of construction schedules;

- Construction cost control;

- Material, equipment and drawing control;

- Inspection of construction and survey control;

- Measurement for payment;

- Start up and acceptance tests for equipment and systems;

- Compilation of as-constructed records; and

- Final acceptance.

(c) Procurement Costs

Procurement costs have been assumed to include:

- Establishment of project procurement procedures;
- Preparation of non-technical procurement documents;
- Solicitation and review of bids for construction services, support services, permanent equipment, and other items required to complete the project;
- Cost administration and control for procurement contracts; and
- Quality assurance services during fabrication or manufacture of equipment and other purchased items.

(d) Owner's Costs

Owner's costs have been assumed to include the following:

- Administration and coordination of project management and engineering organizations;
- Coordination with other state, local, and federal agencies and groups having jurisdiction or interest in the project;
- Coordination with interested public groups and individuals;
- Reporting to legislature and the public on the progress of the project; and
- Legal costs.

1.4 - Operation, Maintenance and Replacement Costs

The facilities and procedures for operation and maintenance of the project are described in the Susitna Feasibility Report (Acres 1982a, Vol. 1). Assumptions for the size and extent of these facilities have been made on the basis of experience at large hydroelectric developments in northern climates. The annual costs for operation and maintenance for the Watana development have been estimated at $10.4 million. When Devil Canyon is brought on line these costs increase to $15.2 million per annum. Interim replacement costs have been estimated at .3 percent per annum of the capital cost.

The breakdown in Table D.5 is provided in support of the allowance used in the finance/economic analysis of the Susitna Hydroelectric Project. It is based on an operating plan involving full staffing of power plant and permanent town site support personnel. A total of 105 will be employed for Watana with another 25 to be added when Devil Canyon comes on line. This manpower level will provide manned supervisory staff on a 24-hour, three-shift basis, with maintenance crews to handle all but major overhauls. A nominal allowance has been made for major maintenance work which would utilize contracted labor. It is unlikely that major overhauls will be necessary in the first ten years of project operation. In earlier years, this allowance is a prudent provision for unexpected start up costs over and above those covered by warranty.

Allowance for contracted services also covers helicopter operations and access road snow clearing and maintenance.

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 rotating shift basis. Cost implications of these alternatives have not yet been examined.

1.5 - Allowance for Funds Used During Construction (AFDC)

At current levels of interest rates, AFDC will amount to a significant element of financing cost for the lengthy periods required for construction of the Watana and Devil Canyon projects. However, 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.

Interest and escalation were calculated as a percent of the total capital costs of the project at the start of construction. The method used for calculating the effects of interest and escalation during construction is documented in Phung 1978.

An S-shaped symmetric cash flow was adopted where:

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

where

$1 + f_{co}$ = Total cost upon commercial service expressed as a multiplier of construction cost.

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

x = effective interest rate
y = escalation rate
ε = 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 OGP-6 economic and financial studies. Interest and escalation were calculated as a percent of annual capital expenditure for the financial analysis as shown in Table D.1.

1.6 - Escalation

All construction costs presented in this Exhibit are at January 1982 levels and consequently include no allowance for future cost escalation. Thus, these costs would not be representative of actual construction and procurement bid prices. This is because provision must be made in such bids for continuing escalation of costs, and the extent and variation of escalation which might take place over the lengthy construction periods involved. Economic and financial evaluations take full account of such escalation at appropriate rates 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, with no provision being made as such for escalation. The cash flow estimates were computed on an annual basis and do not include adjustments for advanced 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 of 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. Escalation in costs due to inflation is not included. 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 is currently under construction. The line will connect existing transmission systems at Willow in the south and Healy in the north. The intertie is being built to the same standards as those proposed for the Susitna project transmission lines. 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 - ESITMATED ANNUAL PROJECT COSTS

The cost of the project has been estimated by two methods. In the first, the cost of energy was determined by preparing a financial forecast for the project assuming 100 percent debt financing. Table 10 Sheet 1 to 4 shows the projected year-by-year energy trends of the project and a 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 financing at 10 percent interest. This results in a nominal cost of power of 298 mills in 1994 (first full year of Watana) and 350 mills in 2003 (first full year of Watana and Devil Canyon) as shown on line 520 of the table . The real cost of power, adjusted for inflation of 7 percent per annum, would be 128 mills in 1994 and 82 mills in 2003 and would then fall progressively for the remaining life of the project. The annual cost of energy from the project for the period 1993 to 2021 in nominal dollars and real dollars is shown on Sheets 5 and 6, respectively, of Table 10.

The cost of power (capacity) from the project is shown on Table D-11. This cost is determined in accordance with FERC procedures and is the sum of the annual plant investment cost and the annual fixed operating cost. As can be seen from Table D.11, the total annual capacity cost in 1982 dollars is $225/kW.

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.

3 - MARKET VALUE OF PROJECT POWER

This section presents an assessment of rates at which energy and capacity of the Susitna development could be priced, together with a proposed basis for contracting for the supply of Susitna energy. Both the marketing approach and financing plan are the subjects of ongoing review and development. 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 partially delivered to the Region via the linkage of the Anchorage and Fairbanks systems by an intertie to be completed in the mid-1980s. The intertie will allow a capacity transfer of up to 70 MW in either direction. The interconnection is designed for 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 Reference 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 is anticipated that Watana energy will be supplied at a single wholesale rate to Railbelt utilities at a level to permit the maximum use of the Susitna Project, thus achieving its full economic benefit. 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. In evaluating the terms of power sales contracts, utilities can be expected to consider the advantages afforded by Susitna's long-term price stability, as well as the price offered in the initial years. That wholesale price at which consumers would be neither better nor worse off in 1994 under the with-Susitna plan or the best alternative plan has been selected for evaluation. The actual wholesale price charged for Susitna energy may vary from this price depending on the course of power sales contract negotiations and on the further development of the marketing approach.

This estimated 1994 price is based on calculations using the financial parameters in Table D.12, Reference Case fuel prices discussed in Section 4.5, and a prevailing 7 percent rate of inflation per annum. The most cost effective without-Susitna plan from which the estimated 1994 price is derived is specified in Secton 4.6. The associated plant capital and operating costs are shown in Table D.18.

In order to determine the cost of the alternative thermal capacity and energy which would replace Susitna generation, the cost of thermal generation under the with Susitna plan was subtracted from the cost of thermal generation under the without Susitna plan. This avoided thermal cost which would be replaced by Susitna generation is shown on Figure 5. The costs shown are expressed in mills per kilowatt-hour which is the total avoided thermal cost divided by the Susitna energy output in a given year. In 1994 this cost is estimated at 136 mills/kWh in nominal dollars.

The financing considerations under which it would be appropriate for Watana energy to be sold at approximately 136 mills per kWh price are considered in Section 6 of this Exhibit.

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 will be constrained both by cost and by the price of energy from the best alternative option.

3.4 - Market and Price for Watana Output 1995-2001

After its first full year of operation in the system in 1994, 2957 GWh of the total 3105 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 16 percent over this period as projected in the Reference Case forecast. Figure D.5 shows the avoided cost of energy for the period 1995 to 2001.

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.4.

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

After the Devil Canyon project comes on line, the Susitna project will provide about 90 percent of the energy demand. The avoided thermal costs in 2003 is 230 mills per kWh (2003 dollars, 7 percent annual escalation) as shown on Figure D.5. 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.

3.6 - Potential Impact of State Appropriations

In the preceding paragraphs, the price facing Railbelt utilities in the absence of Susitna has been identified. Sale of Susitna energy at this price will depend unon the magnitude of any proposed state appropriation and upon the willingness of Railbelt utilities to pay an appropriate rate in light of the project's long-term benefits.

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 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 sponsored by the Alaska Power Authority and the Railbelt Electric Power Alternatives Study sponsored by the Office of the Governor, State of Alaska.

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 Railbelt study 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.

The following presentation focuses primarily on the Susitna Feasibility Study process and findings. A separate section provides findings of the Battelle study.

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 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.

Table D.13 summarizes the total generating capacity within the Railbelt system in 1982, 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 1122.8 MW consists of two hydroelectric plants totaling 46 MW plus 1076.8 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.14 lists the service dates for each of the current generating units which would be retired based on the above retirement policy.

(c) Schedule of Additions

Two new projects are assumed to be added to the Railbelt system prior to 1990, as shown in Table D.15. The Alaska Power Authority is conducting a feasibility study of the Bradley Lake Hydroelectric Project on the Kenai Peninsula. If the project is determined to be feasible the APA will take steps to build the project. For analysis purposes, the project is assumed to provide 90 MW of generating capacity and 347 GWh of annual energy, and to be in service by 1988.

Feasibility study of the Grant Lake Project has been completed by APA recently. This project is planned to serve the City of Seward, and to provide 7 MW of generating capacity and 33 GWh of annual energy. For the purpose of analysis, this project is assumed to be in service by 1988 also.

In addition, Fairbanks Municipal Utility Systems is considering the addition of a 25-30 MW cogeneration unit to replace Chena Units 1, 2 and 3; however, these plans are not definite.

4.3 - Fairbanks - Anchorage Intertie

Engineering studies have been undertaken, equipment has been purchased and construction contracts have been let for construction of an intertie between the Anchorage and Fairbanks systems. 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.

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 Susitna project cost. For the non-Susitna units, transmission costs were added as follows:

- No costs were added for combined-cycle or gas-turbine units, since they were assumed to have sufficient siting flexibility to be placed near the major transmission works;

- A multiple coal-fired unit development in the Beluga fields was estimated to have a transmission system with security equal to that planned for Susitna, costing $220 million. This system would take power from the bus back to the existing load center; and

- A single coal-fired unit development in the Nenana area using coal mined in the Healy fields would require a transmission system costing $117 million dollars.

With the addition of a unit in the Fairbanks area in the 1990's, no additions to the 345 kV line were considered necessary. Thus, no other transmission changes were made to the non-Susitna plans.

4.4 - Hydroelectric Alternatives

Numerous studies of hydroelectric potential in Alaska have been undertaken. These date as far back as 1947 and were performed by various agencies including the then Federal Power Commission, the Corps of Engineers, the U.S. Bureau of Reclamation, the U.S. Geological Survey, and the State of Alaska. A significant amount of the identified potential is located in the Railbelt region, including several sites in the Susitna River Basin.

(a) Selection Process

The application of the five-step methodology (Figure D.6) for selection of non-Susitna plans which incorporate hydroelectric developments is summarized in this section. The analysis was completed in early 1981 and is based on January 1981 cost figures; all other parameters are contained in the Development Selection Report (Acres 1981b). Step 1 of this process essentially established the overall objective of the exercise as the selection of an optimum Railbelt generation plan which incorporated the proposed non- Susitna hydroelectric developments for comparison with other plans.

Under Step 2 of the selection process, all feasible candidate sites were identified for inclusion in the subsequent screening exercise. A total of 91 potential sites were obtained from inventories of potential sites published in the COE National Hydropower Study and the Power Administration report "Hydroelectric Alternatives for the Alaska Railbelt."

The screening of sites under Step 3 required a total of four successive iterations to reduce the number of alternatives to a manageable short list. The overall objective of this process was defined as the selection of approximately ten sites for consideration in plan formulation, essentially on the basis of published data on the sites and appropriately defined criteria. Figure D.7 shows 49 of the sites which remained after the two initial screenings.

In Step 4 of the plan selection process, the ten sites short listed under Step 3 were further refined as a basis for formulation of Railbelt generation plans. Engineering sketch-type layouts were produced for each of the sites, and quantities and capital costs were evaluated. These costs, listed in Table D.16, incorporate a 20 percent allowance for contingencies and 10 percent for engineering and owner's administration. A total of five plans were formulated incorporating various combinations of these sites as input into the Step 5 evaluations.

Power and energy values for each of the developments were reevaluated in Step 5 utilizing monthly streamflow and a computer reservoir simulation model. The results of these calculations are summarized in Table D.16.

The essential objective of Step 5 was the derivation of the optimum plan for the future Railbelt generation incorporating non-Susitna hydro generation as well as required thermal generation.

(b) Selected Sites

The selected potential non-Susitna basin hydro developments were ranked in terms of their economic cost of energy. They were then introduced into the all-thermal generating scenario during the generation planning analyses, in groups of two or three. The most economic schemes were introduced first and were followed by the less economic schemes. The methods of analysis are the same as those discussed in Section 4.5 (f).

The results of these analyses, completed in early 1981, are summarized in Table D.17 and illustrate that a minimum total system cost can be achieved by the introduction of the Chakachamna, Keetna, and Snow projects. Note that further studies of the Chakachamna project were initiated in mid-1981 by Bechtel for the Alaska Power Authority.

(c) Lake Chakachamna

Bechtel Civil and Minerals studied the feasibility of developing the power potential of Lake Chakachamna (Bechtel Civil and Minerals 1981). The lake is on the west side of Cook Inlet 85 miles west of Anchorage. Its water surface lies at about Elevation 1140.

Two basic alternatives have been identified to harness the hydraulic head for the generation of electrical energy. One is via the valley of the Chakachatna River. This river runs out of the easterly end of the lake and descends to about Elevation 400 where the river leaves the confines of the valley and spills out onto a broad alluvial flood plain. A maximum hydrostatic head of about 740 feet could be developed via this alternative.

The other alternative calls for development by diversion of the lake outflow to the valley of the McArthur River which lies to the southeast of the lake outlet. A maximum hydrostatic head of about 960 feet could be harnessed by this diversion.

(i) Project Layout

The Bechtel study evaluated the merits of developing the power potential by diversion of water southeasterly to the McArthur River via a tunnel about 10 miles long, or easterly down the Chakachatna valley either by a tunnel about 12 miles long or by a dam and tunnel development. Few sites, adverse foundation conditions, the need for a large capacity spillway and the nearby presence of an active volcano made it evident that the feasibility of constructing a dam in the Chakachatna valley would be problematical. The main thrust of the initial study was therefore directed toward the tunnel alternatives.

Two alignments were studied for the McArthur tunnel. The first considered the shortest distance that gave no opportunity for an additional point of access during construction via an intermediate adit. The second alignment was about a mile longer, but gave an additional point of access, thus reducing the lengths of headings and also the time required for construction of the tunnel. Cost comparisons nevertheless favored the shorter 10-mile, 25-foot diameter tunnel.

The second alignment running more or less parallel to the Chakachatna River in the right (southerly) wall of the valley afforded two opportunities for intermediate access adits. These, plus the upstream and downstream portals would allow construction to proceed simultaneously in six headings and reduce the construction time by 18 months from that required for the McArthur tunnel.

If all the controlled water were used for power generation, the McArthur powerhouse could support 400 MW installed capacity and produce average annual firm energy of 1753 GWh. Making a provisional reservation of approximately 19 percent of the average annual inflow to the lake for instream flow requirements in the Chakachatna River reduced the economic tunnel diameter to 23 feet. The installed capacity in the powerhouse would then be reduced to 330 MW and the average annual firm energy to 1446 MW.

For the Chakachatna powerhouse, diversion of all the controlled water for power generation would support an installed capacity of 300 MW with an average annual firm energy generation of 1314 GWh. Provisional reservation of approximately 0.8 percent of the average annual inflow to the lake for instream flow requirements in the Chakachatna River was regarded as having negligible effect on the installed capacity and average annual firm energy because that reduction is within the accuracy of the Bechtel study.

(ii) Technical Evaluation and Discussion

Several alternative methods of developing the project have been identified and reviewed. Based on the analyses performed, the more viable alternatives have been identified by Bechtel for further study.

- Chakachatna Dam Alternative

The construction of a dam in the Chakachatna River canyon approximately 6 miles downstream from the lake outlet does not appear to be a reasonable alternative. While the site is topographically suitable, the foundation conditions in the river valley and left abutment are poor. Furthermore, its environmental impact specifically on the fisheries resource will be significant (although provision of fish passage facilities could mitigate this impact to a certain extent).

- McArthur Tunnel Alternatives A and B

Diversion of flow from Chakachamna Lake to the McArthur valley to develop a head of approximately 900 feet has been identified as the most advantageous with respect to energy production and cost.

The geologic conditions for the various project facilities including intake, power tunnel, and powerhouse appear to be favorable based on a 1981 field reconnaissance. No insurmountable engineering problems appear to exist in development of the project.

Alternative A, in which essentially all stored water would be diverted form Chakachamna Lake for power production purposes, could deliver 1664 GWh of firm energy per year to Anchorage and provide 400 MW of peaking capacity. However, since the flow of the Chakachatna River below the lake outlet would be adversely affected, the existing anadromous fishery resource which uses the river to gain entry to the lake and its tributaries for spawning would be lost. In addition, the fish which spawn in the lower Chakachatna River would also be impacted due to the much reduced river flow. For this reason, Alternative B has been developed, with essentially the same project arrangement except that approximately 19 percent of the average annual flow into Chakachamna Lake would be released into the Chakachatna River below the lake outlet to maintain the fishery resource. Because of the smaller flow available for power production, the installed capacity of the project would be reduced to 330 MW and the firm energy delivered to Anchorage would be 1374 GWh per year. Obviously, the long-term environmental impacts of the project in this Alternative B are significantly reduced compared to Alternative A, since the river flow is maintined, albeit at a reduced amount. Estimated project costs for Alternatives A and B are $1.5 billion and $1.45 billion, respectively.

- Chakachatna Tunnel Alternatives C and D

An alternative to the development of this hydroelectric resource by diversion of flows from Chakachamna Lake to the McArthur River is constructing a tunnel through the right wall of the Chakachatna valley and locating the powerhouse near the downstream end of the valley. The general layout of the project would be similar to that of Alternatives A and B for a slightly longer power tunnel.

The geologic conditions for the various project features including intake, power tunnel, and powerhouse appear to be favorable and very similar to those of Alternatives A and B. Similarly, no insurmountable engineering problems appear to exist in development of the project.

Alternative C, in which essentially all stored water is diverted from Chakachamna Lake for power production, could deliver 1248 GWh of firm energy per year to Anchorage and provide 300 MW of peaking capability. While the river flow in the Chakachatna River below the powerhouse at the end of the canyon will not be substantially affected, the fact that no releases are provided into the river at the lake outlet will cause a substantial impact on the anadromous fish which normally enter the lake and pass through it to the upstream tributaries. Alternative D was therefore proposed in which a release of 30 cfs is maintained at the lake outlet to facilitate fish passage through the canyon section into the lake. In either of Alternatives C or D the environmental impact would be limited to the Chakachatna River as opposed to Alternatives A and B in which both the Chakachatna and McArthur Rivers would be affected. Since the instream flow release for Alternative D is less than 1 percent of the total available flow, the power production of Alternative D can be regarded as being the same as the Alternative C (300 MW peaking capability, 1248 GWh of firm energy delivered to Anchorage). Estimated project costs for Alternatives C and D are $1.6 billion and $1.65 billion, respectively.

4.5 - Thermal Options - Development Selection

As discussed earlier in this section, the major portion of generating capability in the Railbelt is currently thermal, principally natural gas with some coal- and oil-fired installations. There is no doubt that the future electric energy demand in the Railbelt could be satisfied by an all-thermal generation mix. In the following paragraphs, an outline is presented of the analysis undertaken in the feasibility study to determine an appropriate all-thermal generation scenario for comparison with the Susitna hydroelectric scenario.

(a) Assessment of Thermal Alternatives

The overall objective established for this selection process was the selection of an optimum all-thermal Railbelt generation plan for comparison with other plans (Figure D.8).

Primary consideration was given to gas-, coal-, and oil-fired generation sources which are the most readily developable alternatives in the Railbelt from the standpoint of technical and economic feasibility. The broader perspectives of other alternative resources such as peat, refuse, geothermal, wind and solar and the relevant environmental, social, and other issues involved were addressed in the Battelle alternatives study (Battelle 1982).

As such, a screening process was therefore considered unnecessary in this study, and emphasis was placed on selection of unit sizes appropriate for inclusion in the generation planning exercise.

For analysis purposes the following types of thermal power generation units were considered:

- Coal-fired steam
- Gas-fired combined-cycle
- Gas-fired gas turbine
- Diesel.

The following paragraphs present the thermal options used in developing the present without-Susitna plan.

(b) Coal-Fired Steam

A coal-fired steam plant is one in which steam is generated by a coal-fired boiler and used to drive a steam-turbine generator. Cooling of these units is accomplished by steam condensation in cooling towers or by direct water cooling.

Aside from the military power plant at Fort Wainwright and the self-supplied generation at the University of Alaska, there are currently two coal-fired steam plants in operation in the Railbelt. These plants are small compared with most new plants installed to meet base load in the lower 48 states and new plants being considered for the railbelt thermal generation alternatives.

(i) Capital Costs

A detailed cost study was done by EBASCO Services Incorporated as part of Battelle's alternatives study (Battelle 1982, Vol. XII). The report found that it was feasible to establish a plant at either the undeveloped Beluga field or near Nenana, using Healy field coal. The study produced costs and operating characteristics for both plants. All new coal units were estimated to have an average heat rate of 10,000 Btu/kWh and involve an average construction period of five to six years. Capital costs and operating parameters are defined for coal and other thermal generating plants in Table D.18. Cost estimates by major account are presented in Tables D.19 and D.20.

It was found that, rather than develop solely at one field in the non-Susitna case, development would be likely to take place in both fields. Thus, two units would be developed near Nenana to service the Fairbanks load center, with the remaining units placed in the Beluga fields.

To satisfy the national New Performance Standards, the capital costs incorporate provision for installation of flue gas desulfurization for sulphur control, highly efficient combustion technology for control of nitrogen acids, and baghouses for particulate removal.

(ii) Fuel Costs

Coal in the Railbelt in quantities sufficient for electric power generation is available from the Nenana Field near Healy and the Beluga Field near Anchorage. The analysis presented in Appendix D-1 developed the base cost of coal from these sources, transportation costs, if required, and real price escalation rates.

For the purposes of the economic analysis, it was assumed that up to two 200-MW coal-fired steam units would be located at Nenana, rather than at mine-mouth, due to the mine's proximity to Denali National Park. A mine-mouth coal-fired boiler and used to drive a steam-turbine generator. Cooling of these units is accomplished by steam condensation in cooling towers or by direct water cooling.

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For the purposes of the economic analysis, it was assumed that up to two 200-MW coal-fired steam units would be located at Nenana, rather than at mine-mouth, due to the mine's proximity to Denali National Park. A mine-mouth price of $1.40/MMBtu in 1983 dollars was estimated for Nenana coal-based on current contracts with Golden Valley Electric Association and Fairbanks Municipal Utility Systems adjusted for changes in production levels and new land reclaimation regulations. Transportation costs to Nenana are estimated to be $0.32/MMBtu in 1983 dollars. Therefore, the total cost of the coal delivered in Nenana would be $1.72/MMBtu. The coal has an average heat content of about 7800 Btu/lb.

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 is executed. 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 applied to operating and maintenance expenses, and or regulation related indices. The original capital investment is not escalated, so the base price of coal to the utility tends to increase with general inflation.

Several escalation rates have been estimated for utility coal in Alaska and in the lower 48 states, and they range from 2.0-2.7%/year (real). Several more generic rates have also been developed by Sherman H. Clark and Associates and by Data Resources Inc. (DRI). Because the forecasts of DRI and Sherman H. Clark are based upon supply-demand factors, they were applied to the base contract price of coal. The 2.6% real rate of increase used by DRI and Sherman H. Clark is applied to the mine-mouth price of Nenana Field 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 assumed to increase at 0.9%/yr. The overall real composite rate of escalation including transportation for coal consumed in a generating plant located at Nenana is 2.3%/yr.

Other than the two 200-MW units installed at Nenana, all other coal-fired units will be mine-mouth units installed at Beluga. The base price of coal has been determined under the assumption of an export market and was calculated as the net back cost in Alaska based on the value of coal in Japan as described in Appendix D-1. This cost is $1.86/MMBtu at 1983 price levels for coal with a heat content of about 7500 Btu/lb.

An escalation rate of 1.6%/yr. of the price of Beluga coal is based on escalation rates developed by DRI and Sherman H. Clark for coal exported to Pacific Rim countries.

Both Nenana and Beluga coal prices have been assumed to escalate to the date a given generating unit enters operation. At that time, the coal price for that unit is assumed to remain constant in real terms until the unit is replaced. Using this approach the average coal price escalation rate for the Reference Case all thermal generation alternative is about 1%/yr.

The coal escalation rates discussed above were used for the reference case and the DRI sensitivity case. Zero real price escalation of coal was assumed for the DOR-mean and -2 percent sensitivity cases.

(iii) Other Performance Characteristics

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

(c) Combined Cycle

Combined cycle plants achieve higher efficiencies than conventional gas turbines. There are two combined cycle plants in Alaska at present. One is the 139-MW G. M. Sullivan plant of Anchorage-Municipal Light and Power (AMLP). The other is the Beluga No. 8 unit owned by Chugach Electric Association (CEA). It is a 42-MW steam turbine, which was added to the system in late 1982, and utilizes 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 using the Battelle study basis (Battele 1982, Vol. XXXI) and is listed in Table D.18. A bid line item cost is shown on Table 21.

(ii) Fuel Costs

The availability, use, and price of natural gas are presented in Appendix D-1. Known recoverable reserves of natural gas in Alaska 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 but 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. Undis- covered 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.

Natural gas is produced and used in Alaska for heating, electrical generation, liquified natural gas (LNG) export, manufacture of ammonia/urea, reinjection in the recovery of oil, and for field operations. Most of the production and use (other than reinjection) currently takes place in the Cook Inlet area. Cook Inlet gas that has been injected (or actually reinjected) is not consumed and is still available for heating, electrical generation, or other uses. Gas used in field operations is the gas consumed at the wells and gathering areas to assist in the lifting and production of oil and gas.

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 in the past and are expected to remain so in future years. 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 are made principally by Enstar and are for space and water heating and other uses by residential, commerical, and industrial customers.

The future consumption of Cook Inlet gas depends on the gas needs of the major users and their ability to contract for needed supplies. Since there is a limited quantity of proven gas and estimated undiscovered reserves in the Cook Inlet area, reserves will be exhausted at some item in the future. To estimate the quantity of Cook Inlet gas available for electrical generation, the requirements and prioritites of the major users are discussed in Appendix D-1. Natural gas consumption for electric generation represents only a small portion of the total Cook Inlet gas consumption. It is projected that, by the year 2005, only about 8 percent of the total cumulative consumption of natural gas would have been for electric generation based on the all thermal generation alternative for the Reference Case.

If other gas consumption by retail sales, and ammonia and gas conversion, continues at the projected rates, the proven reserves plus the mean of the undiscovered reserves estimates will be exhausted by 2010. The proven reserves by themselves will be exhausted by 2000. This is true for any of the world oil price forecast scenarios studied.

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 Policy 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 now 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 North Slope wellhead price can only be estimated based on an estimated final sales price and the estimated costs to deliver the gas to market.

The wellhead price agreed on in the Enstar contracts is \$2.32/Mcf with an additional charge of \$0.35/Mcf beginning in 1986. Estimated severance taxes of \$0.15/Mcf and a fixed pipeline charge of about \$0.30/Mcf for pipeline delivery from Beluga to Anchorage are additional costs. The pipeline charge of \$0.30/Mcf will, of course, not be incurred if the gas is used at Beluga to generate electricity. 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 Janaury 1, 1983. If it were assumed that the generating units were located at the source of gas, the Jan. 1, 1983 price would be \$2.47/Mcf, as discussed in Appendix D-1.

Real escalation of the gas price is assumed to be dependent on the escalation of world oil prices because the current Enstar contract specifically provides for escalation of gas prices based on the price of No. 2 fuel oil on the Kenai peninsula which is closely related to world oil prices. Real escalation rates for the reference case are as follows:

Period	Real Escalation Rate
	%
1984	-4.6
1985	-4.7
1986-1988	0
1989-2010	3.0
2011-2020	2.5
2021-2030	1.5
2031-2051	1.0

Real escalation rates for the sensitivity oil price forecasts are presented in Appendix D-1.

(iii) Other Performance Characteristics

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

(d) Gas-Turbine

Gas turbines are by far the main source of thermal power generating resources in the Railbelt area at present. There are 720 MW of installed gas turbines operating on natural gas in the Anchorage area and approximately 210 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 low-cost of gas in the Anchorage area 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 modern gas turbine plant addition in the Railbelt region.

Gas turbine plants can be built over a two year construction period and new plants have an average heat rate of approximately 12,200 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 No. 2 oil is $6.23/MMBtu (1983) as discussed in Appendix D-1. The real annual growth rates in oil costs are also discussed in Appendix D-1.

(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 Formation and Evaluation

The four unit types and sizes discussed above were used to formulate plans for meeting future Railbelt power generation requirements. The purpose of this study was to formulate 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.

The primary tool used for electric system analysis is the mathematical model developed by the General Electric Company. The model is commonly known as OGP 6 or Optimized Generation Planning Model, Version 6. The general concept of the OGP program and its relationship with other computer models used in the power market forecast is described in Exhibit B, Section 5.3. That section deals specifically with the use of variables and assumptions in all the models to assure that they are consistent throughout the planning process. As explained in Section 4.6, the OGP 6 model was used for the period 1993-2020. The load forecasts produced by the RED model were extended from 2010 to 2020 using the average annual growth for the period 2000 to 2010. The following information is paraphrased from GE literature on the program. (General Electric, 1983)

The OGP6 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. OGP6 will automatically develop optimum generation expansion patterns in terms of economics, reliability and operation.

The OGP6 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.

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 the Reference Case power market forecast. The input to the model included:

- The reference case load forecast (Exhibit B Section 5.4.3);
- Fuel cost as specified above;
- 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 above;
- The existing system as specified and scheduled commitments listed in Tables D.14 and D.15.
- Fuel escalation as specified above;
- Economic parameters of 3 percent interest and 0 percent general inflation;
- 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.

It was found that 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 400MW 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 years, the generating system needs capacity to meet target reliability rather than to generate power continually and adds a mix of coal-fired steam, combined cycle, and gas turbine units.

The following was established as the non-Susitna Railbelt base plan (see Figure D.9):

(a) System as of January 1993

Coal-fired steam:	59 MW
Natural gas GT:	452 MW
Oil GT:	137 MW
Diesel:	21 MW
Natural gas CC:	317 MW
Hydropower:	143 MW
Total (including committed conditions):	1129 MW

(b) System Additions

Year	Gas-Fired Gas Turbine (MW)	Gas-Fired Combined Cycle (MW)	Coal Fired Unit (MW)
1993			1 x 200 (Beluga)
1994	1 x 70		
1995	1 x 70		
1996			1 x 200 (Beluga)
1997	1 x 70		
1998	1 x 70		
1999			
2000			
2001			
2002	1 x 70		
2003	1 x 70		
2004			
2005			1 x 200 (Nenana)
2006	1 x 70		
2007			
2008	1 x 70		
2009			
2010			1 x 200 (Nenana)
2011	1 x 70		
2012			1 x 200 (Beluga)
2013		1 x 200	
2014			
2015			
2016			
2017			
2018			
2019	1 x 70		
Total	840	200	1000

(c) System as of 2020

Coal-fired steam:	1000 MW
Natural gas GT:	840 MW
Oil GT:	0 MW
Diesel:	0 MW
Natural gas CC:	200 MW
Hydropower:	143 MW
Total (accounting for retirements and additions)	2183 MW

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.

The thermal plan described above has been selected as representative of the generation scenario that would be pursued in the absence of Susitna.

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.

Section 4.7 (b) presents the net economic benefits of the proposed hydroelectric power investments compared with this thermal alternative. These are measured in terms of present-value differences between benefits and costs. Recognizing that even the most careful estimates will be surrounded by a degree of uncertainty, particularly in regard to world oil prices, the benefit-cost assessments were subjected to sensitivity analyses as described in Section 4.8 (oil prices) and Section 4.9 (other variables).

(a) Economic Principles and Parameters

(i) Economic Principles - Concept of Net Economic Benefits

A necessary condition for maximizing the increase in state income and economic growth is the selection of public or private investments with the highest present valued net benefits to the state. In the context of Alaskan electric power investments, the net benefits are defined as the difference between the costs of optimal Susitna-inclusive and Susitna-exclusive (all thermal) generation plans.

The energy costs of power generation are initially measured in terms of opportunity values or shadow prices which may differ from accounting or market prices currently prevailing in the state. The concept and use of opportunity values is fundamental to the optimal allocation of finite public resources. Energy investment decisions should not be made solely on the basis of accounting prices in the state if the international value of traded energy commodities such as coal and gas diverge from local market prices. The opportunity value represents the value of the resource if disposed of in the most economically attractive alternative manner. In the case of oil, gas, and coal, it would represent the sale of the Alaskan commodities on the world market, compared to their consumption in state. The world price must be adjusted through a net-back exercise which accounts for the costs of getting the resource to world markets.

The choice of a time horizon is also crucial. If a short-term planning period is selected, the investment rankings and choices will differ markedly from those obtained through a long-term perspective. In other words, the benefit-cost analysis would point to different generation expansion plans depending on the selected planning period. A short-run optimization of state income would, at best, allow only a moderate growth in fixed capital investment; at worst, it would lead to underinvestment in not only the energy sector but also in other infrastructure facilities such as roads, airports, hospitals, schools, and communications.

It therefore follows that the Susitna project, like other Alaskan investments, should be appraised on the basis of long-run optimization, where the long run is defined as the expected economic life of the facility. For hydroelectric projects, this service life is typically 50 years or more. The costs of a Susitna-inclusive generation plan have therefore been compared with the costs of the next-best alternative which is the all-thermal generation plan and assessed over a planning period extending from 1982 to 2051, using internally consistent sets of economic scenarios and appropriate opportunity values of Alaskan energy.

Throughout the analysis, all costs and prices are expressed in real (inflation-adjusted) terms using January 1982 dollars except for fuel which is expressed in January 1983 dollars. Hence, the results of the economic calculations are not sensitive to modified assumptions concerning the rates of general price inflation. In contrast, the financial and market analyses conducted in nominal (inflation-inclusive) terms will be influenced by the rate of general price inflation from 1982 to 2021.

(ii) Price Inflation and Discount Rates

- General Price Inflation

Despite the fact that price levels are generally higher in Alaska than in the lower 48 states, there is little difference in the comparative rates of price changes; i.e., price inflation. Between 1970 and 1978, for example, the U.S. and Anchorage consumer price indexes rose at annual rates of 6.9 and 7.1 percent, respectively. From 1977 to 1978, the differential was even smaller; the consumer prices increased by 8.8 percent and 8.7 percent in the U.S. and Anchorage, respectively (U.S. Department of Labor).

Forecasts of Alaskan prices extend only to 1986 (Alaska Department of Commerce and Economic Development 1980). These indicate an average rate of increase of 8.7 percent from 1980 to 1986. For the longer period between 1986 and 2051, it is assumed that Alaskan prices will escalate at the overall U.S. rate, or at 5 to 7 percent compounded annually. The average annual rate of price inflation is therefore about 7 percent between 1982 and 2051. Since this is consistent with long-term forecasts of the CPI advanced by leading economic consulting organizations, (Data Resources 1980; Wharton Econometric Forecasting Associates 1981) 7 percent has been adopted as the study value. This analysis could have been done with the GNP deflator in lieu of the CPI. Results would be essentially the same.

- Discount Rates

Discount rates are required to compare and aggregate cash flows occurring in different time periods of the planning horizon. In essence, the discount rate is a weighting factor reflecting that a dollar received tomorrow is worth less than a dollar received today. This holds even in an inflation-free economy as long as the productivity of capital is positive. In other words, the value of a dollar received in the future must be deflated to reflect its earning power foregone by not receiving it today. The use of discount rates extends to both real dollar (economic) and escalated dollar (financial) evaluations, with corresponding inflation-adjusted (real) and inflation-inclusive (nominal) values.

