ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

DESIGN TRANSMITTAL

SUBTASK 6.36 - GENERATION PLANNING PARAMETERS

JANUARY 1981

ACRES AMERICAN INCORPORATED
1000 Liberty Bank Building
Main at Court
Buffalo, New York 14202
Telephone (716) 853-7525

TABLE OF CONTENTS

	Page
1 - INTRODUCTION	1
1.1 - Objective	1
1.2 - Approach to Analysis	1
1.3 - Contents of Transmittal	2
2 - BASIC ASSUMPTIONS	3
2.1 - Period of Analysis	3
2.2 - Cost Estimating	3
2.3 - Interest Rates and Annual Carrying Charges	3
2.4 - Cost Excalation Rates	4
3 - PLANNING METHODOLOGY	9
3.1 - Alternative Criteria	9
3.2 - Load Analysis	9
3.3 - Planning Under Uncertainty	9
3.4 - Target Generation Plant Reliability	11
3.5 - Interconnection Capability	11
3.6 - Base System	11
4 - ATTACHMENT	
- Letter dated January 20, 1981 from APA to Acres	

LIST OF TABLES

		Page
2 - 1	Annual Fixed Carrying Charges Used in Generation Planning Model	6
2 - 2	Fuel Prices and Escalation Rates	7
2 - 3	Summary of Economic and Financial Parameters for Generation Planning	8
3 - 1	Load and Energy Forecasts Alaska Railbelt Area	14
3 - 2	1980 Railbelt Existing Capacity	15

1 - INTRODUCTION

1.1 - Objective

The objective of this design transmittal is to document planning parameters to be used in the generation system analyses of Subtask 6.36. The analyses will involve making comparisons of alternatives with the assistance of a production costing model. Costs will be spread over the study period as appropriate and compared on a present worth basis. The intent of the Subtask 6.36 analyses will be to provide cost, size and timing input for selection of one or more Susitna alternatives.

1.2 - Approach to Analysis

It is proposed that as a public investment, the Susitna project be evaluated first from a public or economic perspective, using economic parameters. Initial analysis and screening of Susitna candidates will be supported by a numerical analysis and a system-wide generation planning model (OGP-5). A financial or cost of power perspective and corresponding parameters will also be adopted, but only for those candidates that are judged most favorable from the economic evaluation. That is, the economically viable proposals will be simulated using the same generation planning model to determine the cost of power with and without the proposed Susitna project(s).

The differences between economic and financial perspectives pertain to the following parameters.

(a) Project Life

In economic evaluations, an economic life is used without regard to the terms (repayment period) of debt capital employed to finance the project. Cost of power (or financial) perspective uses an amortization period that is tied to the terms of financing. Retirement period (policy) should be equivalent to project life in economic evaluations; cost of power analysis may use a retirement period that differs from the amortization period.

(b) Denomination of Cash Flows and Discount Rates

The economic evaluation will use real dollars and real discount rates that exclude the effects of general price inflation with the exception of fuel escalation. Cost of power analysis is in nominal or escalated dollar terms; that is, it uses escalated cash flows and nominal interest rates.

(c) Taxes and Subsidies

These intra-state transfer payments are excluded from the economic analyses and considering the current status of taxation needs in Alaska, taxes will be considered as zero for the cost of power analysis.

(d) Market or Shadow Prices

Whenever market and shadow prices diverge, economic evaluations use shadow prices (opportunity costs or values). Cost of power analysis uses market prices projected as applicable based on Subtask 6.32 output.

The values proposed in this transmittal are considered to be estimates. These values will be reviewed and updated as necessary when various studies are undertaken in other subtasks. The planning parameters addressed are selected as those which will be critical to project analysis. These parameters are those which impact all areas of system planning. They are not intended as a substitute for data to be developed in other task 6, 9 or 11 subtasks but will supply a common basis for costing and evaluation of alternatives.

The parameters provide a basis for cost estimation, interest rates, escalation, load analysis, system reliability and interconnection capabilities. Most parameters cannot be associated with a single assumed value. At this time it is not possible to define most likely or expected values with precision, and not desirable to assume an exact value.

Initial trail values will be used for screening and will not be designated as most likely or expected. They will represent a reasonably conservative view of moderate values. The scenarios developed using these moderate parameters are referred to herein as the base case. Sensitivity testing will be undertaken using associated "high" trial values and "low" trial values. High and low trial values should not be interpreted as extreme limits rather, a reflection of an expected range. If a generation development approach is found to be reasonably insensitive to high, moderate and low parameter values, this would indicate the robustness of the development with respect to this parameter, a useful measure of its value. Initial screening will not be concerned with parameter robustness as a selection criteria, but later screening will take this measure into account.

