ALASKA POWER AUTHORITY

Anchorage - Fairbanks Transmission Intertie

Economic Feasibility Study Report

DRAFT

April 1979

INTERNATIONAL ENGINEERING COMPANY, INC.

ROBERT W. RETHERFORD ASSOCIATES

TK
1425
.S8
A23
no. 250d

ALASKA POWER AUTHORITY

Anchorage - Fairbanks Transmission Intertie
Economic Feasibility Study Report

DRAFT

April 1979

LIBRARY
HABITAT DIVISION
ALASKA DEPT. OF FISH & GAME
333 Raspberry Road
Anchorage, Alaska 99502

Merged With
A.R.L.I.S.
ANCHORAGE, ALASKA
Est. 1997

ARLIS
Alaska Resources
Library & Information Services
Anchorage, Alaska

INTERNATIONAL ENGINEERING COMPANY, INC.

ROBERT W. RETHERFORD ASSOCIATES

CONTENTS

ARLIS
Alaska Resources
Library & Information Services
Anchorage, Alaska

CONTENTS

CONTENTS

APPENDIXES

CONTENTS

TABLES

TABLES (Continued)

FIGURES

FIGURES (Continued)

FIGURES (Continued)

ABREVIATIONS

ac	alternating current
ACF	annual cost of fuel
ACSR	aluminium conductor, steel reinforced
AIA	Alaskan Intertie Agreement
AML&P	Anchorage Municipal Light and Power Company
APA	Alaska Power Authority
A.R.R.	Alaska Railroad
AVF	average value factor
bpd	barrels per day
BTU	British thermal units
CEA	Chugach Electric Association, Inc.
CFC\	Cooperative Finance Corporation
dc	direct current
DOE	U.S. Department of Energy
EEI	Edison Electric Institute
FFB	Federal Finance Bank
FGD	flue gas desulphurization
FOH	forced outage hours
FMUS	Fairbanks Municipal Utility System
ft	feet
gal	gallon
GVEA	Golden Valley Electric Association, Inc.
GWh	gigawatt-hours (million kilowatt-hours)
HEA	Homer Electric Association, Inc.
HVDC	high voltage, direct current
IAEAT	Interior Alaska Energy Analysis Team
IECO	International Engineering Company, Inc.
IEEE	Institute of Electrical and Electronics Engineers
ISER	Institute for Social and Economic Research
kcmil	thousand circular mils
kV	kilovolts
kVa	kilovolt-amperes
kW	kilowatts
kWh	kilowatt-hours
LNG	liquid nitrate gas
LOLP	loss of load probability
MAREL	Multi-Area Reliability, a computer program developed by PTI
MBTU	Million British thermal unit
MEA	Matanuska Electrical Association, Inc.
MVA	megavolt-amperes
MW	megawatts
NESC	National Electrical Safety Committee
NOx	nitrous oxide
O&M	operations and maintenance
ORV	off-road vehicle
PCF	Plant capacity factor
P.I.	point of intersection
PRS	power requirements studies
PTI	Power Technology, Inc.
REA	Rural Electrification Administration
RI	radio interference
RWRA	Robert W. Retherford Associates, Inc.
S/C	single circuit
SCGT	simple cycle combustion turbine
SIL	surge impedance loading
TLCAP	Transmission Line Cost Analysis Program, a computer program developed by IECO
TLEAP	Transmission Line Economic Analysis Program, a computer program developed by IECO
TLFAP	Transmission Line Financial Analysis Program, a computer program developed by IECO
tpy	tons per year
TVI	television interference
USA	United States of America
USGS	United States Geological Survey
VAR	volt-amperes reactive

CHAPTER 1

INTRODUCTION

CHAPTER 1
INTRODUCTION

This report presents a determination of the economic feasibility for a transmission line interconnection between the utility systems of the Anchorage and Fairbanks areas. It includes an objective evaluation of the specific conditions under which the intertie is economically feasible. An interconnection between the two previously independent power systems will reduce total installed generation reserve capacity, provide means for the interchange of energy, reduce spinning reserve requirements, and provide the means for optimum economic dispatch of generating plants on the interconnected system basis. The later integration of the Upper Susitna Hydropower Project into the interconnected Anchorage-Fairbanks power system would serve to increase the benefits already available from early operation of the intertie. The work described in this report was performed under the authority of the 26 October 1978 contract between the Alaska Power Authority and the joint-venture of International Engineering Company, Inc. (IECO) and Robert W. Retherford Associates (RWRA).

Alternative system expansion plans were developed and analyzed during this study for each of the following areas:

- Independent Anchorage area
- Independent Fairbanks area
- Interconnected Anchorage-Fairbanks area
  (generation reserve sharing option)
- Interconnected Anchorage-Fairbanks area
  (generation reserve sharing and firm power transfer option)
- Interconnected Anchorage-Fairbanks area (with inclusion of the Upper Susitna Hydropower Project)

This study confirms the economic feasibility of the Anchorage-Fairbanks transmission line interconnection as well as the possibility of an early implementation date for the project, prior to longer-range development of the Upper Susitna Hydropower Project. This study also establishes additional intertie benefits from the supply of construction power to the sites of the Upper Susitna Hydropower Project. It also evaluated potential benefits from firm power supply to Matanuska Electric Association's system at the intermediate Palmer substation of the intertie. Preliminary financial and management plans for the implementation of the project were developed and are presented in the last two chapters of this report.

An Intertie Advisory Committee, composed of managers of Railbelt area utilities with the chairmanship of the Executive Director of the Alaska Power Authority, was formed. During the performance of this study three Intertie Advisory Committee meetings were held (4 December 1978, 8 January 1979, and 14 February 1979) to review factors related to the intertie and to discuss preliminary findings of this study. The following Railbelt utilities were represented on the Intertie Advisory Committee:

- Anchorage Municipal Light & Power (AML&P)
- Copper Valley Electric Association (CVEA)
- Chugach Electric Association (CEA)
- Fairbanks Municipal Utility System (FMUS)
- Golden Valley Electric Association (GVEA)
- Homer Electric Association (HEA)
- Matanuska Electric Association (MEA)

The Consultants wish to acknowledge the valuable information, comments, and support received from the managers and engineers of the Railbelt utilities, and the Alaska Power Administration during the performance of this economic feasibility study.

CHAPTER 2

SUMMARY AND CONCLUSIONS

CHAPTER 2
SUMMARY AND CONCLUSIONS

The purpose of this economic feasibility study is to determine the conditions under which a transmission interconnection between the utility systems of Anchorage and Fairbanks would be economically feasible. Following are the important aspects of work performed and the conclusions of this study.

2.1 STUDY SUMMARY

A. Load Forecasts for Railbelt Area

Load forecast is the basis for system expansion planning. The most recent load forecasts for the utility service areas in the Railbelt area were examined to establish the basis for projection of future trends.

The sum of the most recent forecasts made by the individual utilities in the area has been selected as the upper growth limit to the forecast ranges for the Railbelt area. The median forecast prepared by the Alaska Power Administration, as a revision to the Susitna Project Market Study, was selected as the lower limit. The statistical average of these two forecasts was calculated and used in this study as the "most probable" forecast.

The long-range "most probable" load demand projections in MW for the load areas are:

	Anchorage	Fairbanks	Combined System
1980	573	153	749
1985	977	231	1194
1990	1581	338	1869
1995	2402	477	2842
2000	3446	663	4054

B. Selection of Intertie Route

Alternative transmission corridors considered in previous studies were analyzed as to accessibility, cost of right-of-way, transmission line design, and environmental and aesthetic considerations. The preferred corridor described in the Susitna Report, along the Parks Highway from Anchorage to Fairbanks, was selected for the intertie route. It was selected because of its favorable length, accessibility, and environmental considerations. This corridor was further defined by preparing preliminary layouts. Field trips to important sites along this 323-mile line route were made to confirm the suitability at this corridor for the intertie.

C. Transmission Line Design

To provide a basis for intertie cost estimation, conceptual designs for 230-kV and 345-kV transmission lines and substations were made. The transmission Line Cost Analysis Program (TLCAP), a computer program developed by IECO, was used to select optimum designs. The results favored relatively long spans (1300 feet) and high-strength conductors. Tubular steel, guyed towers and pile-type foundations were selected for both the 230-kV and 345-kV lines as being well suited for Alaska conditions.

D. System Expansion Plans

To determine the intertie's economic feasibility, alternative system expansion plans were prepared with and without the Anchorage-Fairbanks intertie. All system expansion plans were prepared to meet the "most probable" load demand projections.

To assume a nearly constant level of generation reliability (LOLP Index) for all system expansion plans, a multi-area reliability (MAREL) computer study was performed. Annual load models for both areas were developed. The load models indicate that there is very little diversity between the loads in the Anchorage and Fairbanks areas.

The 1984-1997 study period was selected to best suit system requirements. The earliest year when the intertie can be operational is 1984. Based on optimistic assumptions, the last generating unit of Upper Susitna Hydropower Project will be on-line in January 1997.

E. Facility Cost Estimates

Cost estimates were developed for alternative system facilities to allow for economic comparisons. All costs were adjusted to January 1979 levels. Transmission line costs were calculated by using the TLCAP program. The same computer program calculated the line losses.

To provide a means for optimum economic dispatch of generating units on the interconnected system basis, costs for control and communication systems were included in the intertie cost estimates. Cost estimates for new generating plant facilities (gas-turbine units and coal-fired steam plants) were based on cost information in the Power Supply Study - 1978 report to GVEA, prepared by Stanley Consultants. Appropriate Alaskan construction cost location adjustment factors were applied to derive specific site cost estimates.

Construction power costs for the Susitna Project were calculated. The results indicate a clear advantage for utilizing the intertie as a source of construction power.

F. Economic Feasibility Analysis

The economic feasibility analysis of the intertie was performed using the discounted present-worth method. Facility costs for those new generating plants not affected by the introduction of the intertie were excluded from the analysis. The Transmission Line Economic Analysis Program (TLEAP), a computer program, was used to analyze the sensitivity of different escalation and discount rates on the capital costs of various alternatives. In this analysis, a 7% long-term average annual escalation rate and a 10% discount rate was used for principal investigations.

G. Financial and Institutional Planning

A preliminary financial plan for implementation of the transmission intertie on a progressive basis was developed. The probable composition of institutions and participating utilities for ownership, management, and operating responsibilities is reviewed in this report, and present arrangements and possible future requirements are discussed.

2.2 CONCLUSIONS

The study shows that:

- The 230-kV single circuit intertie, having a 130-MW line loading capability (Case IA) is economically feasible in 1984, based only on benefits due to reduction of generation reserve plant capacity. The present-worth of net benefits is $7,968,000.

- A considerable increase in benefits is obtained if the 230-kV single circuit intertie (double circuit after 1992), in addition to line capacity allocated to reserve sharing, includes firm power transfer capability (Case IB). The increase in present-worth net benefits is from $7,968,000 to $14,589,000, or an increase of 83 percent. Additional benefits due to supply of construction power to the Upper Susitna Project sites is $2,943,000, or an added increase of 18 percent.

- The 345-kV single circuit intertie (Case IC) is not economically feasible in 1984 if based only on the benefits due to reduction of installed generation reserve capacity. Further studies, not made, will probably indicate that a 345-kV intertie would be feasible if firm power transfer benefits are included.

- The 230-kV intertie with intermediate substations at Palmer and Healy (Case ID) has the following net benefits:

Study Case	PW of Net Benefits
IA (Reserve sharing only)	$ 7,968,000
ID (Plus supply to MEA)	$10,065,000
ID (Plus constr. power supply)	$13,113,000

- The fully integrated interconnected system operation generates additional benefits which are not quantified in this study. These benefits could be due to:

  - Decrease in spinning reserve requirements by reducing the on-line plant capacity for the combined system.

  - Coordination of maintenance scheduling which would improve combined system security and provide cost savings.

  - Economies from optimum dispatch of generating units on the interconnected system basis.