. Real Discount and Interest Rates

Several approaches have been suggested for estimating the real discount rate applicable to public projects (or to private projects from the public perspective). Three common alternatives include:

.. the social opportunity cost (SOC) rate;

.. the social time preference (STP) rate; and

.. the government's real borrowing rate or the real cost of debt capital (Baumol 1968; Mishan 1975; Prest and Turvey 1965).

The SOC rate measures the real social return (before taxes and subsidies) that capital funds could earn in alternative investments. If, for example, the marginal capital investment in Alaska has an estimated social yield of X percent, the Susitna Hydroelectric Project should be appraised using the X percent measure of "foregone returns" or opportunity costs. A shortcoming of this concept is the difficulty inherent in determining the nature and yields of the foregone investments.

The STP rate measures society's preferences for allocating resources between investment and consumption. This approach is also fraught with practical measurement difficulties since a wide range of STP rates may be inferred from market interest rates and socially-desirable rates of investment.

A subset of STP rates used in project evaluations is the owner's real cost of borrowing; that is, the real cost of debt capital. This industrial or government borrowing rate may be readily measured and provides a starting point for determining project-specific discount rates. For example, long-term industrial bond 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 2051.

. 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*.

. Capital Cost Escalation

Based on present trends in construction costs, no real capital cost escalation has been assumed for either the hydro or the thermal units.

(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 method of comparing the "with" and "without" Susitna alternative generation scenarios is based on the long-term present worth (PW) of 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 of 1993 to 2020. Fuel price real cost escalation was included in the analysis at the rates specified above for the Reference Case.

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

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 28 years of model simulation from 1993 to 2020. The second component is the estimated PW of long-term system costs from 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 2020. The second element of the aggregated PW value is the long-term (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 benefits for only 28 or 19 years, respectively, using an investment horizon that extends to 2020. However, to model the system for an additional 31 years, it would be necessary to develop future load forecasts and generation alternatives which are beyond the extent of normal projections. For this reason, it has been assumed that the production costs for the final study year (2020) would simply recur for an additional 31 years, however they would be adjusted to take into account real fuel price escalation, and the PW of these was added to the 28-year PW (1993 to 2020) to establish the long-term cost differences between alternative methods of power generation.

(ii) Reference Case Analysis

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

The Reference 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 Reference Case values for the energy demand and load forecast, fuel prices, fuel price escalation rates, and capital costs.

The with Susitna case calls for Watana to come on line in 1993 to meet system capacity requirements. Although the initial installation at Watana will be 1020 MW only about 520 MW will be dependable during the period Watana operates on base before Devil Canyon comes on line in 2002, as discussed in Exhibit B, Sections 3.7 and 4.3.

The second stage of Susitna, the Devil Canyon project, is scheduled to come on line in 2002 with an installed capacity of 600 MW. The combined operation of Watana on peak and Devil Canyon on base will have a dependable capacity of 1270 MW in 2020 under flow regime C as discussed in Exhibit B, Section 4.

In addition to the Susitna projects, the with-Susitna plan calls for the addition of a 70-MW gas turbine unit in each of the following years, 2001, 2012, 2014, 2015, 2016, 2017, and2019. Also a 200-MW gas-fired combined cycle unit would be installed in 2020. The without Susitna plan is discussed in Section 4.5.

- Reference 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 $3.4 billion. The annual production cost in 2020 is $0.3 billion. The PW of this level cost, which remains virtually constant except for fuel cost escalation for a period extending to the end of the life of the Devil Canyon plant (2051), is $2.1 billion. The resulting total present worth of the with-Susitna plan is $5.5 billion in 1982 dollars.

The non-Susitna plan (Section 4.5) which was modeled has a 1982 PW cost of $3.9 billion for the 1993 to 2020 period with a 2020 annual cost of $0.5 billion. The total long-term cost has a PW of $7.3 billion. Therefore, the net economic benefit of adopting the Susitna plan is $1.8 billion. In other words, the present value cost difference between the Susitna plan and the expansion plan based on thermal plant addition is $1.8 billion in 1982 dollars.

It is noted that the magnitude of net economic benefits ($1.8 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 $1.8 billion regardless of CPI movements, as long as the real (inflation-adjusted) discount and interest rates are maintained at 3 percent.

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 5.0 percent in real terms, and 10.6 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.*

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*See Alaska legislation A5 44.83.670

The generation planning analysis has implicitly assumed that all environmental costs for both the Susitna and the non-Susitna plans have been costed however there are factors relating to the non-Susitna plans which may increase the net economic benefits to the project. 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 which may underestimate environmental costs. These differences or added costs cannot be quantified at this stage of study on the coal alternative.

The generation planning analysis also did not assume any restrictions on the supply of natural gas. As stated in Section 4.5(c) Cook Inlet proven reserves will be exhausted by the year 2000, and proven reserves plus the mean of the undiscovered reserves estimates will be exhausted by 2010. Under the Reference Case without Susitna expansion plan, gas consumption in 2020 would be about 8000 Mcf and total gas consumption for the period from 2020 to 2051 after proven plus undiscovered reserves are exhausted would be 210,000 Mcf or about 3.8 percent of the 1982 estimte of proven plus undiscovered reserves. Since this value is relatively small, errors in the estimate of the reserves and in the consumption rates for other gas uses could easily affect the date by which gas would be exhausted for electrical generation. Also over the planning horizon to 2051 North Slope gas will probably become available to the Railbelt market, albeit at a higher price than Cook Inlet gas.

Since the generation planning analysis did not assume any supply restrictions of natural gas nor any price increase for substitute gas becoming available, the analysis could underestimate the benefits available to the Susitna project.

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, Section 5.4. Table D.23 contains a summary of the load forecasts considered. A sensitivity analysis was performed to identify the effect of world oil price forecasts lower and higher than the reference case. Sensitivity analyses were performed for the DRI, DOR-mean and -2 percent load forecasts. The fuel price escalation rates which correspond to these forecasts are discussed in Appendix D-1. Table D.24 depicts the results of the sensitivity analysis.

As can been seen from Table D.24, the DOR mean case, with negative net benefits or a net cost of $85 million is approximately a break-even case in which the costs of the with Susitna plan are about equal to the costs of the without Susitna plan. Under the -2 percent case, the without Susitna plan is clearly more attractive, having a present worth about $1.9 billion less than the with Susitna plan. The DRI plan generates net benefits of $1.82 billion or about the same those of the Reference Case.

In performing the above analysis, it was assumed that the initial operating dates of Watana and Devil Canyon would be the same as under the reference case, or 1993 and 2002 respectively. A study of the expansion programs for the sensitivity case showed that new capacity, that could be provided by Watana, would be required in 1993 in all cases and that Devil Canyon could be delayed by up to 5 years under the -2 percent case. However, sensitivity analyses showed that delaying Devil Canyon would not significantly affect the results of the economic analysis.

4.9 - Other Sensitivity Assessments

Rather than relying 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 a change in assumptions on the results. The analysis was directed at the following variables other than those related to the world price of oil.

Variable, Reference Table	Reference Case Value	Sensitivity Values
Discount Rate (%), Table D.25	3.0	2, 5
Watana Cap. Costs ($\$x10^6$), Table D.26	3597	2917, 4316
Base fuel price ($/MMBtu), Table D.27		
Coal - Nenana	1.72	1.38, 2.06
- Beluga	1.86	1.49, 2.23
Natural Gas	2.47	1.98, 2.96
Real Fuel Escalation	Escalation to 2051	Escalation to 2020 only

Tables D.25 to D.27 depict the results of the sensitivity analysis for the variables except for real fuel escalation. Net benefits for the Reference Case would be reduced to about $1.0 billion from $1.8 billion if no real fuel price escalation is applied. Table D.28 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 Reference Case value ($1.827 billion) which is set to 100.

As can be seen from Table D.28 the economic analysis is most sensitive to the forecast of world oil prices and the corresponding power market forecast and related fuel price escalation rates. As stated in Section 4.8 under certain forecasts the with Susitna plan is marginal or unattractive when compared to the without Susitna plan.

The analysis is about equally sensitive to the other three variables mentioned above, discount rate, Watana capital cost, and fuel price as can be seen on Table D.28. Over the range of values given these variables, the with Susitna plan maintains positive net benefits over the without Susitna plan.

In addition to the above sensitivity analyses, the sensitivity of the analysis to a delay in the construction of the Devil Canyon project and to a change in the loss of load probability was evaluated. Changes in these assumptions had no significant affect on the results of the economic analysis.

4.10 - 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 and in

Exhibit B. The results of the fourth task is 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 suc as space or water heating.

The second task, electrical demand forecasts, was required for two reasons. The amount of electricity demanded determines both the size of generating units that can be included in the system and the number of generating units or the total generating capacity required. The forecast used from this study in the Susitna feasibility study is presented in Exhibit B.

The third task's purpose was to identify electric power generation and conservation alternatives potentially applicable to the Railbelt region and to examine their feasibility, considering several factors. These factors include cost of power, environmental and socioeconomic effects, and public acceptance. Alternatives appearing to be best suited for future application to the region were then subjected to additional in-depth study and were incorporated into one or more of the electric energy plans.

The fourth task, the development of electric energy themes or plans, presents possible electric energy "futures" for the Railbelt. These plans were developed both to encompass the full range of viable alternatives available to the region and to provide a direct comparison of those futures currently receiving the greatest interest within the Railbelt. A plan is defined by a set of electrical generation and conservation alternatives sufficient to meet the peak demand and annual energy requirements over the time horizon of the study. The time horizon of the study is the 1981-2050 time period. The set of alternatives used in each plan was drawn from the alternatives selected for further study in the analysis of alternatives task.

As the name implies, the purpose of the fifth task, the system integration/comparative analysis task, was to integrate the results of the other tasks and to produce a comparative evaluation of the electric energy plans. This comparative evaluation basically is a description of the implications and impacts of each electric energy plan. The major criteria used to evaluate and compare the plans are cost of power, environmental and socioeconomic impacts, as well as the susceptibility of the plan to future uncertainty in assumptions and parameter estimates.

This summary focuses on the third task: alternatives evaluation.

(a) Alternatives Evaluation

The companion Battelle study reviewed a much wider range of generating alternatives than the Susitna feasibility study. The following text summarizes the process followed and results of selecting technologies for developing energy plans.

Selecting generating alternatives for the Railbelt electric energy plans proceeded in three stages. First, a broad set of candidate technologies was identified, constrained only by the availability of the technology for commercial service prior to the year 2000. After a study was prepared on the candidate technologies, they were evaluated based on several technical, economic, environmental and institutional considerations. Using the results of that study, a subset of more promising technologies was subsequently identified. Finally, prototypical generating facilities (specific sites in the case of hydropower) were identified for further development of the data required to support the analysis of electric energy plans.

A wide variety of energy resources capable of being applied to the generation of electricity is found in the Railbelt. Resources currently used include coal, natural gas, petroleum-derived liquids and hydropower. Energy resources currently not being used but which could be developed for producing electric power within the planning period of this study include peat, wind power, solar energy, municipal refuse-derived fuels, and wood waste. Light water reactor fuel is manufactured in the lower 48 states and could be readily supplied to the Railbelt, if desired. Candidate electric generating technologies using these resources and most likely to be available for commercial order prior to the year 2000 are listed in Table D.29. The 37 generation technologies and combinations of fuel conversion-generation technologies shown in the table comprised the candidate set of technologies selected for additional study. Further discussion of the selection process and technologies rejected from consideration at this stage are provided in the Battelle Electric Power Alternatives Study (Battelle 1982, Vol. IV).

Selection of generation alternatives was based on the followinng considerations:

- the availability and cost of energy resources;

- the likely effects of minimum plant size and operational characteristics on system operation;

- the economic performance of the various technologies as reflected in estimated busbar power costs;

- public acceptance, both as reflected in the framework of electric energy plans within which the selection was conducted and as impacting specific technologies; and

- ongoing Railbelt electric power planning activities.

From this analysis, described more fully in the Battelle Electric Power Alternatives Study (Battelle 1982, Vol. IV), 13 generating technologies were selected for possible inclusion in the Railbelt electric power plans. For each nonhydro technology, a prototypical plant was defined to facilitate further development of the needed information. For the hydro technologies, promising sites were selected for further study. These prototypical plants and sites constitute the generating alternatives selected for consideration in the Railbelt electric energy plans. In the following paragraphs, each of the 13 preferred technologies is briefly described, along with some of the principal reasons for its selection. Also described are the prototypical plants and hydro sites selected for further study.

(i) Coal-Fired Steam-Electric Plants

Coal-fired steam-electric generation was selected for consideration in Railbelt electric energy plans because it is a commercially mature and economical technology that potentially is capable of supplying all of the Railbelt's base-load electric power needs for the indefinite future. An abundance of coal in the Railbelt should be mineable at costs allowing electricity production to be economically competitive with all but the most favorable alternatives throughout the planning period. Coal may be available from both the Beluga and Nenana fields. However, the Beluga fields are not yet opened and their opening is as yet uncertain. Should the fields not be mined for commercial use, the coal may not be competitive for Railbelt electrical power. Should the fields not open, the existing Nenana coal fields would need to supply an increased tonnage at higher prices.

The extremely low sulfur content of Railbelt coal and the availability of commercially tested oxides of sulfur (SO_x) and particulate control devices will facilitate control of these emissions to levels mandated by the Clean Air Act. Principal concerns of this technology are environmental impacts of coal mining, possible ambient air-quality effects of residual SO_x, oxides of nitrogen (NO_x) and particulate emissions, long-term atmospheric buildup of CO_2 (common to all combustion-based technologies) and the long-term susceptibility of busbar power costs to inflation.

Two prototypical facilities were chosen for in-depth study: in the Beluga area, a 200-MW plant that uses coal mined from the Chutna Field, and at Nenana a plant of similar capacity that uses coal delivered from the Nenana field at Healy by Alaska Railroad.

(ii) Coal Gasifier - Combined-Cycle Plants

These plants consist of coal gasifiers producing a synthetic gas that is burned in combustion turbines that drive electric generators. Heat-recovery boilers use turbine exhaust heat to raise steam to drive a steam turbine-generator.

These plants, when commercially available, should allow continued use of Alaskan coal resources at costs comparable to conventional coal steam-electric plants, while providing environmental and operational advantages compared to conventional plants. Environmental advantages include less waste-heat rejection and water consumption per unit of output due to higher plant efficiency. Better control of NO_x, SO_x and particulate emission is also afforded. From an operational standpoint, these plants offer a potential for load-following duty. (However, much of the existing Railbelt capacity most likely will be available for intermediate and peak loading during the planning period.) Because of superior plant efficiencies, coal gasifer - combined-cycle plants should be somewhat less susceptible to inflation fuel cost than conventional steam-electric plants. Principal concerns relative to these plants include land disturbance resulting from mining of coal, CO_2 production, and uncertainties in plant performance and capital cost due to the current state of technology development.

A prototypical plant was selected for in-depth analysis (Battelle 1982, VOl. XVII). This 200 MW plant is located in the Beluga area and uses coal mined from the Chuitna Field. The plant would use oxygen-blown gasifiers of Shell design, producing a medium-Btu synthesis gas for combustion turbine firing. The plant would be capable of load-following operation.

(iii) Natural Gas Combustion Turbines

Although of relatively low efficiency, natural gas combustion turbines serve well as peaking units in a system dominated by steam-electric plants. The short construction lead times characteristic of these units also offer opportunities to meet unexpected or temporary increases in demand. Except for production of CO_2, and potential local noise problems, these units produce minimal environmental impact. The principal economoc conern is the sensitivity of these plants to esalating fuel costs.

Because the costs and performance of combustion turbines are relatively well understood, no prototype was selected for in-depth study.

(iv) Natural-Gas - Combined-Cycle Plants

Natural gas - combined-cycle plants were selected for consideration because of the current availability of low-cost natural gas in the Cook Inlet area and the likely future availability of North Slope supplies in the Railbelt (although at prices higher than those currently experienced). Combined-cycle plants are the most economical and environmentally benign method currently available to generate electric base-load or mid-range peaking power using natural gas. The principal economic concern is the sensitivity of busbar power costs to the possible substantial rise in natural gas costs. The principal environmental concern is CO_2 production and possible local noise problems.

A nominal 200 MW prototypical plant was selected for further study. The plant is located in the Beluga area and uses Cook Inlet natural gas (Battelle 1982, Vol. XIII).

(v) Natural Gas Fuel-Cell Stations

These plants would consist of a fuel conditioner to convert natural gas to hydrogen and CO_2, phosphoric acid fuel cells to produce dc power by electrolytic oxidation of hydrogen, and a power conditioner to convert the dc power output of the fuel cells to ac power. Fuel-cell stations most likely would be relatively small and sited near load centers.

Natural gas fuel-cell stations were considered in the Railbelt electric energy plans primarily because of the apparent peaking duty advantages they may offer over combustion turbines for systems relying upon coal or natural-gas fired base and intermediate load units. Plant efficiencies most likely will be far superior to combustion turbines and relatively unaffected by partial power operation. Capital investment costs most likely will be comparable to that of combustion turbines. These costs and performance characteristics should lead to significant reduction in busbar power costs, and greater protection from escalation of natural gas prices compared to combustion turbines. Construction lead time should be comparable to those of combustion turbines. Because environmental effects most likely will be limited to CO_2 production, load-center siting will be possible and transmission losses and costs consequently will be reduced. Since the fuel cell is still an emerging technology with commercial availability scheduled for the late 1980's, it was not chosen as a major block in the Railbelt generation future. No prototypical plant was selected for further study.

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(v) Natural Gas Fuel-Cell Stations

These plants would consist of a fuel conditioner to convert natural gas to hydrogen and CO_2, phosphoric acid fuel cells to produce dc power by electrolytic oxidation of hydrogen, and a power conditioner to convert the dc power output of the fuel cells to ac power. Fuel-cell stations most likely would be relatively small and sited near load centers.

Natural gas fuel-cell stations were considered in the Railbelt electric energy plans primarily because of the apparent peaking duty advantages they may offer over combustion turbines for systems relying upon coal or natural-gas fired base and intermediate load units. Plant efficiencies most likely will be far superior to combustion turbines and relatively unaffected by partial power operation. Capital investment costs most likely will be comparable to that of combustion turbines. These costs and performance characteristics should lead to significant reduction in busbar power costs, and greater protection from escalation of natural gas prices compared to combustion turbines. Construction lead time should be comparable to those of combustion turbines. Because environmental effects most likely will be limited to CO_2 production, load-center siting will be possible and transmission losses and costs consequently will be reduced. Since the fuel cell is still an emerging technology with commercial availability scheduled for the late 1980's, it was not chosen as a major block in the Railbelt generation future. No prototypical plant was selected for further study.

Two small-scale hydroelectric projects were selected for consideration in Railbelt electric energy plans: the Allison Hydroelectric Project at Allison Lake near Valdez and the Grant Lake Hydroelectric Project at Grant Lake north of Seward. These two projects appear to have relatively favorable economics compared with other small hydroelectric sites, and relatively minor environmental impact.

(ix) Microhydroelectric Systems

Microhydroelectric systems are hydroelectric installations rated at 100 kW or less They typically consist of a water-intake structure, a penstock, and turbine-generator. Reservoirs often are not provided and the units operate on run-of-the-stream.

Microhydroelectric systems were chosen for analysis because of public interest in these systems, their renewable character and potentially modest environmental impact. Concrete information on power production costs typical of these facilities was not available when the preferred technologies were selected. Further analysis indicated, however, that few microhydroelectric reservoirs could be developed for less than 80 mills/kWh, and even at considerably higher rates, the contribution of this resource would likely be minor. Because of the very limited potential of this technology in the Railbelt, it was subsequently dropped from consideration. However, installations at certain sites (for example, residences or other facilities remote from distribution systems) may be justified.

(x) Large Wind Energy Conversion Systems

Large wind energy conversion systems consist of machines of 100 kW capacity and greater. These systems typically would be installed in clusters in areas of favorable wind resource and would be operated as central generating units. Operation is in the fuel-saving mode because of the intermittent nature of the wind resource.

Large wind energy conversion systems were selected for consideration in Railbelt electric energy plants for several reasons. Several areas of excellent wind resource have been identfied in the Railbelt, notably in the Isabell Pass area of the Alaska Range, and in coastal locations. The winds of these areas are strongest during fall, winter and spring months, coinciding with the winter-peaking electric load of the Railbelt. Furthermore, developing hydroelectric projects in the Railbelt would prove complementary to wind energy systems. Surplus wind-generated electricity could be readily "stored" by reducing hydro generation. Hydro operation could be used to rapidly pick up load during periods of wind insufficiency. Wind machines could provide additional energy, whereas excess installed hydro capacity could provide capacity credit. Finally, wind systems have few adverse environmental effects with the exception of their visual presence and appear to have widespread public support.

A prototypical large wind energy conversion system was selected for further study. The prototype consisted of a wind farm located in the Isabell Pass area and was comprised of ten 2.5 MW rated capacity, Boeing MOD-2, horizontal axis wind turbines (Battelle 1982, Vol. XVI).

(xi) Small Wind Energy Conversion Systems

Small wind energy conversion systems are small wind turbines of either horizontal or vertical axis, design rated at less than 100 kW capacity. Machines of this size would generally be dispersed in individual households and in commercial establishments.

Small wind energy conversion systems were selected for consideration in Railbelt electric energy plans for several reasons. Within the Railbelt, selected areas have been identified as having superior wind resource potential and the resource is renewable. Also, power produced by these systems appeared possibly to be marginally economically competitive with generating facilities currently operating in the Railbelt. However, these machines operate in a fuel-saver mode because of the intermittent nature of the wind resource and because their economic performance can be analyzed only by comparing the busbar power cost of these machines to the energy cost of power they could displace.

Data for further analysis of small wind energy conversion systems were taken from the technology profiles. Further analysis of this alternative indicated that 20 MW of installed capacity producing approximately 40 GWh of electric energy possibly could be economically developed at 80 mill marginal power costs, under the highly unlikely assumption of full penetration of the available market (households). Furthermore, in this analysis these machines were given parity with firm generating alternatives for cost of power comparisons. Because the potential contribution of this alternative is relatively minor even under the rather liberal assumptions of this analysis, the potential energy production of small wind energy conversion systems was not included in the analysis of Railbelt electric energy plans.

(xii) Tidal Power

Tidal power plants typically consist of a "tidal barrage" extending across a bay or inlet that has substantial tidal fluctuations. The barrage contains sluice gates to admit water behind the barrage on the incoming tide and turbine-generator units to generate power on the outgoing tide. Tidal power is intermittent, available, and requires a power system with equivalent amount of installed capacity capable of cycling in complement to the output of the tidal plant. Hydro capacity is especially suited for this purpose. Alternatively, energy storage facilities (pumped hydro, compressed air, storage batteries) can be used to regulate the power output of the tidal facility.

Tidal power was selected for consideration in Railbelt electric energy plans because of the substantial Cook Inlet tidal resource, because of the renewable character of this energy resource and because of the substantial interest in the resource, as evidenced by the first-phase assessment of Cook Inlet tidal power development (Acres 1981a).

Estimated production costs of an unretimed tidal power facility would be competitive with principal alternative sources of power, such as coal-fired power plants, if all power production could be used effectively. The costs would not be competitive, however, unless a specialized industry were established to absorb the predictable, but cyclic, output of the plant. Alternatively, only the portion of the power output that could be absorbed by the Railbelt power system could be used. The cost of this energy would be extremely high relative to other power-producing options because only a fraction of the "raw" energy production could be used. An additional alternative would be to construct a retiming facility, probably a pumped storage plant. Due to the increased capital costs and power losses inherent in this option, busbar power costs would still be substantially greater than for nontidal generating alternatives. For these reasons, the Cook Inlet tidal power alternative was not considered further in the analysis of Railbelt electric energy plans.

(xiii) Refuse-Derived Fuel Steam Electric Plants

These plants consist of boilers, fired by the combustible fraction of municipal refuse, that produce steam for the operation of a steam turbine-generator. Rated capacities typically are low due to the difficulties of transporting and storing refuse, a relatively low energy density fuel. Supplemental firing by fossil fuel may be required to compensate for seasonal variation in refuse production.

Enough municipal refuse appears to be available in the Anchorage and Fairbanks areas to support small refuse-derived fuel-fired steam-electric plants if supplemental firing (using coal) were provided to compensate for seasonal fluctuations in refuse availability. The cost of power from such a facility appears to be reasonably competitive, although this competitiveness depends upon receipt of refuse-derived fuel at little or no cost. Advantages presented by disposal of municipal refuse by combustion may outweigh the somewhat higher power costs of such a facility compared to coal-fired plants. The principal concerns relative to this type of plant relate to potential reliability, atmospheric emission, and odor problems.

Cost and performance characteristics of these alternatives as used in the Battelle study (Battelle 1982, Vol. II) are summarized in Table D.30.

5 - CONSEQUENCES OF LICENSE DENIAL

5.1 - Cost of License Denial

The forecast energy demand for the Railbelt through the year 2020 can be met without constructing the Watana-Devil Canyon hydroelectric project provided that other, albeit more costly, alternatives are developed. The best alternative generating system is outlined in Section 4.5 of this Exhibit. However, the economic comparison described in Section 4.7 concludes that the Susitna project will yield an expected present valued net benefit of $1.8 billion under the Reference Case.

The economic consequences of license denial will be the probable costs mentioned above.

The Susitna project makes a significant contribution to the energy independence of both the State and the nation. Generation of power by a renewable resource in the State allows for export of non-renewable resources to the lower 48 states. Denial of the license will negate this effort.

The most likely alternative to Susitna is subject to a great deal of cost risk due to the uncertain future in fossil fuel prices and the unresolved issues about development in the Beluga coal fields. License denial will force the State into pursuing a less certain program in meeting power needs.

5.2 - Future Use of Damsites if License is Denied

There are no present plants for an alternative use of the Watana and Devil Canyon damsites. In the absence of the hydroelectric project, they would remain in their present state.

6 - FINANCING

6.1 - Forecast Financial Parameters

The financial parameters used in the financial analysis are summarized in Table D.12. The interest rates and forecast rates of inflation 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.) 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.

6.2 - Inflationary Financing Deficit

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.10). 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 early 1990 will be financed by approximately $1.8 billion (1982 dollars) of state appropriations. Thereafter completion of Watana is expected to be accomplished by issuance of approximately $2.0 billion (1982 dollars) of revenue bonds. The year-by-year expenditures in constant and then current dollars are detailed in Table D.31. These annual borrowing amounts do not exceed the Authority's estimated annual debt capacity for the period.

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 (as detailed in Table D.31) by the issuance of approximately $2.0 billion of revenue bonds (in 1982 dollars) over the years 1994 to 2002 with no state contribution.

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.32 and D.10, for the $1.8 billion state contribution and 100 percent debt financing cases, respectively. Figure D.10 shows the cost of energy from Susitna assuming the $1.8 billion state contribution.

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. Also, while the market for Susitna power is relatively insensitive to the world oil prices analyzed, the finance plan is affected by those prices through their impact on the wholesale prices Railbelt utilities would face in the absence of Susitna.

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.

Because of the above conditions, the financing plan is the subject of continuing review and development.

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TABLE D.1: SUMMARY OF COST ESTIMATE

Catagory	Watana	Devil Canyon	Total
	January 1982 Dollars $ X 10^6		
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 (OGP-6, 0 percent inflation, 3 percent interest)			
Escalation	----	----	----
AFDC	485	180	665
TOTAL PROJECT COST	$ 4,081	$ 1,734	$ 5,815
SUSITNA COST OF POWER (Table D.10, 100% Debt Finance)			
Escalation	2,560	3,200	5,760
AFDC	1,796	1,610	3,406
TOTAL PROJECT COST	7,952	6,364	14,316
FINANCIAL ANALYSIS (Table D.32, $1.8 Billion State Appropriation)			
Escalation	2,560	3,200	5,760
AFDC	314	1,610	1,924
TOTAL PROJECT COST	$ 6,470	$ 6,364	$ 12,834

Revised 7/11/83

TABLE D.2: ESTIMATE SUMMARY - WATANA

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	PRODUCTION PLANT			
330	Land & Land Rights	$ 51		
331	Powerplant Structures & Improvements	74		
332	Reservoir, Dams & Waterways	1,547		
333	Waterwheels, Turbines & Generators	66		
334	Accessory Electrical Equipment	21		
335	Miscellaneous Powerplant Equipment (Mechanical)	14		
336	Roads & Railroads	214		
	Subtotal	1,987		
	Contingency	306		
	TOTAL PRODUCTION PLANT		$ 2,293	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 2,293	
	TRANSMISSION PLANT			
350	Land & Land Rights	$ 8		
352	Substation & Switching Station Structures & Improvements	12		
353	Substation & Switching Station Equipment	131		
354	Steel Towers & Fixtures	131		
356	Overhead Conductors & Devices	100		
359	Roads & Trails	13		
	Subtotal	395		
	Contingency	61		
	TOTAL TRANSMISSION PLANT		456	
			$ 2,749	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 2,749	-
	GENERAL PLANT			
389	Land & Land Rights	$ -		Included under 330
390	Structures & Improvements	-		Included under 331
391	Office Furniture/Equipment			Included under 399
392	Transportation Equipment			" "
393	Stores Equipment			" "
394	Tools Shop & Garage Equipment			" "
395	Laboratory Equipment			" "
396	Power-Operated Equipment			" "
397	Communications Equipment			" "
398	Miscellaneous Equipment			" "
399	Other Tangible Property	5		
	TOTAL GENERAL PLANT		$ 5	
			$ 2,754	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 2,754	
	INDIRECT COSTS			
61	Temporary Construction Facilities	$ -		See Note
62	Construction Equipment	-		See Note
63	Camp & Commissary	373		
64	Labor Expense	-		
65	Superintendence	-		See Note
66	Insurance	-		See Note
68	Mitigation	29		
69	Fees	-		See Note
	Note: Costs under accounts 61, 62, 64, 65, 66, and 69 are included in the appropriate direct costs listed above.			
	Subtotal	402		
	Contingency	40		
	TOTAL INDIRECT COSTS		$ 442	
	TOTAL CONSTRUCTION COSTS		$ 3,196	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL CONSTRUCTION COSTS BROUGHT FORWARD		$ 3,196	
	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)			
71	Engineering/ Administration	$ 386		
	Environmental Monitoring	14		
72	Legal Expenses	-		Included in 71
75	Taxes	-		Not applicable
76	Administrative & General Expenses	-		Included in 71
77	Interest	-		Not included
80	Earnings/Expenses During Construction	-		Not included
	Total Overhead		400	
	TOTAL PROJECT COST		$ 3,596	

TABLE D.3: ESTIMATE SUMMARY - DEVIL CANYON

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	PRODUCTION PLANT			
330	Land & Land Rights	$ 22		
331	Powerplant Structures & Improvements	69		
332	Reservoir, Dams & Waterways	646		
333	Waterwheels, Turbines & Generators	42		
334	Accessory Electrical Equipment	14		
335	Miscellaneous Powerplant Equipment (Mechanical)	11		
336	Roads & Railroads	119		
	Subtotal	923		
	Contingency	142		
	TOTAL PRODUCTION PLANT		$ 1,065	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 1,065	
	TRANSMISSION PLANT			
350	Land & Land Rights	$ -		Included in Watana Estimate
352	Substation & Switching Station Structures & Improvements	7		
353	Substation & Switching Station Equipment	21		
354	Steel Towers & Fixtures	29		
356	Overhead Conductors & Devices	34		
359	Roads & Trails	-		Included in Watana Estimate
	Subtotal	91		
	Contingency	14		
	TOTAL TRANSMISSION PLANT		$ 105	
			$ 1,170	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 1,170	
	GENERAL PLANT			
389	Land & Land Rights	$		Included under 330
390	Structures & Improvements			Included under 331
391	Office Furniture/Equipment			Included under 399
392	Transportation Equipment			" "
393	Stores Equipment			" "
394	Tools Shop & Garage Equipment			" "
395	Laboratory Equipment			" "
396	Power Operated Equipment			" "
397	Communications Equipment			" "
398	Miscellaneous Equipment			" "
399	Other Tangible Property	5		-
	TOTAL GENERAL PLANT		$ 5	
			$ 1,175	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 1,175	-
	INDIRECT COSTS			
61	Temporary Construction Facilities	$ -		See Note
62	Construction Equipment	-		See Note
63	Camp & Commissary	184		
64	Labor Expense	-		See Note
65	Superintendence	-		See Note
66	Insurance	-		See Note
68	Mitigation	4		
69	Fees	-		See Note
	Note: Costs under accounts 61, 62, 64, 65, 66, and 69 are included in the appropriate direct costs listed above.			
	Subtotal	188		
	Contingency	18		
	TOTAL INDIRECT COSTS		$ 206	
	TOTAL CONSTRUCTION COSTS		$ 1,381	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL CONSTRUCTION COSTS BROUGHT FORWARD		$ 1,381	
	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)			
71	Engineering/Administration	$ 167		
	Environmental Monitoring	6		
72	Legal Expenses	-		Included in 71
75	Taxes	-		Not Applicable
76	Administrative & General Expenses	-		Included in 71
77	Interest	-		Not Included
80	Earnings/Expenses During Construction	-		Not Included
	Total Overhead Costs		173	
	TOTAL PROJECT COST		$ 1,554	

TABLE D.4: MITIGATION MEASURES - SUMMARY OF COSTS INCORPORATED IN CONSTRUCTION COST ESTIMATES

COSTS INCORPORATED IN CONSTRUCTION ESTIMATES	WATANA $ X 10^3	DEVIL CANYON $ X 10^3	
Outlet Facilities			
Main Dam at Devil Canyon		14,600	
Tunnel Spillway at Watana	47,100		
Restoration of Borrow Area D	1,600	NA	
Restoration of Borrow Area F	600	NA	
Restoration of Camp and Village	2,300	1,000	
Restoration of Construction Sites	4,100	2,000	
Fencing around Camp	400	200	
Fencing around Garbage Disposal Area	100	100	
Multilevel Intake Structure	18,400	NA	
Camp Facilities Associated with trying to Keep Workers out of Local Communities	10,200	9,000	
Restoration of Haul Roads	800	500	
SUBTOTAL	85,600	27,400	
Contingency 20%	17,100	5,500	
TOTAL CONSTRUCTION	102,700	32,900	
Engineering 12.5%	12,800	4,100	
TOTAL PROJECT	115,500	37,000	152,500

TABLE D.5: SUMMARY OF OPERATION AND MAINTENANCE COSTS

	WATANA[1] ($ 000's Omitted)			($ 000's Omitted)		
	Labor	Expense Items	Subtotal	Labor	Expense Items	Subtotal
Power & Transmission Operation/ Maintenance	5330	990	6320	1920	500	2420
Contracted Services	--	900	900	--	480	480
Permanent Townsite Operations	540	340	880	120	80	200
Allowance for Environmental Mitigation	--	--	1000			1000
Contingency	--	--	900			500
Additional Allowance from 2002 to Replace Community Facilities			400			200
Total Operating and Maintenance Expenditure Estimate Power Development and Transmission Facilities		WATANA	10,400		DEVIL CANYON	4,800

(1) Incremental

TABLE D.6: VARIABLES FOR AFDC COMPUTATIONS

	Analysis	
	Economic	Financial
Effective Interest Rate (x)%	3	10
Escalation Rate (y)%	0	7
Construction Period (B) yrs.		
Watana	8.5	8.5
Devil Canyon	7.5	7.5

TABLE D.7 - SUSITNA HYDROELECTRIC PROJECT

Watana and Devil Canyon Cumulative and Annual Cash Flow

JANUARY 1982 DOLLARS - IN MILLIONS

YEAR	ANNUAL CASH FLOW WATANA	DEVIL CANYON	COMBINED	CUMULATIVE CASH FLOW (TO END OF YEAR) WATANA	DEVIL CANYON	COMBINED
1981	27.6		27.6	27.6		27.6
82	12.9		12.9	40.4		40.5
83	28.7		28.7	69.2		69.2
84	48.5		48.5	117.7		117.7
85	199.5		199.5	317.2		317.2
86	283.9		283.9	601.1		601.1
87	295.4		295.4	896.5		896.5
88	369.0		369.0	1265.5		1265.5
89	438.4		438.4	1703.9		1703.9
90	627.6		627.6	2331.5		2331.5
91	608.8	4.9	613.7	2940.3	4.9	2945.2
92	429.0	47.9	476.9	3369.3	52.8	3422.1
93	153.2	68.6	221.8	3522.5	121.4	3643.9
94	73.7	64.3	138.0	3596.2	185.7	3781.9
95		64.9	64.9		250.6	3846.8
96		115.3	115.3		365.9	3962.1
97		201.3	201.3		567.2	4163.4
98		291.8	291.8		854.0	4455.2
99		279.7	279.7		1138.7	4734.9
2000		241.7	241.7		1380.4	4976.6
2001		156.0	156.0		1536.4	5132.6
2002		17.6	17.6		1554.0	5150.2
TOTAL	3596.2	1554.0	5150.2			

TABLE D.8: ANCHORAGE FAIRBANKS INTERTIE
PROJECT COST ESTIMATE

	TOTAL COST (Thousands of Dollars)
Total Line 175.1 miles	56,556
Total Substation Cost	9,449
Subtotal	66,005
R/W Acquisition ($40.00/Mile)	6,784
Mobilization - Demobilization 5%	3,300
Surveying	3,100
Engineering 6%	3,960
Construction Management 5%	3,300
Subtotal	86,449
Contingencies 25%	21,612
Total Sept. 1981 Dollars	108,061
Inflation @ 10%/year - 2 years	130,754

Source: Commonwealth Associates, January 1982

TABLE D.9: SUMMARY OF EBASCO CHECK ESTIMATE

The following figures and comments are taken from EBASCO's estimate dated March 26, 1982.