It is important to note that application of the various parameters contained herein will not necessarily provide an accurate reflection of the true life cycle cost of any single generating resource of the system. From the public (State of Alaska) perspective, the relevant project costs are based on opportunity values and exclude transfer payments such as taxes and subsidies. This comparative analysis of project economics and state net economic benefits will be addressed under Task II.

1.3 - Contents of Transmittal

This transmittal contains study parameters separated into basic assumptions and methodology. The assumptions include those values associated with cost estimating, interest rates, period of analysis and cost escalation. Methodology addresses generation plant reliability, interconnection capability, alternative criteria and load forecasts.

APA's comments on this design transmittal are incorporated in the attachment.

2 - BASIC ASSUMPTIONS

2.1 - Period of Analysis

The time period which will be modeled in the generation planning phase will extend from the present to 2010, corresponding to the ISER forecasts. It is realized that the project life of all Susitna alternatives may not be completed in this period. However, the project life cycle economics are not the primary consideration of the generation planning subtask. Full life cycle analysis will be addressed in Task 11. If necessary, to confirm cost trends, system costs may be analyzed for an additional period beyond 2010. Annual system costs will be present valued to the year 1980 in all cases.

2.2 - Cost Estimating

Cost estimates for generating alternatives developed for the generation planning studies, except for Susitna hydroelectric alternatives, have been obtained from previous studies of Alaska hyrdoelectric and thermal generating sources. These existing estimates will be compared for consistency, accuracy, and level of detail in Subtask 6.32 and 6.33.

Cost estimates will be based on a January 1, 1980 price level, to be consistent with work performed in Subtasks 6.03 and 6.06. Costs will be updated to this level using the Handy-Whitman Index of Public Utility Construction costs, compiled by Whitman, Requardt and Associates. The indices for the Pacific Coast Region will be used. Although this region does not include Alaska, it is expected to reflect Alaska price escalation relationships.

Where applicable the contingency factor to be used on project preliminary construction cost estimate is 20 percent for hydro alternatives and 16 percent for thermal alternatives. In addition, a 12 percent allowance for engineering, administration and construction management will be placed on the subtotal of construction cost plus contingency for projects greater than 100 MW and 14 percent engineering/administration will be added to projects less than 100 MW. These factors are specific to the Task 6 alternative analysis and will be reexamined as necessary for cost estimation of other study elements.

Interest during construction (IDC) is accounted for by compounding the annual investment expenditures to the in-service year of the project and computing the equivalent annual capital cost based on this 'future value' of the investment. The interest rate used to compute future values will correspond to those selected for economic and financial evaluations.

2.3 - Interest Rates and Annual Carrying Charges

Generation planning based on economic parameters and criteria will use a 3 percent real discount rate in the base analysis. This figure corresponds to the historical and expected real cost of the debt capital. Sensitivity analysis will examine in 1981 the effects of low and high real discount rates, using a range of 1.5 percent (recent real return on Alaska Permanent Fund investments) to 5 percent. The issue of tax-exempt financing does not impinge on these economic evaluations.

Financial or cost of power analyses require a nominal or market rate of interest for discounted cash flow analysis. This rate will depend on, among others, general price inflation, capital structure (debt-equity ratios) and tax-exempt status. In the base case, a general rate of price inflation of 7 percent is assumed for the period 1980 to 2010. Given a 100 percent debt capitalization and a 3 percent real discount rate, the appropriate nominal interest rate is approximately 10 percent in the base case.1/

To calculate annual carrying charges, the following assumptions were made regarding the economic life of various power projects.

- Large steam plant - 30 years
- Small steam plant - 35 years
- Hydroelectric project - 50 years
- Gas turbine, oil-fired - 20 years
- Gas turbine, gas-fired - 30 years
- Diesel - 30 years

It should be noted that the 50-year life for hydro projects was selected as a conservative estimate and does not include replacement investment expenditures. The factors for insurance costs (0.10 percent for hydro projects and 0.25 percent for all others) are based on FERC guidelines.2/ State and federal taxes were assumed to be zero for all types of power projects. This assumption is valid for planning based on economic criteria since all intra-state taxes should be excluded as transfer payments from Alaska's perspective. The subsequent financial analyses may relax this assumption if non-zero state and/or local taxes or payments in lieu of identified. Table 2-1 summarizes the annual fixed carrying charges relevant to the generation planning analysis based on economic and financial parameters.