- Expansion plans for the interconnected system with the Upper Susitna Project were developed to determine the effect of this project on the interconnected system expansion plans, the displacement of thermal generating units, and intertie transmission requirements with Susitna Project.

- If an early 230-kV transmission intertie is constructed in 1984, due considerations should be given for constructing the Anchorage-Susitna portion of this intertie for 345-kV and operating it temporarily at 230-kV.

- Generation and interconnection planning is a complex and continuous process. This Intertie Feasibility Study is only a part of the overall power system expansion plans for the Railbelt area. Further intertie studies will be required to establish definitive characteristics for this transmission intertie. These studies should be closely coordinated with the future expansion plans of all utilities in the Railbelt area.

CHAPTER 3
LOAD FORECASTS FOR RAILBELT AREA

3.1 ENERGY AND DEMAND FORECAST RANGE

The basis for establishing a range of future load projections for the Anchorage - Cook Inlet and Fairbanks - Tanana Valley areas, together with a combined forecast for an interconnected system service area in the Railbelt, was obtained from an examination of previous forecasts[1/] compared in the Battelle Report of March 1978 (Ref. 1). These were examined in relation to a combination of the most recent utility forecasts prepared for the REA and an August 1978 revision of previous forecasts for the Upper Susitna Project, issued by the Alaska Power Administration in December 1975 (Ref. 2).

A. Range of Energy Consumption Resulting from Battelle Study

The Battelle study provides a compendium of previous forecasts and an analysis of assumptions intrinsic to their projections. It attempts to eliminate low probability scenarios and select a range of utility and industrial loads for the intertied Railbelt system. The following summary of annual energy consumption, excluding national defense and non-interconnected users, represents the definitive results of the Battelle study:

	1974		1980		1990		2000
Annual Consumption-GWh							
Upper Range Limit	1,600		3,400		10,800		22,500
Interval Growth Rate		13.4%		15.3%		10.2%	
Lower Range Limit	1,600		2,600		8,500		16,000
Interval Growth Rate		8.4%		9.6%		4.0%	

1/ See Section 3.3 for references used in this chapter.

Battelle selected this energy consumption range after carefully evaluating the methodology used in several previous forecasts and relevant assumptions pertaining to economic factors. Two load studies were deemed most appropriate to future load projections for the Railbelt. They are, in order of preference, the Upper Susitna Project Power Market Study by the Alaska Power Administration, and the report Electric Power in Alaska, 1976-1995 (Ref 3.) by the Institute for Social and Economic Research (ISER) of the University of Alaska.

1. Forecasts for Anchorage - Cook Inlet Area - From the several load forecasts corresponding to various growth scenarios of the ISER study, Battelle selected Forecasts 2 and 4 as most appropriate for the Anchorage and Cook Inlet area. These forecasts assume limited petroleum development, which was considered to be the most likely prospect. The assumptions underlying the scenario for limited petroleum development are:

- Petroleum Production will be 2 million bpd in 1980, and 3.6 million in 1990.
- A natural gas pipeline will be constructed from Prudhoe Bay through Canada.
- An LNG plant for natural gas from the Gulf of Alaska will be constructed.

The assumptions regarding electrical energy consumption are:

Sector	Case 2	Case 4
• Residential	Moderate Electrification	No Growth
• Commercial/Industrial	Growth as Usual	Minimum Electrification

The ISER study did not include new industrial consumption in forecasts, other than expansion of existing loads served by utilities. However, it did relate utility forecasts to economic scenarios, in which future energy consumption was quantitatively projected according to specified assumptions of petroleum development, population, aggregate income, saturation levels, and average usage per customer.

In 1975 the Alaska Power Administration prepared forecasts for the potential power market of the Upper Susitna Project. The forecasts contained projections of industrial load for existing and possible future installations. Battelle modified these projections to include the following assumptions:

- In addition to gradual expansion of existing refinery capacity, a new 150,000-bpd refinery will be built by 1983.
- An aluminum smelter with a capacity of 300,000 tpy will be constructed, to be on-line by 1985.
- A nuclear fuel enrichment plant, included in previous load projections, was deleted from future industrial load.
- Industrial development in the interior region was assumed to be excluded from the load area of an intertied Railbelt system.

A summary of industrial facilities included in the Battelle forecast for the Anchorage and Cook Inlet area is as follows:

Existing Facilities	New Facilities
Chemical Plant	Aluminum Smelter
LNG Plant	LNG Plant
Refinery	Refinery
Timber Mills	Timber Mills
	Coal Gasification Plant
	Mining and Mineral Processing Plants
	New City

2. Forecasts for Fairbanks - Tanana Valley Area - A similar evaluation by Battelle defined the most probable forecasts for the Fairbanks and Tanana Valley area. It assumed that industrial development in the interior region will consist largely of self-supplied mining operations in remote areas. Thus, load growth will be attributable only to utility customers in the service areas of the Fairbanks Municipal Utilities System (FMUS) and the Golden Valley Electric Association, Inc. (GVEA).

In the judgment of Battelle, the most likely consumption range for the Fairbanks area is bounded by the mid-range projections of the Upper Susitna Market Study, with mid-range forecasts prepared by the Interior Alaska Energy Analysis Team (IAEAT) (Ref. 4) as the upper bound and the ISER Case 4 as the lower bound.

3. Combined Forecasts for the Railbelt - The Battelle energy and demand forecast range for the combined utility and industrial load of the Railbelt, encompassing the Anchorage - Cook Inlet and Fairbanks - Tanana Valley areas, is shown graphically on Figures 3-1 and 3-4, respectively. These are intended to serve as background comparisons with combined utility forecasts and the revised projections of the Alaska Power Administration for the potential market of the Upper Susitna Project.

B. Forecasts by Utilities and the Alaska Power Administration

The most recent Power Requirements Studies (PRS) of the REA utilities (Ref. 5) in the Anchorage and Fairbanks areas were obtained, together with the most probable load forecasts, as projected for the Anchorage Municipal Light and Power Company (AML&P) and the Fairbanks Municipal Utilities System (FMUS).

Tables 3-1 and 3-2 provide tabulations of utility forecasts and extrapolated projections to the horizon year 2000, for the Anchorage - Cook Inlet area and the Fairbanks - Tanana Valley area, respectively. The Valdez - Copper Valley area is not included in the forecasts for the

Railbelt, as these load areas are assumed not to be interconnected with the intertied Railbelt system until after the completion of the Upper Susitna Project. As the PRS provided load projections for a base year and at two 5-year intervals, interpolations were made on the basis of assumed compound growth between reported values. On the further assumption that growth rates will decline progressively to the horizon year, extrapolations were made of net energy generation with growth rates declining from reported values at 5-year intervals to 2000. These growth rates were applied on the assumption that there will be no abrupt transition to low growth rates. Rather, growth will diminish in gradual steps as markets are saturated and the effects of conservation and price elasticity reflect in future energy consumption levels. Reported load factors were interpolated for intermediate years and the trend extrapolated to the horizon year to obtain projections of annual peak demand.

The utility forecasts were combined for the Anchorage - Cook Inlet area, the Fairbanks - Tanana Valley area, and the total Railbelt. Table 3-3 provides tabulations of net energy generation, load factor, and annual peak diversified demand. It is obtained by the application of coincidence factors to the sum of individual utility peak demands. These load forecasts are shown on Figures 3-1 through 3-6, in comparison with load projections prepared in August 1978 by the Alaska Power Administration for the Upper Susitna Project, as revisions to previous power market forecasts evaluated as part of the Battelle study.

A summary of the Alaska Power Administration load projections is given in Table 3-4. These projections include only utility and industrial load forecasts, on the assumption that national defense installations will not be supplied as part of the interconnected system load. Since the Battelle forecasts also excluded load forecasts for national defense installations, direct comparisons can be made.

The range of load forecasts was based on a ± 20% spread from projected mid-range growth to 1980. The industrial load projected by Battelle was included in the forecast range on a selective basis. The differential between the "high" and "extra high" forecasts is an additional 280 MW of load, representing an aluminum smelter. The "low" forecast excludes the load projected for the New City.

C. Comparison and Selection of Forecast Range

The forecasts of net energy generation for the Railbelt are shown on Figure 3-1. Curve 1 represents the combination of the most recent forecasts for municipal and REA utilities, as presented in Tables 3-1, 3-2, and 3-3. The forecast aligns closely up to 1990 with the upper bound of the Battelle forecast range. Beyond 1990 the divergence arises from the different assumptions made in regard to growth rates in the 1990-2000 period. The upper bound of the Battelle range exhibits an abrupt change of growth rate, from 15.3% to 10.2%, applied to total energy in the Railbelt, while the combined utilities forecast exhibits a more gradual transition to lower growth rates. Although many economic factors will contribute to lower overall growth rates in energy consumption, a reasonable approach to establishing an upper limit has been taken, in that individual utility forecasts were assumed to decline without abrupt change. This assumption is based on the fairly constant percentage expenditure from disposable income for energy needs, as determined by the study of future consumption patterns in Alaskan service areas (Ref. 6), the results of which are given in an extract from the RWRA report (Ref. 7) presented in Appendix A.

Accordingly, the combined utilities forecast has been selected as the maximum growth limit to the possible range of total energy forecasts for the Railbelt. The median forecast prepared by the Alaska Power Administration, as a revision to the Susitna Project Market Study, has been selected as the lower limit to the forecast range for the Railbelt. This recently prepared forecast exhibits lower growth than the 1975 forecast for the Susitna Project, and represents a prudent choice for a conservative growth scenario.

Figures 3-2 and 3-3 show the relationship between the combined utilities forecast and the range of forecasts prepared by the Alaska Power Administration. The effect of the aluminum smelter load can be observed as the differential between curves 2C and 3C on Figure 3-2, and curves 2A and 3A on Figure 3-3. The median forecast also excludes the aluminum smelter load but provides for a reasonable realization of the industrial potential in the Anchorage area. In setting the lower limit of the forecast range in the context of the considerable industrial growth potential of this area of Alaska, it is thought that the selected forecast range will provide a good test of the economic feasibility of establishing an interconnection in the Railbelt.

A similar comparison of forecast demand can be made by reference to Figures 3-4, 3-5, and 3-6. The combined utilities demand forecast is below the upper bound of the Battelle range until after 1985 and aligns in fairly close proximity until 1990. Beyond 1990 divergence occurs based upon the assumption discussed previously in relation to energy growth. The median demand forecast for the Susitna Project, prepared by the Alaska Power Administration, exhibits a growth characteristic that roughly parallels the lower bound of the Battelle range between 1985 and 2000. As the low growth limit to the range of demand beyond 1981 selected for the interconnection study, it represents a moderately conservative view of overall growth potential.

Prior to 1981, the short-range combined utilities demand forecast is acceptable as a single demand projection, approximately at Battelle mid-range. The demand forecasts for the Susitna Project may be observed in relation to the combined utilities demand forecasts of Figures 3-5 and 3-6. The selected range of demand forecasts represents a moderate to high expectation of a continued growth of the Railbelt economy through the end of the century, this being accentuated by the interconnection of utility systems in the area.

3.2 DEMAND FORECASTS FOR GENERATION PLANNING

Once the range of load forecasts has been established, it remains to select definitive demand forecasts for generation expansion planning. Between the upper limit of the combined utilities forecast and the lower limit, represented by the median forecast by the Alaska Power Administration, lies a range of possible load growth projections, each having a certain probability of realization through time.

A. Probabilistic Representation of Load Forecast Uncertainty

On the assumption that the load forecast range obeys a normal probability distribution, the uncertainty associated with the forecast can be represented by the normal continuous probability curve of Figure 3-7A. The most probable forecast for this symmetrical representation is then the statistical average between the maximum and minimum limits, these being assumed to occur at the $\pm$ 3 standard deviation extremities of the normal bell curve. The statistical average forecasts for the Railbelt area are given in Table 3-5, these being now designated the most probable forecasts for the selected range. The statistical average or mean value is the same as the most probable value, due to the basic assumption regarding the symmetrical shape of the normal probability distribution curve.