PROJECT COST SUMMARY

The hydroelectric development cost in January 1982 dollars is as follows:

DESCRIPTION	WATANA	DEVIL CANYON
Hydraulic Production Plant	$2,502,053,000	$ 955,723,000
Transmission Plant	411,774,000	77,712,000
General Plant	1,113,000	-
Total Direct Construction Cost	$2,914,940,000	$1,033,435,000
Indirect Construction Cost	362,681,000	170,688,000
Subtotal for Contingency	$3,277,621,000	$1,204,123,000
Contingency	503,979,000	184,177,000
Total Specific Construction Cost	$3,781,600,000	$1,388,300,000
Professional Services	280,000,000	115,000,000
Client Costs	Not Included	Not Included
Total Project Cost	$4,061,600,000	$1,503,300,000

The above costs are based on quantities contained in the Revision 4 Estimating Package dated February 12, 1982, as prepared by Acres American. We have not considered any quantities contained in the Revision 5 Estimating Package dated March 4, 1982, since the transmittal was received one month later than the revised information cutoff date of February 8, 1982.

Major cost quantities have been checked to verify Revision 4 quantities as compared to Acres' Project drawings. We have provided an asterisk next to the accounts added by Ebasco to reflect costs not properly included in other accounts. Unit prices supplied by Acres American Incorporated are footnoted.

REVISED SUMMARY (BY ACRES)

Watana Cost	$\$4,062 \times 10^6$
Devil Canyon Cost	$1,503 \times 10^6$
Total Project (Rev. 4)	$5,565 \times 10^6$
Adjustment for Revision 5	-79×10^6
Adjustment Total Project	$\$5,486 \times 10^6$

NOTE: Adjustments were given by EBASCO in meeting in New York on April 14, 1982.

CATA12K.D12 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	2953	2957
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.55	128.05
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	260.30	298.21
-----INCOME-----------------										
513 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	768.6	882.1
179 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	24.2
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	746.0	857.9
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	4.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.6
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	746.0	795.3
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	653.7	176.6
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	15.3
549 TOTAL SOURCES OF FUNDS	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	780.0	246.3
320 LESS CAPITAL EXPENDITURE	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	653.7	201.7
443 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	15.3
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0	49.2
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.3	92.3
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8220.7	8422.4
455 CAPITAL EMPLOYED	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8347.0	8563.9
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
553 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	141.5
554 DEBT OUTSTANDING-LONG TERM	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8220.7	8367.9
542 ANNUAL DEBT DRAWDOWN $1982	317.2	313.5	352.4	455.2	561.5	795.1	839.7	776.0	300.2	75.9
543 CUM. DEBT DRAWDOWN $1982	317.2	630.7	983.1	1438.3	1999.8	2795.0	3634.6	4410.7	4710.9	4786.7
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.03

NO STATE CONTRIBUTION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 1 OF 6

TABLE D.10

DATA12K.D12 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	2953	2957
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.55	128.05
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	260.30	298.21
-----INCOME-----------------										
515 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	768.6	882.1
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	24.2
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	746.0	857.8
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.0	4.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.6
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	746.0	795.3
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	653.7	176.6
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	15.3
549 TOTAL SOURCES OF FUNDS	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	780.0	246.3
320 LESS CAPITAL EXPENDITURE	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	653.7	201.7
443 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	15.3
250 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0	49.2
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.3	92.3
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8220.7	8422.4
455 CAPITAL EMPLOYED	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8347.0	8563.9
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
553 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	141.5
554 DEBT OUTSTANDING-LONG TERM	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8220.7	8367.9
542 ANNUAL DEBT DRAWDOWN $1982	317.2	313.5	352.4	455.2	561.5	795.1	839.7	776.0	300.2	75.8
543 CUM. DEBT DRAWDOWN $1982	317.2	630.7	983.1	1438.3	1999.8	2795.0	3634.6	4410.7	4710.9	4786.7
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.03

NO STATE CONTRIBUTION SCENARIO

7% INFLATION AND 10% INTEREST

SHEET 1 OF 6

TABLE D.10

DATA12K.D12 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3005	3019	3028	3055	3057	3064	3105	4555	4670	4786
521 REAL PRICE-MILLS	118.38	110.59	103.51	96.35	90.45	84.80	78.66	85.99	81.62	74.88
466 INFLATION INDEX	249.23	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
5[illegible] PRICE-MILLS	295.10	294.97	295.43	294.22	295.54	296.47	294.25	344.22	349.58	343.17
-----INCOME-----------------										
516 REVENUE	886.7	890.5	894.5	898.8	903.4	908.3	913.6	1567.8	1632.4	1642.3
170 LESS OPERATING COSTS	25.9	27.7	29.7	31.8	34.0	36.4	38.9	60.8	65.1	69.7
517 OPERATING INCOME	860.8	862.7	864.8	867.0	869.4	871.9	874.7	1506.9	1567.3	1572.6
214 ADD INTEREST EARNED ON FUNDS	4.9	5.3	5.6	6.0	6.4	6.9	7.4	7.9	12.4	13.2
550 LESS INTEREST ON SHORT TERM DEBT	14.2	14.6	15.0	15.5	15.9	16.5	17.0	17.7	28.9	30.5
391 LESS INTEREST ON LONG TERM DEBT	792.4	789.2	785.6	791.7	777.4	772.7	767.5	1391.1	1391.9	1382.6
543 NET EARNINGS FROM OPERS	59.2	64.3	69.8	75.9	82.5	89.7	97.5	106.1	158.8	172.7
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	59.2	64.3	69.8	75.9	82.5	89.7	97.5	106.1	158.8	172.7
445 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	206.2	372.6	676.8	1061.1	1190.0	1240.1	1102.7	70.5	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	4.0	4.4	4.6	4.9	5.2	5.7	6.1	112.9	15.8	10.9
549 TOTAL SOURCES OF FUNDS	269.4	441.2	751.3	1141.9	1277.8	1335.5	1206.4	289.5	174.6	183.7
320 LESS CAPITAL EXPENDITURE	233.1	401.3	707.6	1094.0	1225.2	1277.8	1143.0	113.6	66.2	70.8
448 LESS WORCAP AND FUNDS	4.0	4.4	4.6	4.9	5.2	5.7	6.1	112.9	15.8	10.9
260 LESS DEBT REPAYMENTS	32.3	35.5	39.1	43.0	47.3	52.0	57.2	62.9	92.7	101.9
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	52.6	56.3	60.3	64.5	69.0	73.8	79.0	123.5	132.2	141.4
371 OTHER WORKING CAPITAL	92.9	93.6	94.3	95.0	95.7	96.6	97.5	165.9	173.1	174.7
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	8655.5	9056.8	9764.4	10858.4	12083.6	13361.5	14504.5	14618.1	14684.3	14755.1
465 CAPITAL EMPLOYED	8801.0	9206.7	9918.9	11017.8	12248.3	13531.8	14681.0	14907.6	14989.5	15071.3
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	113.6	177.9	247.8	323.7	406.2	495.9	593.4	699.5	858.4	1031.1
555 DEBT OUTSTANDING-SHORT TERM	145.5	149.9	154.5	159.4	164.7	170.4	176.5	289.4	305.2	316.2
554 DEBT OUTSTANDING-LONG TERM	8541.8	8878.9	9516.6	10534.7	11677.4	12865.6	13911.0	13918.6	13825.9	13724.0
542 ANNUAL DEBT DRAWDOWN $1982	82.7	139.7	237.1	347.4	364.2	354.7	294.7	17.6	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	4869.4	5009.1	5246.2	5593.7	5957.8	6312.5	6607.3	6624.9	6624.9	6624.9
519 DEBT SERVICE COVER	1.03	1.03	1.04	1.04	1.04	1.05	1.05	1.03	1.04	1.05

NO STATE CONTRIBUTION SCENARIO

7% INFLATION 10% INTEREST

SHEET 2 OF 6

TABLE D.10

DATA12K.012 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
73 ENERGY GWH	4902	5064	5224	5384	5544	5704	5862	6023	6148	6317
521 REAL PRICE-MILLS	68.73	62.59	57.11	52.15	47.70	43.69	[illegible].08	36.79	34.02	31.27
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	901.52
520 PRICE-MILLS	337.03	328.42	320.62	313.30	306.62	300.48	294.94	289.72	286.62	281.86
-----INCOME-----------------										
516 REVENUE	1652.0	1663.0	1674.8	1686.7	1699.8	1713.8	1728.8	1744.9	1762.0	1780.4
170 LESS OPERATING COSTS	74.5	79.8	85.3	91.3	97.7	104.5	111.9	119.7	128.1	137.0
517 OPERATING INCOME	1577.5	1583.2	1589.5	1595.4	1602.1	1609.3	1617.0	1625.2	1634.0	1643.4
214 ADD INTEREST EARNED ON FUNDS	14.1	15.1	16.2	17.3	18.5	19.8	21.2	22.7	24.3	26.0
550 LESS INTEREST ON SHORT TERM DEBT	31.6	32.8	34.0	35.4	36.8	38.3	39.9	41.7	43.6	45.5
391 LESS INTEREST ON LONG TERM DEBT	1372.4	1361.2	1348.8	1335.3	1320.4	1303.5	1285.9	1266.0	1244.2	1220.1
543 NET EARNINGS FROM OPERS	187.6	204.4	222.8	242.1	263.5	286.9	312.4	340.2	370.5	403.7
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	187.6	204.4	222.8	242.1	263.5	286.9	312.4	340.2	370.5	403.7
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 WORCAP DEBT DRAWDOWNS	11.5	12.5	13.4	14.2	15.2	16.4	17.5	18.7	20.0	21.4
349 TOTAL SOURCES OF FUNDS	199.1	216.9	236.1	256.3	278.7	303.3	329.8	358.8	390.5	425.1
320 LESS CAPITAL EXPENDITURE	75.8	81.1	86.7	92.8	99.3	106.3	113.7	121.7	130.2	139.3
448 LESS WORCAP AND FUNDS	11.5	12.5	13.4	14.2	15.2	16.4	17.5	18.7	20.0	21.4
260 LESS DEBT REPAYMENTS	112.1	123.4	135.7	149.3	164.2	180.6	198.7	218.5	240.4	264.4
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	-0.3	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.3	0.0	-0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	151.3	161.9	173.2	185.4	198.3	212.2	227.1	243.0	260.0	278.2
371 OTHER WORKING CAPITAL	176.4	178.3	180.3	182.4	184.7	187.2	189.8	192.6	195.5	198.8
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14830.9	14911.9	14998.7	15091.5	15190.8	15297.0	15410.7	15532.4	15662.6	15801.9
465 CAPITAL EMPLOYED	15158.5	15252.1	15352.2	15459.2	15573.8	15696.4	15827.6	15967.9	16118.1	16278.8
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	1218.7	1423.1	1645.9	1887.9	2151.4	2438.3	2750.6	3090.8	3461.4	3865.1
555 DEBT OUTSTANDING-SHORT TERM	328.0	340.5	353.5	367.8	383.0	399.4	416.9	435.5	455.5	476.9
554 DEBT OUTSTANDING-LONG TERM	13611.8	13488.5	13352.8	13203.5	13039.4	12858.8	12660.1	12441.6	12201.2	11936.8
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9
519 DEBT SERVICE COVER	1.05	1.05	1.06	1.06	1.07	1.07	1.08	1.08	1.09	1.09

NO STATE CONTRIBUTION SCENARIO

7% INFLATION 10% INTEREST

SHEET 3 OF 6

TABLE D.10

DATA12K.U12 WATANA (ON LINE 1993)-NO STATE FUNCS-INFLATICN 7%-INTEREST 10%-CAPCCST $5.15 BN 24-JUN-83

CASH FLOW SUMMARY

===($MILLION)====

	2015	2016	2017	2018	2019	2020	2021	TOTAL
73 ENERGY GWH	6449	6616	6708	6760	6875	6984	6984	144802
521 REAL PRICE-MILLS	28.94	26.67	24.89	23.38	21.78	20.33	19.29	0.00
466 INFLATION INDEX	964.63	1032.15	1104.40	1181.71	1264.43	1352.94	1447.64	0.00
520 PRICE-MILLS	279.14	275.28	274.86	276.31	275.44	275.09	279.31	0.00
-----INCOME-----------------								
516 REVENUE	1300.1	1821.1	1843.6	1867.7	1393.5	1921.1	1950.6	42992.6
170 LESS OPERATING COSTS	146.6	156.9	167.9	179.6	192.2	205.6	220.0	2765.5
517 OPERATING INCOME	1653.4	1664.2	1675.7	1688.1	1701.3	1715.4	1730.5	40227.1
214 ADD INTEREST EARNED ON FUNDS	27.8	29.8	31.8	34.1	36.5	39.0	41.7	516.7
550 LESS INTEREST ON SHORT TERM DEBT	47.7	50.0	52.4	55.1	57.9	60.9	64.1	965.9
391 LESS INTEREST ON LONG TERM DEBT	1193.7	1164.6	1132.6	1097.4	1058.7	1016.1	969.3	31863.7
548 NET EARNINGS FROM OPERS	439.9	479.4	522.6	569.7	621.2	677.5	738.9	7914.2
-----CASH SOURCE AND USE----								
548 CASH INCOME FROM OPERS	439.9	479.4	522.6	569.7	621.2	677.5	738.9	7914.2
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14317.1
243 WORCAP DEBT DRAWDOWNS	22.9	24.5	26.2	28.1	30.0	32.1	34.4	675.2
549 TOTAL SOURCES OF FUNDS	462.8	503.9	548.8	597.8	651.2	709.6	773.3	22906.5
320 LESS CAPITAL EXPENDITURE	149.0	159.5	170.6	182.6	195.4	209.0	223.7	17091.6
443 LESS WORCAP AND FUNDS	22.9	24.5	26.2	28.1	30.0	32.1	34.4	675.2
260 LESS DEBT REPAYMENTS	290.9	319.9	351.9	387.1	425.8	468.4	515.3	5139.7
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
240 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------								
225 RESERVE AND CONT. FUND	297.6	318.5	340.8	364.6	390.2	417.5	446.7	446.7
371 OTHER WORKING CAPITAL	202.2	205.8	209.9	214.0	218.5	223.3	228.5	228.5
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	15950.9	16110.4	16281.0	16463.6	16658.9	16867.9	17091.6	17091.6
465 CAPITAL EMPLOYED	16450.7	16634.7	16831.5	17042.2	17267.6	17508.8	17766.8	17766.8
451 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	4305.0	4784.4	5306.9	5876.6	6497.8	7175.3	7914.2	7914.2
555 DEBT OUTSTANDING-SHORT TERM	499.8	524.3	550.6	578.7	608.7	640.8	675.2	675.2
554 DEBT OUTSTANDING-LONG TERM	11645.9	11326.0	10974.1	10586.9	10161.1	9692.7	9177.4	9177.4
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6624.9
543 CUM. DEBT DRAWDOWN $1982	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9
519 DEBT SERVICE COVER	1.10	1.11	1.11	1.12	1.13	1.14	1.15	0.00

NO STATE CONTRIBUTION SCENARIO

7% INFLATION 10% INTEREST

SHEET 4 OF 6

TABLE D.10

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Nominal $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	8	11	12	12	13	13	14	15	15	15
Capital Renewals	0	8	9	10	10	11	12	12	13	9
Debt Service Cost	252	279	274	273	272	270	270	269	266	320
Total	260	298	295	295	295	294	296	296	294	344

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	17	18	19	19	20	20	21	22	22	23
Capital Renewals	14	15	15	16	17	17	18	19	19	[illegible]
Debt Service Cost	318	310	303	293	284	276	268	259	253	247
Total	349	343	337	328	321	313	307	300	295	290

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operating Expenses	24	25	26	27	28	30	31	33	35
Capital Renewals	21	22	23	24	25	27	28	30	32
Debt Service Cost	242	235	230	224	222	219	216	212	212
Total	287	282	279	275	275	276	275	275	279

NO STATE CONTRIBUTION SCENARIO
7% INFLATION 10% INTEREST
SHEET 5 OF 6

TABLE D.10

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Real $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	4	5	5	5	5	4	4	4	4	4
Capital Renewals	0	4	4	4	4	4	4	4	3	2
Debt Service Cost	116	119	109	102	95	88	82	77	72	80
Total	120	128	118	111	104	96	90	85	79	86

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	4	4	4	4	4	3	3	3	3	3
Capital Renewals	3	3	3	3	3	3	3	3	3	3
Debt Service Cost	75	68	62	56	50	46	42	38	34	31
Total	82	75	69	63	57	52	48	44	40	37

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operating Expenses	3	3	3	3	3	2	2	2	2
Capital Renewals	3	2	2	2	2	2	2	2	2
Debt Service Cost	28	26	24	22	20	19	18	16	15
Total	34	31	29	27	25	23	22	20	19

NO STATE CONTRIBUTION SCENARIO
7% INFLATION 10% INTEREST
SHEET 6 OF 6

TABLE D.10

TABLE D.11: SUSITNA COST OF POWER (Revised)

First Full Year of Watana & Devil Canyon - 2003

		$'s Per Net Kilowatt 1982 $'s
Total Plant Investment Inc. I.D.C (RL[1]370 ÷ 466)		2116
I. Fixed Charges	Percent	
(a) Cost of Money	10.00	
(b) Depreciation (10% 50 yr S.F.)	.09	
(c) Insurance	.10	
(d) Taxes	.00	
1. Federal Income	0.00	
2. Federal Miscellaneous	0.00	
3. State & Local	0.00	
	~~10.19~~	
		215.62
II. Fixed Operating Costs		
(a) Operation & Maintenance Including Administrative and General Expense (RL171 divided by 466)		9.38
Total Annual Capacity Costs		225.00

Notes: (1) RL = Reference Line on far left of printout on Table D.10.

<u>TABLE D.12: FORECAST FINANCIAL PARAMETERS</u>

	Watana	Devil Canyon	Total
Project Completion - Year	1993	2002	
Energy Level - 1994			2,957 GWh
- 2002			4.555 "
- 2020			6,934 "
Costs in January 1982 Dollars			
Capital Costs	3,596.2 billion	1,554.0 billion	5,150.2 billion
Operating Costs - per annum	$10.4 million	$4.8 million	$15.20 million
Provision for Capital Renewals - per annum (0.3 percent of Capital Costs)	$10.79	$4.66	$15.45
Operating Working Capital		15 percent of Operating Costs 10 percent of Revenue	
Reserve and Contingency Fund		100 percent of Operating Costs 100 percent of Provision for Capital Renewals	
Interest Rate		10 percent per annum	
Debt Repayment Period		35 years	
Inflation Rate		7 percent per annum	

Revised 7/11/83

TABLE D.13: TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM-1982

Abbreviations	Railbelt Utility	Installed Capacity[1]
AMLP	Anchorage Municipal Light & Power Department	311.6
CEA	Chugach Electric Association	463.5
GVEA	Golden Valley Electric Association	221.6
FMUS	Fairbanks Municipal Utility System	68.5
MEA	Matanuska Electric Association	0.9
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		1122.8[2]

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

Revised 7/11/83

TABLE D.14 (Sheet 1 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Alaska Power Administration			
Eklutna[a]	H	--	1955	30.0	--	--
			Anchorage Municipal Light and Power			
Station #1[b]						
Unit #1	SCCT	NG/O	1962	14.0	16.3	14,000
Unit #2	SCCT	NG/O	1964	14.0	16.3	14,000
Unit #3	SCCT	NG/O	1968	18.0	18.0	14,000
Unit #4	SCCT	NG/O	1972	28.5	32.0	12,500
Diesel 1[c]	D	O	1962	1.1	1.1	10,500
Diesel 2[c]	D	O	1962	1.1	1.1	10,500
Station #2[d]						
Unit #5	SCCT	O	1974	32.3	40.0	12,500
Unit #6	CCST	--	1979	33.0	33.0	--
Unit #7	SCCT	O	1980	73.6	90.0	11,000
Unit #8	SCCT	NG/O	1982	73.6	90.0	12,500
			Chugach Electric Association			
Beluga						
Unit #1	SCCT	NG	1968	15.25	16.1	15,000
Unit #2	SCCT	NG	1968	15.25	16.1	15,000
Unit #3	RCCT	NG	1973	53.3	53.0	10,000
Unit #4[e]	SCCT	NG	1976	10.0	10.7	15,000
Unit #5	RCCT	NG	1975	58.5	58.0	10,000
Unit #6	CCCT	NG	1976	72.9	68.0	15,000
Unit #7	CCCT	NG	1977	72.9	68.0	15,000
Unit #8[f]	CCST	NG	1982	55.0	42.0	--

TABLE D.14 (Sheet 2 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Chugach Electric Association (Continued)			
Cooper Lake(g)						
Unit #1,2	H	--	1961	15.0	16.0	--
International						
Unit #1	SCCT	NG	1964	14.0	14.0	15,000
Unit #2	SCCT	NG	1965	14.0	14.0	15,000
Unit #3	SCCT	NG	1970	18.5	18.0	15,000
Bernice Lake						
Unit #1	SCCT	NG	1963	7.5	8.6	23,400
Unit #2	SCCT	NG	1972	16.5	18.9	23,400
Unit #3	SCCT	NG	1978	23.0	26.4	23,400
Unit #4	SCCT	NG	1982	23.0	26.4	12,000
Knik Arm(h)						
Unit #1	ST	NG	1952	0.5	0.5	--
Unit #2	ST	NG	1952	3.0	3.0	--
Unit #3	ST	NG	1957	3.0	3.0	--
Unit #4	ST	NG	1957	3.0	3.0	--
Unit #5	ST	NG	1957	5.0	5.0	--
			Homer Electric Association			
Kenai						
Unit #1	D	O	1979	0.9	0.9	15,000
Pt. Graham						
Unit #1	D	O	1971	0.2	0.2	15,000
Seldovia						
Unit #1	D	O	1952	0.3	0.3	15,000
Unit #2	D	O	1964	0.6	0.6	15,000
Unit #3	D	O	1970	0.6	0.6	15,000

TABLE D.14 (Sheet 3 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Matanuska Electric Association			
Talkeetna						
Unit #1	D	O	1967	0.9	0.9	15,000
			Seward Electric System			
SES[j]						
Unit #1	D	O	1965	1.5	1.5	15,000
Unit #2	D	O	1965	1.5	1.5	15,000
Unit #3	D	O	1965	2.5	2.5	15,000
			Military Installations - Anchorage Area			
Elmendorf AFB						
Total Diesel	D	O	1952	2.1	--	10,500
Total ST	ST	NG	1952	31.5	--	12,000
Fort Richardson						
Total Diesel[c]	D	O	1952	7.2	--	10,500
Total ST[i]	ST	NG	1952	18.0	--	20,000
			Golden Valley Electric Association			
Healy Coal	ST	Coal	1967	64.7	65.0	13,200
Healy Diesel[c]	D	O	1967	64.7	65.0	10,500
North Pole						
Unit #1	SCCT	O	1976	64.7	65.0	14,000
Unit #2	SCCT	O	1977	64.7	65.0	14,000
Zendher						
GT1	SCCT	O	1971	18.4	18.4	15,000
GT2	SCCT	O	1972	17.4	17.4	15,000
GT3	SCCT	O	1975	2.8	3.5	15,000
GT4	SCCT	O	1975	2.8	3.5	15,000
Combined Diesel	D	O	1960-70	21.0	21.0	10,500

TABLE D.14 (Sheet 4 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
University of Alaska - Fairbanks						
S1	ST	Coal	--	1.50	1.50	12,000
S2	ST	Coal	1980	1.50	1.50	12,000
S3	ST	Coal	--	10.0	10.0	12,000
D1	D	0	--	2.8	2.8	10,500
D2	D	0	--	2.8	2.8	20,500
Fairbanks Municipal Utilities System						
Chena						
Unit #1	ST	Coal	1954	5.0	5.0	18,000
Unit #2	ST	Coal	1952	2.5	2.5	22,000
Unit #3	ST	Coal	1952	1.5	1.5	22,000
Unit #4	SCCT	0	1963	5.3	7.0	15,000
Unit #5	ST	Coal	1970	21.0	21.0	13,320
Unit #6	SCCT	0	1976	23.1	28.8	15,000
Diesel #1	D	0	1967	2.8	2.8	12,150
Diesel #2	D	0	1968	2.8	2.8	12,150
Diesel #3	D	0	1968	2.8	2.8	12,150
Military Installations - Fairbanks						
Eielson AFB						
S1, S2	ST	0	1953	2.50	--	--
S3, S4	ST	0	1953	6.25	--	--
Fort Greeley						
D1, D2, D3[i]	D	0	--	3.0	--	10,500
D4, D5[i]	D	0	--	2.5	--	10,500
Ft. Wainwright[j]						
S1, S2, S3, S4	ST	Coal	1953	20	--	20,000
S5[i]	ST	Coal	1953	2	--	--

TABLE D.14 (Sheet 5 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Legend			
	H	-	Hydro
	D	-	Diesel
	SCCT	-	Simple cycle combustion turbine
	RCCT	-	Regenerstive cycle combustion turbine
	ST	-	Steam turbine
	CCCT	-	Combined cycle combustion turbine
	NG	-	Natural gas
	O	-	Distillate fuel oil

Notes

(a) Average annual energy production for Eklutna is approximately 148 GWh.

(b) All AMLP SCCTs are equipped to burn natural gas or oil. In normal operation they are supplied with natural gas. All units have reserve oil storage for operation in the event gas is not available.

(c) These are black-start units only. They are not included in total capacity.

(d) Units #5, 6, and 7 are designed to operate as a combined-cycle at plant. When operated in this mode, they have a generating capacity at 0°F of approximately 139 MW with a heat rate of 8500 Btu/kWh.

(e) Jet engine, not included in total capacity.

(f) Beluga Units #6, 7, and 8 operate as a combined-cycle plant. When operated in this mode, they have a generating capacity of about 178 MW with a heat rate of 8500 Btu/kWh. Thus, Units #6 and 7 are retired from "gas turbine operation" and added to "combined-cycle operations."

(g) Average annual energy production for Cooper Lake is approximately 42 GWh.

(h) Knik Arm units are old and have higher heat rates; they are not included in in total.

(i) Standby units.

(j) Cogeneration used for steam heating.

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities and Planned Addition for the Railbelt Region of Alaska, Volume VI, September, 1982; updated by Harza-Ebasco Susitna Joint Venture, 1983.

TABLE D.15: SCHEDULE OF PLANNED UTILITY ADDITIONS (1982-1988)

Utility	Unit	Type	MW	Year	Avg. Energy (GWh)
APA	Bradley Lake	Hydro	90.0	1988	347
APA	Grant Lake	Hydro	7.0	1988	33
TOTAL			97.0		380

TABLE D.16: OPERATING AND ECONOMIC PARAMETERS FOR SELECTED HYDROELECTRIC PLANTS

No.	Site	River	Max. Gross Head (ft)	Installed Capacity (MW)	Average Annual Energy (GWh)	Plant Factor (%)	(1981 $) Capital Cost[1] ($$10^6$)	Economic[2] Cost of Energy ($/1000 KWh)
1	Snow	Snow	690	50	220	50	255	45
2	Bruskasna	Nenana	235	30	140	53	238	113
3	Keetna	Talkeetna	330	100	395	45	463	73
4	Cache	Talkeetna	310	50	220	51	564	100
5	Browne	Nenana	195	100	410	47	625	59
6	Talkeetna-2	Talkeetna	350	50	215	50	500	90
7	Hicks	Matanuska	275	60	245	46	529	84
8	Chakachamna[3]	Chakachatna	945	500	1925	44	1480	30
9	Allison	Allison Creek	1270	8	33	47	54	125
10	Strandline Lake	Beluga	810	20	85	49	126	115

Notes:

(1) Including engineering and owner's administrative costs but excluding AFDC.
(2) Including IDC, Insurance, Amortization, and Operation and Maintenance Costs.
(3) An independent study by Bechtel has proposed an installed capacity of 330 MW, 1500 GWh annually at a cost of $1,405 million (1982 dollars), including AFDC.

TABLE D.17: RESULTS OF ECONOMIC ANALYSES OF ALTERNATIVE GENERATION SCENARIOS

Generation Scenario Type	Generation Scenario Description	Load Forecast	OGP5 Run Id. No.	Installed Capacity (MW) by Category in 2010: Thermal Coal	Thermal Gas	Thermal Oil	Hydro	Total System Installed Capacity in 2010 (MW)	Total System Present Worth Cost - ($$10^6$)
All Thermal	No Renewals	Medium	LME1	900	801	50	144	1895	8130
Thermal Plus Alternative Hydro	No Renewals Plus: Chakachamna (500)[1]-1993 Keetna (100)-1997	Medium	L7W1	600	576	70	744	1990	7080
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1997 Snow (50)-2002	Medium	LFL7	700	501	10	894	2005	7040
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Strandline (20), Allison Creek (8), Snow (50)-1998	Medium	LWP7	500	576	60	822	1958	7064
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Strandline (20), Allison Creek (8), Snow (50)-2002	Medium	LXF1	700	426	30	822	1978	7041
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Snow (50), Cache (50), Allison Creek (8), Talkeetna-2 (50), Strandline (20)-2002	Medium	L403	500	576	30	922	2028	7088

Notes:

(1) Installed capacity.

TABLE D.18: SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS/1982$ (Revised)

Parameter	Coal Fired 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	-	-	-

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.

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

TABLE D.19: BID LINE ITEM COSTS FOR BELUGA AREA STATION[(a)(c)]
(January 1982 Dollars)

		Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Subcontracts	Total Direct Cost
1.	Improvements to Site	$ 350,000	$ 2,100	$	$ 901,000	$ 110,000	$	$ 1,363,100
2.	Earthwork and Piling	2,541,000	3,888,000		5,706,000	16,000		12,151,000
3.	Circulating Water System	2,511,000	174,200		2,391,000	1,235,000	10,000,000	16,311,200
4.	Concrete	5,733,000	540,000		1,091,000	2,387,000		9,751,000
5.	Struct. Steel, Lifting Equip., Stacks	1,757,000				7,155,000		8,912,000
6.	Buildings	682,000				800,000		1,482,000
7.	Turbine-Generator	1,800,000				19,500,000		21,300,000
8.	Steam Generator and Accessories	15,764,000				21,800,000		37,564,000
9.	Air Quality Control System	12,400,000				27,100,000		39,500,000
10.	Other Mechanical Equipment					8,950,000		8,950,000
11.	Coal and Ash Handling	576,000				1,500,000	5,000,000	7,076,000
12.	Piping	14,435,000				9,000,000		23,435,000
13.	Insulation and Lagging						1,500,000	1,500,000
14.	Instrumentation						3,000,000	3,000,000
15.	Electrical Equipment	1,000,000					30,000,000	31,000,000
16.	Painting	1,015,000				1,100,000		2,115,000
17.	Off-Site Facilities						3,000,000	3,000,000
18.	Waterfront Construction						600,000	600,000
19.	Substation	1,275,000	22,000		92,000	2,686,000		4,075,000
20.	Indirect Construction Cost and Architect/Engineer Services[(b)]	44,515,000	50,907,000	2,562,000	2,084,000	9,000	-	100,077,000

Subtotal	$106,354,000	$55,533,300	$2,562,000	$12,265,000	$103,348,000	$53,100,000	$333,162,300
Contractor's Overhead and Profit	21,000,000	9,000,000					30,000,000
Contingencies							47,000,000
TOTAL PROJECT COST							$410,162,300

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.

(b) Includes $39,229,000 for construction camp, $31,300,000 for engineering services, and $29,548,000 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

(c) Source Battelle 1982, Vol. XII.

TABLE D.20: BID LINE ITEM COSTS FOR NENANA AREA STATION[a][c]
(January 1982 Dollars)

	Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Subcontracts	Total Direct Cost
1. Improvements to Site	$ 350,000	$ 2,100	$	$ 901,000	$ 110,000	$	$ 1,363,100
2. Earthwork and Piling	2,100,000	13,000		5,400,000	16,000		7,529,000
3. Circulating Water System	2,561,000	174,200		2,391,000	1,235,000	11,500,000	17,861,200
4. Concrete	5,982,000	540,000		1,091,000	2,387,000		10,000,000
5. Struct. Steel, Lifting Equip., Stacks	1,757,000				7,155,000		8,912,000
6. Buildings	682,000				800,000		1,482,000
7. Turbine-Generator	1,800,000				19,500,000		21,300,000
8. Steam Generator and Accessories	15,662,000	138,000		12,000	21,800,000		37,612,000
9. Air Quality Control System	12,400,000				27,100,000		39,500,000
10. Other Mechanical Equipment					8,950,000		8,950,000
11. Coal and Ash Handling	1,937,000	18,000		150,000	5,785,000		7,890,000
12. Piping	14,435,000				9,000,000		23,435,000
13. Insulation and Lagging	441,000	46,000		11,000	1,049,000		1,547,000
14. Instrumentation					3,000,000		3,000,000
15. Electrical Equipment	12,720,000	1,150,000		800,000	18,000,000		32,670,000
16. Painting	1,142,000	58,000		25,000	575,000		1,800,000
17. Off-Site Facilities	4,827,000			3,600,000	3,260,000		11,687,000
18. Waterfront Construction							N/A
19. Substation - Switchyard	1,623,000	34,000		143,000	3,017,000		4,817,000
20. Indirect Construction Cost and Architect/Engineer Services[b]	54,943,000	42,560,000	2,882,000	2,617,000	9,000	....	103,011,000

Subtotal	$135,362,000	$44,733,300	$2,882,000	$17,141,000	$132,748,000	$11,500,000	$344,366,300
Contractor's Overhead and Profit	21,000,000	9,000,000					30,000,000
Contingencies							47,000,000
TOTAL PROJECT COST							$421,366,300

N/A = Not Applicable.

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.

(b) Includes $40,816,000 for construction camp, $31,300,000 for engineering services, and $30,895,000 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

(c) Source Battelle 1982, Vol. XII.