2.4 - Cost Escalation Rates

In the initial set of generation planning parameters, it is assumed that all cost items except energy escalate at the rate of general price escalation (7 percent per year). This results in real growth rates of zero percent for non-energy costs in the set of economic parameters used in real dollar generation planning and nominal growth rates of 7 percent for the subsequent escalated dollar cost of power analysis.

1/ The nominal interest rate is computed as (1 + inflation rate) x (1 + real interest rate), or 1.07 x 1.03.

2/ Federal Energy Regulatory Commission, Hydroelectric Power Evaluation, Washington, August 1979.

Base period (January 1980) energy prices will be estimated based on both market and shadow (opportunity) values. The initial set of generation planning parameters will use base period costs (market and shadow prices) of $\$1.15/10^6$ Btu and $\$4.00/10^6$ Btu for coal and distillate respectively. For natural gas, the current actual market price is about $\$1.05/10^6$ Btu and the shadow price is estimated to be $\$2.00/10^6$ Btu. The shadow price for gas represents the expected market value assuming an export market were developed. This assumption and value is to be used for both the economic and cost of power analysis.

Real growth rates in energy costs (excluding general price inflation) are shown in Table 2-2. These are based on fuel escalation rates from the Department of Energy (DOE) mid-term Energy Forecasting System for DOE Region 10 (including the States of Alaska, Washington, Oregon and Idaho).[3/] Price escalators pertaining to the industrial sector were selected over those available for the commercial and residential sectors to reflect utilities' bulk purchasing advantage. A composite escalation rate has been computed for the period 1980 to 1995 reflecting average compound growth rate per year. As DOE has suggested that the forecasts to 1995 may be extended to 2005, the composite escalation rates are assumed to prevail in the period 1996 to 2005. Beyond 2005, zero real growth in energy prices is assumed.

In sensitivity analysis, the impacts of alternative energy price escalators will be analyzed with respect to the economic viability of proposed Susitna developments. This analysis will include a case where fuel prices are held constant in real terms.

For cost of power analyses, the nominal (inflation-inclusive) rates of energy price escalation will be used. These are defined as (1 + general price inflation rate) x (1 + energy price escalator). For example, using 7 percent and 3 percent values for the rates of general price inflation and fuel prices, the nominal escalator for fuel would be 1.07 x 1.03, or 10.2 percent.

Table 2-3 summarizes the sets of economic and financial parameters proposed for generation planning.

3/ Department of Energy, Office of Conservation and Solar Energy, Methodology and Procedures for Life Cycle Cost Analysis, Federal Register, October 7, 1980.

TABLE 2-1

ANNUAL FIXED CARRYING CHARGES

USED IN GENERATION PLANNING MODEL

PARAMETERS	PROJECT LIFE/TYPE			
	30-Year Thermal %	35-Year Thermal %	50-Year Hydro %	20-Year Thermal %
ECONOMIC PARAMETERS				
Cost of Money	3.00	3.00	3.00	3.00
Sinking Fund	2.10	1.65	0.89	3.72
Insurance	0.25	0.25	0.10	0.25
TOTALS	5.35	4.90	3.99	6.97
FINANCIAL PARAMETERS				
Non-exempt				
Cost of Money	10.00	10.00	10.00	10.00
Amortization	0.61	0.37	0.09	1.75
Insurance	0.25	0.25	0.10	0.25
TOTALS	10.86	10.62	10.19	12.00
Tax-exempt				
Cost of Money	8.00	8.00	8.00	8.00
Amortization	0.88	0.58	0.17	2.19
Insurance	0.25	0.25	0.10	0.25
TOTALS	9.13	8.83	8.27	10.44

TABLE 2-2

FUEL PRICES AND ESCALATION RATES

Base Period (January 1980) Prices ($/million Btu)	Natural Gas	Coal	Distillate
Market Prices	$1.05	$1.15	$4.00
Shadow (Opportunity) Values	2.00	1.15	4.00
Real Escalation Rates (Percentage) Change Compounded Annually)			
1980 - 1985	1.79%	9.56%	3.38%
1986 - 1980	6.20	2.39	3.09
1991 - 1995	3.99	-2.87	4.27
Composite (average) 1980 - 1995	3.98	2.93	3.58
1996 - 2005	3.98	2.93	3.58
2006 - 2010	0	0	0