The variability of the forecast is defined in terms of standard deviations from a most probable value, with the bandwidth of the forecast taken to be within $\pm$ 2 standard deviations from the most probable value. The degree of uncertainty associated with the forecast range determines this bandwidth, which may be expressed as a 95% chance that the actual peak demand will lie between the limits of the selected bandwidth.

As the uncertainty associated with a load forecast increases with time, the demand value defined by the bandwidth will increase with time; however, the probability of being within the bandwidth will remain constant. The demand values corresponding to this bandwidth are given in Table 3-6, these being obtained from the range of forecasts, as follows:

The demand forecast limits define the range of possible values, such that the actual future peak demand will have a 99.8% probability of being within the upper and lower forecast limits, these being the ± 3 standard deviation bounds. This can be represented by the probability plot of Figure 3-8, the implicit assumption being that the forecast limits correspond approximately to the 99.9 percentile on the three standard deviation limit. Connection of the extreme percentile limits enables the determination of the bandwidth between the ± 2 standard deviations limits, as a 2/3 ratio between the high and most probable forecasts at any point in time. The bandwidth is given in terms of demand values, as tabulated in Table 3-6. The probability multipliers given in this table, for the load levels corresponding to the forecast bandwidth, are obtained from the discrete representation of forecast uncertainty shown on Figure 3-7B, this being the usual representation of forecast uncertainty for generation planning studies.

B. Selection of Demand Forecasts for the Railbelt Area

The most probable load demands and forecast bandwidths for the Anchorage - Cook Inlet, Fairbanks - Tanana Valley and the Railbelt areas are shown on Figures 3-9 and 3-10. As the ± 2 standard load level limits cross over for the Anchorage - Cook Inlet area, the divergent bandwidth is shown on Figure 3-9 as beginning in 1982. The most probable forecast then appears as a single demand line from 1979 through 1981, which considering the short time projection is quite reasonable. The demand trend is well established for the Anchorage area and can be expected to persist in the immediate short-range time frame.

The long-range load projections are given in Table 3-6, with a total diversified demand for the combined areas of the Railbelt rising to approximately 4000 MW in the year 2000.

3.3 REFERENCES

1. Battelle Pacific Northwest Laboratories, Alaska Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, March 1978.
2. U.S. Department of the Interior, Alaska Power Administration, Upper Susitna River Hydroelectric Studies, Report on Markets for Project Power, December 1975.
3. University of Alaska, Institute for Social and Economic Research, Electric Power in Alaska, 1976-1995, August 1976.
4. Interior Alaska Energy Analysis Team, Report of Findings and Recommendations, June 1977.
5. Rural Electrification Association, Power Requirements Study for:
   Alaska 2 - Matanuska Electric Association, Inc., May 1978
   Alaska 5 - Kenai-Homer Electric Association, Inc., May 1978
   Alaska 6 - Golden Valley Electric Association, Inc., May 1976
   Alaska 8 - Chugach Electric Association, Inc., May 1976
   Alaska 18 - Copper Valley Electric Association, Inc., May 1977.
6. E. O. Bracken, Alaska Department of Commerce and Economic Development, Power Demand Estimators, Summary and Assumptions for the Alaska Situation, June 1977.
7. Robert W. Retherford Associates, System Planning Report, Matanuska Electric Association, Inc., January 1979.
8. U.S. Department of the Interior, Alaska Power Administration, A Report of the Technical Advisory Committee on Economic Analysis and Load Projections, 1974.
9. Federal Power Commission, The 1976 Alaska Power Survey, Vol. 1, 1976.
10. U.S. Army Corps of Engineers, South-central Railbelt Area, Alaska, Upper Susitna River Basin Interim Feasibility Report, December 1975.
11. U.S. Department of the Interior, Alaska Power Administration, Bradley Lake Project Power Market Analyses, August 1977.
12. Tippett and Gee, Consulting Engineers, 1976 Power System Study, Chugach Electric Association, Inc., Anchorage, Alaska, March 1976.

TABLE 3-1

ANCHORAGE - COOK INLET AREA
UTILITY FORECASTS AND EXTRAPOLATED PROJECTIONS

Year	Anchorage Municipal Light and Power Company			Alaska 2 - Matanuska Electric Association, Inc.			Alaska 5 - Kenai: Homer Electric Assoc., Inc.			Alaska 5 - Kenai: Kenai City Light System			Alaska 8 - Chugach Electric Association, Inc.		
	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)
1979	633.6	58.1	124.4	280.4	47.5	67.4	275.2	55.0	57.1	34.4	56.0	7.0	1,108.9	53.0	238.8
1980	699.4	58.1	137.5	332.8	47.0	80.8	336.6	55.0	69.9	37.5	56.0	7.6	1,283.0	54.0	271.2
1981	770.6	57.9	151.8	395.1	46.5	97.0	411.6	55.0	85.4	40.8	56.0	8.3	1,467.8	54.0	310.3
1982	847.3	57.8	167.3	468.0	56.0	116.1	502.0	55.0	104.2	44.4	56.0	9.1	1,679.1	54.0	355.0
1983	929.6	57.7	183.9	559.3	45.0	141.9	572.3	55.0	118.8	48.1	56.0	9.8	1,920.9	54.0	406.1
1984	1,017.5	57.6	201.8	668.3	44.5	171.4	652.4	55.0	135.4	52.1	56.0	10.6	2,197.5	54.0	464.5
1985	1,110.8	57.4	220.8	798.6	44.0	207.2	743.7	55.0	154.4	56.4	56.0	11.5	2,509.0	54.0	530.4
1986	1,209.5	57.3	241.1	954.4	43.5	250.5	847.9	55.0	176.0	61.1	56.0	12.5	2,810.1	54.0	594.1
1987	1,313.2	57.1	262.5	1,140.0	43.0	302.6	967.0	55.0	201.0	66.3	56.0	13.5	3,147.3	54.0	665.3
1988	1,421.6	56.9	285.0	1,322.4	44.0	343.1	1,083.0	55.0	224.8	71.5	56.0	14.6	3,525.0	54.0	745.2
1989	1,534.2	56.8	308.5	1,534.0	45.0	389.1	1,213.0	55.0	251.8	77.0	56.0	15.7	3,948.0	54.0	834.6
1990	1,650.5	56.6	333.0	1,779.4	46.0	441.6	1,358.6	55.0	282.0	83.1	56.0	16.9	4,421.7	55.0	934.7
1991	1,769.8	56.4	358.2	2,064.1	47.0	501.3	1,521.6	55.0	315.8	89.5	56.0	18.2	4,863.9	55.0	1,028.2
1992	1,891.3	56.2	384.1	2,394.4	48.0	569.4	1,704.2	55.0	353.7	96.5	56.0	19.7	5,350.3	55.0	1,131.0
1993	2,014.4	56.0	410.5	2,705.7	49.0	630.3	1,874.6	55.0	389.1	103.5	56.0	21.1	5,885.3	55.0	1,244.1
1994	2,138.0	55.8	437.2	3,057.4	50.0	698.0	2,062.1	55.0	428.0	111.1	56.0	22.6	6,473.9	55.0	1,368.6
1995	2,244.9	55.6	460.9	3,454.9	51.0	773.3	2,268.3	55.0	470.8	119.2	56.0	24.3	7,121.2	55.0	1,505.4
1996	2,357.1	55.4	485.7	3,904.0	52.0	857.0	2,495.1	55.0	517.9	127.9	56.0	26.1	7,690.9	55.0	1,625.8
1997	2,475.0	55.2	511.8	4,411.5	53.0	950.2	2,744.6	55.0	569.7	137.3	56.0	28.0	8,306.2	55.0	1,755.9
1998	2,598.8	55.0	539.4	4,852.7	54.0	1,025.9	2,964.2	55.0	615.2	146.9	56.0	29.9	8,970.7	55.0	1,900.6
1999	2,728.7	54.8	568.4	5,337.9	55.0	1,107.9	3,201.3	55.0	664.4	157.2	56.0	32.0	9,688.3	55.0	2,048.1
2000	2,865.0	54.6	599.0	5,871.7	56.0	1,196.9	3,457.4	55.0	717.6	168.2	56.0	34.3	10,463.4	55.0	2,211.9

Growth Rates:

	Anchorage Municipal	Matanuska	Homer	Kenai City	Chugach
Reported	Logistic Curve 3	18.7% (1977-1982) 19.5% (1983-1987)	22.3% (1977-1982) 14.0% (1983-1987)	8.8% (1977-1982) 8.3% (1983-1987)	15.7% (1977-1980) 14.4% (1981-1985)
Projected	5.0% (1995-2000)	16.0% (1988-1992) 13.0% (1993-1997) 10.0% (1998-2000)	12.0% (1988-1992) 10.0% (1993-1997) 8.0% (1998-2000)	7.8% (1988-1992) 7.3% (1993-1997) 7.0% (1998-2000)	12.0% (1986-1990) 10.0% (1991-1995) 8.0% (1996-2000)

TABLE 3-2

FAIRBANKS - TANANA VALLEY AREA
UTILITY FORECASTS AND EXTRAPOLATED PROJECTIONS

	Fairbanks Municipal Utilities System			Alaska 6 - Golden Valley Electric Association, Inc.		
Year	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)	Net Energy (GWh)	Load Factor (%)	Peak Demand (MW)
1979	144.3	50.0	32.9	450.0	46.3	111.0
1980	153.0	50.0	34.9	501.8	46.6	122.9
1981	162.2	50.0	37.0	559.5	46.9	136.2
1982	171.9	50.0	39.2	624.6	47.2	150.9
1983	182.2	50.0	41.6	692.6	47.3	167.1
1984	193.2	50.0	44.1	768.8	47.3	185.5
1985	204.7	50.0	46.7	853.4	47.4	205.5
1986	217.0	50.0	49.5	947.3	47.4	228.1
1987	230.0	50.0	52.5	1,050.0	47.5	252.3
1988	243.9	50.0	55.7	1,155.0	47.5	277.6
1989	258.5	50.0	59.0	1,270.5	47.6	304.7
1990	274.0	50.0	62.6	1,397.6	47.6	335.2
1991	287.7	50.0	65.7	1,537.3	47.7	367.9
1992	302.1	50.0	69.0	1,691.0	47.7	404.7
1993	317.2	50.0	72.4	1,843.2	47.8	440.2
1994	333.0	50.0	76.0	2,009.1	47.8	479.8
1995	349.7	50.0	79.8	2,189.9	47.9	521.0
1996	367.2	50.0	83.8	2,387.0	47.9	568.9
1997	385.5	50.0	88.0	2,601.8	48.0	618.8
1998	404.8	50.0	92.4	2,809.9	48.0	668.3
1999	425.1	50.0	97.1	3,034.7	48.0	721.7
2000	446.3	50.0	101.9	3,277.5	48.0	779.5

Growth Rates:

	Fairbanks Municipal Utilities System	Alaska 6 - Golden Valley Electric Association, Inc.
Reported	6.0% (1978-1990)	11.5% (1977-1982) 11.0% (1983-1987)
Projected	5.0% (1991-2000)	10.0% (1988-1992) 9.0% (1993-1997) 8.0% (1998-2000)