TABLE D.21: BID LINE ITEM COSTS FOR NATURAL GAS-FIRED COMBINED-CYCLE 200-MW Station[a][c] (January 1982 Dollars)

	Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Total Direct Cost
1. Improvements to Site	$ 95,600	$	$ 109,700	$ 83,700	$ 13,800	$ 302,800
2. Earthwork and Piling	313,000	2,666,300	87,300	151,600		3,218,200
3. Circulating Water System	2,455,600	484,400	16,100	28,500	4,400,000	7,384,600
4. Concrete	3,450,700	348,000	372,700	226,600	1,496,000	5,894,000
5. Structural Steel and Life Equipment	305,000				1,900,000	2,205,000
6. Buildings	192,200				491,000	683,200
7. Heat Recovery Boilers, Gas Turbines, and Generators	5,197,200	172,500		250,000	31,200,000	36,819,700
8. Steam Turbines and Generator	3,631,900	115,000		200,000	8,600,000	12,546,900
9. Other Mechanical Equipment	2,588,700	115,000		65,000	4,946,200	7,714,900
10. Piping	3,164,500	345,000		120,000	4,500,000	8,129,500
11. Insulation and Logging	126,500	86,300		50,000	250,000	512,800
12. Instrumentation	379,500	46,000		10,000	700,000	1,135,500
13. Electrical Equipment	4,586,000	57,500		15,000	5,250,000	9,908,500
14. Painting	632,600	11,500		2,500	500,000	1,146,600
15. Off-Site Facilities	2,451,400	211,000	3,621,100	2,693,600	979,200	9,956,400
16. Waterfront Construction	14,400		31,800	23,700	131,700	201,600
17. Substation	948,800	23,000		10,000	4,035,500	5,017,300
18. Construction Camp Expenses	4,292,400	12,362,000				16,654,400
19. Indirect Construction Costs and Architect/Engineer Services[b]	26,341,900	4,313,900	1,301,600	1,588,700		33,546,100
SUBTOTAL	61,167,900	21,357,500	5,540,300	5,518,900	69,393,400	162,978,000
Contractor's Overhead and Profit						15,000,000
Contingencies						22,224,200
TOTAL PROJECT COST						$200,202,200

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.

(b) Includes $14,816,200 for engineering services and $18,729,900 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

(c) Source Battelle 1982, Vol. XIII.

TABLE D.22: ECONOMIC ANALYSIS
SUSITNA PROJECT - BASE PLAN

		1982 Present Worth of System Costs $ x 10^6			
Plan	Components	1993-2020	2020	Estimated 2021-2051	1993-2051
Non-Susitna	600 MW Coal-Beluga	3,930	479	3,386	7,316
	400 MW Coal-Nenana				
	840 MW GT				
	200 MW CC				
Susitna	1020 MW Watana	3,396	316	2,093	5,489
	600 MW Devil Canyon				
	490 MW GT				
	200 MW CC				
Net Economic Benefit of Susitna Plan					1,827

Revised 7/11/83

TABLE D.23: FORECASTS OF ELECTRIC POWER DEMAND NET AT PLANT

Year	Reference Case		DRI		DOR		-2 Percent Escalation	
	MW	GWh	MW	GWh	MW	GWh	MW	GW
1990	844	4054	850	4085	793	3808	848	407
2000	1020	4898	1158	5558	950	4567	959	461
2010	1306	6280	1599	7681	1206	5799	1168	562
2020	1672	8039	2208	10615	1528	7364	1422	686

Revised 7/11/83

TABLE D.24: ELECTRIC POWER DEMAND SENSITIVITY ANALYSIS

Plan	1982 Present Worth of System Costs $\$ \times 10^6$				Net Benefits $\$ \times 10^6$
	1993-2020	2020	Estimated 2021-2051	1993 2051	
Reference Case					
Non-Susitna	3930	479	3386	7316	---
Susitna	3396	316	2093	5489	1827
DRI					
Non-Susitna	4906	624	4380	9286	---
Susitna	4084	499	3384	7468	1818
DOR					
Non-Susitna	2640	334	2392	5032	---
Susitna	3259	283	1858	5117	-85.2
-2 Percent					
Non-Susitna	1941	186	1056	2997	---
Susitna	3220	263	1711	4931	-1934

Revised 7/11/83

TABLE D.25: DISCOUNT RATE SENSITIVITY ANALYSIS

Plan	Real Discount Rate (Percent)	1982 Present Worth of System Costs ($ x 10^6): 1993-2020	2020	Estimated 2021-2051	Net 1993-2051	Economic Benefit
Non-Susitna	2	4,829	457	5,418	10,247	-
Susitna	2	3,679	276	3,058	6,737	3,510
Non-Susitna	3	3,930	479	3,386	7,316	-
Susitna	3	3,396	316	2,093	5,489	1,827
Non-Susitna	5	2,669	562	1,374	4,043	-
Susitna	5	2,925	423	1,048	3,973	70

(Revised 7/11/83)

TABLE D.26: CAPITAL COST SENSITIVITY ANALYSIS

Plan	1982 Present Worth of System Costs ($ x 10^6) 1993-2010	2010	Estimated 2011-2051	1993-2051	Net Economic Benefit
Watana Capital Coats Costs up 20 Percent					
Non-Susitna	3,930	479	3,386	7,316	-
Susitna	3,839	347	2,300	6,139	1,117
Watana Capital Costs Costs Less 23 Percent					
Non-Susitna	3,930	479	3,386	7,316	-
Susitna	2,977	286	1,899	4,876	2,440

Revised 7/11/83

TABLE D.27: FUEL PRICE – SENSITIVITY ANALYSIS

	1982 Present Worth of System Costs ($ x 10^6) Costs of Non-Susitna Plan	Costs of Susitna Plan	Net Economic Benefits
Reference Case	7,316	5,489	1,827
Fuel Costs Increased 20 Percent	8,281	5,607	2,674
Fuel Costs Decreased 20 Percent	6,474	5,418	1,056

Revised 7/11/83

TABLE D.28: SUMMARY OF SENSITIVITY ANALYSIS INDEXES OF NET ECONOMIC BENEFITS

	Index Values
BASE REFERENCE CASE ($1,827 MILLION)	100
Oil Price Forecast	
DRI	100
DOR	-5
-2 Percent	-106
Discount Rates	
High (5%)	4
Low (2%)	192
Watana Capital Cost	
+ 20 Percent	61
- 23 Percent	134
Fuel Price	
+ 20 Percent	146
- 20 Percent	58
Real Fuel Price Escalation	
No Escalation after 2020	53

(Revised 7/11/83)

TABLE D.29: BATTELLE ALTERNATIVES STUDY FOR RAILBELT CANDIDATE ELECTRIC ENERGY GENERATING TECHNOLOGIES

Resource Base	Principal Sources for Railbelt	Fuel Conversion	Generation Technology	Typical Application	Availability for Commercial Order
Coal	Beluga Field, Cook Inlet Nenana Field, Healy	Crush	Direct Fired Steam-Electric	Baseload	Currently Available
		Gasification	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload	1985-1990 1985-1990 1990-1995
		Liquefaction	Direct Fired Steam-Electric Combined Cycle Fuel-Cell Station Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload/Cycling Baseload	1985-1990 1985-1990 1985-1990 1990-1995
Natural Gas	Cook Inlet North Slope	None	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Station Fuel-Cell - Combined-Cycle Combustion Turbine	Baseload Baseload/Cycling Baseload/Cycling Baseload Baseload/Cycling	Currently Available Currently Available 1985-1990 1990-1995 Currently Available
Petroleum	Cook Inlet North Slope	Refine to distillate and residual fractions	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Stations Fuel-Cell - Combined-Cycle Combustion Turbine Diesel Electric	Baseload Baseload/Cycling Baseload/Cycling Baseload Baseload/Cycling Baseload/Cycling	Currently Available Currently Available 1985-1990 1990-1995 Currently Available Currently Available
Peat	Kenai Peninsual Lower Susitna Valley	None	Direct-Fired Steam-Electric	Baseload	Currently Available
		Gasification	Direct-Fired Steam-Electric Combined cycle Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload	1990-2000 1990-2000 1990-2000
Municipal Refuse	Anchorage Fairbanks	Sort & Classify	Direct-Fired Steam-Electric	Baseload(a)	Currently Available
Wood Waste	Kenai Anchorage Nenana Fairbanks	Hog	Direct-Fired Steam-Electric	Baseload(a)	Currently Available

TABLE D.29 Continued

Resource Base	Principal Sources for Railbelt	Fuel Conversion	Generation Technology	Typical Application	Availability for Commercial Order
Geothermal	Wrangell Mountains Chigmit Mountains	-- --	Hot Dry Rock-Steam-Electric Hydrothermal-Steam-Electric	Baseload Baseload	1990-2000 Currently Available
Hydroelectric	Kenai Mountains Alaska Range	-- --	Conventional Hydroelectric Small-Scale Hydroelectric Microhydroelectric	Baseload/Cycling (b) Fuel Saver	Currently Available Currently Available Currently Available
Tidal Power	Cook Inlet	--	Tidal Electric Tidal Electric w/Retime	Fuel Saver Baseload/Cycling	Currently Available Currently Available
Wind	Isabell Pass Offshore Coastal	--	Large Wind Energy Systems Small Wind Energy Systems	Fuel Saver Fuel Saver	1985-1990 1985-1990
Solar	Throughout Region	--	Solar Photovoltaic Solar Thermal	Fuel Saver Fuel Saver	1985-1990 1995-2000
Uranium	Import	Enrichment & Fabrication	Light Water Reactors	Baseload	Currently Available

(a) Supplemental firing (w/coal) would be required to support baseload operation due to cyclical fuel supply.
(b) May be baseload/cycling or fuel saver depending upon reservoir capacity.

TABLE D.30: BATTELLE ALTERNATIVES STUDY, SUMMARY OF COST AND PERFORMANCE CHARACTERISTICS OF SELECTED ALTERNATIVES

Alternative	Capacity (MW)(a)	Heat Rate (Btu/kWh)	Availability (%)	Average Annual Energy (GWh)	Capital Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)
Coal Steam-Electric (Beluga)	200	10,000	87	-	2090	16.70	0.6
Coal Steam-Electric (Nenana)	200	10,000	87	-	2150	16.70	0.6
Coal Gasifier-Combined Cycle	220	9,290	85	-	-	14.80	3.5
Natl. Gas Combustion Turbines	70	13,800(b)	89	-	730	48	-
Natl. Gas Combined Cycle	200	8,200(c)	85	-	1050	7.30	1.7
Natl. Gas Fuel Cell Stations	25	9,200	91	-	890	42	-
Natl. Gas Fuel Cell Comb. Cyc.	200	5,700	83	-	-	50	-
Bradley Lake Hydroelectric	90	-	94	347	3190	9	-
Chakachamna Hydroelec. (330 MW)(d)	330	-	94	1570	3860	4	-
Chakachamna Hydroelec. (480 MW)(e)	480	-	94	1923	2100	4	-
Upper Susitna (Watana I)	680	-	94	3459	4669	5	-
Upper Susitna (Watana II)	340	-	94	-	168	5	-
Upper Susitna (Devil Canyon)	600	-	94	3334	2263	5	-
Snow Electric	63	-	94	220	5850	7	-
Keetna Hydroelectric	100	-	94	395	5480	5	-
Strandline Lake Hydroelec.	20(17)	-	94	85	7240	44	-
Browne Hydroelectric	100(80)	-	94	430	4470	5	-
Allison Hydroelectric	8	-	94	37	4820	44	-
Grant Lake Hydroelectric	7	-	-	-	2840	44	-
Isabell Pass Wind Farm	25	-	36	8	2490	3.70	3.3
Refuse-Derived Fuel Steam Electric (Anchorage)	50	14,000	N/A	-	2980	140	15
Refuse-Derived Fuel Steam Electric (Fairbanks)	20	14,000	N/A	-	3320	140	15

(a) Configuration in parentheses used in analysis of Railbelt electric energy plus taken from earlier estimates (Alaska Power Authority 1980)
(b) A heat rate of 12,000 Btu/kWh was used in analysis of Railbelt electric energy plans. 13,000 Btu/kWh is probably more representative of partial load operation characteristic of peaking duty.
(c) An earlier estimate of 8500 Btu/kWh was used in the analysis of Railbelt electric energy plans.
(d) Configuration selected in preliminary feasibility study (Bechtel Civil and Minerals 1981)
(e) Configuration selected in Railbelt alternatives study (Ebasco 1982b)

TABLE D.31: FINANCING REQUIREMENTS - $ MILLION
FOR 1.8 BILLION STATE APPROPRIATION

		Nominal $ x 10^6 Interest Rate - 10% Inflation Rate - 7% Actual	1982 Purchasing Power $ x 10^6
1985	State Appropriation	402	317
86		385	284
87		429	296
88		573	369
89		728	438
90		171	96
Total State Appropriation		2688	1800
1990		945	532
91		1252	658
92		1093	537
93		472	217
Total Watana Bonds		3782	1953
1992		107	53
93		160	73
94		177	76
95		206	83
96		373	140
97		677	237
98		1061	347
99		1190	364
2000		1240	355
01		1103	295
02		70	18
Total Devil Canyon Bonds		6364	2041
Total Susitna Bonds		10146	3994
Total Susitna Cost		12834	5794

(Revised 7/11/83)

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAFCOST $5.15 BN 23-JUN-83

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

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	2953	2957
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.02	58.11
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	126.32	135.52
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	373.0	400.7
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	24.2
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.4	376.5
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	329.0	376.2
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	-3.8
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	-3.8
446 STATE CONTRIBUTION	402.0	384.9	428.6	572.8	728.2	170.8	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	944.6	1252.2	1200.1	632.3	176.6
243 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	6.2
549 TOTAL SOURCES OF FUNDS	402.0	384.9	428.6	572.8	728.2	1115.4	1252.2	1200.1	740.4	179.0
320 LESS CAPITAL EXPENDITURE	402.0	384.9	428.6	572.8	728.2	1115.4	1252.2	1200.1	653.7	201.7
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	6.2
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-42.8
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.8
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0	49.2
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.7	43.7
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	402.0	786.9	1215.5	1788.3	2516.5	3631.9	4884.2	6084.2	6737.9	6939.6
465 CAPITAL EMPLOYED	402.0	786.9	1215.5	1788.3	2516.5	3631.9	4884.2	6084.2	6824.6	7032.5
461 STATE CONTRIBUTION	402.0	786.9	1215.5	1788.3	2516.5	2687.3	2687.3	2687.3	2687.3	2687.3
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	17.6
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	135.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	944.6	2196.9	3397.0	4029.2	4191.9
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	531.5	659.5	599.7	290.4	75.8
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	531.5	1189.9	1779.7	2070.1	2145.9
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.07	0.95

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.32

DATA12K.D12 WATANA (ON-LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 23-JUN-83

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

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3005	3019	3028	3055	3057	3064	3105	4555	4670	4796
521 REAL PRICE-MILLS	58.20	65.31	60.47	55.55	51.50	47.68	43.70	54.18	54.16	52.77
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	145.07	174.21	172.57	169.65	168.29	166.70	163.49	216.88	231.99	241.83
-----INCOME-----------------										
516 REVENUE	435.9	525.9	522.5	518.2	514.4	510.7	507.6	987.8	1083.3	1157.3
170 LESS OPERATING COSTS	25.9	27.7	29.7	31.8	34.0	36.4	38.9	60.0	65.1	69.7
517 OPERATING INCOME	410.0	498.1	492.8	486.5	480.4	474.4	468.7	927.0	1018.2	1087.6
214 ADD INTEREST EARNED ON FUNDS	4.9	5.3	5.6	6.0	6.4	6.9	7.4	7.9	12.4	13.2
350 LESS INTEREST ON SHORT TERM DEBT	13.6	15.9	10.9	4.9	-0.7	-6.3	-11.5	-16.6	2.2	12.8
391 LESS INTEREST ON LONG TERM DEBT	374.8	373.3	371.6	369.7	367.7	365.5	363.0	989.6	993.7	988.1
543 NET EARNINGS FROM OPERS	26.5	114.3	116.0	117.8	119.9	122.1	124.6	-38.2	34.7	99.9
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	26.5	114.3	116.0	117.8	119.9	122.1	124.6	-38.2	34.7	99.9
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	206.2	372.6	676.8	1061.1	1190.0	1240.1	1102.7	70.5	0.0	0.0
249 WORCAP DEBT DRAWDOWNS	7.2	19.2	7.2	8.2	6.2	7.8	6.5	76.2	19.8	17.3
549 TOTAL SOURCES OF FUNDS	240.0	506.1	800.0	1197.1	1316.1	1370.0	1233.7	108.4	53.5	117.3
320 LESS CAPITAL EXPENDITURE	233.1	401.3	707.6	1094.0	1225.2	1277.8	1143.0	113.6	66.2	70.8
448 LESS WORCAP AND FUNDS	7.2	19.2	7.2	8.2	6.2	7.8	6.5	76.2	18.8	17.3
250 LESS DEBT REPAYMENTS	15.3	16.8	13.5	20.3	22.4	24.6	27.0	29.8	56.2	61.8
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	-15.6	68.7	56.7	64.6	62.3	59.8	57.2	-111.2	-87.7	-32.7
249 SHORT TERM DEBT	15.6	-58.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET-----------										
225 RESERVE AND CONT. FUND	52.6	56.3	60.3	64.5	69.0	73.6	79.0	123.5	132.2	141.4
371 OTHER WORKING CAPITAL	47.5	53.0	66.3	70.3	72.0	74.9	76.3	107.9	118.1	126.2
454 CASH SURPLUS RETAINED	0.0	10.3	77.1	141.5	203.9	263.7	320.8	209.7	122.0	89.2
370 CUM. CAPITAL EXPENDITURE	7172.7	7574.1	8281.6	9375.6	10600.9	11878.7	12021.7	13135.4	13201.5	13272.4
465 CAPITAL EMPLOYED	7272.8	7703.7	8485.2	9652.0	10945.8	12291.2	12497.8	13576.5	13573.8	13629.2
461 STATE CONTRIBUTION	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3
462 RETAINED EARNINGS	44.2	158.5	274.5	392.3	512.2	634.3	758.8	720.6	755.3	855.2
553 DEBT OUTSTANDING-SHORT TERM	158.5	119.3	126.5	134.8	141.0	148.8	155.2	231.4	250.3	267.6
554 DEBT OUTSTANDING-LONG TERM	4382.8	4738.6	5396.9	6437.7	7605.3	8820.8	9896.5	9937.2	9880.9	9819.1
542 ANNUAL DEBT DRAWDOWN $1982	82.7	139.7	237.1	347.4	364.2	354.7	294.7	17.6	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	2228.6	2368.3	2605.4	2952.8	3317.0	3671.7	3966.5	3984.1	3984.1	3984.1
519 DEBT SERVICE COVER	1.03	1.25	1.25	1.25	1.25	1.25	1.25	0.93	0.98	1.04

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 2 OF 6

TABLE D.32

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 23-JUN-83

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

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
73 ENERGY GWH	4902	5064	5224	5384	5544	5704	5862	6023	6149	6317
521 REAL PRICE-MILLS	57.86	53.04	49.28	44.01	40.16	36.70	33.66	30.83	28.44	26.09
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	901.52
520 PRICE-MILLS	283.71	278.29	271.08	264.35	258.16	252.38	247.69	242.73	239.64	235.17
-----INCOME-----										
516 REVENUE	1390.6	1409.1	1416.0	1423.2	1431.2	1439.5	1451.9	1461.9	1473.2	1485.5
179 LESS OPERATING COSTS	74.5	79.8	85.3	91.3	97.7	104.5	111.9	119.7	128.1	137.0
517 OPERATING INCOME	1316.1	1329.4	1330.7	1331.9	1333.5	1334.9	1340.0	1342.2	1345.1	1348.4
214 ADD INTEREST EARNED ON FUNDS	14.1	15.1	16.2	17.3	18.5	19.8	21.2	22.7	24.3	26.0
350 LESS INTEREST ON SHORT TERM DEBT	17.8	32.1	34.5	36.8	39.6	42.4	48.8	52.5	57.0	62.0
391 LESS INTEREST ON LONG TERM DEBT	981.9	975.1	967.6	959.4	950.3	940.4	929.4	917.4	904.1	889.6
543 NET EARNINGS FROM OPERS	330.5	337.3	344.8	353.0	362.1	372.0	383.0	395.0	408.3	422.9
-----CASH SOURCE AND USE----										
343 CASH INCOME FROM OPERS	330.5	337.3	344.8	353.0	362.1	372.0	383.0	395.0	408.3	422.9
445 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
243 WORCAP DEBT DRAWDOWNS	53.6	23.5	23.0	28.2	27.9	64.6	36.6	45.3	50.0	79.0
49 TOTAL SOURCES OF FUNDS	384.1	360.7	367.8	381.2	389.9	436.6	419.6	440.3	458.3	501.9
329 LESS CAPITAL EXPENDITURE	75.8	81.1	86.7	92.8	99.3	106.3	113.7	121.7	130.2	139.3
443 LESS WORCAP AND FUNDS	53.6	23.5	23.0	28.2	27.8	64.6	36.6	45.3	50.0	79.0
260 LESS DEBT REPAYMENTS	68.0	74.8	82.3	90.5	99.6	109.5	120.5	132.5	145.8	160.4
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	186.7	181.4	175.7	169.7	163.2	156.2	148.8	140.8	132.3	123.2
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	276.0	181.4	175.7	169.7	163.2	156.2	148.8	140.8	132.3	123.2
-----BALANCE SHEET-----										
225 RESERVE AND CONT. FUND	151.3	161.9	173.2	185.4	198.3	212.2	227.1	243.0	260.0	278.2
371 OTHER WORKING CAPITAL	169.9	182.8	194.5	210.5	225.4	276.1	297.8	327.3	360.3	421.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	13348.1	13429.2	13515.9	13608.7	13708.0	13814.3	13928.0	14049.7	14179.8	14319.1
465 CAPITAL EMPLOYED	13669.3	13773.9	13883.6	14004.6	14131.8	14302.6	14452.9	14619.9	14800.1	15018.4
461 STATE CONTRIBUTION	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3
462 RETAINED EARNINGS	909.7	1065.6	1234.6	1418.0	1616.9	1832.6	2066.8	2321.0	2597.0	2896.6
555 DEBT OUTSTANDING-SHORT TERM	321.2	344.7	367.7	395.9	423.7	488.3	524.9	570.2	620.3	699.3
554 DEBT OUTSTANDING-LONG TERM	9751.1	9676.3	9594.0	9503.5	9403.9	9294.4	9173.9	9041.3	8895.9	8735.2
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 3 OF 6

TABLE D.32

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 23-JUN-83

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

	2015	2016	2017	2018	2019	2020	2021	TOTAL
73 ENERGY GWH	6449	6616	6708	6760	6875	6984	6984	144802
521 REAL PRICE-MILLS	24.13	22.17	20.61	19.28	17.89	16.63	15.69	0.00
465 INFLATION INDEX	954.63	1032.15	1104.40	1181.71	1264.43	1352.94	1447.64	0.00
520 PRICE-MILLS	232.79	228.78	227.64	227.89	226.22	224.96	227.19	0.00
-----INCOME-----								
516 REVENUE	1501.1	1513.5	1526.9	1540.4	1555.2	1571.0	1586.6	32714.1
170 LESS OPERATING COSTS	146.6	156.9	167.9	179.6	192.2	205.6	220.0	2765.5
517 OPERATING INCOME	1354.5	1356.6	1359.0	1360.8	1363.0	1365.4	1366.5	29948.6
214 ADD INTEREST EARNED ON FUNDS	27.8	29.8	31.8	34.1	36.5	39.0	41.7	516.7
550 LESS INTEREST ON SHORT TERM DEBT	69.9	74.0	78.5	82.5	87.0	92.0	95.9	1037.1
391 LESS INTEREST ON LONG TERM DEBT	873.5	855.9	836.5	815.1	791.6	765.8	737.4	21353.2
543 NET EARNINGS FROM OPERS	438.9	456.5	475.9	497.3	520.8	546.6	575.0	8074.9
-----CASH SOURCE AND USE-----								
543 CASH INCOME FROM OPERS	438.9	456.5	475.9	497.3	520.8	546.6	575.0	8074.9
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2687.3
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10125.6
248 WORCAP DEBT DRAWDOWNS	40.5	44.9	40.1	45.4	49.7	38.8	31.4	990.0
549 TOTAL SOURCES OF FUNDS	479.4	501.4	516.0	542.7	570.5	585.3	606.4	21877.9
320 LESS CAPITAL EXPENDITURE	149.0	159.5	170.6	182.6	195.4	209.0	223.7	15608.9
443 LESS WORCAP AND FUNDS	40.5	44.9	40.1	45.4	49.7	38.8	31.4	990.0
260 LESS DEBT REPAYMENTS	176.4	194.0	213.9	234.8	258.3	284.1	312.5	3064.1
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	113.4	103.0	91.9	79.9	67.1	53.5	38.8	2214.9
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	113.4	103.0	91.9	79.9	67.1	53.5	38.8	2214.9
-----BALANCE SHEET-----								
225 RESERVE AND CONT. FUND	297.6	318.5	340.8	364.6	390.2	417.5	446.7	446.7
371 OTHER WORKING CAPITAL	442.1	466.2	484.0	505.5	529.7	541.2	543.3	543.3
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14468.1	14627.6	14798.2	14980.8	15176.2	15385.2	15608.9	15608.9
465 CAPITAL EMPLOYED	15207.9	15412.3	15623.0	15851.0	16096.0	16343.8	16598.9	16598.9
461 STATE CONTRIBUTION	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3
452 RETAINED EARNINGS	3222.1	3575.6	3959.7	4377.1	4830.7	5323.8	5960.0	5860.0
555 DEBT OUTSTANDING-SHORT TERM	739.8	784.7	824.8	870.2	919.9	958.6	990.0	990.0
554 DEBT OUTSTANDING-LONG TERM	8553.8	8364.7	8151.3	7916.5	7658.2	7374.1	7061.6	7061.6
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3984.1
543 CUM. DEBT DRAWDOWN $1982	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 4 OF 6

TABLE D.32

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Real $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	8	10	10	11	11	12	13	14	14	15
Capital Renewals	0	8	9	10	10	11	12	12	13	9
Debt Service Cost	111	132	130	129	129	128	128	127	126	224
Total	119	140	149	150	150	151	153	153	153	248

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	16	17	18	18	19	20	20	21	22	22
Capital Renewals	14	15	15	16	17	17	18	19	19	20
Debt Service Cost	225	219	214	207	201	195	189	184	179	174
Total	255	251	247	241	237	232	227	224	220	216

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operating Expenses	23	24	25	26	27	29	30	32	34
Capital Renewals	21	22	23	24	25	27	28	30	32
Debt Service Cost	171	166	163	159	157	155	153	150	150
Total	215	212	211	209	209	211	211	212	216

NOTE: FOR ANNUAL ENERGY SOLD, SEE LINE 73 OF SHEETS 1-3 OF THIS TABLE

ANNUAL ENERGY COST
$1.8 BILLION STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.32

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Real $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	4	4	4	4	4	4	4	4	4	4
Capital Renewals	0	4	4	4	4	4	4	4	3	2
Debt Service Cost	51	57	52	48	45	42	39	36	34	56
Total	55	65	60	56	53	48	47	44	41	62

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	4	4	4	4	3	3	3	3	3	3
Capital Renewals	3	3	3	3	3	3	3	3	3	3
Debt Service Cost	53	48	44	40	36	32	30	27	24	22
Total	60	55	51	47	42	38	36	33	31	28

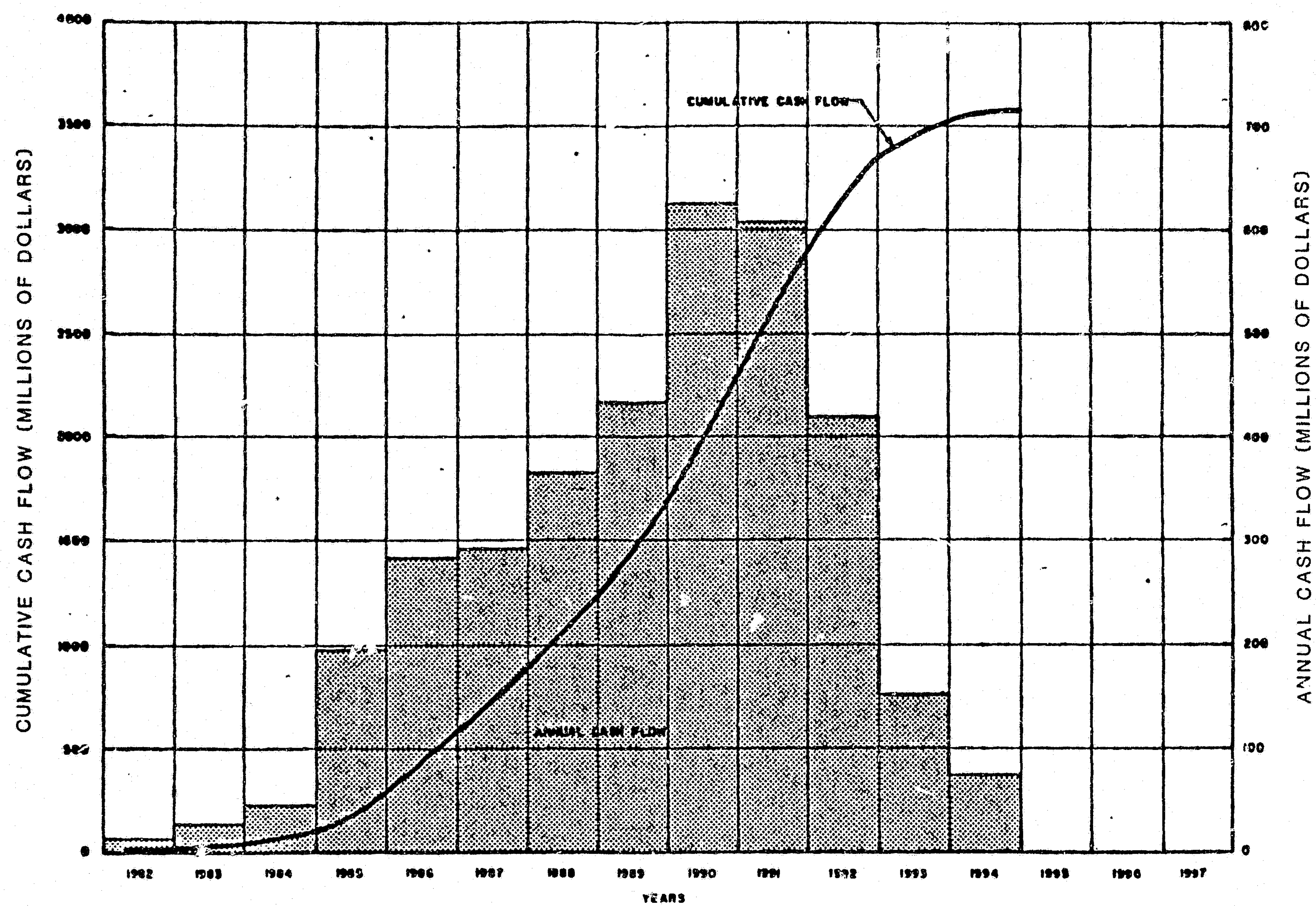
	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operating Expenses	3	3	3	3	2	2	2	2	2
Capital Renewals	3	2	2	2	2	2	2	2	2
Debt Service Cost	20	18	17	15	14	13	12	11	10
Total	26	23	22	20	18	17	16	15	14

NOTE: FOR ANNUAL ENERGY SOLD, SEE LINE 73 CF SHEET 1-3 OF THIS TABLE

ANNUAL ENERGY COST
$1.8 BILLION STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