TABLE 2- 3

SUMMARY OF ECONOMIC AND FINANCIAL PARAMETERS FOR GENERATION PLANNING

	Generation Planning Analysis	
	Economic*	Financial*
1 - Base Period (January 1980) Energy Prices ($/million Btu)		
1.1 - Natural Gas	2.00	2.00
1.2 - Coal	1.15	1.15
1.3 - Distillate	4.00	4.00
2 - General Price Inflation Per Year (%)	not applicable	7
3 - Discount & Interest Rates Per Year (%)		
3.1 - Real Discount Rate	3	not applicable
3.2 - Nominal Interest Rate (Non-exempt Case)	not applicable	10
3.3 - Nominal Interest Rate (Tax-exempt Case)	not applicable	8
4 - Non-energy Cost Escalation Per Year (%)	0	7
5 - Energy Price Escalation Per Year (%)		
5.1 - Natural Gas		
1980 - 2005	3.98	11.26
2006 - 2010	0	7.00
5.2 - Coal		
1980 - 2005	2.93	10.14
2006 - 2010	0	7.00
5.3 - Distillate		
1980 - 2005	3.58	10.83
2006 - 2010	0	7.00
6 - Economic Life		
6.1 - Large Steam Turbine	30	not applicable
6.2 - Small Steam Turbine	35	not applicable
6.3 - Hydro	50	not applicable
6.4 - Diesel and Gas Turbine (Gas-fired)	30	not applicable
6.5 - Gas Turbine (Oil-fired)	20	not applicable
7 - Amortization Period		
7.1 - Steam	not applicable	30
7.2 - Hydro	not applicable	50
7.3 Diesel and Gas Turbine (Gas-fired)	not applicable	30
7.4 - Gas Turbine (Oil-fired)	not applicable	20

*Note that economic and financial parameters apply to real dollar and escalated dollar analyses respectively.

3 - PLANNING METHODOLOGY

3.1 - Alternative Criteria

Generation alternatives will be selected for inclusion in planning scenarios based upon relative merits in the area of fuel availability, environmental and technical viability, robustness with respect to inflation and other parameter changes, operating characteristics and costs. In effect, if two alternatives are comparable in all other areas except cost, the less expensive alternative will be used in generation planning, and the more expensive alternative will be rejected.

A base scenario with and without the Susitna alternatives will be established, made up of those alternatives which are the least expensive among viable alternatives. The resultant selection of a Susitna alternative will be tested against the existing system in competition with these viable alternatives and with further testing as to the sensitivity of cost to selected parameters.

3.2 - Load Analysis

The forecasts to be used for generation planning will be based on Acres analysis of the ISER energy forecast. The energy forecast that will be used by Acres as the basis for generation planning is the mid-range forecast. Sensitivity analyses will be carried out using variable loads developed using the ISER scenarios of high and low economic activity and government spending.

The energy and load forecasts developed by ISER and Woodward Clyde Consultants include energy projections from self-supplied industrial and military generation sectors. It is forseeable that these markets will be unavailable for the future electrical suppliers to a large extent. By the same token, the capacity owned by these sectors will not be available as a supply by the general market.

A review of the industrial self suppliers indicates that they are primarily offshore operations, drilling operational and others which would not likely add nor draw power from the system. Thus, those amounts have been deleted from the ISER totals.

Additionally, although it is considered likely that the military would purchase available cost effective power from a general market, much of their capacity resource is tied to district heating systems, and thus would need to continue operation. For these reasons only one-third of the military generation total will be considered as a load on the total system. This amount is about 4 percent of total energy in 1980 and decreases to 2.5 percent in 1990. This method of accounting for these loads has no real effect total capacity additions needed to meet projected loads after 1985.

The adjusted forecast was used in generation planning as shown in Table 3-1.

3.3 - Planning Under Uncertainty

In order to incorporate the variable forecasts and uncertainty of the load forecasts into planning, a probability based load model feature of the OGP program will be used. A bried description of this feature follows.

The middle level forecast or most likely forecast, is introduced into the program in detail. This would include daily load shapes, monthly variability and annual growth of peaks and energy. Additional variables are added which introduce forecast uncertainty in terms of higher and lower levels of peak demand and the probability of the occurrence of these forecasts. For example: in year 1985 the middle level demand forecast entered is 1000 MW. Variable forecasts are entered for 850, 900, 1100 and 1150 MW, with associated probabilities of occurrence of .10, .20, .20 and .10, leaving the middle level as .40.