TABLE 3-3

COMBINED UTILITY FORECASTS FOR RAILBELT AREA

Year	Anchorage Cook - Inlet Net Energy (GWh)	Anchorage Cook - Inlet Load Factor (%)	Anchorage Cook - Inlet Peak Demand 1/ (MW)	Fairbanks - Tanana Valley Net Energy (GWh)	Fairbanks - Tanana Valley Load Factor (%)	Fairbanks - Tanana Valley Peak Demand 2/ (MW)	Combined Load Areas Net Energy (GWh)	Combined Load Areas Load Factor (%)	Combined Load Areas Peak Demand 3/ (MW)
1979	2,332.5	56.1	475	594.3	47.6	142	2,926.8	55.3	605
1980	2,689.3	56.4	544	654.8	47.9	156	3,344.1	55.6	686
1981	3,085.9	56.2	627	721.7	48.0	171	3,807.6	55.6	782
1982	3,540.8	56.0	722	795.9	48.3	188	4,336.7	55.5	892
1983	4,030.2	55.7	826	874.8	48.3	207	4,905.0	55.3	1,012
1984	4,587.8	55.5	944	962.0	48.3	227	5,549.8	55.2	1,148
1985	5,218.5	55.2	1,079	1,058.1	48.4	250	6,276.6	55.0	1,302
1986	5,883.0	54.9	1,223	1,164.3	48.4	275	7,047.3	54.8	1,468
1987	6,633.8	54.6	1,387	1,280.0	48.4	302	7,913.8	54.6	1,655
1988	7,423.5	54.7	1,548	1,398.9	48.4	330	8,822.4	54.7	1,840
1989	8,306.2	54.9	1,728	1,529.0	48.5	360	9,835.2	54.9	2,046
1990	9,293.3	55.0	1,928	1,671.6	48.5	394	10,964.9	55.0	2,276
1991	10,308.9	55.2	2,133	1,825.0	48.5	429	12,133.9	55.2	2,511
1992	11,436.7	55.3	2,360	1,993.1	48.5	469	13,429.8	55.3	2,772
1993	12,583.5	55.5	2,587	2,160.4	48.6	507	14,743.9	55.5	3,032
1994	13,842.5	55.7	2,836	2,342.1	48.6	550	16,184.6	55.7	3,318
1995	15,208.5	55.9	3,105	2,539.6	48.6	596	17,748.1	55.9	3,627
1996	16,575.0	56.1	3,372	2,754.2	48.7	646	19,329.2	56.0	3,938
1997	18,074.6	56.3	3,663	2,987.3	48.7	700	21,061.9	56.2	4,276
1998	19,533.3	56.5	3,947	3,214.7	48.7	753	22,748.0	56.4	4,606
1999	21,113.4	56.8	4,244	3,459.8	48.7	811	24,573.2	56.6	4,954
2000	22,825.7	57.0	4,569	3,723.8	48.7	873	265,49.5	56.8	5,333

Diversified Demand
for Coincidence Factor: 1/ 0.96 2/ 0.99 3/ 0.98

TABLE 3-4
Sheet 1 of 2

LOAD FORECAST FOR UPPER SUSITNA PROJECT
BY
ALASKA POWER ADMINISTRATION

	1977	1980	1985	1990	1995	2000
1. ANCHORAGE-COOK INLET AREA POWER DEMAND AND ENERGY REQUIREMENTS						
(Excluding National Defense)						
Peak Demand (MW)						
Utility Loads						
High		620	1,000	2,150	3,180	7,240
Median	424	570	810	1,500	2,045	3,370
Low		525	650	1,040	1,320	1,520
Industrial Loads						
Extra high		32	344	399	541	683
High		32	64	119	261	403
Median	25	32	64	119	199	278
Low		27	59	70	87	104
Total						
Extra high		652	1,344	1,914	2,691	3,863
High		652	1,064	1,634	2,411	3,583
Median	449	602	874	1,234	1,699	2,323
Low		552	709	890	1,127	1,424
Annual Energy (GWh)						
Utility Loads						
High		2,720	4,390	6,630	9,430	13,920
Median	1,790	2,500	3,530	4,880	6,570	8,960
Low		2,300	2,840	3,590	4,560	5,770
Industrial Loads						
Extra high		170	1,810	2,100	2,840	3,590
High		170	340	625	1,370	2,120
Median	70	170	340	630	1,050	1,460
Low		141	312	370	460	550
Total						
Extra high		2,890	6,200	8,730	12,270	17,510
High		2,890	4,730	7,255	10,800	16,040
Median	1,860	2,670	3,870	5,510	7,620	10,420
Low		2,441	3,152	3,960	5,020	6,320

TABLE 3-4
Sheet 2 of 2

LOAD FORECAST FOR UPPER SUSITNA PROJECT
BY
ALASKA POWER ADMINISTRATION

	1977	1980	1985	1990	1995	2000
2. FAIRBANKS-TANANA VALLEY AREA POWER DEMAND AND ENERGY REQUIREMENTS						
(Excluding National Defense)						
Peak Demand (MW)						
Utility Loads						
High		158	244	358	495	685
Median	119	150	211	281	358	452
Low		142	180	219	258	297
Annual Energy (GWh)						
Utility Loads						
High		690	1,070	1,570	2,170	3,000
Median	483	655	925	1,230	1,570	1,980
Low		620	790	960	1,130	1,300
3. COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY AREAS						
Peak Demand (MW)						
Extra high		810	1,588	2,272	3,186	4,548
High		810	1,308	1,992	2,906	4,268
Median	568	752	1,085	1,515	2,057	2,775
Low		694	889	1,109	1,385	1,721
Annual Energy (GWh)						
Extra high		3,580	7,270	10,300	14,440	20,510
High		3,580	5,800	8,825	12,970	19,040
Median	2,343	3,325	4,795	6,740	9,190	12,400
Low		3,061	3,942	4,920	6,150	7,620

TABLE 3 - 5

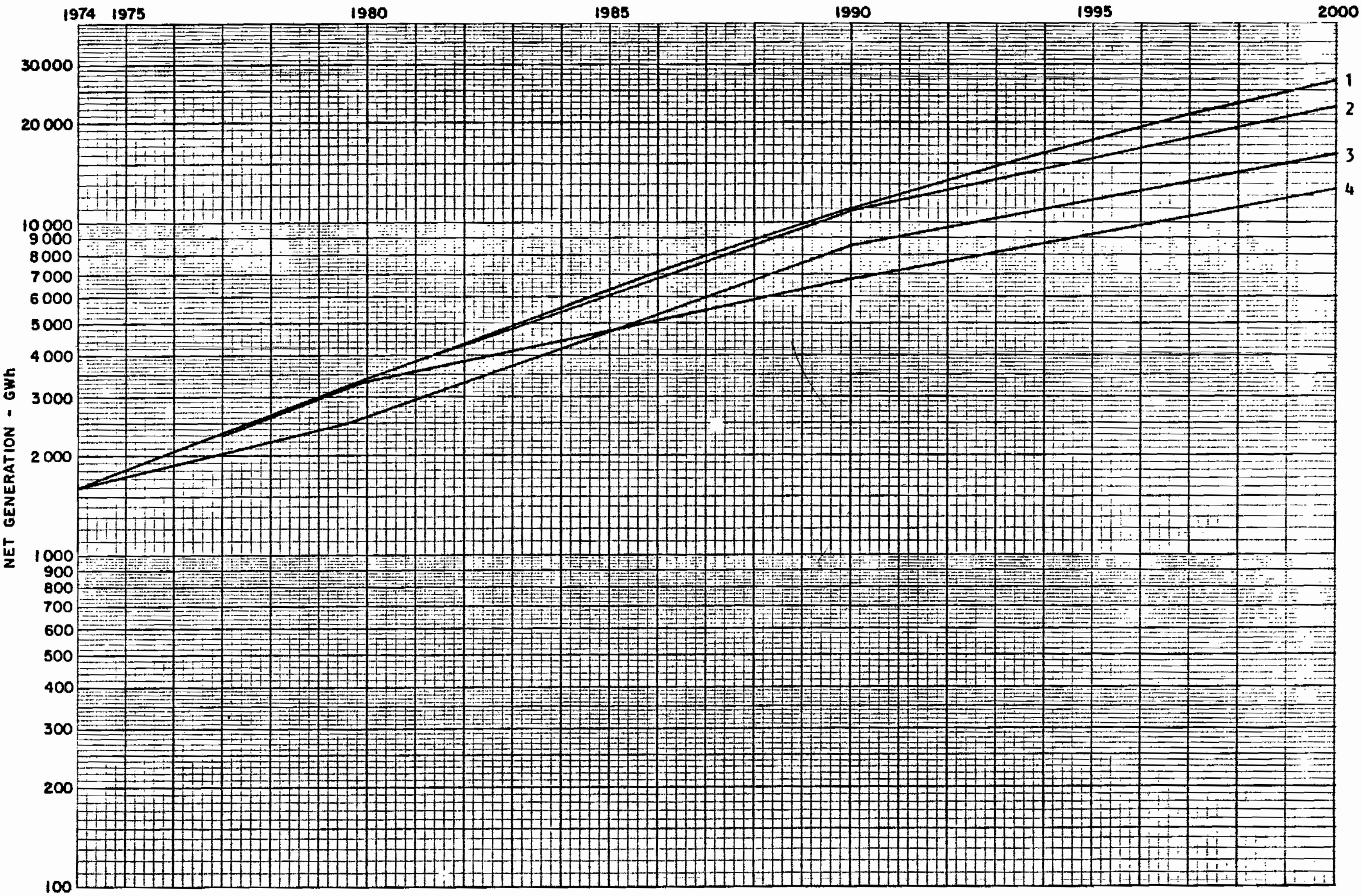
LOAD DEMAND FORECASTS FOR RAILBELT AREA TO DETERMINE STATISTICAL AVERAGE FORECAST

Year	Anchorage - Cook Inlet: Combined Utilities Forecast (MW)	Anchorage - Cook Inlet: Alaska Power Administration Median Forecast (MW)	Anchorage - Cook Inlet: Statistical Average Forecast (MW)	Fairbanks - Tanana Valley: Combined Utilities Forecast (MW)	Fairbanks - Tanana Valley: Alaska Power Administration Median Forecast (MW)	Fairbanks - Tanana Valley: Statistical Average Forecast (MW)	Combined Load Areas: Combined Utilities Forecast (MW)	Combined Load Areas: Alaska Power Administration Median Forecast (MW)	Combined Load Areas: Statistical Average Forecast (MW)
1979	475	546	511	142	139	141	605	685	645
1980	544	602	573	156	150	153	686	752	719
1981	627	648	638	171	161	166	782	809	796
1982	722	698	710	188	172	180	892	870	881
1983	826	752	789	207	184	196	1012	936	974
1984	944	810	877	227	197	212	1148	1007	1078
1985	1079	874	977	250	211	231	1302	1085	1194
1986	1223	937	1080	275	223	249	1468	1160	1314
1987	1387	1004	1196	302	237	270	1655	1241	1448
1988	1548	1077	1313	330	251	291	1840	1328	1584
1989	1728	1154	1441	360	265	313	2046	1419	1733
1990	1928	1234	1581	394	281	338	2276	1515	1896
1991	2133	1315	1724	429	295	362	2511	1610	2061
1992	2360	1402	1881	469	310	390	2772	1712	2242
1993	2587	1495	2041	507	325	416	3032	1820	2426
1994	2834	1593	2215	550	342	446	3318	1935	2627
1995	3105	1699	2402	596	358	477	3627	2057	2842
1996	3372	1809	2591	646	375	511	3938	2184	3061
1997	3663	1925	2794	700	393	547	4276	2318	3297
1998	3947	2049	2998	753	412	583	4606	2461	3534
1999	4244	2182	3213	811	432	622	4954	2614	3784
2000	4569	2323	3446	873	452	663	5333	2755	4054