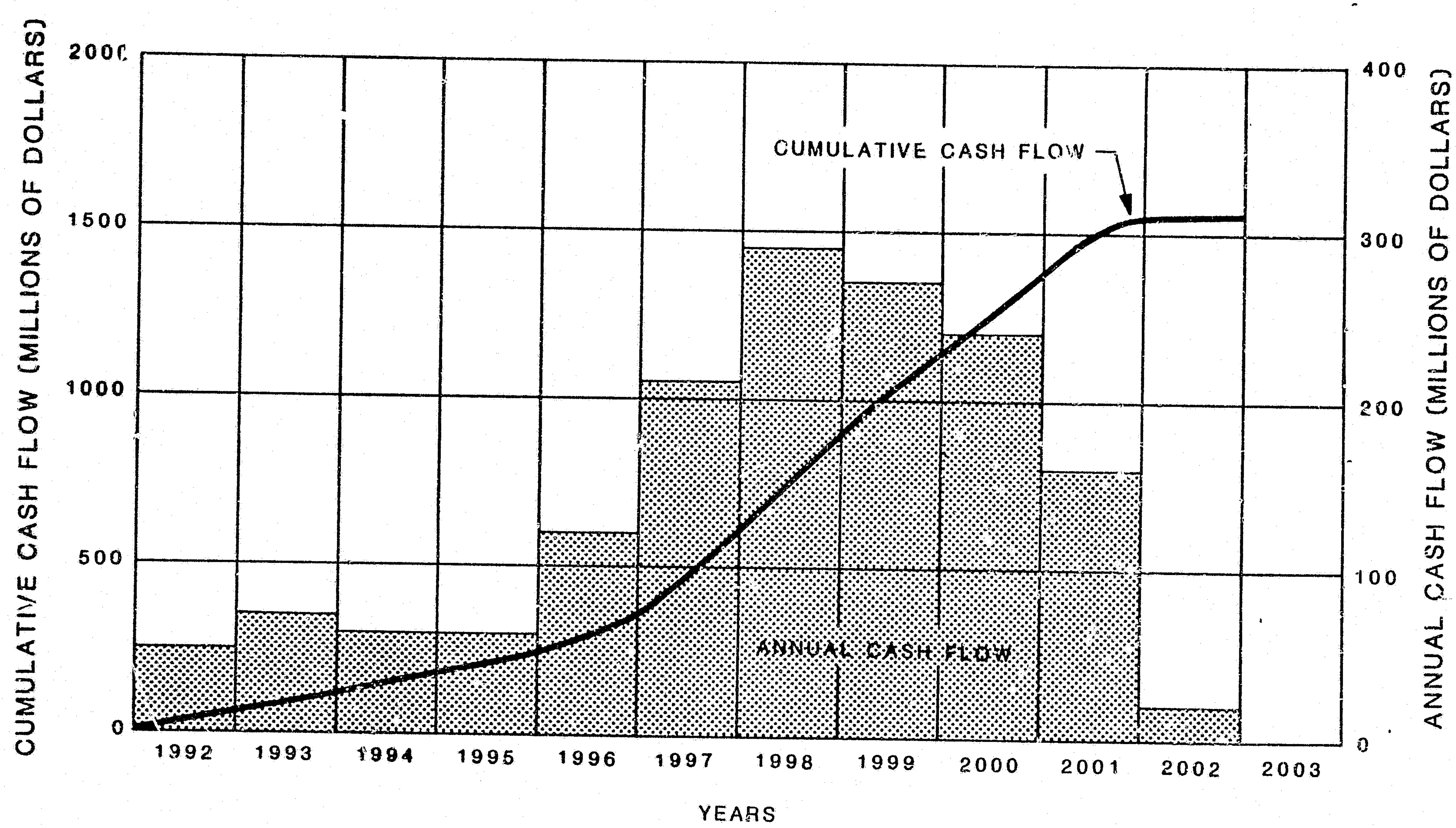
SHEET 6 OF 6

TABLE D.32



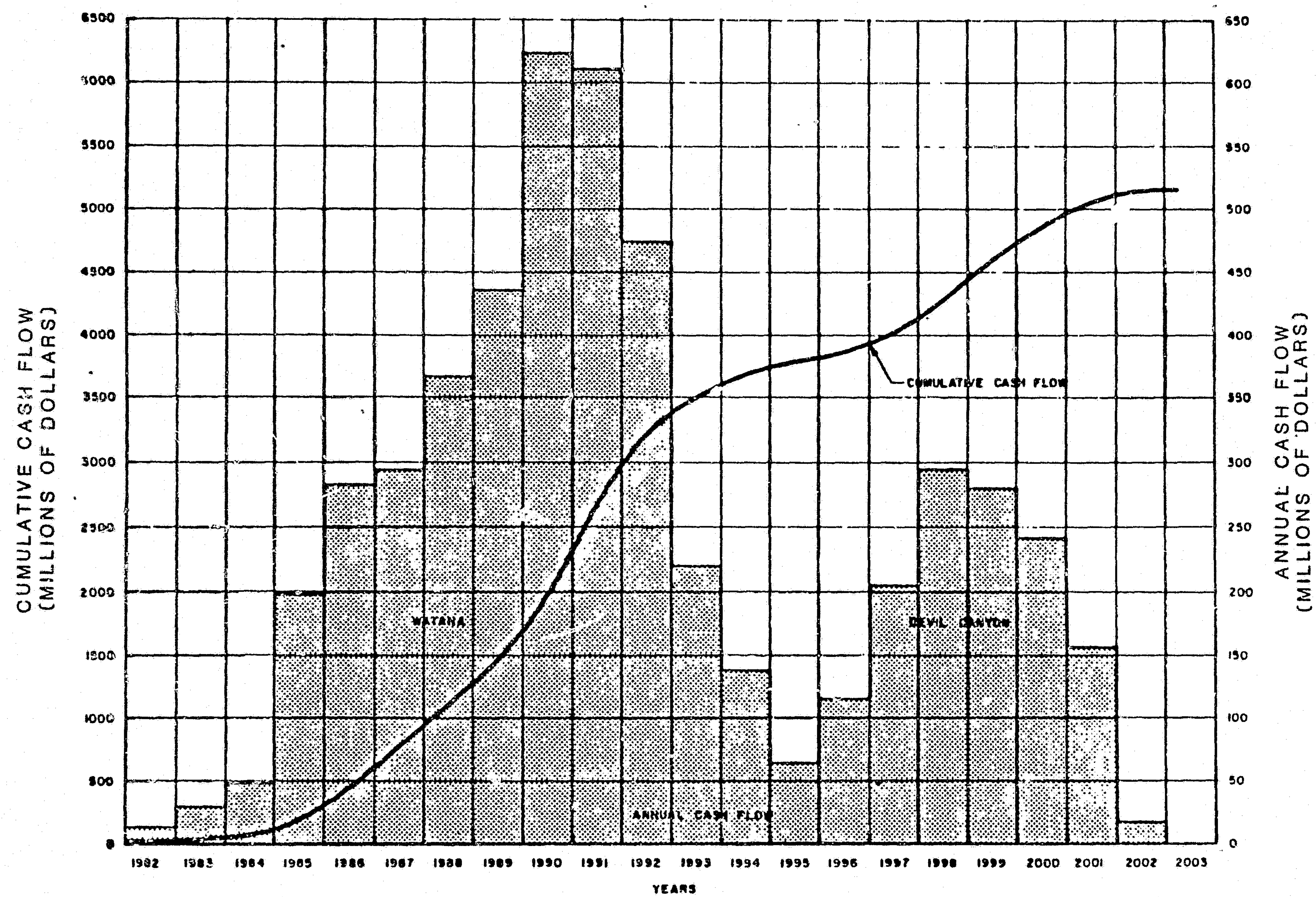
WATANA DEVELOPMENT
CUMULATIVE AND ANNUAL CASH FLOW
JANUARY,1982 DOLLARS

FIGURE D.1



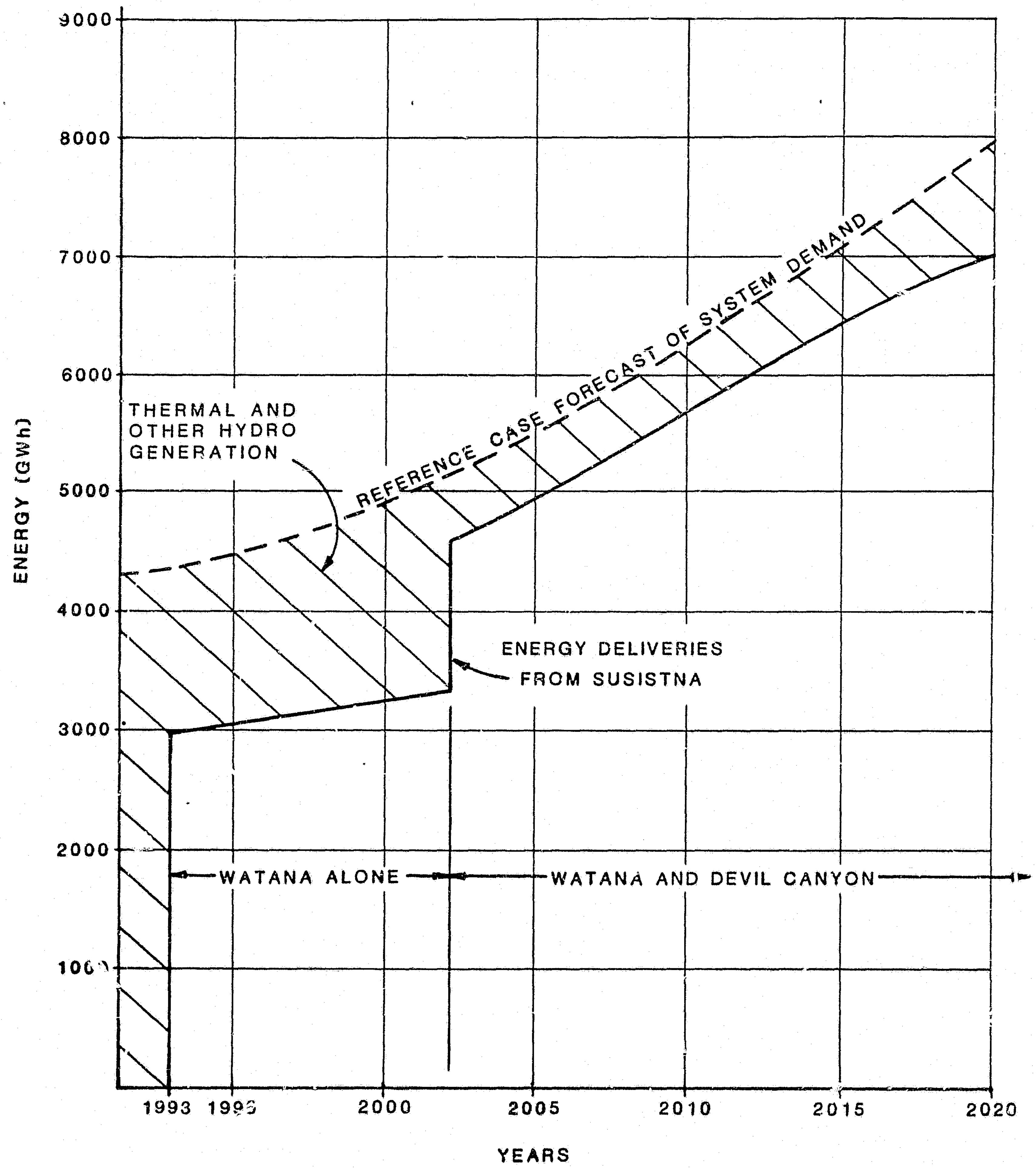
DEVIL CANYON DEVELOPMENT
CUMULATIVE AND ANNUAL CASH FLOW
JANUARY, 1982 DOLLARS

FIGURE D.2



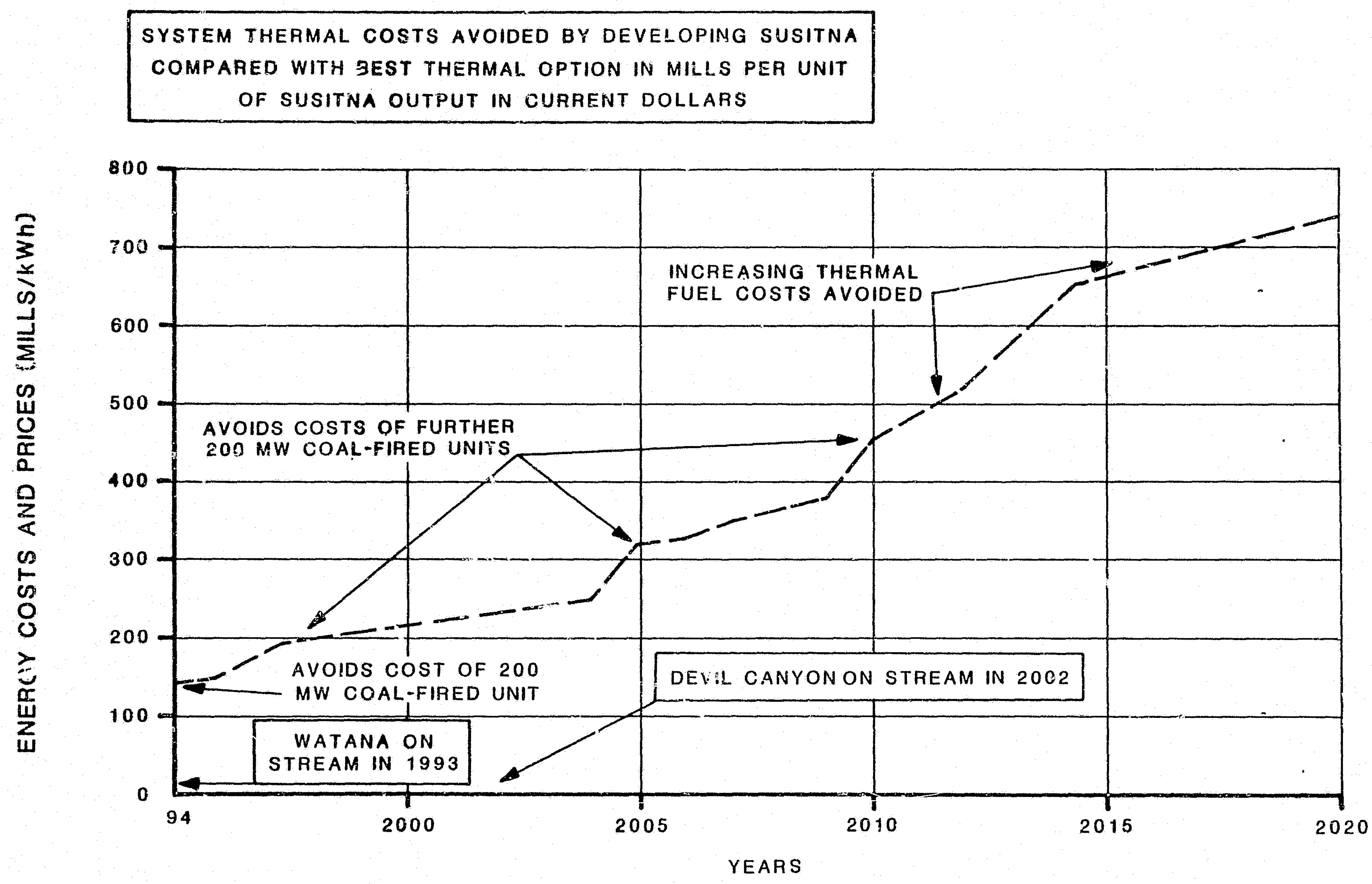
SUSITNA HYDROELECTRIC PROJECT
CUMULATIVE & ANNUAL CASH FLOW ENTIRE PROJECT
JANUARY 1982 DOLLARS

FIGURE D.3



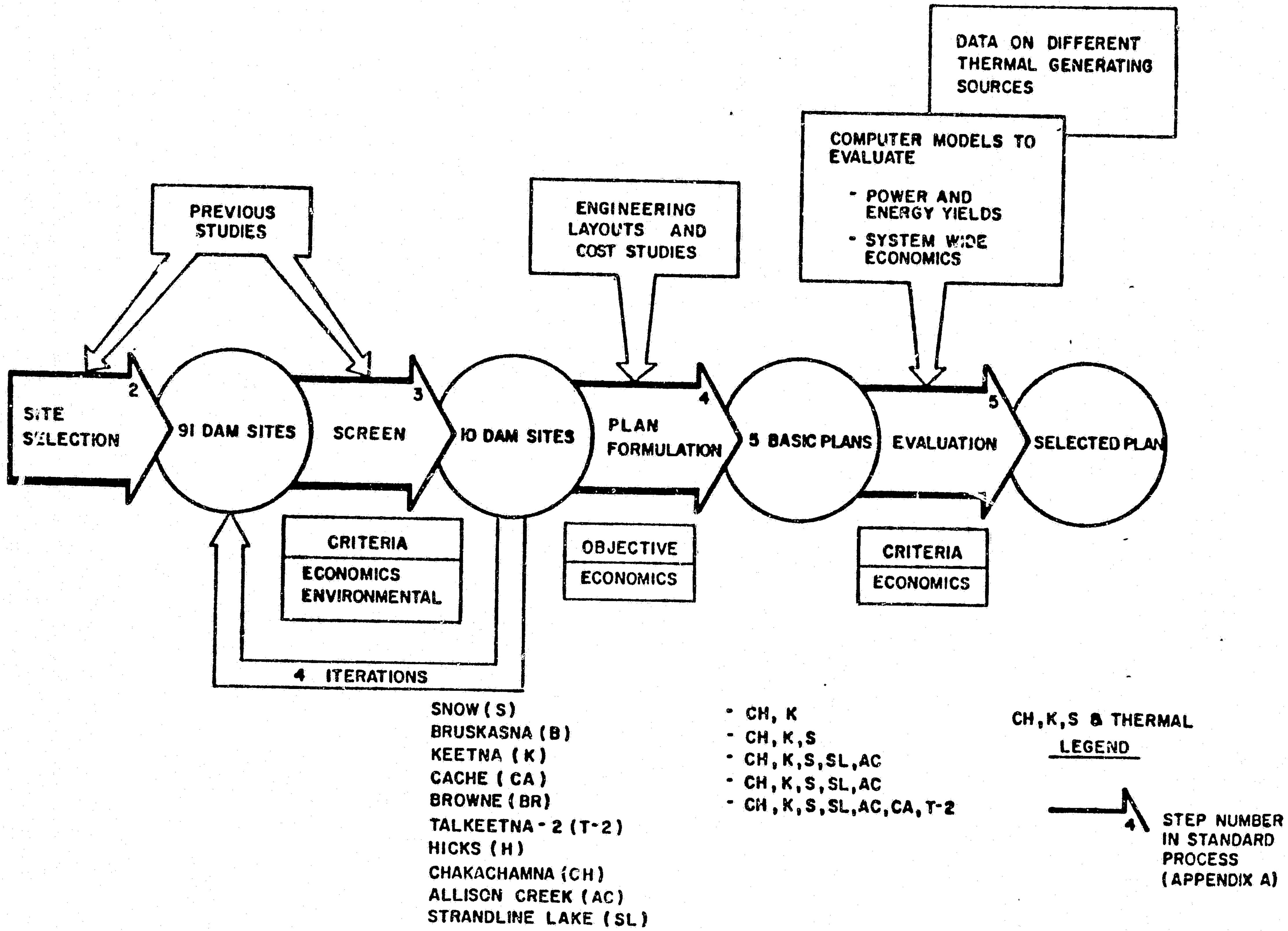
ENERGY DEMAND AND DELIVERIES FROM SUSITNA

FIGURE D.4



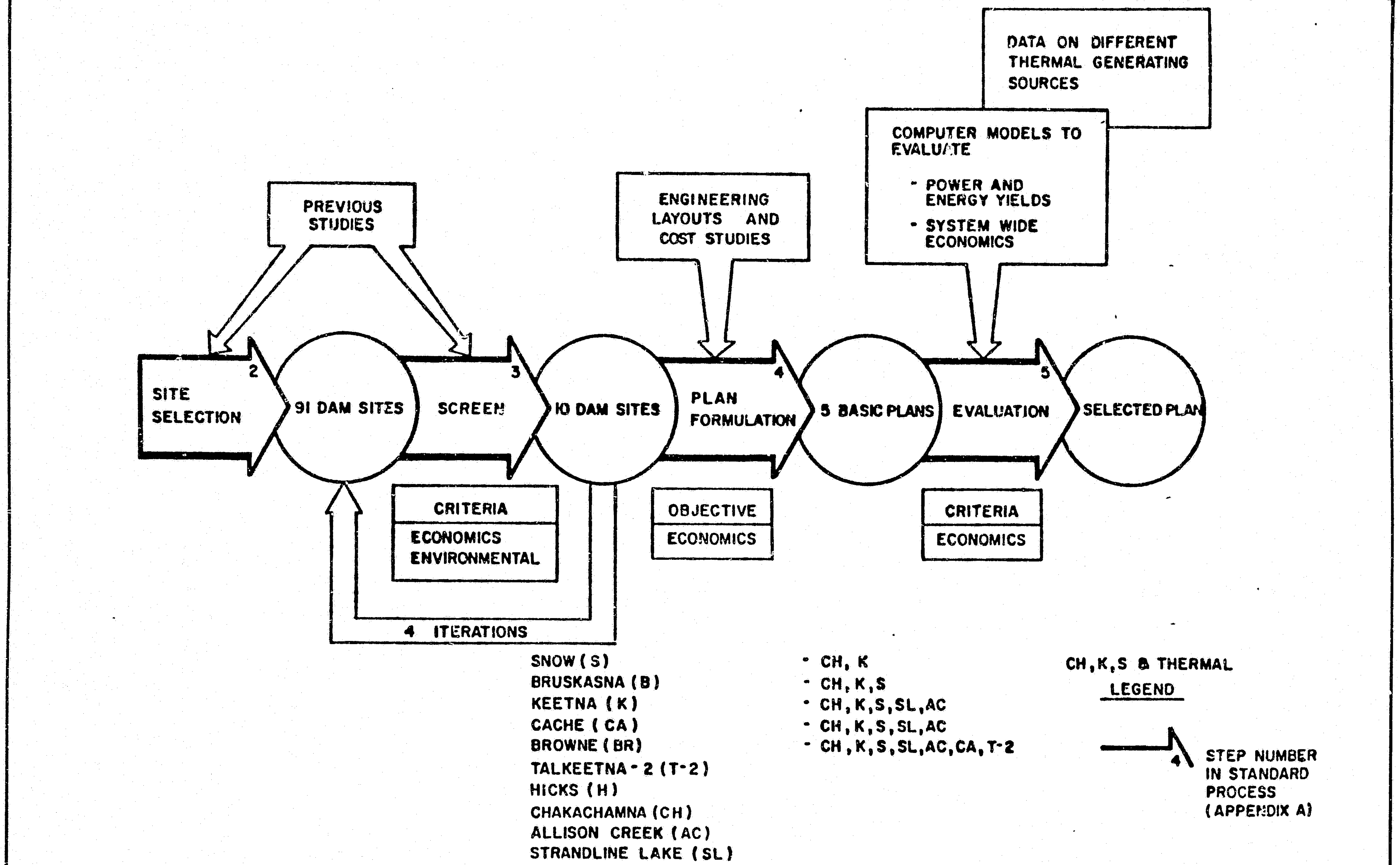
SYSTEM THERMAL COSTS AVOIDED BY DEVELOPING SUSITNA

FIGURE D.5



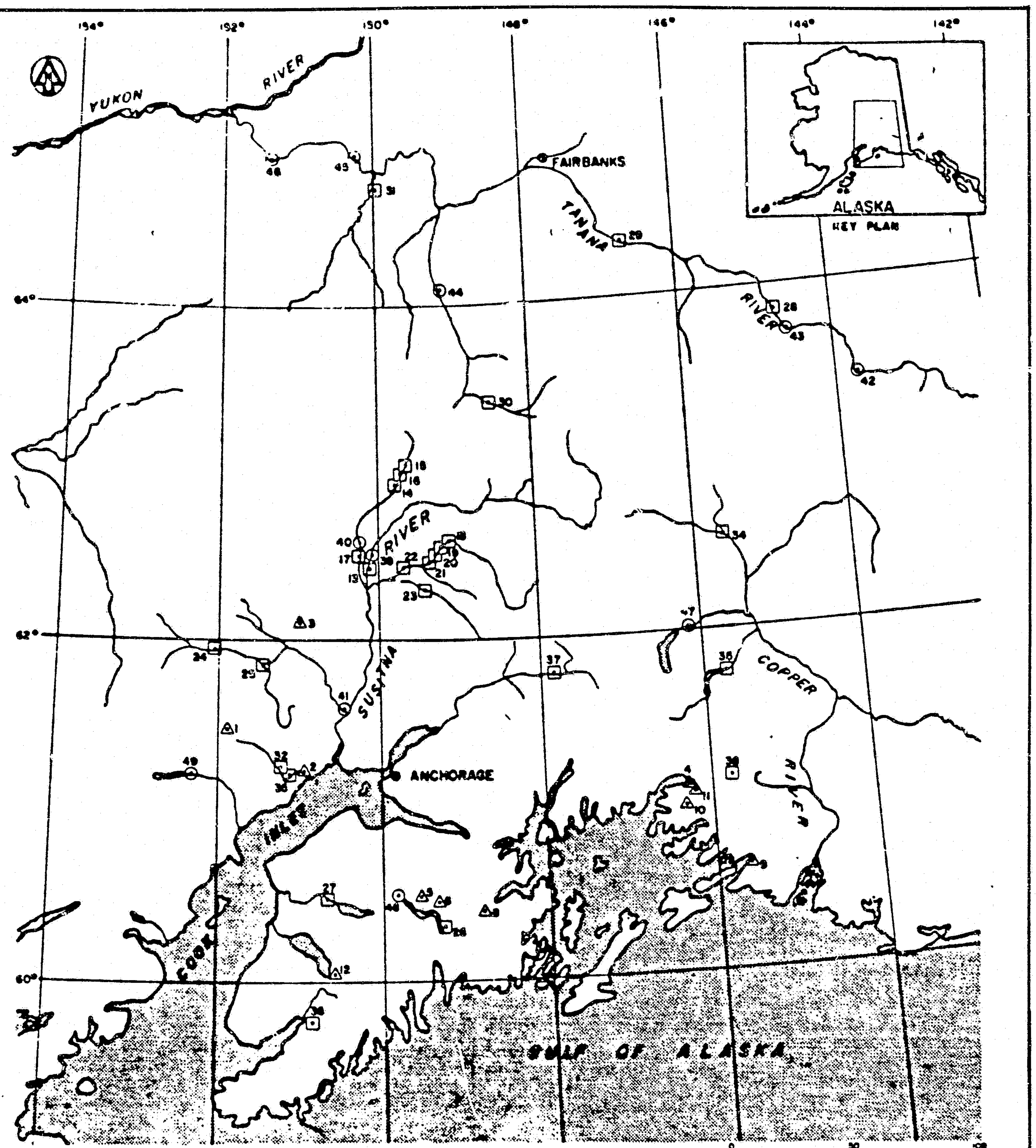
FORMULATION OF PLANS INCORPORATING NON-SUSITNA HYDRO GENRATION

FIGURE D.6



FORMULATION OF PLANS INCORPORATING NON-SUSITNA HYDRO GENRATION

FIGURE D.6



ALASKA RAILBELT REGION

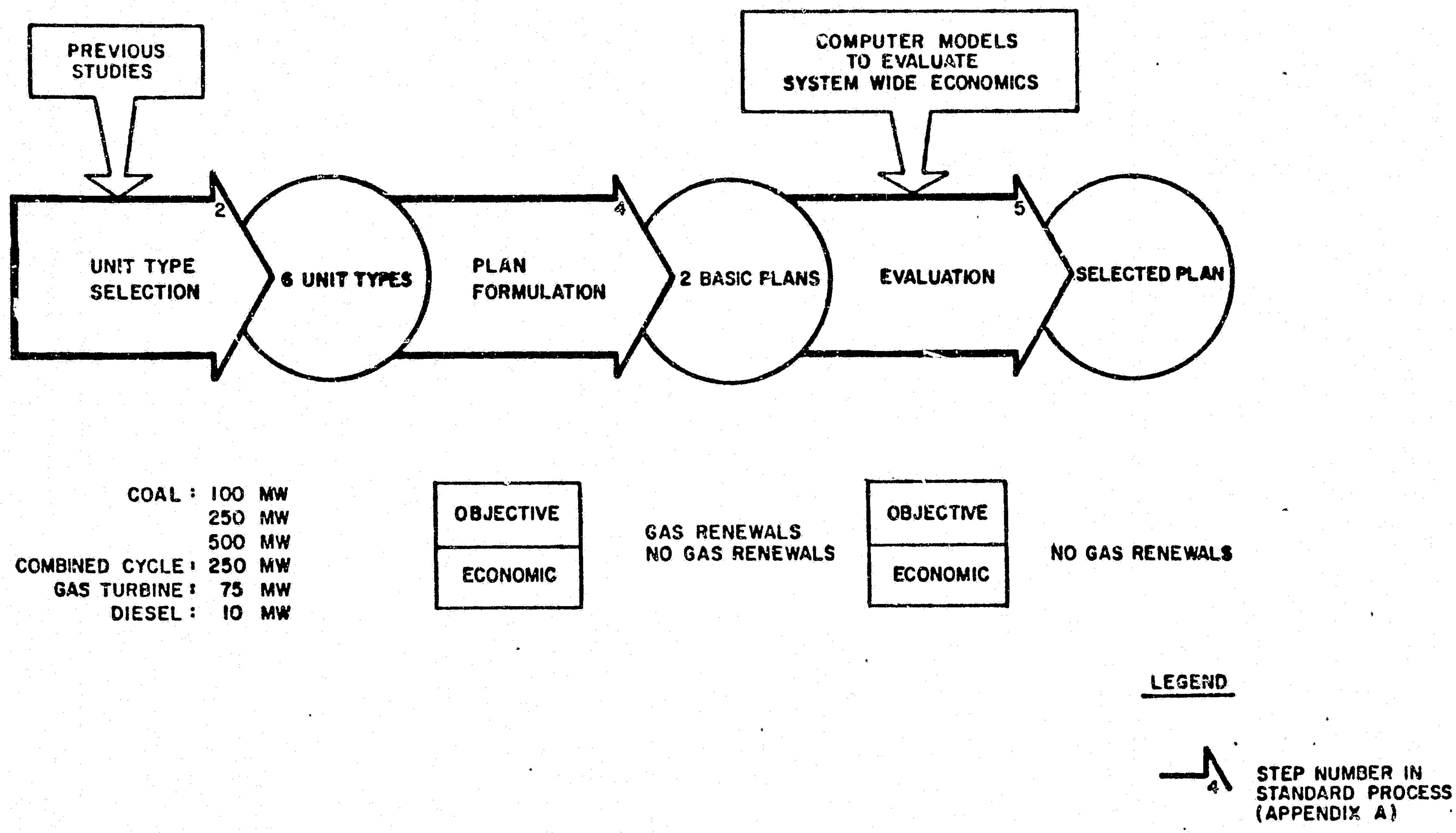
SCALE - MILES
1 INCH EQUALS APPROXIMATELY 40 MILES

▲ 0 - 25 MW	⊡ 25 - 100 MW	⊙ > 100 MW

1. STRANDLINE L.
2. LOWER BELUGA
3. LOWER LAKE CR.
4. ALLISON CR.
5. CRESCENT LAKE 2
6. GRANT LAKE
7. McCLURE BAY
8. UPPER NELLIE JUAN
9. POWER CREEK
10. SILVER LAKE
11. SOLOMON GULCH
12. TUSTUMENA
13. WHISKERS
14. COAL
15. CHULITNA
16. OHIO
17. LOWER CHULITNA
18. CACHE
19. GREENSTONE
20. TALKEETNA 2
21. GRANITE GORGE
22. KEETNA
23. SHEEP CREEK
24. SKWENTNA
25. TALACHULITNA
26. SNOW
27. KENAI LOWER
28. GERSTLE
29. TANANA R.
30. DRUSKASNA
31. KANTISHNA R.
32. UPPER BELUGA
33. COFFEE
34. GULKANA R.
35. KLUTINA
36. BRADLEY LAKE
37. HICK'S SITE
38. LOWE
39. LANE
40. TOKICHITNA
41. YENTNA
42. CATHEDRAL BLUFFS
43. JOHNSON
44. BROWNE
45. JUNCTION IS
46. VACHON IS
47. TAZILNA
48. KENAI LAKE
49. CHAKACHAMNA

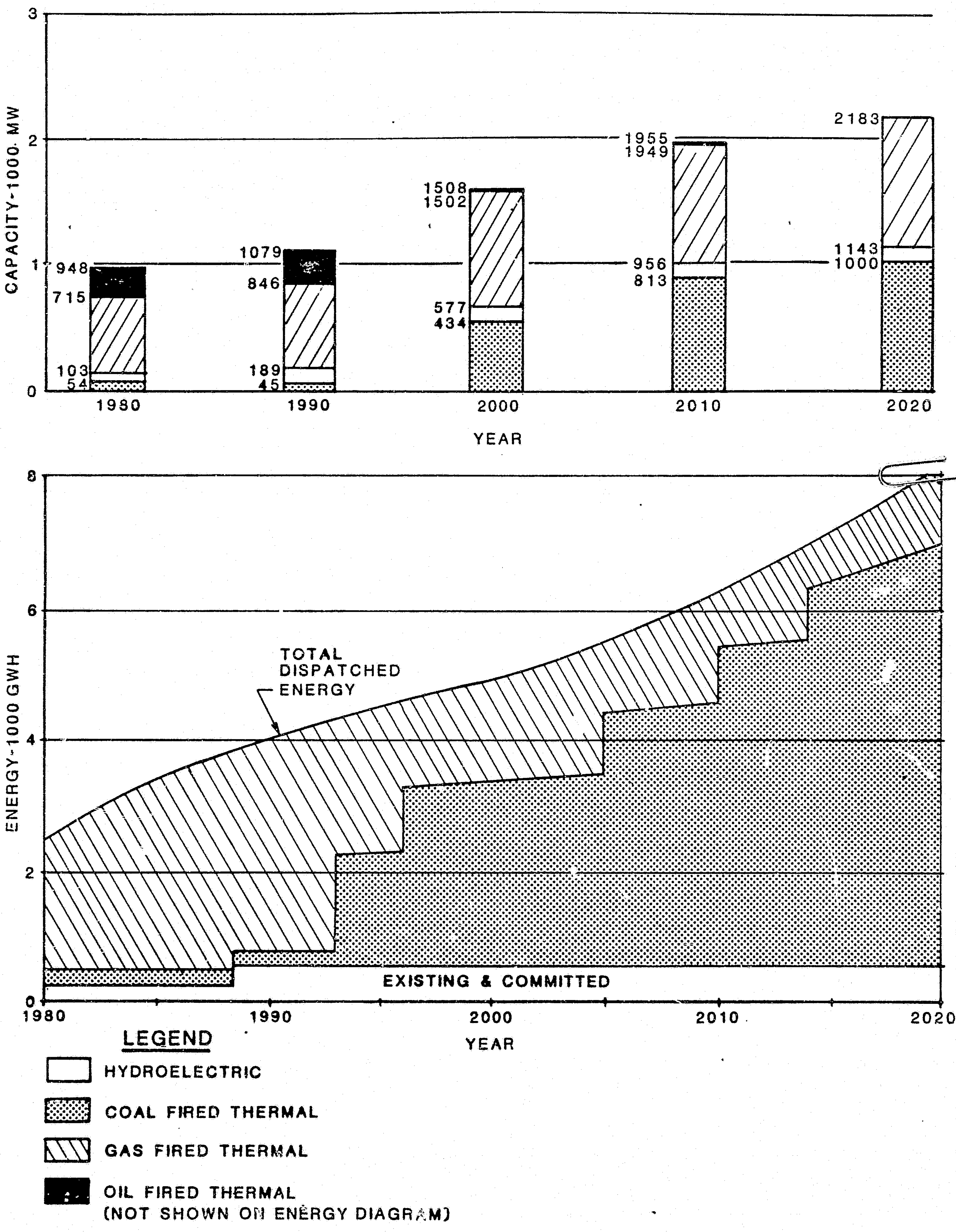
SELECTED ALTERNATIVE HYDROELECTRIC SITES

FIGURE D.7



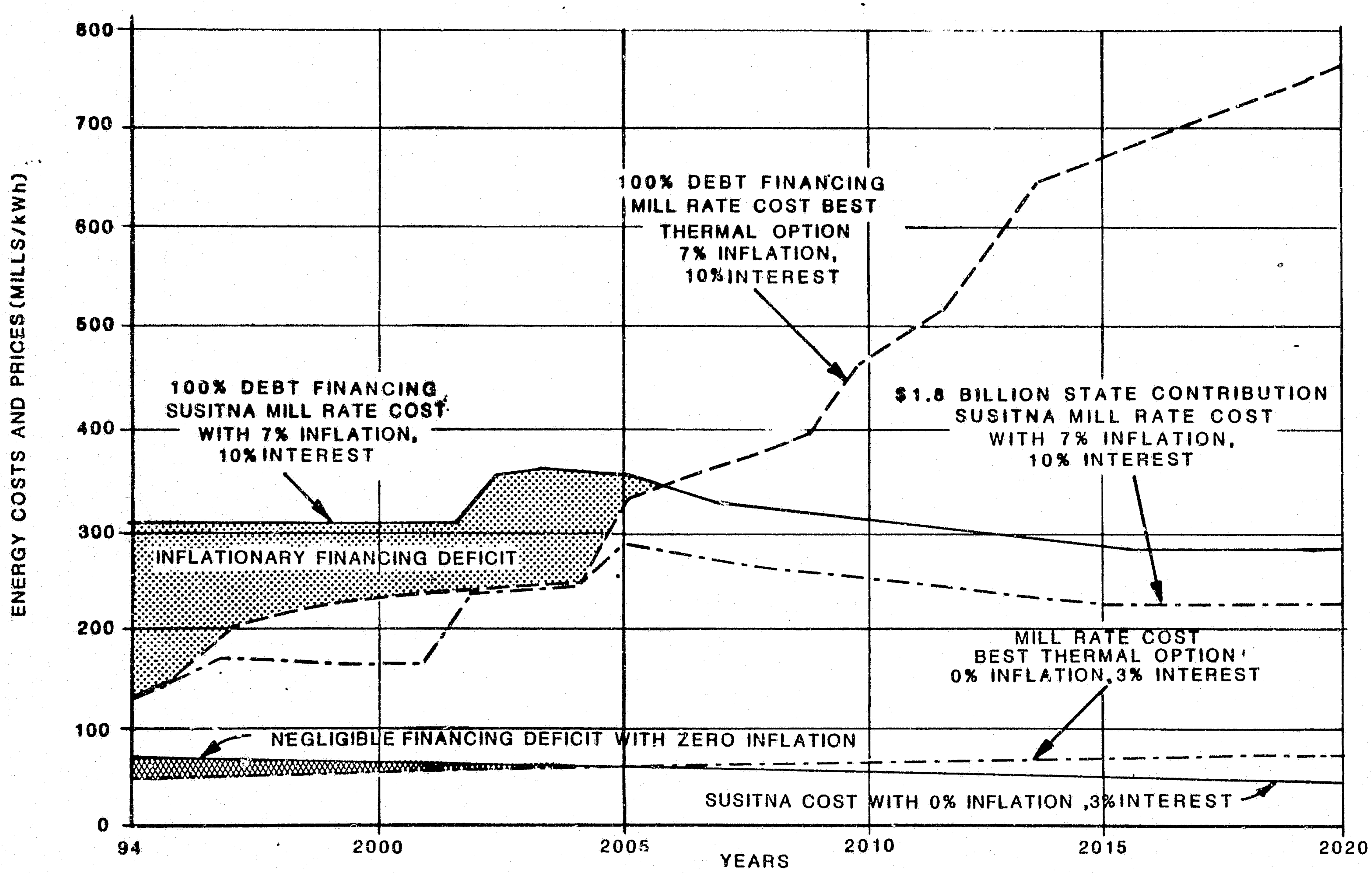
FORMULATION OF PLANS INCORPORATING ALL-THERMAL GENERATION

FIGURE D.8



ALTERNATIVE GENERATION SCENARIO
REFERENCE CASE LOAD FORECAST

FIGURE D.9



ENERGY COST COMPARISON-0 AND 7% INFLATION

FIGURE D.10

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

EXHIBIT D, APPENDIX D-1

FUELS PRICING STUDIES

SUSITNA HYDROELECTIC PROJECT
VOLUME 1
EXHIBIT D, APPENDIX D-1

FUELS PRICING STUDIES

TABLE OF CONTENTS

Appendix D-1

LIST OF TABLES

Appendix D-1

LIST OF TABLES

Appendix D-1

LIST OF FIGURES

APPENDIX D-1

FUELS PRICING STUDIES

Introduction

There are thermal alternatives to the Susitna Hydroelectric Project fueled by 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 meet 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 Region of Alaska. Projections of future natural gas and distillate fuel prices are tied to the future world price of oil. Projections of future world oil prices are presented in Exhibit B, Section 5.4 of the Application.