The OGP program will use this variable forecast in generating system reliability calculation only. A loss of load probability will be calculated for each projected demand level as compared to the available capacity and a weighted average will be taken. This loss of load probability will then be used for capacity addition decisions. After capacity decisions are made, the program uses the middle level forecast detail for operating the production cost model.

This method of dealing with uncertainty is directly applicable to the data available for 6.36 studies. There are five forecasts which could be plugged in to the reliability calculations, the three by ISER and the two extremes calculated by Acres. Subjectivity is reduced to the decision of placing probabilities on the load forecasts.

The probability set will be the same as that introduced in the example. This is based on the assumption that each outside forecast is half as likely to happen as the adjacent forecast towards the middle. The loads and probability will be analyzed as:

FORECAST	Probability Set 1
LES-LG*	.10
LES-MG	.20
MES-MG	.40
HES-MG	.20
HES-HG	.10

*ES - Economic Activity
G - Government
L, M, H - Low, Medium, High

An inquiry will be made to ISER to gain their opinions of these probability sets and invite a probability set of their own.

3.4 - Target Generation Plant Reliability

In order to perform this system study, a criteria for generating plant system reliability are necessary. These criteria are important to determine the adequacy of the available generating capacity as well as the sizing and timing of additional units.

There appear to be no specific criteria currently applied to generation planning in the Railbelt area. The primary reason for this is that utilities have developed individually without the benefits of reliable interconnections. Since Susitna planning is to meet region needs some 15 to 20 years hence, it is assumed that within this time frame an interconnected system will exist or be in the process of implementation. There are two alternative methods to account for reliability which are currently in wide use in eletric generation system planning; the use of a reserve margin or a loss of load probability (LOLP).

A reserve margin refers to the excess available capacity to a system during the peak power demand of the year. Typical target reserve margins are from 15 to 25 percent. In recent years, reserve margins have been greater than planned in some regions due to the depressed load growth trends. These margins have in some cases approached 45 percent.

A LOLP for a system is a calculated probability based on the characteristics of capacity, forced and scheduled outage and cycling ability of individual units in the generating system. The probability defines the likelihood of not meeting the full demand within a one year period. For example, a LOLP of 1 relates to the probability of not meeting demand one day in one year; a LOLP of 0.1 is one day in ten years. For this study, a LOLP of 0.1 will be adopted. This value is widely used by utility planners in the country as a target for independent systems. This target value will be used both for the base plan and for sensitivity analyses dealing with the effects of over/under capacity availability.

3.5 - Interconnection Capability

The assumption of a fully intertied system will not be assumed for generation planning. A 138 kV line will be assumed to be in place by 1984 with limited transfer capabilities between Fairbanks and Anchorage. The addition of future capacity will bear the cost of transmission to either the 138 kV line, or to the load centers, as applicable to the location of the generation alternative.

3.6 - Base System

The system to be used as existing capacity in the Railbelt will include the capacity of all utilities in the region, plus all utilities committed by these utilities. The Corps of Engineers Bradley Lake project, although not utility owned, will also be included. To develop the existing generation model for Railbelt utilities, a number of sources were consulted:

- Woodward Clyde Consultants "Forecasting Peak Electrical Demand for Alaska's Railbelt", September, 1980.

- IECO Transmission Report for the Railbelt, 1978.

- U.S. DOE, "Inventory of Power Plants in the U.S.", April, 1979.

- Electrical World Directory of Public Utilities 1979 - 1980 edition.

- FERC Form 12A for the following utilities.

  - Anchorage Municipal Light & Power (AMLP)
  - Chugach Electric Association (CEA)
  - Homer Electric Association (HEA)
  - Fairbanks Municipal Utility System (FMUS)

- Williams Brothers Engineering Company
  1978 Report on FMUS and GVEA Systems (Golden Valley Electric Association).

- Discussions with:

  - AMLP - Mr. Hank Nichols
  - FMUS - Larry Colp
  - GVEA - Woody Baker
  - APA - Don Gotschall

Table 3.2 summarizes the information received from these sources. Some discrepancies were apparent especially with respect to AML&P and Copper Valley Electric Association (CVEA). According to two sources, CVEA has no installed capacity and is a purchaser. AML&P has a recently installed combined cycle addition of 33 MW to the George M. Sullivan Plant No. 2 (Unit 6) which is not reflected in the other estimates. The column: ACRES GM represents the installed capacity to be used in the OGP-5 Generation Model for Task 6.36 studies which is a resolution of all data sources collected.