TABLE 3 -6

LOAD DEMAND BANDWIDTH FOR RAILBELT AREA FORECASTS
"MOST PROBABLE" FORECAST ± 2 STANDARD DEVIATIONS

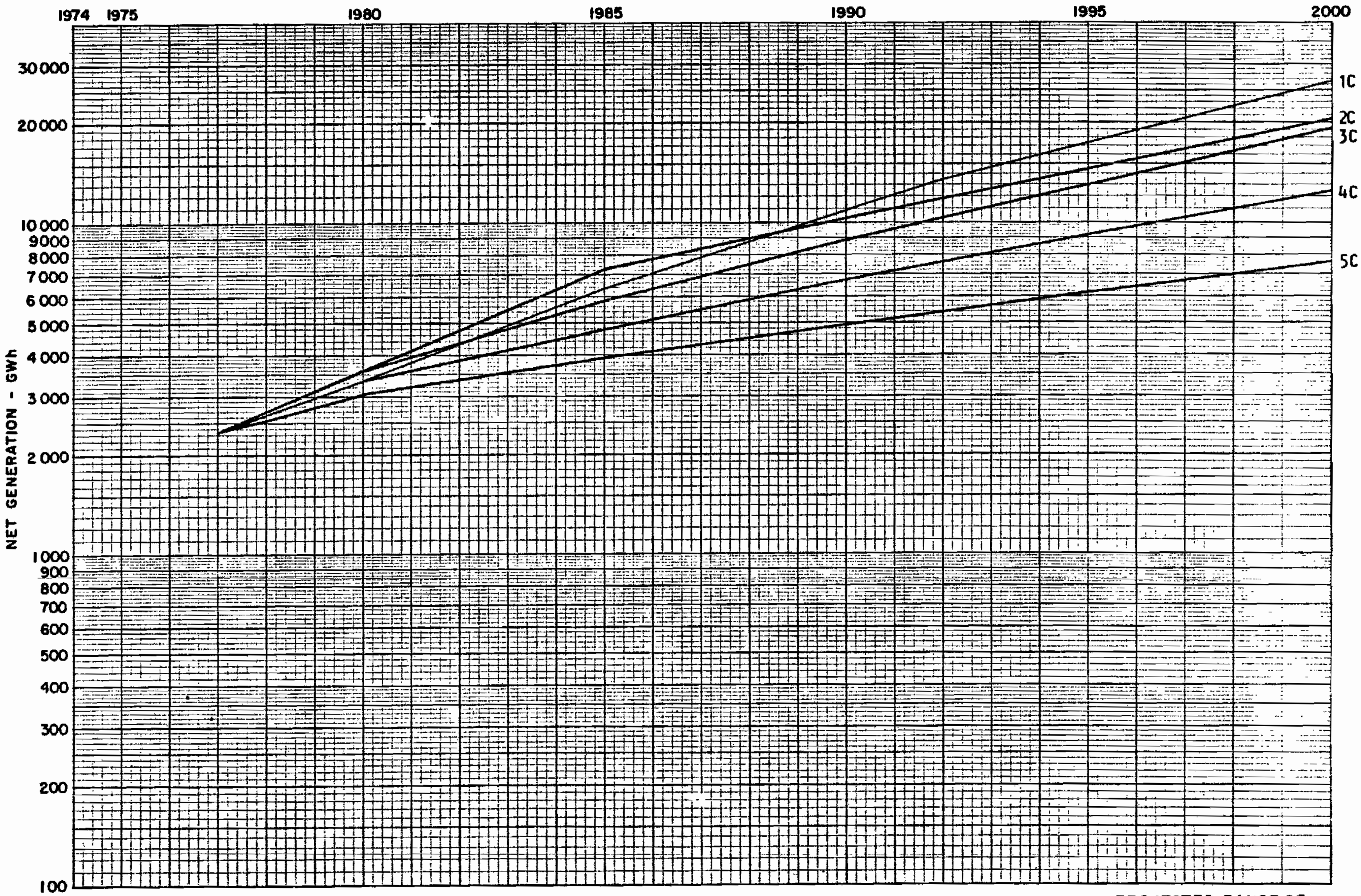
Year	Anchorage - Cook Inlet			Fairbanks - Tanana Valley			Combined Load Areas		
	Load Level -2 Standard Deviations (MW)	Most Probable Forecast (MW)	Load Level +2 Standard Deviations (MW)	Load Level -2 Standard Deviations (MW)	Most Probable Forecast (MW)	Load Level +2 Standard Deviations (MW)	Load Level -2 Standard Deviations (MW)	Most Probable Forecast (MW)	Load Level +2 Standard Deviations (MW)
1979	535	511	487	140	141	142	671	645	619
1980	592	573	554	151	153	155	741	749	697
1981	644	638	632	163	166	169	805	796	787
1982	702	710	718	175	180	185	874	881	888
1983	765	789	813	188	196	204	949	974	999
1984	832	877	922	202	212	222	1031	1078	1125
1985	908	977	1046	218	231	244	1121	1194	1267
1986	985	1080	1175	232	249	266	1212	1314	1416
1987	1068	1196	1324	248	270	292	1310	1448	1586
1988	1156	1313	1470	264	291	318	1413	1584	1755
1989	1250	1441	1632	281	313	345	1523	1733	1943
1990	1350	1581	1812	300	338	376	1642	1896	2150
1991	1451	1724	1997	317	362	407	1760	2061	2362
1992	1562	1881	2200	337	390	443	1888	2242	2596
1993	1677	2041	2405	355	416	477	2021	2426	2831
1994	1800	2215	2630	377	446	515	2167	2627	3087
1995	1933	2402	2871	398	477	556	2319	2842	3365
1996	2070	2591	3112	420	511	602	2476	3061	3646
1997	2215	2794	3373	444	547	650	2644	3297	3950
1998	2365	2998	3631	469	583	697	2820	3534	4248
1999	2526	3213	3900	495	622	749	3004	3784	4564
2000	2697	3446	4195	522	663	804	3203	4054	4905
Probability Multipliers	0.0665	0.383	0.0665	0.0665	0.383	0.0665	0.0665	0.383	0.0665



1 COMBINED UTILITIES FORECAST
2 UPPER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
3 LOWER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
4 MEDIAN FORECAST - ALASKA POWER ADMINISTRATION, SUSITNA PROJECT MARKET STUDY, REVISIONS OF AUGUST 1978

COMPARATIVE
NET ENERGY GENERATION
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
RAILBELT AREA

FIGURE 3-1

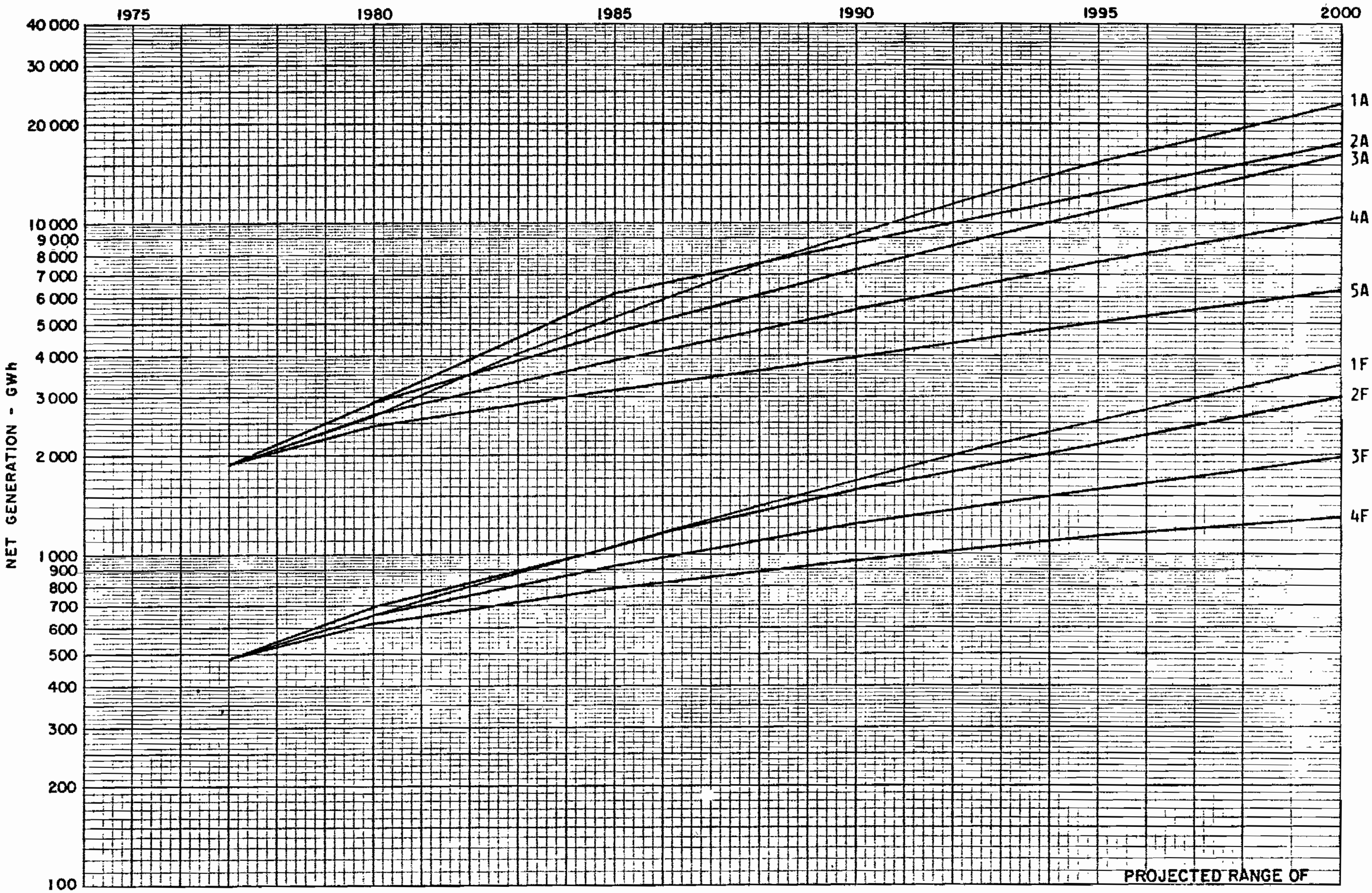


1C COMBINED UTILITIES FORECAST
2C EXTRA HIGH FORECAST
3C HIGH FORECAST
4C MEDIAN FORECAST
5C LOW FORECAST

ALASKA POWER ADMINISTRATION
SUSITNA PROJECT MARKET STUDY
REVISIONS OF AUGUST 1978

PROJECTED RANGE OF
NET ENERGY GENERATION
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
RAILBELT AREA

FIGURE 3-2

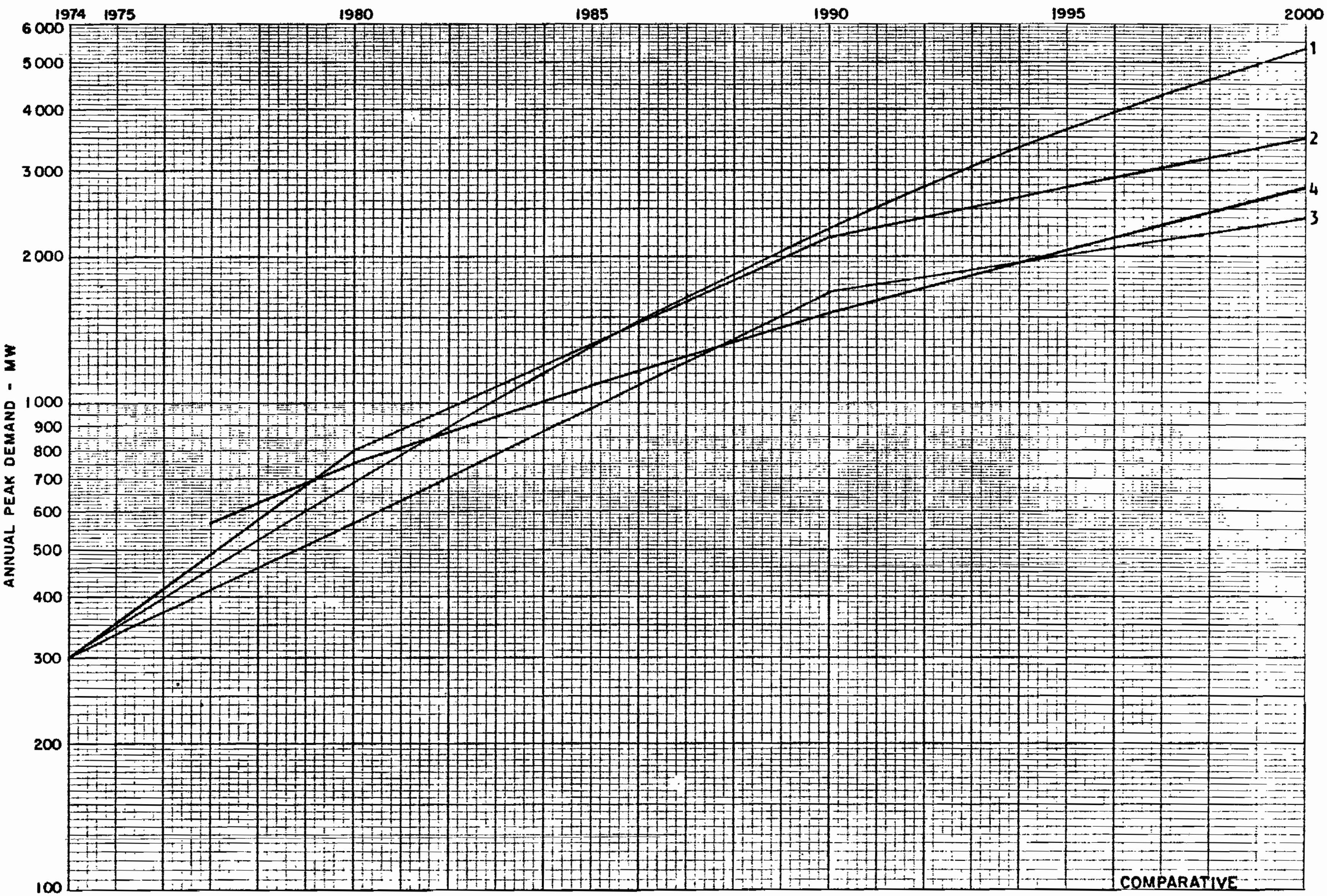


1A UTILITIES FORECAST FOR ANCHORAGE - COOK INLET AREA
2A EXTRA HIGH FORECAST
3A HIGH FORECAST
4A MEDIAN FORECAST
5A LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