Results concerning the availability and price of natural gas, coal and distillate oils are used as inputs into the Optimum Generation Planning Model (OGP) in the determination of the cost of thermal generating alternatives.

1. Natural Gas

1.1 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 but 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. 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, potential and undiscovered gas from these areas are discussed below.

(a) Cook Inlet Proven Reserves

The locations of the Cook Inlet gas fields are shown in Figure D-1.1. Estimated recoverable reserves from the Cook Inlet fields and the commitment status of those reserves are shown in Figure D.1.2. This table has been developed from an earlier study[(1)]* and, 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 Figure D-1.2 as well as the five-year extension of the Phillips/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. This is discussed further under Section 1.2(c). Much of the proven gas is not at present under contract. Figure D-1.2 shows that 1,654 billion cubic feet (BCF) of proven reserves is uncommitted.

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

(b) Cook Inlet Undiscovered Gas

Earlier estimates of additional natural gas resources in the Cook Inlet area ranged from 6.7 trillion cubic feet (TCF) to 29.2 TCF.[(5)] These estimates may be high since subsequent drilling by Mobil and Arco in Lower Cook Inlet has not resulted in producing wells.

A recent study by the Department of Natural Resources of the State of Alaska presents estimates of undiscovered gas and oil and assigns probabilities to finding those quantities.[(6)] The mean or average quantity that is expected to be found is about 3.0 TCF. The estimate is presented in Table D-1.1.

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 D-1.1. with an estimate of undiscovered gas is about 2.0 TCF.

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*References for the Natural Gas section are given on p. D1-23.

(c) North Slope Gas

Estimated recoverable natural gas reserves from the North Slope are about 29 TCF for the Sadlerochit Reservoir at Prudhoe Bay. Additional gas from the North Slope is estimated to be 4.5 TCF.[7] 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 utilized for electrical generation, heating or other uses.

(d) 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 D-1.3). 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.

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.[8] For their low estimate, there is a probability of 95% that the estimated value will exceed. For the high estimate, there is a 5% probability that the estimated value will exceed recovering the cost of those volumes. 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:[9]

Low	0.46 TCF
High	9.24 TCF
Mean	3.14 TCF

The estimate for the Gulf of Alaska Slope, i.e. 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

The long-term availability of Gulf of Alaska gas for electrical generation is at this time highly speculative. First, the gas (if any) must be found and developed; second, a pipeline must be constructed to deliver the gas to where electric generation would take place and third, the delivered price would have to be competitive with alternative fuels. Therefore, at this time, gas from the Gulf cannot be depended upon to supply Railbelt generation needs.

1.2 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.

(a) Cook Inlet Current Production and Use

The production and use of Cook Inlet gas for the past five years is shown in Table D-1.2. 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 is the gas consumed at the wells and gathering areas to assist in the lifting and production of oil and gas. Use depends on the level of activity in oil and gas production which 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. These uses of gas have been fairly constant in the past and are expected to remain so in future years.

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 and are for space and water heating, and other uses by residential, commercial, and industrial customers in the Anchorage area. These sales grow with increases in population and increased use by existing consumers. The growth is expected to continue in the future and will increase when Enstar begins gas service to the Matanuska Valley in 1986.

The item, Other Sales, shown in Table D-1.2 is a residual figure according to the Alaska Department of Natural Resources and is the difference between total sales as published by the Oil and Gas Commission and the sum of gas obtained from the utilities, Phillips/Marathon, Collier Chemical and other large users.

(b) Cook Inlet Future Use

The future consumption of Cook Inlet gas depends on the gas needs of the major users and their ability to contract for needed supplies. Since there is a limited quantity of proven gas and estimates of undiscovered reserves in the Cook Inlet area have yet to be proven, gas reserves will be exhausted by the late 1990's. 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 LNG currently have 360 BCF of gas under contract and Collier Chemical has 377 BCF (Figure D-1.2). It is highly probable that both entities will obtain enough of the uncommitted gas in Figure D-1.2 to meet their needs through 2010. The reason is that both Phillips/ Marathon LNG and Collier are established, economically viable facilities. They are also owned by Cook Inlet gas producers who control part of the uncommited reserves. Phillips/Marathon LNG and Collier are therefore estimated to consume 62 BCF and 55 BCF respectively per year from 1982 through 2010.

At present, Enstar has enough gas under contract to serve its retail customers until after the year 2000, but since Enstar also sells gas to the military, Chugach Electric Association, and Anchorage Municipal Light and Power for electric generation, it may have to seek additional reserves in order to meet the needs of those larger customers. It is assumed, however, that Enstar will be able to acquire sufficient gas to meet the needs of its retail customers (including new Matanuska Valley customers). Further, it is reasonable to assume that 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. This estimate incorporates an annual growth rate in sales of 3.5% from 1982 to 1998 plus additional sales of 1.5 BCF/year. beginning in 1986 (and growing at 3.5% annually) to customers in the Matanuska Valley. Sales from 1999 to 2010 were obtained by extrapolating total sales at the 1982-1998 growth rate of 3.5% per year. The effective growth rate for total sales from 1982-1998 is 4.5%. The Enstar estimate is reasonably close to a State of Alaska estimate which provides for a growth rate of 4.7% per year.(10)

Gas used in field operations and the residual, "Other Sales" vary from year to year but together are estimated to average about 25 BCF/yr. over the period 1982 to 2010 based on historical use as shown in Table D-1.3.

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 Figure D-1.2) and Enstar has 759 BCF contracted, some of which will be sold to Anchorage Municipal Power and Light and Chugach Electrical Association for electrical generation. Assuming that the Anchorage/Fairbanks intertie is completed in 1984-85, the electrical requirements of both cities could be met (at least in part) with generation using Cook Inlet gas.

An estimate of the quantities of Cook Inlet gas that would be required to meet all Railbelt electrical requirements was made using the estimated load and energy forecast (Reference Case) for the Railbelt area. Estimated generation from the existing Eklutna and Cooper Lake hydro units, 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 (principally simple-cycle combustion turbines) were assumed to be 15,000 Btu/KWh until 1995 when the heat rate would decrease to 8500 Btu/kWh to reflect the installation of high efficiency, combined cycle units.

The estimated annual gas requirements for power generation increase from 35 BCF in 1983 to 54 BCF in 2010. The quantity of gas used for electrical generations would, of course, vary with the load and energy use forecast that was assumed. The quantities calculated for electrical generation incorporate electrical energy use from the Reference Case forecast (see Exhibit B, Section 5.4). If the forecast for the DOR Mean case were assumed, the Cook Inlet proven reserves would provide for generation for a longer period while if the forecast for the SHCA Basecase was assumed, proven reserves would last for a shorter period.

The forecast annual and cumulative use of gas for each of the major users, and the total use of gas for the Railbelt, is shown in Table D-1.3. 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 D-1.4.

The data from Table D-1.3 indicates that relying on all gas-fired electrical generation to provide the Railbelt's needs past the year 2000 is risky because it depends on the future availability of undiscovered reserves for electrical generation.

Other developments could also reduce or eliminate the availability of proven natural gas reserves for use in electrical generation. For example, there is the view that using natural gas for electric generation does not constitute the best use for the gas and that the gas should be conserved and used for space heating and process heat.[11]

The uncommitted, proven reserves and any undiscovered resources could be acquired by entities not shown in Table D-1.3, reducing or eliminating the availability of Cook Inlet gas for electric generation. This possibility is discussed next.

(c) Competition For Cook Inlet Gas

Known potential purchasers for the uncommitted, recoverable and undiscovered Cook Inlet gas reserves, in addition to those shown in Table D-1.3, are Pacific Alaska LNG Associates and whoever 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 final 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, PALNG 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 Company sold 220 BCF of gas that was formerly committed to PALNG to Enstar Natural Gas Company. This reduced reserves committed to the PALNG project to 760 BCF (see Figure D-1.2).

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 for Phase II.[12] Pacific Gas and Electric Company, one of the PALNG partners, does not plan to invest any more funds in 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. 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 erly 1990's.

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, Thomas J. Joyce, there are sufficient proven and probable reserves of conventional gas in the lower forty eight states to last fifteen to twenty years.(13) When all of these factors are considered, it does not appear that the PALNG project will be implemented prior to 1995. 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.(14) The proposed project is an alternative method of bringing North Slope gas to market. If implemented it would eliminate the need for the Alaska Natural Gas Transportation System (ANGTS) which would pipe the gas across Alaska, through Canada and to market in the lower forty eight states.

If the project were implemented, Cook Inlet gas producers might be able to sell their gas to Trans Alaska Gas System for liquefaction and sale to Asia. Sale will depend on the capacity of the liquefaction plant and the market for LNG. The price paid by TAGS to Cook Inlet producers might be high enough to outbid competing purchasers, since the Cook Inlet gas would not be burdened with the costs of the transmission line from Prudhoe Bay (although 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. However, an estimate of the maximum price that TAGS would probably be willing to pay Cook Inlet producers for gas delivered to the TAGS liquifacation plant has been made. (See a following section entitled, Current Prices).

(d) North Slope Gas

Over ninety percent of the North Slope gas is currently reinjected. Some is used in field operations, by Trans Alaska Pipeline System, 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 D-1.4 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 it is needed, i.e. Fairbanks or Anchorage. Alternatively, 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): In this plan a pipeline would be constructed from the North Slope via Fairbanks and through Canada to the lower forty eight states. The project has been temporarily shelved due to a high estimated delivered price and the resulting difficulty in obtaining financing. The project will probably not be operational before the early to mid-1990s, so it is uncertain when North Slope gas can be transported to the Railbelt for electrical generation by this system.

Trans Alaska Gas System (TAGS): This alternative was recently proposed by the Governor's Economic Committee on North Slope Natural Gas. A pipeline would be constructed from Prudhoe Bay to the Kenai Peninsula where the gas would be liquified and sold to Japan and other Asian countries.[15] 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 TAGS is highly uncertain at this time and therefore cannot be counted on to provide gas for future electric generation.

Pipeline to Fairbanks: In this plan, the North Slope gas would be transported 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 estimates indicate that this method is economically inferior to other proposed methods for utilization of North Slope gas and will therefore probably not be implemented.[16]

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. The costs of this plan are also believed to be prohibitive.[17]

(e) 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.

1.3 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 Policy 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 North Slope 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.

(a) Cook Inlet

Currently there are four contracts for the sale/purchase of Cook Inlet gas where the agreements 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 River Field.[20]

(4) Enstar/Marathon contract for purchase of gas from the Kenai and 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 Figure D-1.2).

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 be deregulated in 1985 under the NGPA.

The Phillips/Marathon LNG gas (see Section 1.2(b)) is not regulated and has 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 all 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 therefore they are not relevant in the Susitna vs. gas-fired unit alternative economic analyses which covers the period 1993-2040. There may, however, be some marketing effects in the period 1993-1995 where electric utilities are still using low cost gas for fuel.

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 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 below.

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 in 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. Estimated severance taxes of $0.15/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 $2.47/MCF. (See Table D-1.5).

The price in Table D-1.5 represents the best estimate currently available for the cost of Cook Inlet gas for electrical generation. Therefore this price was used as the base price of fuel for gas-fired generation in the thermal alternatives 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, conditions may change in the future. The price producers might be able to obtain if LNG export opportunities existed might then become important. A method that can be used to estimate wellhead prices for LNG export is to begin with the market price for delivered LNG and then subtract shipping, 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. Phillips/Marathon is presently selling LNG to Japan, and the TAGS study previously mentioned plans on selling to the Asian countries. 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.[23] For an imported oil price of $34/bbl, the equivalent LNG price would be about $5.85/Mcf (1000 Btu/CF gas) and for an oil price of $29/bbl, about $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.(24) These estimated costs are based on the large volumes of gas available from the North Slope. An LNG facility for only Cook Inlet gas 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, it is just as likely that the 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 D-1.6. 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 where no LNG export opportunities exist as shown in Table D-1.5. Therefore, if LNG opportunities did exist, the price of Cook Inlet gas for electrical generation would be higher than the price assumed herein (Table D-1.5) since the utilities would have to outbid potential LNG exporters.

(b) 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 do not 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 anlayze 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 project if constructed as currently proposed, would deliver North Slope gas to the lower forty eight states by means of a large diameter pipeline traversing central Alaska, and Canada. A portion of the proposed line would be routed near Fairbanks, Alaska. Due to the line's proximity to Fairbanks, it would be feasible to construct a lateral line from the main ANGTS trunkline to Fairbanks, and thus bring North Slope gas to Fairbanks for use in both electric generation and heating. In a study conducted by Battelle, first year transportation costs to Fairbanks were estimated by apportioning the Alaska segment of the pipeline between Fairbanks customers and lower forty eight customers and adding the full costs of gas conditioning.(25) Battelle's estimated transportation costs in 1982 dollars were $3.79/MMBtu ($4.03 in 1983 dollars) and at the maximum wellhead price of $2.30/MMBtu (June 1983) the delivered price to Fairbanks would be $6.32/MMBtu in 1983 dollars.

In a 1982 study for the U.S. General Accounting Office (Study I), the fixed costs for ANGTS were estimated.(26) If the same allocation method that was used by Battelle is applied to the results of the General Accounting Office study, the first year transportation costs are about $4.60/MMBtu in 1982 dollars ($4.88/MMBtu in 1983 dollars). If the costs are levelized over the project's life, the costs would be about $3.87/MMBtu in 1983 dollars.

In a separate 1983 study, the General Accounting Office (Study II) has also estimated conditioning and transportation costs associated with ANGTS.(27) The estimated cost of delivery to the lower forty eight is $5.25/MMBtu (1982$). When the allocation method used by Battelle to determine delivered costs at Fairbanks is employed, the conditioning and transportation costs are $2.80/MMBtu in 1983 dollars. With a maximum wellhead price of $2.30/MMBtu, the delivered price in Fairbanks is $5.10/MMBtu. The cost estimates of Battelle and the GAO are summarized below in 1983 dollars per MMBtu.

Estimate	Transportation Costs	Maximum Wellhead Price	Maximum Total Cost Delivered to Fbks.
Battelle (1st yr.)	$4.03	$2.30	$6.32
GAO Study I			
First Year	4.88	2.30	7.18
Levelized	3.87	2.30	6.17
GAO Study II First Year	2.80	2.30	5.10

None of the cost estimates include severance or state of Alaska property taxes. These taxes are roughly estimated to total somewhere between $0.50 and $1.00/MMBtu.

The estimated costs delivered to Fairbanks are well above the Cook Inlet estimated gas costs for 1983 even with a North Slope wellhead price of $0.00. Because implementation of the ANGTS project is doubtful, its estimated gas costs are not considered to be reasonable prices to use as inputs 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. The costs to electric utilities of the gas can be estimated from information in the TAGS report. This information is presented in Table D-1.7 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.

The price that electric utilites would have to pay is dependent upon the LNG sales price in Japan so prices of $5.85/MMBtu and $5.00/MMBtu have been shown. These correspond to oil prices in Japan of $34/bbl and $29/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 assumptions seem to be reasonable and a 1983 cost of North Slope gas of $4.00/MMBtu delivered to the Kenai Peninsula for electric generation will therefore be assumed.

Pipeline to Fairbanks: Transportation costs of a small diameter pipeline to Fairbanks have been estimated to be about $4.80/MMBtu for electrical generation.[28] 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 cost of the gas transmission lines.[26] Based on this, an equivalent "gas" transportation cost would be $3.84/MMBtu (0.8 x $4.80/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 D-1.8. The only cost for North Slope gas 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.

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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.

1.4 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 purchase 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 future LNG exporters will probably also have to pay a price which is adjusted to the world oil price.

The future price of Cook Inlet natural gas was calculated by escalating the base 1983 price from Table D-1.5 with the world oil price change scenarios from Exhibit B, Section 5.4. Future gas prices using alternative oil price projections are shown in Table D-1.9.

The future price of North Slope natural gas was calculated by escalating the base 1983 price from Table D-1.8 with the same world oil price change scenarios used for Cook Inlet gas. The estimated future prices are shown in Table D-1.10.

The natural gas prices from Tables D-1.9 and D-1.10 were used as the price of gas fuel in the evaluation of Railbelt thermal alternatives.

1.5 Effect of Gas Price Deregulation

The wellhead price of all interstate and intrastate natural gas in the United States is currently set by the Natural Gas Policy Act of 1978 (NGPA). Among other things, the NGPA sets the maximum ceiling prices which can lawfully be changed for specific categories of gas production; extends federal price controls over the interstate market to include intrastate gas; and deregulates as of November 1, 1979 the price of certain categories of "high cost" gas, i.e. deep gas, geopressurized gas, coal seam gas and Devonian shale gas. In addition, the NGPA provides a schedule for price deregulation of additional categories of gas beginning January 1, 1985.

To speed up the process of natural gas price decontrol, the Reagan Administration has recently proposed a bill, appearing as S.615 in the Senate and as H.R.1760 in the House. It would deregulate the price of all natural gas, regardless of production category, for which a new contract had been entered, or an old contract amended, after the effective date of the legislation when passed. Several legislative proposals have surfaced in both the Senate and House in oppositon to this proposal. Primarily, the opposition is committed to retaining price controls on "old price", that is, gas which has been dedicated to interstate commerce prior to passage of the NGPA. Further, opponents would maintain, and in some areas restrict, the present NGPA schedule of phased decontrol of new gas. Representative of this oppositon is a measure sponsored by Senator John Heinz, (R-Pa.) Heinz's bill, the Natural Gas Policy Amendment of 1983 (S.689), would continue indefinitely price controls on all old gas, and for certain old gas would actually roll back the current price to November 1, 1978 levels. Further, it would continue the NGPA schedule for decontrolling the price for certain new gas categories by January 1, 1985.

In this section, an analysis and comparison has been made of the potential costs of both Cook Inlet and North Slope natural gas under several legislative scenarios. First, examination is made of the effects on existing Cook Inlet contracts and potential future contracts of continuing present NGPA pricing and phased decontrol provisions. Second, proposed legislative changes either to accelerate deregulation of both old and new gas, or to limit deregulation, are examined for their most likely effects on Alaska gas prices. These most likely resulting Alaska gas prices are then analyzed to determine the potential cost of electrical generation from thermal alternatives in the Railbelt area.

(a) Existing Law

Title I, Subtitle A, the NGPA establishes discrete categories of natural gas production, and sets a maximum ceiling price for each category of gas. In defining these categories, the NGPA draws a distinction between "old gas," which was under contract prior to passage of the NGPA, and "new gas," or post-NGPA supplies. Old gas generally has lower ceiling prices than new gas, and is governed by Sections 104 and 106 in the case of interstate contracts, and Sections 105 and 106 in the case of intrastate contracts. New gas is governed generally by Sections 102 and 103. In addition to enjoying higher ceiling prices under Subtitle A, this gas is potentially subject to decontrol in 1985 under the provisions of Subtitle B, Section 121. Further, North Slope gas to be transported by ANGTS can only be priced under Section 109 and is not eligible for decontrol under Section 121.

To adequately evaluate the effect of NGPA pricing on Alaska gas, all existing contracts are individually analyzed. Potential future contracts are also addressed.

(i) Chugach and Chevron, ARCO, Shell Contract. Chugach Electric Co-op has a contact with Chevron, ARCO and Shell for purchase of Beluga field gas, in the Cook Inlet area.

Production under the contract began in 1968, and the current price is approximately 27¢/mcf.

As an existing intrastate contract at the time of the NGPA's adoption, gas prices under this contract would be governed by Section 105 of the NGPA. Section 105 provides that the maximum lawful price shall be the lower of the existing contract price, or the new natural gas maximum price as computed under Section 102. The Section 102 ceiling price was $1.75/MMBtu in April, 1977, and has been escalating monthly since that time, in accordance with the terms of Section 101 of the NGPA. The contract price of the 27¢/mcf for this Cook Inlet Area gas (which has an HV of approximately 1000 Btu/ft^3) obviously is lower than the Section 102 price. Therefore, in accordance with Section 105, the contract price must serve as the ceiling price, at least until 1985, when some of the gas under contract may be eligible for decontrol. However, Section 121(a)(3) pertaining to deregulation of prices for gas under existing intrastate contracts provides that such gas prices will only be deregulated if the price for such gas would exceed $1.00/MMBtu on December 31, 1984. As gas under this contract is at present expected to stay at 27¢/MMBtu on December 31, 1984, deregulation may not change the contract price of this gas.

<u>Enstar, Union, Marathon, ARCO, Chevron Contract.</u> This <u>contract for purchase of Kenai field gas from</u> Union, Marathon, ARCO, and Chevron was originally executed by Enstar in 1960, but has been amended several times. The price currently is about $0.64/Mcf. As such, it too is governed by Section 105 of the NGPA. As explained in the discussion of the Chugach/Chevron contract under Section 105 the contract price would serve as the NGPA ceiling price, for it also is lower than the Section 102 ceiling price.As with the Chugach/Chevron contract, some of the gas to be produced under this contrct may be eligible for decontrol in 1985. But if the price under this contract remains under $1.00/MMBtu on December 31, 1984, decontrol will not alter this contract price.

<u>Enstar/Shell, Enstar/Marathon Contracts.</u> These contracts <u>were signed in December, 1982 for purchase</u> by Enstar of Kenai field gas from Shell and Marathon. The current price is $2.32/Mcf. Most of the gas under contract is new gas governed by Section 102 of the NGPA. The contract also includes some Section 103 gas. The maximum prices for these categories of gas in June 1983 were $2.78/MMBtu and $3.42/MMBtu, respectively.

Pursuant to Subsection B, Section 121, prices for Section 102 and 103 gas would be decontrolled on January 1, 1985, therefore gas prices under these two contracts are subject to eventual decontrol.

Production under the contract began in 1968, and the current price is approximately 27¢/mcf.

As an existing intrastate contract at the time of the NGPA's adoption, gas prices under this contract would be governed by Section 105 of the NGPA. Section 105 provides that the maximum lawful price shall be the lower of the existing contract price, or the new natural gas maximum price as computed under Section 102. The Section 102 ceiling price was $1.75/MMBtu in April, 1977, and has been escalating monthly since that time, in accordance with the terms of Section 101 of the NGPA. The contract price of the 27¢/mcf for this Cook Inlet Area gas (which has an HV of approximately 1000 Btu/ft^3) obviously is lower than the Section 102 price. Therefore, in accordance with Section 105, the contract price must serve as the ceiling price, at least until 1985, when some of the gas under contract may be eligible for decontrol. However, Section 121(a)(3) pertaining to deregulation of prices for gas under existing intrastate contracts provides that such gas prices will only be deregulated if the price for such gas would exceed $1.00/MMBtu on December 31, 1984. As gas under this contract is at present expected to stay at 27¢/MMBtu on December 31, 1984, deregulation may not change the contract price of this gas.

<u>Enstar, Union, Marathon, ARCO, Chevron Contract</u>. This contract for purchase of Kenai field gas from Union, Marathon, ARCO, and Chevron was originally executed by Enstar in 1960, but has been amended several times. The price currently is about $0.64/Mcf. As such, it too is governed by Section 105 of the NGPA. As explained in the discussion of the Chugach/Chevron contract under Section 105 the contract price would serve as the NGPA ceiling price, for it also is lower than the Section 102 ceiling price.As with the Chugach/Chevron contract, some of the gas to be produced under this contrct may be eligible for decontrol in 1985. But if the price under this contract remains under $1.00/MMBtu on December 31, 1984, decontrol will not alter this contract price.

<u>Enstar/Shell, Enstar/Marathon Contracts</u>. These contracts were signed in December, 1982 for purchase by Enstar of Kenai field gas from Shell and Marathon. The current price is $2.32/Mcf. Most of the gas under contract is new gas governed by Section 102 of the NGPA. The contract also includes some Section 103 gas. The maximum prices for these categories of gas in June 1983 were $2.78/MMBtu and $3.42/MMBtu, respectively.

Pursuant to Subsection B, Section 121, prices for Section 102 and 103 gas would be decontrolled on January 1, 1985, therefore gas prices under these two contracts are subject to eventual decontrol.

New Cook Inlet Contracts. Contracts for Cook Inlet gas signed between now and January 1, 1985 will probably be regulated as to maximum price by Subtitle A, Section 102 or Section 103. The current maximum prices for these categories of gas (June 1983) are \$3.42/MMBtu and \$2.78/MMBtu respectively. The prices are allowed to increase at a rate in excess of the inflation rate for Section 102 gas and at the inflation rate (GNP deflator) for Section 103 gas.

New contracts will probably be decontrolled by Subtitle B, Section 121(a) of the NGPA on January 1, 1985. Further, Section 121(a)(3) provides for decontrol of existing intrastate contracts where the contract price of the gas is in excess of \$1.00/MMBtu on December 31, 1984.

North Slope Gas. There are currently no contracts for sale/purchase of gas from the North Slope. Morever, Section 102(e) and Section 103(d) specifically exclude from regulation gas produced from the Prudhoe Bay Unit of Alaska and transported through ANGTS. North Slope gas transported via ANGTS is regulated under Section 109, Ceiling Price For Other Categories of Natural Gas. The base price under Section 109 was \$1.45/MMBtu in April 1977 and adjusted for inflation gives the current price of \$2.30/MMBtu (June 1983). If the North Slope gas were transported under another system, e.g. TAGS or a small diameter pipeline to Fairbanks, presumably it would be controlled under Section 102 or 103.

(b) Proposed Changes to the NGPA

Bills have been introduced into Congress which would change the NGPA and its effect on natural gas prices. Chief among these are the Reagan Administration bill (S.615) and a bill introduced by Senator Heinz of Pennsylvania (S.689.) A House bill advancing similar concepts as S.689 has been introduced by Congressman Philip Sharp (D-Ind.) The effects of S.615 and S.689, and the probable effect on Alaska natural gas prices of efforts to accelerate, or alternatively restrict, gas price decontrol are discussed below.

The Administrations' Bill. This proposed bill would immediately remove federal price controls from all gas not presently committed by contract. In addition, any existing contract could be abrogated by either seller or purchaser during a period from Jan. 1, 1985 to Nov. 15, 1985. If the contract was not abrogated during that period, its existing terms and conditions would remain in effect until contract expiration.

The Chugach/Chevron, ARCO, Shell contract would undoubtedly be abrogated by the producers if the Administration bill were implemented. The price of gas under that contract is estimated to be $0.32/MCF on Jan 1, 1985 and that price is well below any reasonable estimate of market price at that time (see Table D-1.9).

The Enstar/Union contract would also undoubtedly be abrogated since the estimated price of gas under that contract will be $0.64/MCF on Jan. 1, 1985, again well below estimates of market value.

The Enstar/Shell and Enstar/Marathon contracts signed in Dec. 1982 may or may not be abrogated depending on what the producers and Enstar believe the market price of gas to be relative to the contract price in 1985. The base contract price of $2.32/MCF (plus $0.35/MCF beginning in 1986) changes with the price of No. 2 fuel oil and is estimated to be about $2.16/MMBtu in 1985, jumping to about $2.51/MMBtu in 1986 (See Table D-1.9 - Reference Case). The estimated maximum price that will be obtainable for Cook Inlet gas if deregulation occurs is discussed in a later section.

The Heinz Bill. Introduced by Senator Heinz of Pennsylvania, the bill would amend the NGPA to prevent deregulation of certain intrastate contracts that would otherwise be deregulated in 1985 (Section 121 (a) (3) - Intrastate Contracts in Excess of $1.00) and declare indefinite price escalators to be null and void. The bill apparently makes no change in the status of North Slope gas, i.e. the gas will remain regulated as Section 109 gas, provided it is transported via ANGTS.

The bill would deregulate New Natural Gas and New Onshore Production Wells that are now scheduled for deregulation under Sections 121(a)(1) and 121(a)(2) of the NGPA. Any uncommitted or undiscovered gas in the Cook Inlet area and the Gulf of Alaska would therefore not be controlled after passage of the Bill.

The principal differential effect this bill would seem to have on Alaska gas when compared with the NGPA would be the nullification of the escalation clauses in the Enstar/Marathon and Enstar/Shell contracts.

(c) Deregulated Cook Inlet Gas Prices

Of the proposed bills, implementation of the Reagan bill would have the greatest effect on natural gas prices in Alaska. The greatest potential effect would be on Cook Inlet gas prices where producers would undoubtedly exercise their market out rights in 1985 for two of the existing contracts and possibly for the remaining two. There would probably be no effect on the price for future sales of North Slope gas for the wellhead price of that gas is dictated by the cost to deliver the gas to market and all estimates show that the netback wellhead price is already below the NGPA regulated price.

The price that Cook Inlet producers would be able to command for their deregulated gas is of course unknown, but an estimate of the maximum price that they would be able to charge for sales of gas to use in the generation of electricity is possible. The maximum price would be that price at which electric utilities became indifferent to whether they generated using gas or coal. If producers attempted to charge a higher price, the electric utilities would build coal-fired rather than gas-fired units.

The cost of generation using coal can be estimated from the capital, fuel, and operating and maintenance expense associated with coal-fired generation. The capital and operating and maintenance expenses for a gas-fired unit can also be estimated and when these costs are subtracted from the total costs of coal generation, the maximum amount that can be paid for gas fuel is left. This dollar difference can then be translated into a cost per MMBtu through use of the gas-fired units heat rate and annual generation.

The calculation of an indifferent gas fuel price is presented in Figure D-1.5. The size of both coal and gas-fired units are assumed to be 200MW and generate 1.5 billion kWh per year. Other key paramters for the two units are listed in the figure..

The resulting indifferent gas price is $3.19/MMBtu. This price is the maximum estimated 1983 price that gas producers could charge electric utilities for gas fuel under full deregulation of gas prices. Future year prices for deregulated gas would be obtained by escalating the estimated 1983 price at the oil price rates of change from Exhibit B, Section 5.4.

1.6 References and Notes

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17. Reference 20, p. 86.

18. Battelle, Op. Cit. p.A.2

19. Battelle, Op. Cit. p.A.10

20. See Reference 3.

21. Battelle, Op. Cit. p. 2.20

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27. Issues Facing the Future Use of Alaskan North Slope Natural Gas. Report to the Honorable Ted Stevens, United States Senate, by the Comptroller General of the United States, GAO/RCED-83-102, May 12, 1983, p. 16.

28. Use of North Slope Gas for Heat and Electricity in The Railbelt, Draft Final Report, Feasibility Level Assessment to the Alaska Power Authority, Ebasco Services Inc., January 1983. (Costs on a $/MMBtu basis were not calculated in this report. However, using the reports estimated capital and O&M costs and estimated average gas throughout produces a rough estimate of about $4.80/MMBtu).

2 - Coal

This analysis of coal availability and cost in Alaska has been developed to provide the basis for evaluating thermal alternatives 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. The literature reviewed 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. In addition, Paul Weir Company of Chicago was engaged to develop the estimated cost of a mine in the Beluga field for the purpose of electric power generation for the Railbelt only.

2.1. Resources and Reserves

Alaska has three major coal fields: Nenana, Beluga, and Kukpowruk. It also has lesser deposits on the Kenai Peninsula, in the northwest 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 shown in Table D-2.1. The Nenana and Peluga fields are the most economically promising Alaska deposits as they are very large and have favorable mining conditions. The Kukpowruk deposits of North Slope cannot be mined economically, and also face substantial environmental problems (Kaiser Engineers, 1977). The northwest deposits in the area of Kotzebue Sound and Norton Sound are small and have high mining costs associated with them, although little is known about these fields (Dames and Moore 1980; Dames and Moore, 1981a; Dames and Moore, 1981b). The Kenai and Matanuska fields are also 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 D-2.2. Its subbituminous coal ranges in quality from 7400-8200 Btu/lb. It is high in moisture content, low in sulfur content, and very reactive (see Table D-2.3). 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 subbituminous coal varies according to report. Several analyses are shown in Table D-2.4. Beluga deposits typically are in seams greater than 10 ft. in thickness (Energy Resources Co., 1980) and may be up to 50 ft. thick in places (Barnes, 1966). Stripping ratios from 2.2 to 6 are commonly found.

2.2 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 mine 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 D-2.5. Plans exist at Fairbanks Municipal Utility System (FMUS) to increase the total coal-fired electric generating capacity in Alaska to 108 MW (Sworts, 1983). The FMUS capacity shown in Table D-2.5 also serves the Fairbanks district heating system.

To produce the 830 thousand tons/yr., Usibelli Coal Co. employs a 33 cubic yard 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. Much of that capacity would be employed 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.

Production at the Usibelli mine ultimately could be increased to 4 million tons/yr (Department of Energy, 1980; Battelle, 1982). The mine, which has been in operation since 1943, has 300 years of reserves remaining at current rates of production. 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 due to proximity to the Denali National Park (Ebasco, 1982), 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 auxiliary systems 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. The mine itself involves two draglines plus power shovels and trucks. The target timeframe for production is 1988-1991. 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, 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 to diversify their sources of coal supply favor the exporting of Alaskan coal (Swift, Haskins, and Scott, 1980). The export of U.S. coal to Japan also is seen as a means for treating the balance of payment problems between the two countries, and this could work in favor of Alaskan development. Certain factors, however, might impede development of an Alaskan coal export market, e.g. quality of coal and Japanese coal specifications (Swift, Hasins and Scott, 1980).

It is also feasible to develop the Beluga Field at a smaller scale for local needs, however. This potential is recognized, inferentially, by Olsen, et. al. (1979) of Battelle and supported explicitly by Placer-Amex (McFarland, 1983). Diamond Alaska Coal Co. currently is performing detailed engineering studies on a 1-3 million ton/yr mine in this field. 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, with or without the development of an export market.

2.3. 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 after taxes -- 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 coal market. These concepts are employed separately for Nenana and Beluga coal.

(a) Nenana Field

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 long term contract at a price of $1.16/MMBtu (Baker, 1983), and to FMUS at a mine-mouth price of $1.35/MMBtu. The current average price for Usibelli coal is $23.38/ton of 7800 Btu/lb coal, or $1.50/MMBtu. This value is based, to a large extent, on labor productivity of 50 tons/man day. That is a slight decline in productivity, as Usibelli had achieved 60 tons/man day a value confirmed by the National Coal Association (1980).

The $1.50/MMBtu reflects the price of coal from the Usibelli mine operating at about 50 percent of capacity. If production were increased to 1.6 million tons/yr, coal prices would decline to $20/ton ($1.28/MMBtu). 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/MMBtu

The Usibelli mine could be expanded to 4 million tons/yr., given the reserve base available. At such production levels, the additional 2 million tons of production would exhibit the same prices as the current mine when operating at full capacity.