The 943.6 MW consists of 53 units as follows:

No. Units	Type	Capacity (MW)
1	Combined Cycle	140.9
2	Hydro	45.0
18	NG Gas Turbines (Anchorage)	470.5
6	Oil Gas Turbines (Fairbanks)	168.3
5	Coal-Fired Steam	54.0
21	Small Diesels	64.9
53		943.6

In order to establish a retirement policy for Railbelt utilities, a number of references were consulted including the APA draft feasibility report guidelines, FERC guidelines, historical records and consultation with utilities, particularly in the Fairbanks area. From consideration of all of these sources, the following retirement policy is proposed for use:

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

** 100 years changed to 50 years for consistency in economic approach to all alternatives.

The Power Plant and Industrial Fuel Use Act prohibits the use of natural gas in existing major electric generating plants after 1990. Alaska, however, was exempted from that portion of the Act.

TABLE 3-1

LOAD AND ENERGY FORECASTS* ALASKA RAILBELT AREA

YEAR	Low Forecast		Mid Forecast		High Forecast	
	MW	Gwh	MW	Gwh	MW	Gwh
1980 Base	514	2,789	514	2,787	514	2,789
1985	578	3,158	650	3,565	695	3,859
1990	641	3,503	735	4,032	920	5,085
1995	797	4,351	944	5,171	1,294	7,119
2000	952	5,198	1,173	6,413	1,669	9,153
2005	1,047	5,707	1,379	7,526	2,287	12,543
2010	1,141	6,215	1,635	8,938	2,901	15,933

* Derived from the Woodward-Clyde Consultants submittal of September 23, 1980, adjusted to eliminate industrial self-supplied and two-thirds of the military sector.

TABLE 3-2

1980 RAILBELT EXISTING CAPACITY

RAILBELT UTILITY	Installed Capacity (1980) MW				
	WCC 1980	IECO 1978	DOE 1979	ELEC. WO. 1979	ACRES GM
AMLP	184.0	130.5	148.0	108.8	215.4
CEA	420.0	411.0	402.2	410.9	411.0
GVEA	211.0	218.6	230.0	211.0	211.0
FMUS	67.0	65.5	68.2	67.4	67.2
CVEA*	18.0	--	13.0	--	--
MEA*	0.9	0.6	3.0	0.9	0.9
HOMER (HEA)	2.6	9.2	1.7	3.5	2.6
SES*	5.5	5.5	5.5	5.5	5.5
APAd*	--	30.0	30.0	30.0	30.0
TOTAL	909.0	870.9	901.6	838.0	943.6

*SES - Seward Electrical System
MEA - Matanuska Electrical Association
APAd - Alaska Power Administration

ALASKA POWER AUTHORITY

333 WEST 4th AVENUE - SUITE 31 - ANCHORAGE, ALASKA 99501

Phone: (907) 277-7641
(907) 276-2715

4 - Attachment

January 20, 1981

Mr. John Lawrence
Project Manager
Acres American Incorporated
The Liberty Bank Building
Main at Court
Buffalo, New York 14202

Dear John:

Your Subtask 6.36 design transmittal (Revision 3, December 1980) has been received. This letter constitutes an interim response provided for the purpose of keeping the studies on schedule.

We are not convinced that DOE Region 10 fuel cost escalation rates are appropriate for Susitna planning. In particular we question the use of Region 10 figures for Alaskan coal. Attached is the final Beluga Coal Market Study that we hope you will review in detail. It should provide some useful information on (1) the likelihood of a world market for Alaskan coal, (2) the cost of transporting Alaskan coal, and (3) Beluga field production costs. Coupled with knowledge of present world coal prices and estimates for world coal price escalation, this information should provide a sound basis for forecasting Railbelt coal prices.

As a general approach to forecasting costs of Alaskan fuels with access to U. S. or world markets, we suggest that you apply escalation rates to world prices and then net out appropriate transportation costs to give Alaskan prices. This makes more sense than applying world or U. S. escalation rates directly to Alaskan fuel costs. For each fuel, the assumptions regarding transportation systems and access to world markets should be made explicit.

The design transmittal should emphasize that the Susitna studies depend on long term price trends (post 1993) and that the short term fluctuations over the next 12 years are relatively unimportant.

Sincerely,

FOR THE EXECUTIVE DIRECTOR

Robert A. Mohn

Robert A. Møhn
Director of Engineering

Attachment: Beluga Coal Market Study
(transmitted to Chuck Debelius,
January 20, 1981)