1F UTILITIES FORECAST FOR FAIRBANKS - TANANA VALLEY AREA
2F HIGH FORECAST
3F MEDIAN FORECAST
4F LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

PROJECTED RANGE OF NET ENERGY GENERATION FORECASTS FOR COMBINED UTILITIES AND INDUSTRIAL LOAD ANCHORAGE - COOK INLET AREA AND FAIRBANKS - TANANA VALLEY AREA

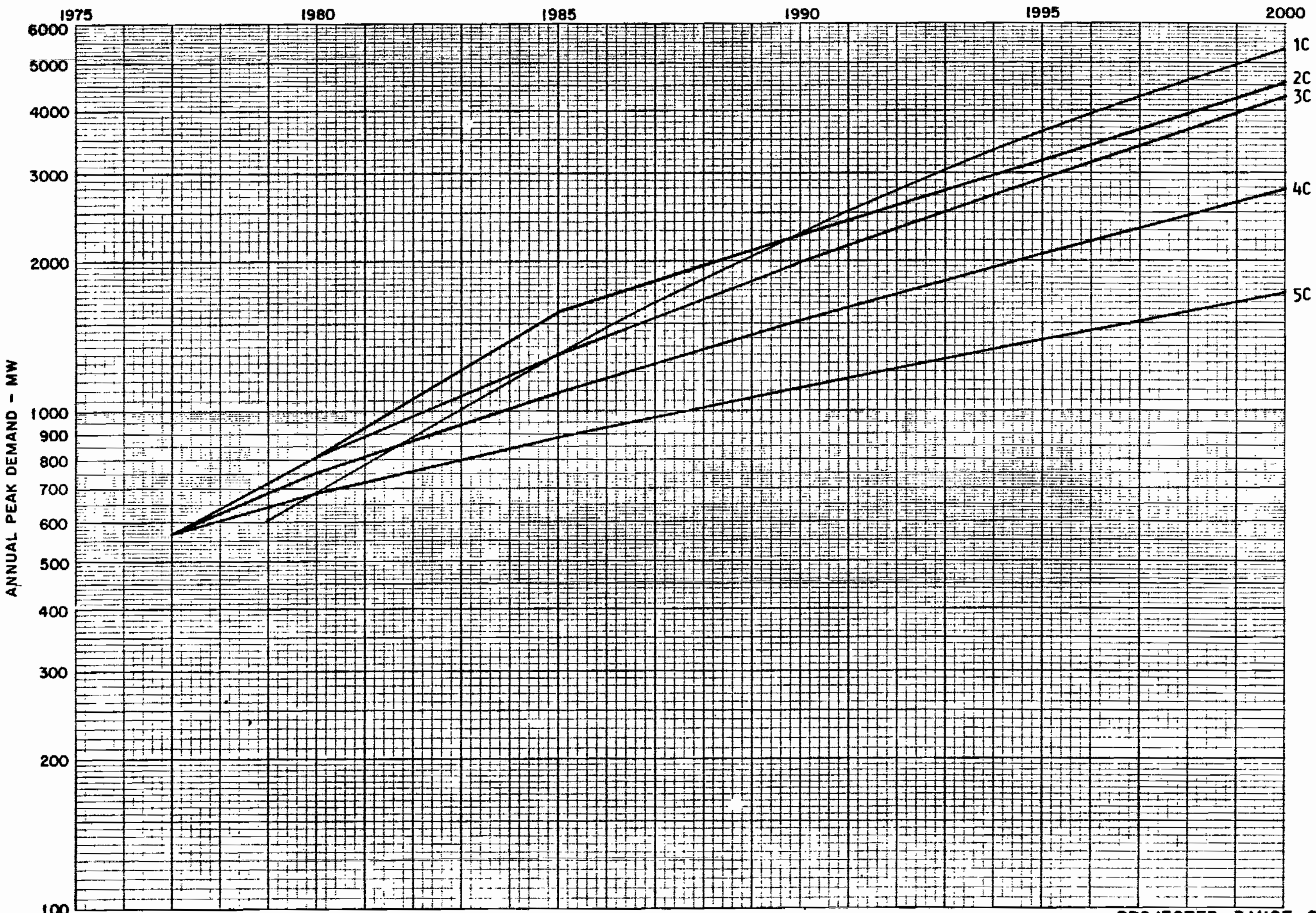
FIGURE 3-3



1 COMBINED UTILITIES FORECAST
2 UPPER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
3 LOWER BOUND - BATTELLE STUDY FORECAST, MARCH 1978
4 MEDIAN FORECAST - ALASKA POWER ADMINISTRATION, SUSITNA PROJECT MARKET STUDY, REVISIONS OF AUGUST 1978

COMPARATIVE
ANNUAL PEAK DEMAND
FORECASTS FOR COMBINED
UTILITIES AND INDUSTRIAL LOAD
RAILBELT AREA

FIGURE 3-4

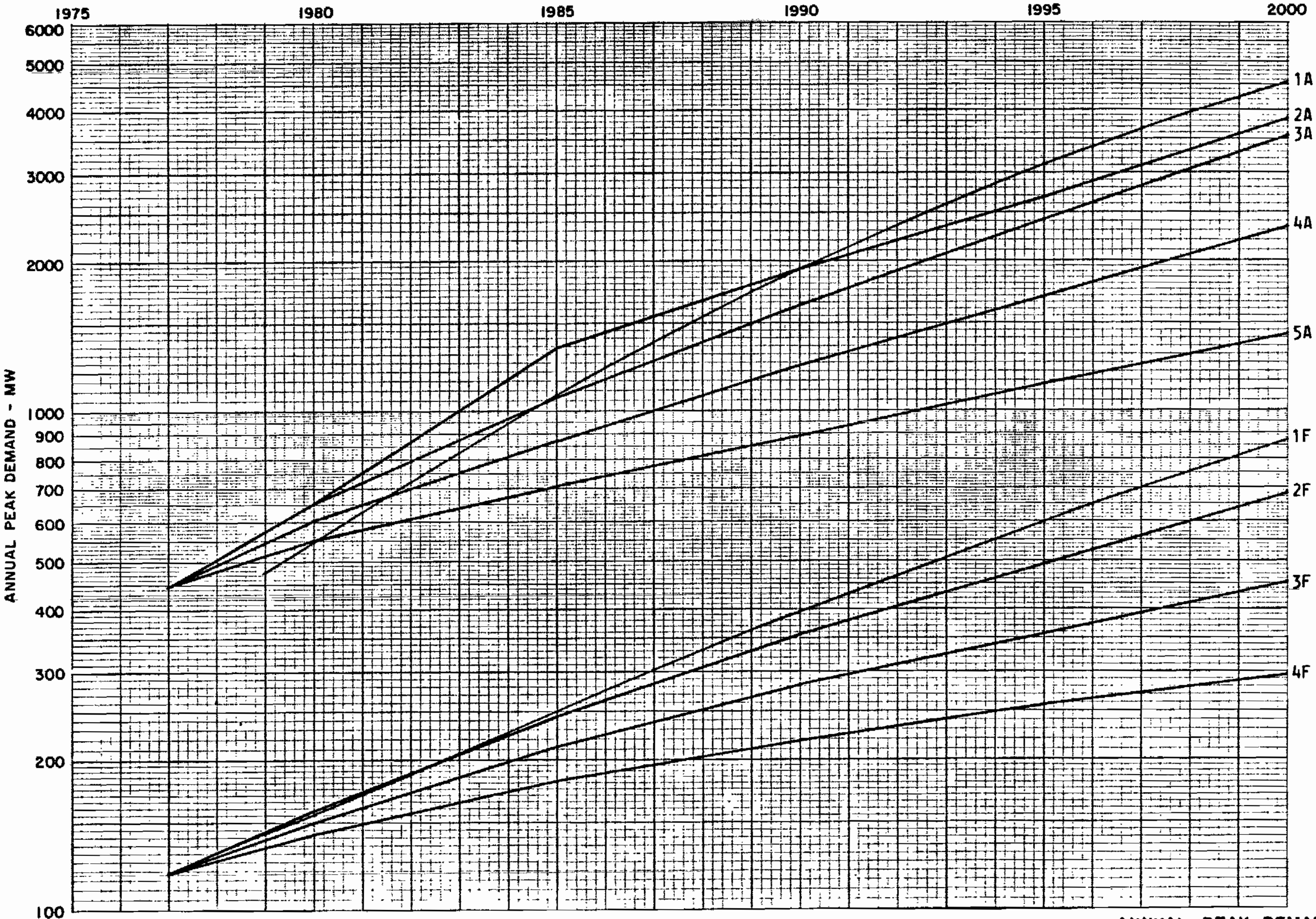


1C COMBINED UTILITIES FORECAST
2C EXTRA HIGH FORECAST
3C HIGH FORECAST
4C MEDIAN FORECAST
5C LOW FORECAST

(2C–5C:) ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

PROJECTED RANGE OF ANNUAL PEAK DEMAND
FORECASTS FOR COMBINED UTILITIES AND INDUSTRIAL LOAD
RAILBELT AREA

FIGURE 3-5



1A UTILITIES FORECAST FOR ANCHORAGE - COOK INLET AREA
2A EXTRA HIGH FORECAST
3A HIGH FORECAST
4A MEDIAN FORECAST
5A LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

1F UTILITIES FORECAST FOR FAIRBANKS - TANANA VALLEY AREA
2A HIGH FORECAST
3F MEDIAN FORECAST
4F LOW FORECAST
} ALASKA POWER ADMINISTRATION SUSITNA PROJECT MARKET STUDY REVISIONS OF AUGUST 1978

ANNUAL PEAK DEMAND
FORECASTS FOR COMBINED UTILITIES AND INDUSTRIAL LOAD
ANCHORAGE - COOK INLET AREA AND FAIRBANKS - TANANA VALLEY AREA