This pricing perspective of the additional two million tons of capacity, 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/MMBtu in January 1983 dollars ($1.62-$1.75/MMBtu 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. Such coal must be transported to market by railroad, however. FMUS, for example, pays $0.50/million Btu for rail shipment of Usibelli coal. Battelle (1982) developed railroad cost functions for coal transport and, on this basis, the following charges should be added to Usibelli coal:

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. The appropriate base coal prices for use in power plant analysis are therefore \$1.72-\$1.91/MMBtu.

(b) Beluga Field

The methods for estimating 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 may apply, with production costs establishing a minimum price. In the absence of that market, production costs must be estimated for smaller mines.

The factors affecting development of an export market for Alaskan coal have been previously noted. 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 D-2.2 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 D-2.3 and D-2.4, 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 D-2.6.

There are other estimates of the export market in the Pacific Rim countries. The U.S. Department of Energy Interagency Task Force estimates that U.S. exports to the Pacific Rim will be 15 million tons in 1990, and 52 million tons in the year 2000; and Barry Levy, in Western Coal Survey, estimates U. S. exports to the Pacific Rim at 25 million tons in the year 2000 (Levy, 1982). These values are consistent with the MRI export estimate of 11.1 million metric tons to Japan in 1990, since they would assume smaller amounts of coal being exported to Korean and Taiwan (see Figures D-2.3 and D-2.4).

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. They are consistent with the data from Swift, Haskins, and Scott (1980).

The Pacific Rim export market is potentially highly available to the Alaskan mines due to their favorable transportation cost differentials compared to other supply sources (Swift, Haskins, and Scott, 1980). Transportation cost differentials are based upon the distance to market, as illustrated in Figure D-2.5. 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. Levy estimates that 15 - 20 million tons of coal will be exported each year from Alaska by the year 1995 (Levy, 1982). The ultimate proof of the viability of a Pacific Rim export market, and the ability of Alaskan coal to penetrate that market, is the existence of the Suneel Alaska - KEPCO contract. This 15-year contract demonstrates that Alaskan coal can compete successfully in the Pacific Rim.

Because of the 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 estimated by Diamond Shamrock Corp. (1983). The value of coal in Japan, therefore, is $2.37-$2.49/ million Btu as is shown in Table D-2.7. 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 $1.78-$1.94/million Btu, as is shown in Table D-2.8.

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 $1.78-$1.94/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 associated with coal transport to tidewater 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 $1.78-$1.94/million Btu are assumed to hold.

Production cost estimates for Beluga coal have also 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 D-2.9. 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 ($1.86/million Btu) being averaged with the production cost of $1.45/million Btu to achieve a price of $1.66/million Btu.

While this averaging technique 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 $1.86/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, the practice of selling at the average price rather than the market value would result in decreased revenues to the coal operation of $15-$32 million per year. It is not reasonable to assume that the operator would forego revenues based on market value, therefore the market value of coal is 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. 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 various potential vendors, at $1.50/MMBtu to $2.00/MMBtu.

Independent estimates were made of the cost of producing Beluga coal at rates of one million tons/year and three million tons/year. These estimates were made by Paul Weir (1983) consulting mining engineers. These coal price estimates were developed under the following assumptions.

(1) a 100% equity investment,

(2) rates of return at 10%, 15%, and 20%,

(3) a mine investment including an ancillary town for workers (with town costs divided between the mine and the power plant);

(4) an investment including a road or conveying system between the mine and a power plant located at tidewater.

Because of the low levels of production, Paul Weir assumed that a truck-shovel operation would be more cost effective than a dragline operation on a bucket wheel excavator system. On this basis, Paul Wier estimated the delivered cost of coal to be as follows:

Cost of Coal	1 Million Ton/Year	2 Million Ton/Year
Private Financing		
At 10% ROE	$2.72	1.91
At 15% ROE	3.20	2.23
At 20% ROE	3.76	2.65
State Financing		
At 3.5% ROR	2.23	1.61

Under the private financing case, it was assumed that the coal mine was financed without debt. If a 25 percent debt were incorporated into the analysis, the cost of coal would decrease slightly.

Paul Weir Company also estimated the cost of coal under the assumption that the State of Alaska would own and operate the mine. A real cost of capital of 3.5% was assumed and the resulting estimated cost of coal is shown in the table above. This cost can be compared with the private ownership, 10% ROE case which is close to the real rate of return that private equity investors would require as a minimum.

2.4. 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 is executed. 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, or the consumer price index. The index selected is applied to the beginning operating and maintenance expenses so that the level of operating and maintenance expense increases or decreases over time with changes in the index. The original capital investment is not escalated, so the price of coal to the utility tends to increase with general inflation, provided the escalation index selected reflects the general rate of inflation.

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 free market price escalation rates were estimated for utility coal in Alaska and in the lower 48 states, and they range from 2.0-2.7%/year as is shown in Table D-2.11. These are real escalation rates, that is in addition to or in excess of the inflation rate. Several more real market rates have also been developed by Sherman H. Clark and Associates and by DRI, and these are shown in Table D-2.12.

These rates of escalation can be compared to the real historical rate of increase of 2.3%/yr. experienced by Golden Valley Electric Association, since 1974. 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 substantial provisions of the Coal Mine Safety Act of 1969 were being implemented thereby affecting the price of coal.

The estimates of Sherman H. Clark and DRI are based more upon supply-demand analyses rather than upon extrapolations of historical data. The demand/supply relationship varies for different types of coal which results in different estimated future price escalation rates. This relationship is shown in Figure D-2.6 where future real escalation rates for western coal (average 2.9%/year) and western lignite (average 2.3%/yr.) are graphed using data from Sherman Clark and Associates.

The SHCA estimated real escalation rates for new contract domestic U.S. coal are shown below by period.

Period	Real Escalation Rate - %/yr. Western Coal	Western Lignite
1980-1990	2.9	2.8
1990-2000	2.0	2.0
2000-2010	3.9	2.0
Average 1980-2010	2.9	2.3

The rates of price change from period to period for domestic U.S. coal are directly related to mine capacity utilization. The lignite price changes reflect projected declines in capacity utilization in Texas and North Dakota fields (Clark, 1983), while western coal capacity utilization is expected to increase. Capacity utilization rates in Alaska depend upon future use by electric utilities and cannot be readily determined. Therefore, when a domestic escalation rate is applicable, the long-term average rate is employed rather than period rates.

DRI's estimated real escalation rates (Spring 1983) for new contract, domestic, U.S. coal are shown below by period (DRI does not differentiate by coal type).

Period	Real Escalation Rate -%/yr.
1981-1990	3.1
1991-2000	1.7
2001-2005	2.5
Average 1983-2005	2.6

For coal exports, SHCA is forecasting a 2.6%/yr. growth in demand by Japan and a 5.2%/yr. demand growth by South Korea (Figure D-2.1). This growth in demand together with a forecast weakening in United States currency versus the currencies of the two Asian countries results in an estimated real price escalation rate of 1.6%/yr. which is below the forecast U.S. domestic rates.

The forecasts by SHCA and DRI of future coal prices are based on demand/supply analyses performed by knowledgable, experienced firms. The forecasts are reasonable assessments of the future price trends and have been applied to Alaskan coal produced from the Nenana and Beluga fields.

Coal from the Nenana Field is used principally to supply Alaskan domestic markets. Therefore a domestic price escalation rate of 2.6%/year based on the average of SCHA western coal and lignite (2.9% and 2.3%) and the DRI forecast (2.6%) has been assumed. The 2.6% rate is applied to the 1983 estimated mine-mouth price of $1.40/MMBtu to provide the future cost of coal at the Usibelli Mine. Prices for

Nenana coal that is consumed at other locations are determined by adding transportation costs which are shown in Table D-2.13. Composite real escalation rates which include transportation costs are shown below for Usibelli coal used at Nenana and Willow.

Location	Composite Real Escalation Rate-%/yr.
Usibelli mine-mouth	2.6
Nenana	2.3
Willow	2.2

Assuming that an export market for the Beluga field develops, all coal sold from the field will probably be at a price dictated by Pacific Rim market conditions. This includes sales to electric utilities for use as fuel for electric generation. Therefore, it is reasonable to escalate the estimated \$1.86/MMBtu 1983 base price of Beluga Field coal at the estimated export market rate of escalation of 1.6%/yr. (Table D-2.12)

The resulting fuel prices for Nenana and Beluga field coal for the period 1983-2010 are shown in Table D-2.14. There are no known projections of coal prices past the year 2010.

If an export market for Beluga coal does not develop, the 1983 base price should be assumed to be based on the production costs for a small 1-3 million ton per year mine. This would result in higher coal costs, especially in the initial years when consumption in the Beluga steam plant would be in the 1 million ton per year range required by one 200 MW unit.

While there has been some correlation between export coal prices and world oil prices historically, 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 necessary to treat coal prices as being independent of world oil prices.

Several scenarios of future world oil prices have been used in the economic analysis of thermal alternatives. Natural gas prices for these scenarios move with the oil prices since it is assumed that future natural gas prices in both the Cook Inlet area and the North Slope will be tied directly to the future price of oil (See Section 1.4).

Coal prices are treated independently of oil prices, but a coal price scenario is required with each oil and natural gas price scenario in

3.1 Availability

According to Battelle, there is adequate availability of distillate oil during the analysis period.[1/] Although part of the distillate oil used in Alaska is imported, this fact alone will not affect its availability. It has been assumed that distillate oil in the required quantities will be available during the economic analysis period 1993 to 2040 from refineries within Alaska or the lower forty-eight states.

3.2 Price

The average current price for medium distillate fuels in Anchorage and Fairbanks is shown in Table D-3.1. These prices will change with the world market price for oil.[2/] The estimated price changes for several projections of future world oil prices have been applied to the 1983 price of distillate oil to obtain the future prices during the period 1983 to 2040. These are shown in Table D-3.2.

1/ Battelle Pacific Northwest Laboratories. Railbelt Electric Power Alternative Study: Fossil Fuel Availability and Price Forecasts, Volume VII, March 1982, p. 8.1.

2/ See Battelle, p. 8.3-8.5.

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Table D-1.1

PRELIMINARY ESTIMATES OF UNDISCOVERED GAS RESOURCES IN PLACE AND ECONOMICALLY RECOVERAGLE GAS RESOURCES FOR THE COOK INLET BASIN(1)

	Quantity of Gas - TCF	
Probability - %(2)	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) Source: 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.

Table D-1.2

HISTORICAL AND CURRENT PRODUCTION AND
USE OF COOK INLET NATURAL GAS

USE	1978	1979	1980	1981	1982
	QUANTITY - BCF				
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 Sales	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.

*Does not include sales made by gas utilities to electric utilities for electric generation.

Table D-1.3

ES[illegible]ED [illegible]F CO[illegible]NLET [illegible]RAL [illegible] BY U[illegible] - AL[illegible]UMES [illegible] BCF

Year	Phillips/Marathon LNG/Plant	Collier Ammonia/Urea	Enstar Retail Sales	Field Operations & Other Sales	Electric Generation: Military	Electric Generation: All Others	Total Gas Use	Total Cumulative Gas Use	Year End Remaining Reserves: Proven	Year End Remaining Reserves: Proven Plus Mean Undiscovered
1982	62	55	17.7	25	5	38.4	203.1	203.1	3337.9	5377.9
1983	62	55	19.2	25	5	40.8	207.0	410.1	3130.9	5170.9
1984	62	55	19.8	25	5	43.2	210.0	620.1	2920.9	4960.9
1985	62	55	20.5	25	5	45.5	213.0	833.1	2707.9	4747.9
1986	62	55	22.8	25	5	47.6	217.4	1050.5	2490.5	4530.5
1987	62	55	23.6	25	5	49.7	220.3	1270.8	2270.2	4310.2
1988	62	55	24.4	25	5	46.5	217.9	1488.7	2052.3	4092.3
1989	62	55	25.3	25	5	48.5	220.8	1709.5	1831.5	3871.5
1990	62	55	26.1	25	5	50.5	223.6	1933.1	1607.9	3647.9
1991	62	55	27.1	25	5	51.8	225.9	2159.0	1382.0	3422.0
1992	62	55	28.0	25	5	53.1	228.1	2387.1	1153.9	3193.9
1993	62	55	29.0	25	5	30.9 54.5	230.5	2617.6	923.4	2963.4
1994	62	55	30.1	25	5	31.6 55.8	232.9	2850.5	690.5	2730.5
1995	62	55	31.1	25	5	32.5	210.6	3061.1	479.9	2519.9
1996	62	55	32.2	25	5	33.1	212.3	3273.4	267.6	2307.6
1997	62	55	34.4	25	5	33.8	215.2	3488.6	52.4	2092.4
1998	62	55	34.6	25	5	34.5	216.1	3704.7	(163.7)	1876.3
1999	62	55	35.8	25	5	35.1	217.9	3922.6		1658.4
2000	62	55	37.0	25	5	35.8	219.8	4142.4		1438.6
2001	62	55	38.3	25	5	36.8	222.1	4364.5		1216.5
2002	62	55	39.7	25	5	37.7	224.4	4588.9		992.1
2003	62	55	40.1	25	5	40.0	227.1	4816.0		765.0
2004	62	55	42.6	25	5	41.0	230.6	5046.6		534.4
2005	62	55	44.1	25	5	42.0	233.1	5279.7		301.3
2006	62	55	45.6	25	5	44.6	237.2	5516.9		64.1
2007	62	55	47.2	25	5	46.0	240.2	5757.1		(176.1)
2008	62	55	48.9	25	5	47.3	243.2	6000.3		
2009	62	55	50.6	25	5	48.7	246.3	6246.6		
2010	62	55	52.4	25	5	50.1	249.5	6496.1		

3337.7 + 203.1 = 3541
190.1

5377.7 + 203.1 = 5581
190.1

1 Based on historical use from Table D-1.2 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, VP 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 D-1.2.

4 Estimate based on historic use shown in Table D-1.2.

5 Calculated based on the Reference Case 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 1982-1995 which includes older, high heat rate units, and 8,500 Btu/kWh from 1996-2010, which assumes predomonately combined cycle units.

6 Proven reserves of 3,541 BCF on Jan 1, 1982. See Exhibit D-1.1.

7 Includes proven revenues of 3,541 BCF plus expected value for undiscovered economically recoverable reserves from Figure D-1.1.

Table D-1.4

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
Trans Alaska Pipeline System	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.

Table D-1.5

ESTIMATED BASE PRICES FOR NEW PURCHASES OF UNCOMMITTED AND 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(2)	0.15	0.15
Total (unescalated)(3)	\$2.47/Mcf	\$2.82/Mcf
Transmission charge(4)	0.30	0.30
Delivered to Anchorage	\$2.77/Mcf	\$3.12/Mcf

(1) Demand charge of \$0.35/MCF 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) Severance taxes are the greater of \$0.064/MCF or 10% of the wellhead cost adjusted by the "Economic Limit Factor." The economic limit factor is based on actual monthly production versus the wells production rate at the economic limit. See Alaska Statutes, Chapter 55, Section 43.55.013 and 43.55.016. The tax of \$0.15/MCF was estimated based on conversations with Enstar Natural Gas Co.

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

(4) Estimated transmission charges would be about \$0.30/MCF. Per telephone conversation with Mr. Harold Schmidt, VP Enstar.

Table D-1.6

ESTIMATED 1983 BASE PRICES FOR NEW PURCHASES OF UNCOMMITTED AND 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
Maximum Price to Producer(3)	$3.85/MCF	$3.00/MCF

---

(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 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.

Table D-1.7

ESTIMATED COST OF NORTH SLOPE NATURAL GAS FOR ELECTRIC GENERATION AT KENAI ASSUMING IMPLEMENTATION OF THE TRANS ALASKA GAS SYSTEM (TAGS) (1983 Dollars/MMBtu)

	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)

(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 an inflation rate of 7%/yr.

(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 Section.

Table D-1.8

ESTIMATED 1983 DELIVERED COST OF NORTH SLOPE NATURAL GAS FOR RAILBELT ELECTRICAL GENERATION (1983 Dollars/MMBtu)

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

N.A. Not Available

(1) Cost of $3.80/MMBtu in 1982$ 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 D-1.7. 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 31. 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 31. 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 D-1.9 (Sheet 1 of 2)

PROJECTED COOK INLET WELLHEAD NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

							Constant Change Cases			
Year	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case (Sherman Clark NSD Case)	+2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
1983(1)	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47
84	1.97	1.94	2.05	2.07	2.27	2.27 2.36	2.43	2.47	2.36	2.33
85	1.86	1.79	2.10	2.22	2.16	2.16 2.25✓	2.48	2.47	2.33	2.29
86(1)	2.18	2.07	2.19	2.74	2.51	2.51 2.60	2.88	2.73	2.66	2.58
87	2.14	1.99	2.14	2.92	2.51	2.51 -2.60	2.94	2.73	2.63	2.53
88	2.17	1.97	2.12	3.11	2.51	2.59 -2.60	3.00	2.73	2.60	2.48
89	2.20	1.95	2.11	3.31	3.82	2.66 2.68	3.06	2.73	2.58	2.43
1990	2.23	1.83	2.09	3.52	3.82	2.74 2.76	3.12	2.73	2.55	2.38
91		1.76	2.02	3.68	3.93	2.83		2.73		
92		1.73	2.00	3/84	4.05	2.91		2.73		
93		1.65	1.92	4.01	4.17	3.00		2.73		
94		1.63	1.88	4.19	4.30	3.09		2.73		
95	2.38	1.59	1.87	4.37	4.43	3.18	3.45	2.73	2.43	2.15
96		1.57	1.79	4.50	4.56	3.27		2.73		
97		1.53	1.79	4.64	4.70	3.37		2.73		
98		1.52	1.78	4.79	4.84	3.47		2.73		
99		1.51	1.76	4.94	4.98	3.58		2.73		
2000	2.54	1.48	1.74	5.09	5.13	~~3.69~~ 3.71	3.80	2.73	2.31	1.95
01				5.15	5.31	3.80		2.73		
02				5.20	5.50	3.91		2.73		
03				5.26	5.69	4.03		2.73		
04				5.32	5.89	4.15		2.73		
05	2.71	1.38	1.64	5.38	6.09	4.27	4.20	2.73	2.10	1.76
06				5.44	6.31	4.40		2.73		
07				5.56	6.53	4.53		2.73		
08				5.62	6.76	4.67		2.73		
09				5.68	6.99	4.81		2.73		
2010	2.89	1.28	1.56	5.74	7.24	4.95	4.64	2.73	2.09	1.59

Table D-1.9 (Sheet 2 of 2)

PROJECTED COOK INLET WELLHEAD NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

YEAR	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case (Sherman Clark NSD Case)	Constant Change Cases +2/yr	-0%/yr.	-1.0/yr.	-2.0%/yr.
2011				5.81	7.34	5.08		2.73		
12				5.87	7.46	5.20		2.73		
13				5.93	6.68	5.33		2.73		
14				6.00	7.80	5.47		2.73		
2015	3.08	1.18	1.47	6.00	7.91	5.60	5.12	2.73	1.98	1.44
16				6.07	8.03	5.74		2.73		
17				6.13	8.15	5.89		2.73		
18				6.20	8.27	6.04		2.73		
19				6.27	8.40	6.19		2.73		
2020	3.28	1.10	1.39	6.34	8.40	6.34	5.65	2.73	1.89	1.30
21				6.41	8.40	6.44				
22				6.48	8.40	6.53				
23				6.55	8.40	6.63				
24				6.62	8.40	6.73				
2025	3.59	1.10	1.32	6.69	8.40	6.83	6.24	2.73	1.79	1.17
26				6.77	8.40	6.93				
27				6.84	8.40	7.04				
28				6.92	8.40	7.14				
29				6.99	8.40	7.25				
2030	3.74	1.10	1.25	7.07	8.40	7.36	6.89		1.71	1.06
31				7.15	8.40	7.43				
32				7.23	8.40	7.51				
33				7.31	8.40	7.58				
34				7.39	8.40	7.66				
2035	3.99	1.10	1.18	7.47	8.40	7.73	7.61		1.62	0.96
36				7.55	8.40	7.81				
37				7.63	8.40	7.89				
38				7.72	8.40	7.97				
39				7.80	8.40	8.05				
2040	4.25	1.10	1.12	7.89	8.40	8.13	8.40	2.73	1.54	0.87

(1) Estimated 1983 price of Cook Inlet gas from Table D-2.5.
(2) Additional demand charge of $0.35/MMBtu applies from 1986 forwrd and is escalated by price of oil change.

Table D-1.10 (Sheet 1 of 2)

PROJECTED NORTH SLOPE DELIVERED NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

YEAR	(DCR Mean)	DCR 30%	DCR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case (Sherman Clark NSD Case)	Constant Change Cases +2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
1983(1)	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
1984	3.31	3.14	3.32	3.48	3.82	3.82	4.08	4.00	3.96	3.92
1985	3.13	2.90	3.40	3.73	3.64	3.64	4.16	4.00	3.92	3.84
1986	3.09	2.81	3.05	3.98	3.64	3.64		4.00		
1987	3.03	2.70	2.97	4.23	3.64	3.64		4.00		
1988	3.07	2.66	2.95	4.51	3.64	~~3.75~~ 3.64.		4.00		
1989	3.11	2.64	2.94	4.80	5.53	3.86		4.00		
1990	3.15	2.48	2.90	5.11	5.53	~~3.98~~ 3.86	4.59	4.00	3.73	3.47
1991		2.38	2.81		5.69			4.00		
1992		2.34	2.78		5.86			4.00		
1993		2.24	2.66		6.04	4.22		4.00		
1994		2.20	2.61		6.22			4.00		
1995	3.36	2.15	2.59	6.34	6.41	4.61	5.07	4.00	3.55	3.14
1996		2.12	2.49					4.00		
1997		2.07	2.48					4.00		
1998		2.06	2.46					4.00		
1999		2.04	2.44					4.00		
2000	3.59	2.01	2.42	7.39	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	3.83	1.86	2.29	7.81	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	4.08	1.73	2.16	8.24	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	4.36	1.60	2.05	9.20	11.29	8.13	7.54	4.00	2.90	2.10

Table D-1.10 (Sheet 2 of 2)

PROJECTED NORTH SLOPE DELIVERED NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

YEAR	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case Sherman Clark NSD Case	+2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
2016								4.00		
2017								4.00		
2018								4.00		
2019								4.00		
2020	4.65	1.49	1.94	9.20	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	4.96	1.49	1.83	9.71		9.91	9.19	4.00	2.62	1.71
2026					12.16			4.00		
2027					12.16			4.00		
2028					12.16			4.00		
2029					12.16			4.00		
2030	5.29	1.49	1.73	10.26	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	5.64	1.49	1.64	10.84	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	6.02	1.49	1.55	11.45	12.16	11.79	12.37	4.00	2.26	1.26

(1)Estimated 1983 price of North Slope gas from Table D-1.8.

Table D-2.1

DEMONSTRATED RESERVE 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	239,272.2
Subbituminous	5,443.0	182,0[illegible].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 D-2.2

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 D-2.3

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
Ultimate Analysis, As Received (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 D-2.4

ULTIMATE ANALYSIS OF BELUGA COAL

Element/ Compound (wt %)	Analyses		
	Stanford[a] Research Institute	Battelle[b] Waterfall Seam)	Diamond-Shamrock[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 Value (Btu/lb)	7200	7536	7800

a/Stanford Research Institute, 1974

b/Swift, Haskins, and Scott, 1980

c/Diamond Shamrock Corporation, 1983

Table D-2.5

COAL FIRED GENERATING 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 D-2.6

PROJECTED NATIONAL SHARES OF JAPANESE COAL MARKET FOR IMPORTS IN THE YEAR 1990[a]

Nation	Market Share: Percentage	Market Share: 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

a/Includes steam co al and metallurgical coal.

Source: MRI, 1982

Table D-2.7

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)	Value of Coal ($/million Btu)
Australia[a]/	$45.00	10.50	$55.50	$2.49
South Africa[b]/	37.50	15.30	52.80	2.37
Canada[c]/	45.00	10.35	55.35	2.48

a/From Sherman H. Clark and Associates, 1983

b/From Diamond Shamrock Corp., 1983

c/Assumes 11,160 Btu/lb per Japanese Specification in Swift, Haskins, and Scott, 1980.

Table D-2.8

THE MARKET VALUE OF COAL FROM THE BELUGA FIELD
FOB GRANITE POINT, ALASKA
(Jan. 1983 Dollars)

	Value of Coal ($/Million Btu)	
	Low	High
The Value of Coal in Japan[a]	$2.37	$2.49
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	$2.33	$2.45
Cost to Transport Coal[c]	$0.55	$0.51
Net Value of Coal at Granite Point	$1.78	$1.94

a/From Table D-2.7

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 D-2.4).

Table D-2.9

PRODUCTION COST ESTIMATES FOR BELUGA COAL IN 1983 DOLLARS

Source	Mine Site (tons/yr)	Coal Location (FOB)	Price[a] Range $/million Btu
Diamond Alaska[b]	10 million	ship	1.20-1.70
Bechtel[c]	7.7 million	ship	1.27-1.65
Placer Amex[d]	5 million	mine	1.16-1.74

a/ All previous estimates escalated by the implicit price deflation series.
b/ Source: Styles, 1983.
c/ Source: Bechtel Report for H-B-W (Bechtel, 1980).
d/ Source: DOE, 1980.

Table D-2.10

BELUGA AREA HYPOTHETICAL MINE
SUMMARY OF SELECTED DATA

	Case 1	Case 2
Production Rate Per Year (Tons)	1,000,000	3,000,000
Mine Life At Full Production (Years)	30	30
Average Stripping Ratio (BCY/Ton)	5.93	5.89
Personnel (Average)		
Operating	81	194
Maintenance	74	176
Salaried	33	56
Total	188	426
Tons Per Man-Shift (Average)	21.3	28.2
Initial Capital Investment	$101,041,000	$186,321,000
Initial Capital Investment Per Annual Ton	$101.04	$62.11
Life Of Mine Capital Required	$183,027,000	$353,450,000
Average Annual Operating Costs (Per Ton)		
Drainage Control and Reclamation	$0.60	$0.32
Stripping	9.19	8.52
Mining And Hauling Coal	1.11	1.08
Coal Handling And Transporting	3.05	1.77
Haul Road Construction And Maintenance	1.24	0.65
General Mine Services	1.22	0.79
Supervision And Administration	2.96	1.64
Production Taxes And Fees	0.35	0.35
Total Cash Costs	$19.72	$15.12
Average Depreciation	6.10	3.97
Average Total Cost	$25.82	$19.09
Average Coal Prices (Per Ton)		
At 10% R.O.R.	$40.85	$28.52
At 15% R.O.R.	47.99	33.52
At 20% R.O.R.	56.40	39.70
Average Coal Prices (Per MM Btu)(a)		
At 10% R.O.R.	$2.72	$1.90
At 15% R.O.R.	3.20	2.23
At 20% R.O.R.	3.76	2.65

Note:

(a) Assumes 7,500 Btu/Lb.

Source: Mining Cost Estimates, Beluga Area Hypothetical Mine, Paul Weir Company, June 27, 1983.

Table D-2.11

SOME PROJECTED REAL 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 D-2.12

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	
	Western Coal[a]	2.9
	Western Lignite[b]	2.3
	Coal Exports	1.6

a/HV of 10,000 Btu/lb.
b/HV of 7,500 Btu/lb.

Sources: DRI, 1983; Clark, 1983.

Table D-2.13

NENANA COAL TRANSPORTATION COSTS
FROM HEALY TO GENERATING PLAN LOCATION (1983 $/MMBtu)

	Plant Location				
Year	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:

Nenana = $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 D-2.14

ESTIMATED DELIVERED PRICES OF COAL IN ALASKA BY YEAR
(In 1983 $/Btu x10^6)

Year	Nenana Field Coal Delivered To			Beluga Field Coal
	Mine Mouth (2.6%/yr.)	Nenana (2.2%/yr)	Willow (2.2%/yr)	With Exports (1.6%/yr)
1983	1.40	1.72	1.91	1.86
1984	1.44	1.74	1.92	1.89
1985	1.47	1.77	1.95	1.92
1986	1.51	1.83	2.00	1.95
1987	1.55	1.88	2.05	1.98
1988	1.59	1.92	2.09	2.01
1989	1.63	1.97	2.14	2.05
1990	1.68	2.02	2.20	2.08
1991	1.72	2.07	2.24	2.11
1992	1.76	2.11	2.29	2.15
1993	1.81	2.17	2.35	2.18
1994	1.86	2.22	2.40	2.21
1995	1.91	2.27	2.46	2.25
1996	1.85	2.32	2.50	2.29
1997	2.01	2.38	2.56	2.32
1998	2.06	2.43	2.62	2.36
1999	2.11	2.48	2.67	2.40
2000	2.17	2.55	2.74	2.44
2001	2.22	2.60	2.79	2.48
2002	2.28	2.66	2.85	2.51
2003	2.34	2.73	2.92	2.55
2004	2.40	2.79	2.98	2.60
2005	2.46	2.85	3.05	2.64
2006	2.53	2.93	3.12	2.68
2007	2.59	2.99	3.19	2.72
2008	2.66	3.06	3.26	2.77
2009	2.73	3.14	3.34	2.81
2010	2.80	3.21	3.41	2.86

Table D-3.1

PRICES OF TURBINE AND DIESEL OIL
FOR ELECTRICAL GENERATION - 1983 $/MMBtu

Type Fuel	Location	
	Anchorage	Fairbanks
Diesel oil - No. 1[1/]	6.87	7.46
Turbine oil - No. 1-2[2/]	6.23	7.02

1/ Based on average of price quotes from Chevron and Tesoro Oil Companies of about $0.95/gal. for Anchorage and $1.03/gal. for Fairbanks (June 1983) the heating value is about 5.8 X 10^6 Btu/bbl.

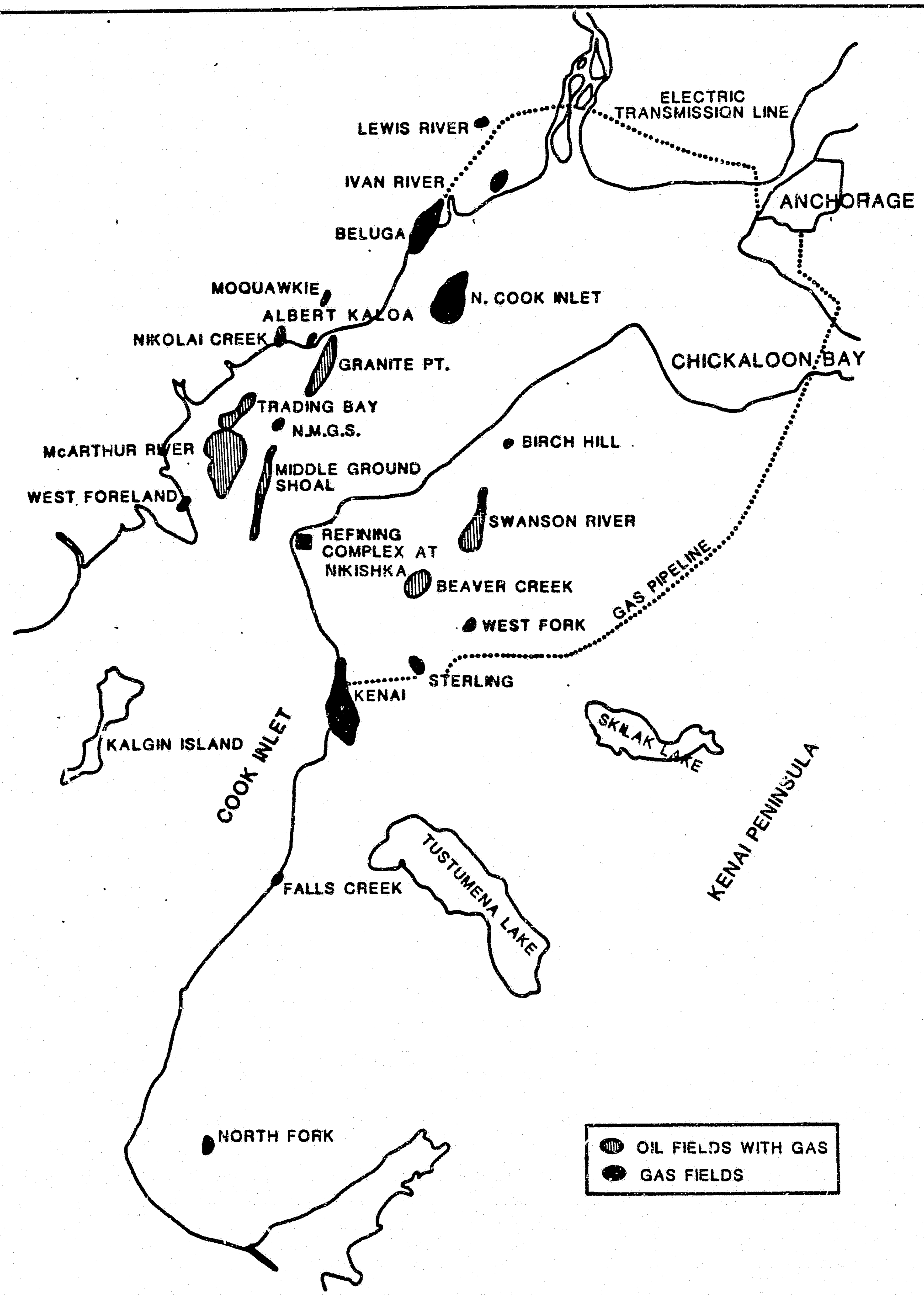
2/ Based on price quote by Tesoro Oil Comapny of $0.86/gal. in Anchorage and $0.97/gal. in Fairbanks (June 1983) the heating value is about 5.8 X 10^6 Btu/bbl.

Table D-3.2

PROJECTED PRICES OF DIESEL AND TURBINE FUEL AT ANCHORAGE FOR VARIOUS OIL PRICE SCENARIOS[1] - 1983--2010 (1983 $/MMBtu)

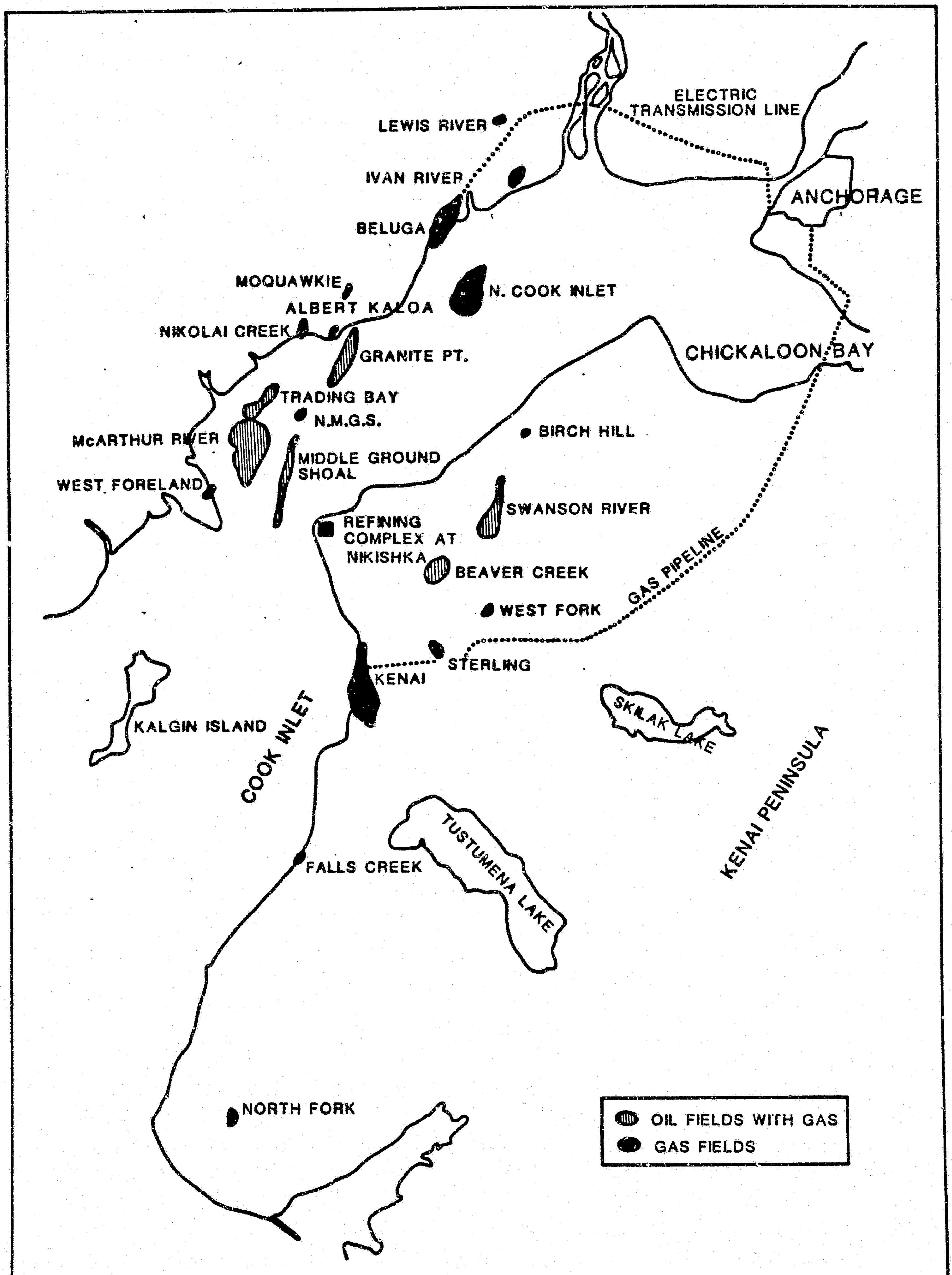
	DOR Mean		DOR 30%		DOR 50%		DRI Spring 1983		SHCA Basecase		Reference Case		Constant Rates of Change							
													+2%/yr.		0%/yr.		-1%/yr.		-2%/yr.	
Year	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine
1983[2]	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23
1984	5.69	5.16	5.39	4.89	5.70	5.17	5.97	5.41	6.55	5.94	6.55	5.94	7.01	6.35	6.87	6.23	6.80	6.17	6.73	6.11
1985	5.38	4.88	4.98	4.51	5.84	5.30	6.41	5.81	6.25	5.66	6.25	5.66	7.15	6.48	6.87	6.23	6.73	6.11	6.60	5.98
1986	5.31	4.81	4.82	4.37	5.23	4.74			6.25	5.66	6.25	5.66	7.29	6.61			6.67	6.04	6.47	5.86
1987	5.21	4.72	4.63	4.20	5.10	4.63			6.25	5.66	6.25	5.66	7.44	6.74			6.60	5.98	6.34	5.75
1988			4.57	4.15	5.06	4.59			6.25	5.66	6.25	5.66	7.59	6.88			6.53	5.92	6.21	5.63
1989			4.53	4.10	5.04	4.57			9.50	8.62	6.43	5.83	7.74	7.02			6.47	5.87	6.09	5.52
1990	5.49	4.98	4.25	3.85	4.99	4.52	8.78	7.97	9.50	8.62	6.63	6.01	7.89	7.16	6.87	6.23	6.40	5.81	5.96	5.41
1991			4.10	3.71	4.82	4.37														
1992			4.01	3.63	4.77	4.32														
1993			3.85	3.48	4.57	4.14														
1994			3.78	3.42	4.48	4.06														
1995	5.85	5.24	3.70	3.35	4.46	4.04	10.90	9.88	11.02	9.99	7.68	6.97	8.71	7.90	6.87	6.23	6.09	5.52	5.39	4.89
1996			3.64	3.30	4.27	3.88														
1997			3.55	3.21	4.26	3.86														
1998			3.53	3.20	4.22	3.83														
1999			3.50	3.20	4.20	3.81														
2000	6.24	5.52	3.45	3.15	4.15	3.76	12.69	11.51	12.78	11.58	8.91	8.08	9.62	8.72	6.87	6.23	5.79	5.25	4.87	4.42

1/See Exhibit B Section 5.4 for projected rates of change in oil prices.
2/Prices from Table D-3.1



COOK INLET GAS FIELDS

FIGURE D-1.1



COOK INLET GAS FIELDS

FIGURE D-1.1

Table D-3.2

PROJECTED PRICES OF DIESEL AND TURBINE FUEL AT ANCHORAGE
FOR VARIOUS OIL PRICE SCENARIOS[1/] - 1983-2010
(1983 $/MMBtu)

	DOR Mean		DOR 30%		DOR 50%		DRI Spring 1983		SHCA Basecase		Reference Case		Constant Rates of Change +2%/yr.		Constant Rates of Change 0%/yr.		Constant Rates of Change -1%/yr.		Constant Rates of Change -2%/yr.	
Year	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine
2001																				
2002																				
2003																				
2004																				
2005	6.66	5.81	3.20	2.92	3.93	3.56	13.40	12.16	15.17	13.75	10.32	9.36	10.62	9.63	6.87	6.23	5.51	4.99	4.40	3.99
2006																				
2007																				
2008																				
2009																				
2010	7.10	6.12	2.97	2.71	3.72	3.37	14.16	12.84	18.02	16.33	11.97	10.85	11.73	10.63	6.87	6.23	5.24	4.75	3.98	3.61

	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	10[illegible]
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		--
Swanson River		--	--	--	--	--	--	259(8)	--
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(9)

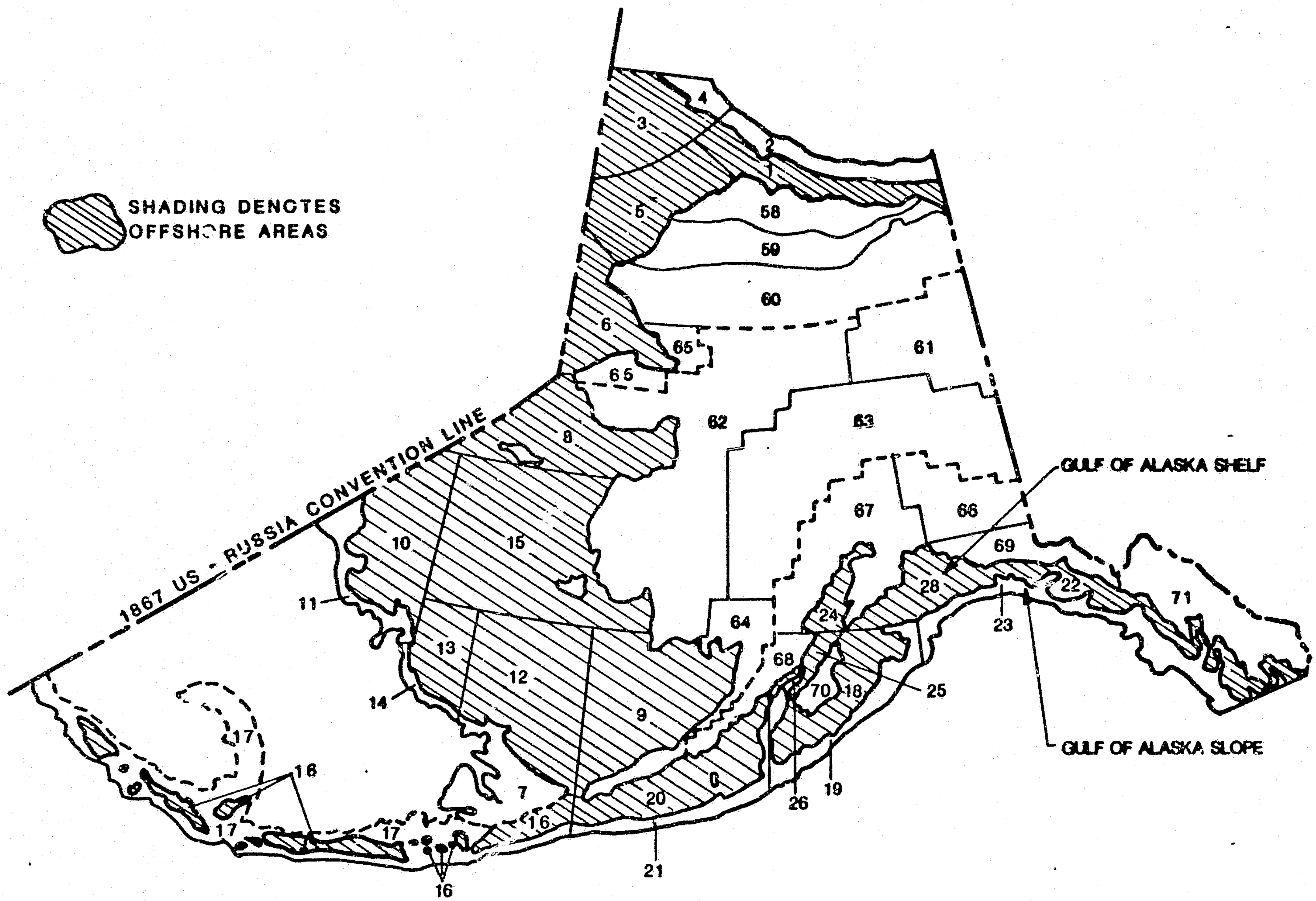
Notes

(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 1976.
(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.

ESTIMATED COOK INLET NATURAL GAS RECOVERABLE RESERVES AND COMMITMENT STATUS AS OF JANUARY 1,1982

FIGURE D-1.2

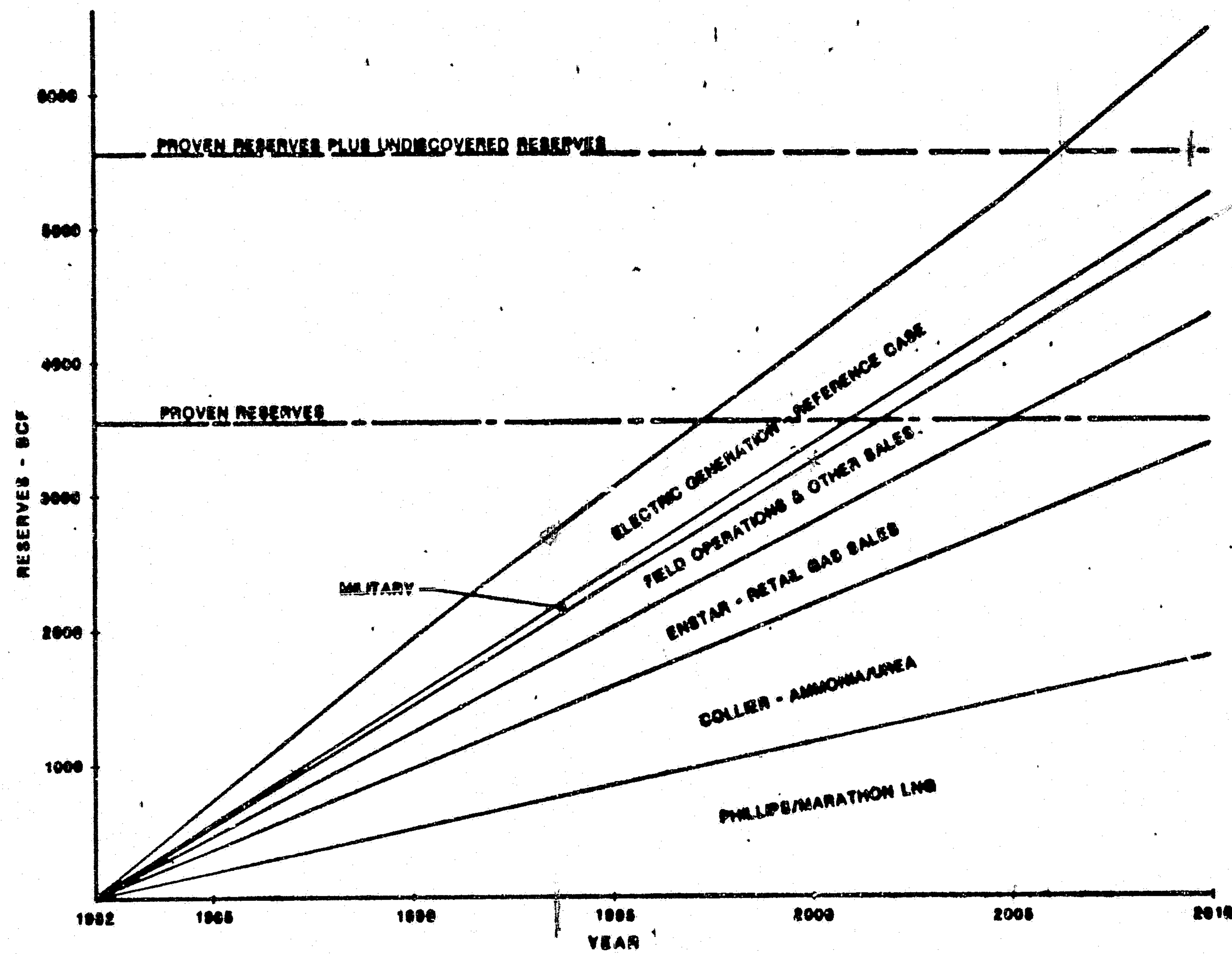
00063



AREAS OF ALASKA ASSESSED BY THE U.S.G.S. FOR UNDISCOVERED RESOURCES

SOURCE: U.S. DEPARTMENT OF THE INTERIOR GEOLOGICAL SURVEY, OPEN-FILE REPORT 82-666A, 1981.

FIGURE D-1.3



COOK INLET NATURAL GAS RESERVES AND
ESTIMATED CUMULATIVE CONSUMPTION

FIGURE D-1.4

Coal Generation Cost

Unit Size	200 MW
Unit Capital Cost	$2,340/kw
Availability	85%
Annual Generation	1.5×10^9 kwh
Fuel Cost	$1.70/MMBtu
Heat Rate	9,750 Btu/kwh
O & M Cost	$0.0032/kwh
Real Cost of Capital	3.5%
Economic Life	35 years

Annual Capital Cost:

$$C_{cap} = (\$2340/\text{kw})(200{,}000\ \text{kw})(\text{CRF; 35 yrs; 3.5\%}) = \quad \$22.6 \times 10^6$$

Annual O & M Cost:

$$C_{O\&M} = (1.5 \times 10^9\ \text{kwh/yr.})(\$0.0032/\text{kwh}) = \quad \$4.8 \times 10^6$$

Annual Fuel Cost:

$$C_F = (1.5 \times 10^9\ \text{kwh/yr})(9750\ \text{Btu/kwh})(\$1.70/10^6\ \text{Btu}) = \$24.9 \times 10^6$$

Total Annual Costs $\underline{\$52.3 \times 10^6}$

MAXIMUM DEREGULATED COOK INLET GAS PRICES
(BASED ON SUBSTITUTABILITY OF COAL-FIRED UNITS)

FIGURE D-1.5

Coal Generation Cost

Unit Size	200 MW
Unit Capital Cost	\$2,340/kw
Availability	85%
Annual Generation	1.5×10^9 kwh
Fuel Cost	\$1.70/MMBtu
Heat Rate	9,750 Btu/kwh
O & M Cost	\$0.0032/kwh
Real Cost of Capital	3.5%
Economic Life	35 years

Annual Capital Cost:

$$C_{cap} = (\$2340/\text{kw})(200{,}000\ \text{kw})(\text{CRF; 35 yrs; 3.5\%}) = \$22.6 \times 10^6$$

Annual O & M Cost:

$$C_{O\&M} = (1.5 \times 10^9\ \text{kwh/yr.})(\$0.0032/\text{kwh}) = \$4.8 \times 10^6$$

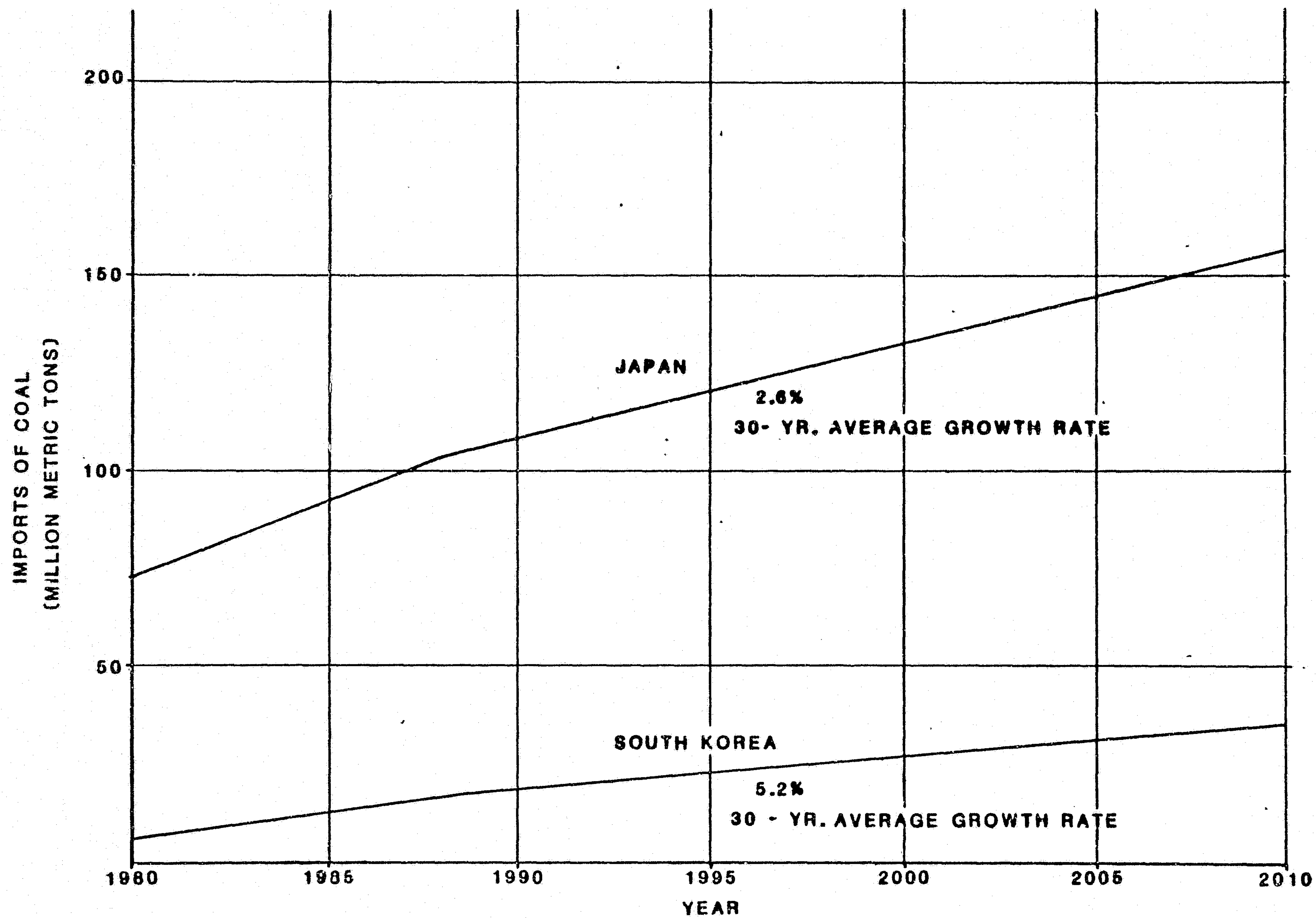
Annual Fuel Cost:

$$C_F = (1.5 \times 10^9\ \text{kwh/yr})(9750\ \text{Btu/kwh})(\$1.70/10^6\ \text{Btu}) = \$24.9 \times 10^6$$

Total Annual Costs $\underline{\$52.3 \times 10^6}$

MAXIMUM DEREGULATED COOK INLET GAS PRICES
(BASED ON SUBSTITUTABILITY OF COAL-FIRED UNITS)

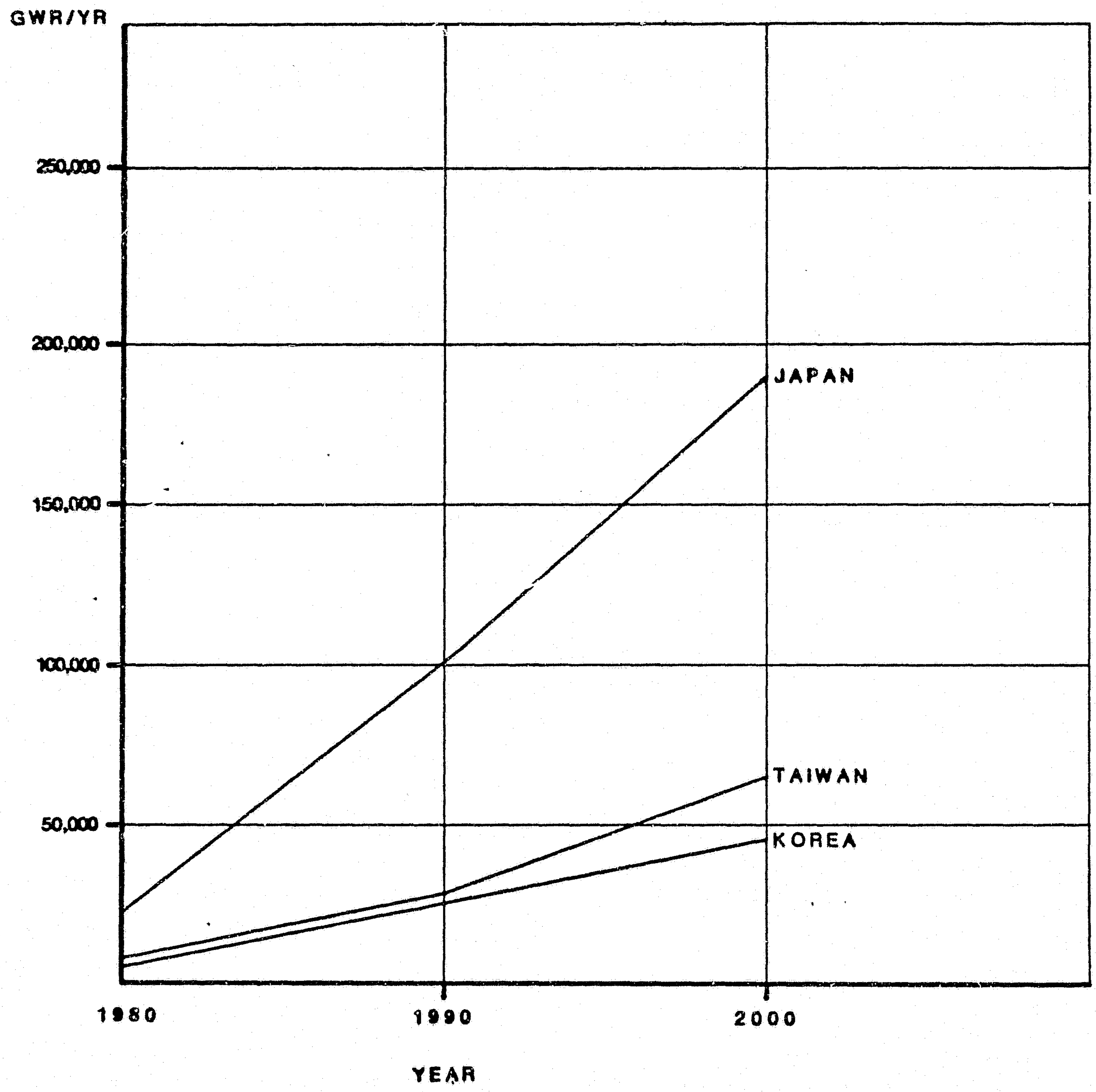
FIGURE D-1.5



PRESENT AND PROJECTED COAL IMPORTS
IN JAPAN AND SOUTH KOREA, 1980-2010

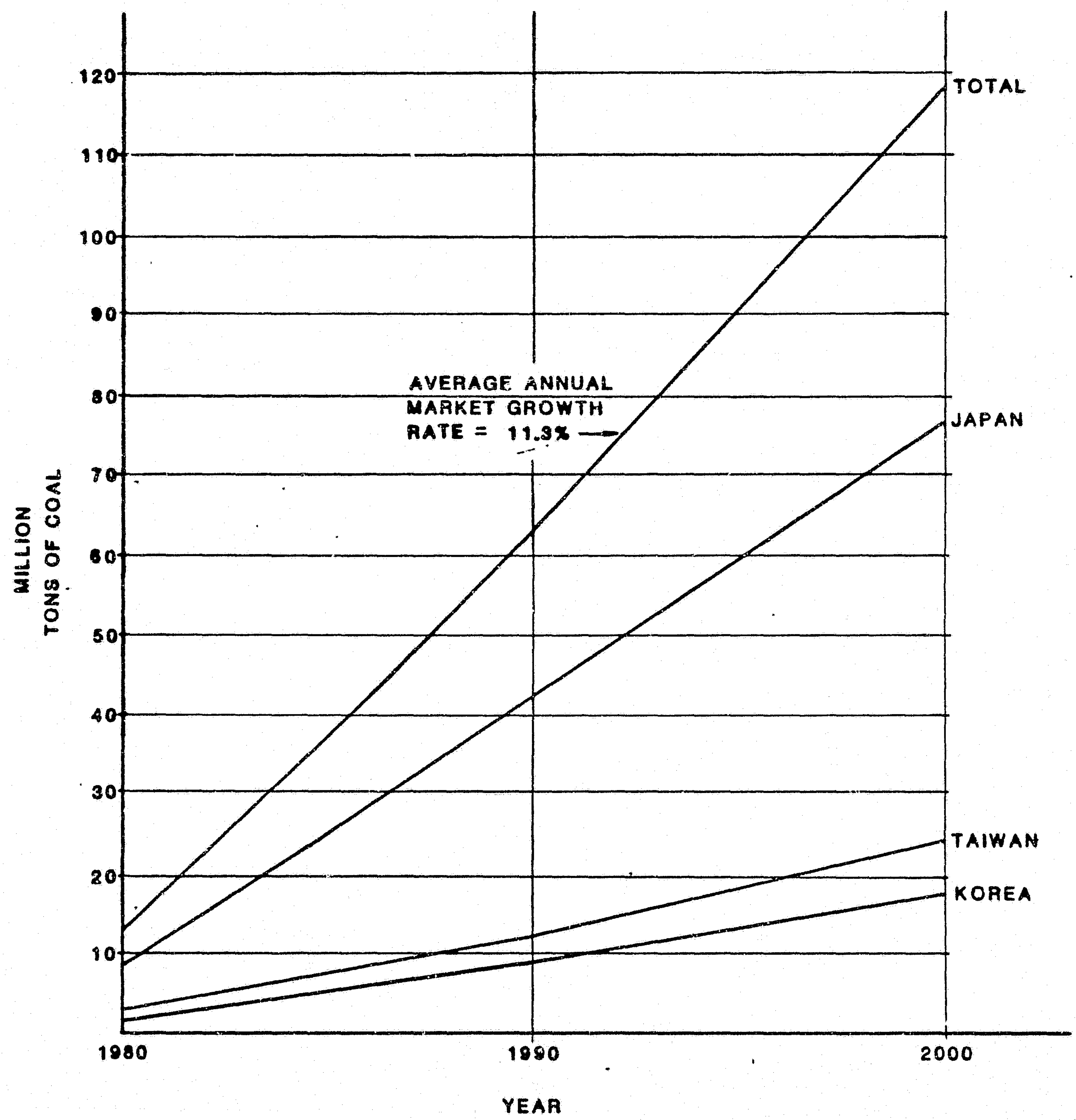
SOURCE: SHERMAN CLARK ASSOCIATES 1983

FIGURE D-2.1



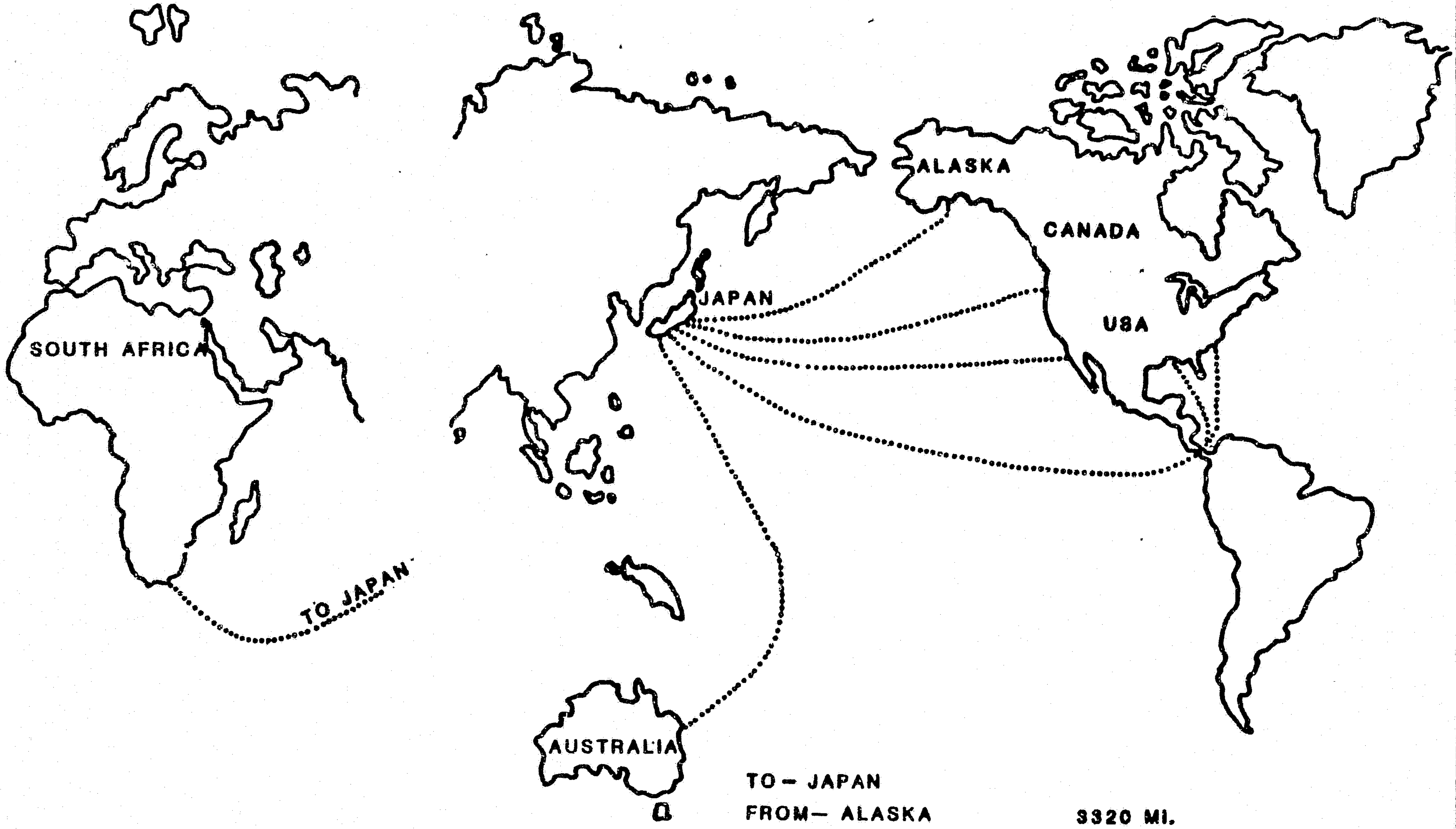
PROJECTED COAL FIRED ELECTRICITY GENERATION
IN PACIFIC RIM COUNTRIES,1980-2000
(GWR/YR)

FIGURE D-2.2



TOTAL COAL NEEDS FOR ELECTRIC POWER GENERATION IN PACIFIC RIM NATIONS, 1980-2010

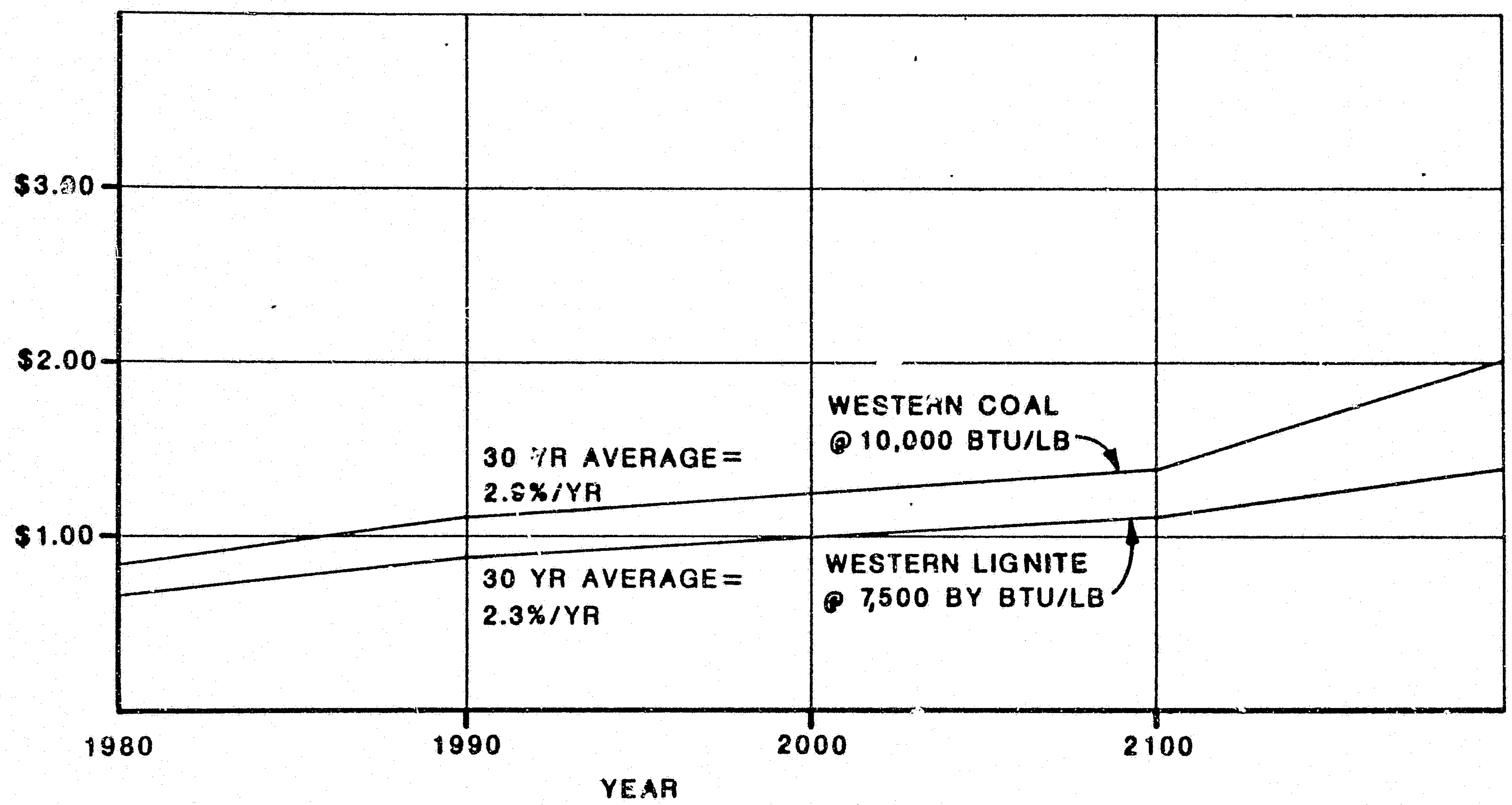
FIGURE D-2.3



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.

DISTANCES FROM COAL PORTS TO JAPAN

FIGURE D-2.4



FORECAST REAL COAL PRICES FOR WESTERN
COAL AND LIGNITE,1980-2010;NEW CONTRACT
AND SPOT MARKET STEAM COAL
(1982DOLLLARS)

FIGURE D-2.5