FIGURE 3-6

PROBABILITY MODEL REPRESENTATION OF LOAD FORECAST UNCERTAINTY

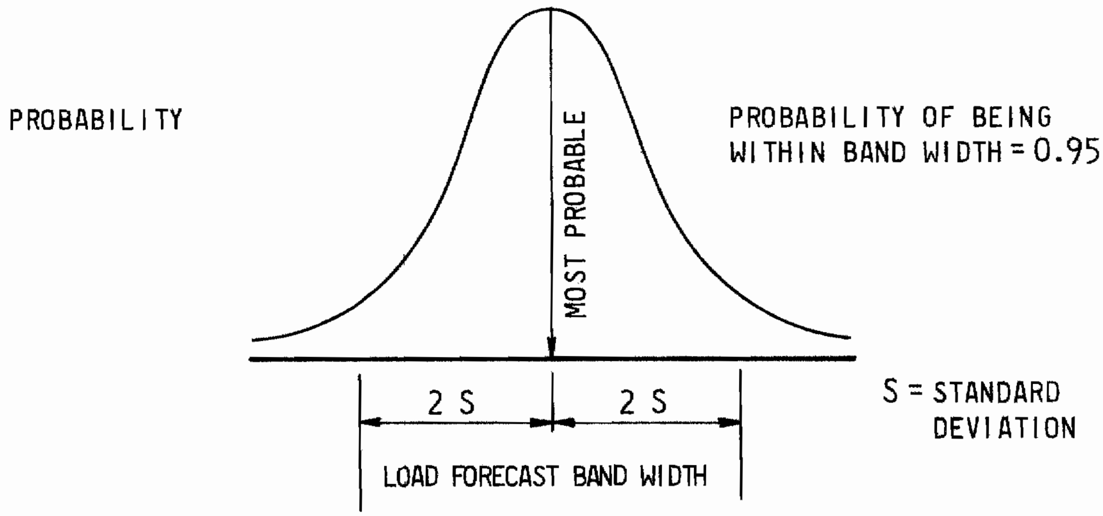


FIGURE 3-7A CONTINUOUS REPRESENTATION

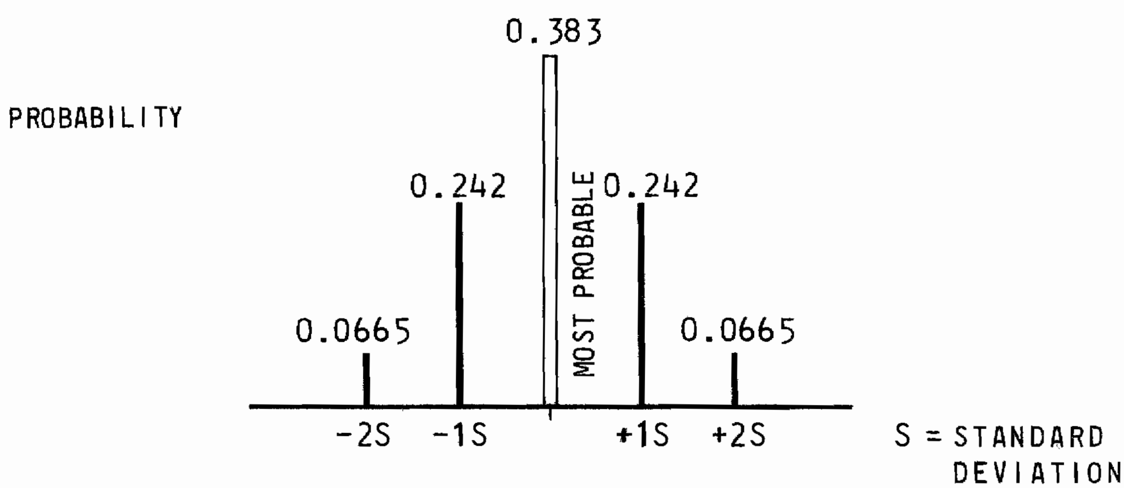
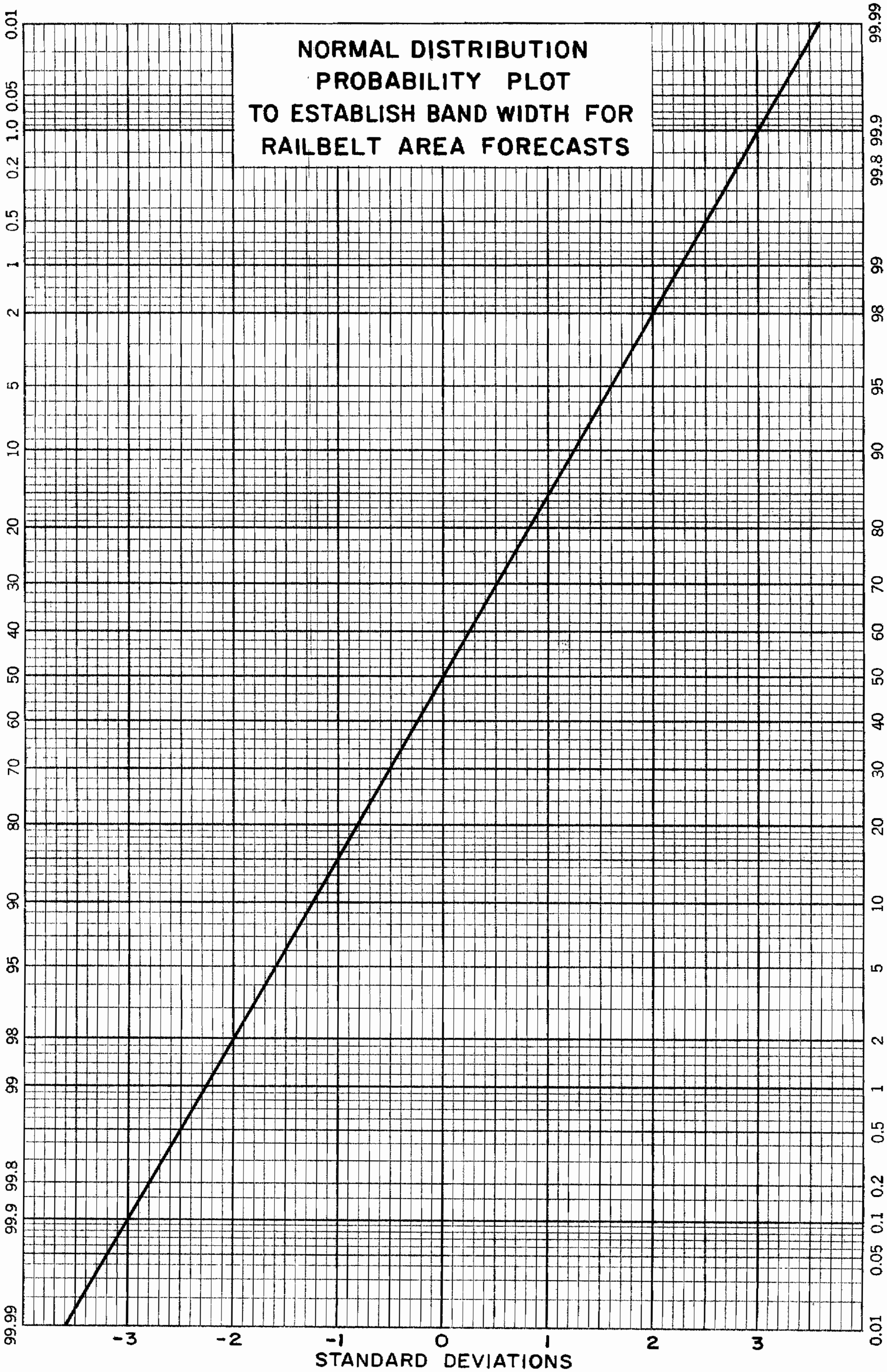
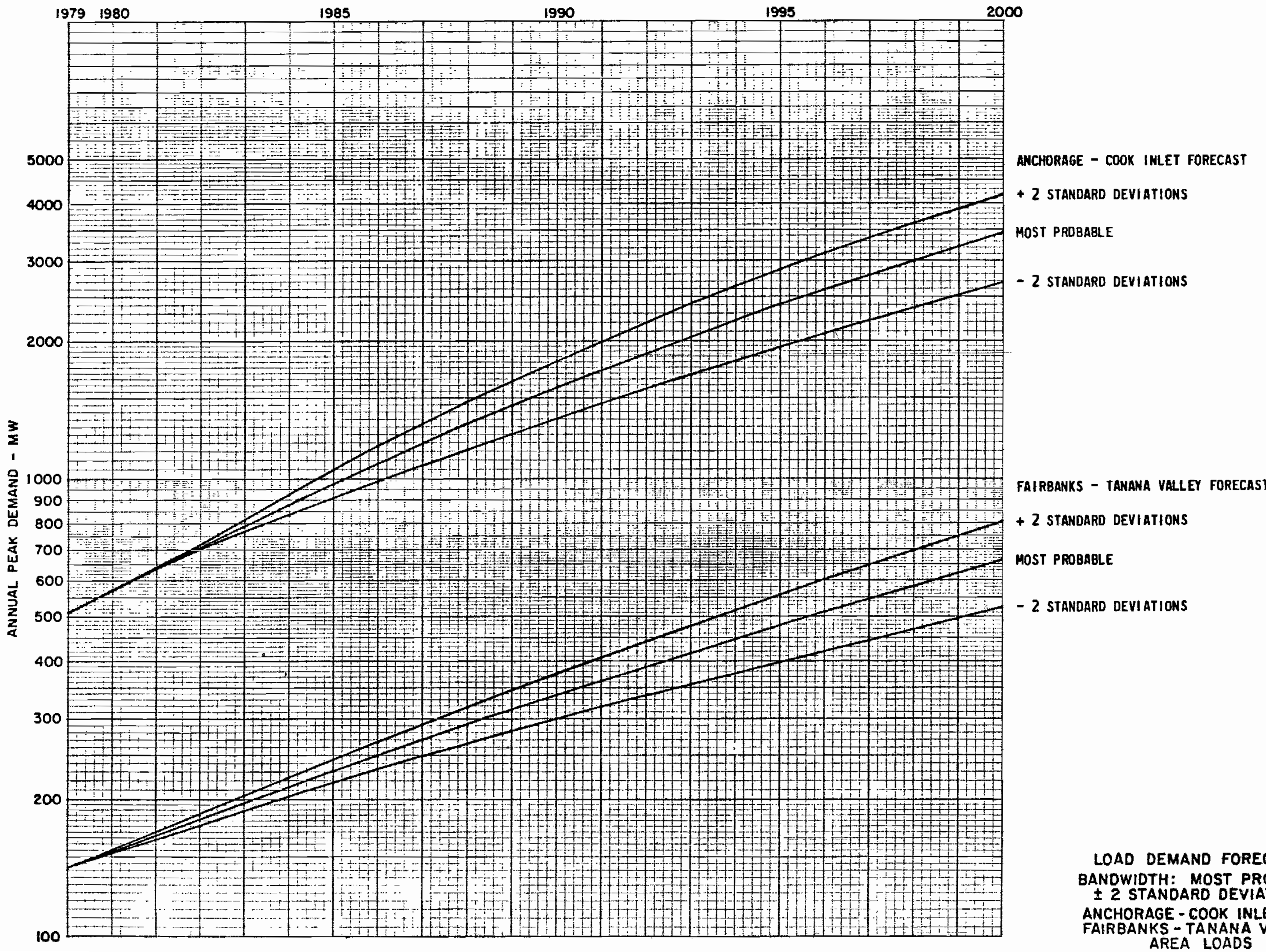


FIGURE 3-7B DISCRETE REPRESENTATION

FIGURE 3-8



NORMAL DISTRIBUTION PROBABILITY PLOT TO ESTABLISH BAND WIDTH FOR RAILBELT AREA FORECASTS

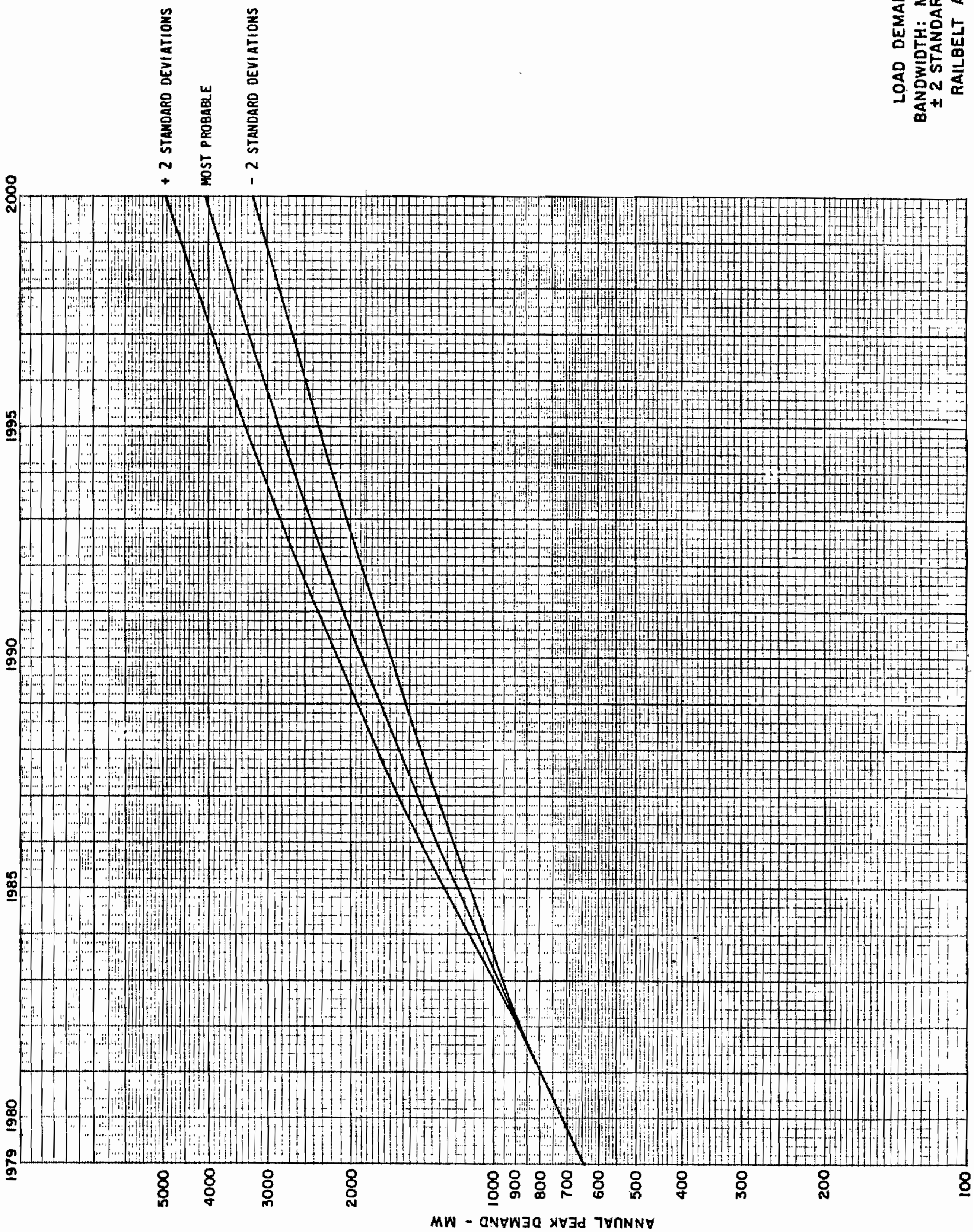


LOAD DEMAND FORECASTS
BANDWIDTH: MOST PROBABLE
± 2 STANDARD DEVIATIONS
ANCHORAGE - COOK INLET AND
FAIRBANKS - TANANA VALLEY
AREA LOADS

FIGURE 3-9

FIGURE 3-10

LOAD DEMAND FORECAST
BANDWIDTH: MOST PROBABLE
± 2 STANDARD DEVIATIONS
RAILBELT AREA LOADS



CHAPTER 4

SELECTION OF INTERTIE ROUTE

CHAPTER 4
SELECTION OF INTERTIE ROUTE

4.1 REVIEW OF EARLIER STUDIES

A number of studies have considered the electrical interconnection of the Fairbanks, South Central, and Anchorage areas (Refs. 1-8). The Susitna Hydroelectric Project Interim Feasibility Report (Ref. 2), hereafter called Susitna Report, reviewed a number of alternative transmission corridors in considerable depth. None of the studies included a specific route for a transmission line. The Susitna Report provides an excellent inventory of topography, geology, soils, vegetation, wildlife, climate, existing development, land ownership status, existing rights-of-way, and scenic quality and recreation values by corridor segments of about 5-mile widths.

4.2 SURVEY OF ALTERNATIVE CORRIDORS

Alternative corridors reviewed for this report were those along or near the Railbelt region between the Anchorage and Fairbanks areas. A reconnaissance (by USGS Quad's and local knowledge) of routes connecting the Railbelt area to Glennallen was also made to provide a basis for estimating the cost of such a connection at a later date.

4.3 PREFERRED ROUTE FOR TRANSMISSION INTERTIE

The preferred corridor described in the Susitna Report was further defined by making an actual preliminary layout of a definitive route (with some alternatives) using engineering techniques. This preliminary routing provides a basis for refining cost estimates, displaying a definitive location for use in studying potential environmental impacts, and providing a specific engineering recommendation for use in right-of-way negotiations.

The preliminary line routing is shown on the accompanying maps, Figures 4-1, 4-2, and 4-3, these being spatially related to the key map on the inside of the front cover of this report. These routes come from a working strip map of 1" = 1 mile (USGS Quad's.) on which these preliminary routes are drawn. The route was plotted by an engineer with nearly 30 years of experience with Alaskan transmission systems. It was also visually inspected throughout much of its length over the Parks Highway from Anchorage to Fairbanks.

The definitive line route was established within the preferred corridor, with due regard to the following restraints, insofar as they could be identified in this preliminary review:

- Avoidance of highway rights-of-way, which are better locations for distribution lines that will be required to serve homes and enterprises served by the highway.

- Avoidance of telephone lines, because of electrical interference problems. (An open-wire telephone circuit exists on the entire length of the Alaska Railroad right-of-way.)

- Avoidance of aircraft landing and takeoff corridors, including all lakes of sufficient size to accommodate small floatplanes. Where lines may cross landing patterns, at least 1/2 mile is allowed from the end of runways or lakes, so that special designs are not required.

- Avoidance of highly subdivided land areas and dwellings.

- Avoidance of crossings over developed agricultural lands.

- Selection of routings that provide for minimum visibility from highways and homes.

- Avoidance of heavily timbered lands.

- Selection of routes that provide for minimum changes in grade as the terrain will allow.

- Parallel alignments with property lines are favored, if not precluded by other considerations.

- Avoidance of sensitive wildlife areas, if practicable, and cooperation in regard to construction and operating restraints where lines pass through such areas.

- Alignments located in reasonable proximity to transportation corridors (roads, railroads, navigable waterways) so that construction, operation, and maintenance routines are not inordinately difficult.

4.4 FIELD INVESTIGATIONS

Principal engineers of the IECO-RWRA team made field trips by helicopter and surface transportation to important sites and typical structures of existing transmission lines in both the Anchorage and Fairbanks areas. Particular attention was given to lines using designs developed especially for Alaskan conditions of muskeg swamp, permafrost, and flood plain. These designs have had more than ten years of successful service, and are the basis for more recent tubular steel structure designs now being installed on Alaska projects.

Actual field records of Resident Engineers and Inspectors on Alaska transmission line construction projects were analyzed along with contractor bids for these projects to provide authoritative basic data on the actual manhours, materials use, and dollar costs of completed transmission lines.

4.5 PRELIMINARY ENVIRONMENTAL ASSESSMENT

A. Description of the Environment

1. Point MacKenzie to Talkeetna - The corridor travels north along the east flank of the Susitna River Valley, an extremely wide and poorly drained plain. Heavy forests of bottomland spruce and poplar, interspersed with muskeg and black spruce, are typical. The soils vary from deep, very poorly drained peat to well-drained gravels and loams, with the well-drained soils being more abundant. Although permafrost is almost absent in this lower part of the Susitna Valley, the poorly drained areas are subject to freezing and heaving in the winter.

A sizeable concentration of moose inhabits the lower Susitna River Valley. This valley also supports black and brown bear and a moderate density of water fowl.

The proposed transmission line route generally follows a "tractor trail" (USGS designation) to three miles northeast of Middle Lake. Here, at the approach to the Nancy Lake area, an alternate route (A) may be used to avoid this area. The proposed route (B) is located in marshes and wetlands, between Papoose Twins and Finger Lakes, across the Little Susitna River. The corridor then travels northward along the east side of Lynx Lake, Rainbow Lake, and Long Lake where it crosses the Willow River. Here alternate routes (A) and (B) rejoin and intersect an existing 115-kV MEA transmission corridor at the Little Willow Junction and a proposed corridor to Anchorage on the east side of Knik Arm. Travelling north, the corridor crosses several major tributaries of the Susitna River including Sheep Creek and the Kashwitna River. In this area the terrain becomes more rolling, and the relative proportion of well-drained soils supporting thick poplar-spruce forests is considerably greater than to the south. The corridor then travels some five miles east of Talkeetna to the Bartlett Hills P.I. (point of intersection).

2. Talkeetna to Gold Creek - From Bartlett Hills P.I. the corridor crosses the Talkeetna River near the confluence of the Talkeetna and Chulitna Rivers, where it follows the west bank of the Chulitna River at a mean elevation of 600 feet. Where the Chulitna River curves eastward, the corridor travels northward, along the Susitna River Valley, through forested uplands, gradually rising to an elevation of 1000 feet. The uplands above the valley support sparser forests, and increasing amounts of permafrost soils are encountered. At the 1000-foot elevation, one to three miles east of the Susitna River, the corridor crosses Lane Creek, MacKenzie Creek, Portage Creek, Deadhorse Creek, and numerous other small tributaries of the Susitna River. It then crosses Gold Creek and the Susitna River, 1-1/2 miles east of A.R.R. Mile 265, to the Susitna Junction, one mile east of A.R.R. Mile 266. At the Susitna Junction, the proposed Devil Canyon-Watana-Glennallen line meets the corridor.

3. Gold Creek to Glennallen - The corridor parallels the Susitna River to the proposed Devil Canyon damsite and then travels east to the proposed Watana damsite. The vegetation in the canyons varies from upland spruce-hardwood to alpine tundra. Soils vary from poorly drained river bottoms to unstable talus. Permafrost occurs in this portion of the corridor. Some localized moose populations are crossed. The corridor passes through low lake areas west of Lake Louise until it intersects the Richardson Highway at Tazlina. From Tazlina the route follows the Richardson Highway into Glennallen.

4. Gold Creek to Cantwell - The transmission corridor travels north some 1 to 3 miles east of the Alaska Railroad between elevation 1500 and 2000 feet. The timber density becomes successively less in this area. This portion of the corridor is a good bear and moose habitat. Shallow permafrost occurs in this portion. The corridor crosses several major and minor tributaries to the Chulitna River including Honolulu Creek, Antimony Creek, Hardage Creek, the East Fork of the Chulitna River, and the Middle Fork of the Chulitna River. The corridor area is of medium scenic quality and is not readily accessible, except at the Denali Highway Crossing.

5. <u>Cantwell to Healy</u> - The corridor rises to the 3200 foot level along the west side of Reindeer Hills and then descends into the Nenana River Valley. It follows the east flank of the Nenana River northward at the 2200 foot level, through sparsely timbered country. This is an area of high scenic quality especially in the canyons. The terrain varies from rolling hills and valleys to high passes and sharp ridges. Habitats of moose, bear, and Dall sheep are traversed. Bedrock is exposed in the canyons. The corridor crosses several tributaries to the Nenana River including Slime Creek, Carlo Creek, Yanert Fork, and Montana Creek, and the Nenana River itself. It also crosses the Alaska Railroad at the Moody Tunnel, near A.R.R. Mile 354 and the Healy River. The boundary of Mt. McKinley National Park is on the west flank of the Nenana River.

6. <u>Healy to Ester</u> - The corridor leaves Healy and crosses the Parks Highway near Dry Creek. It then roughly parallels the west side of the highway at elevation 1500 feet, crossing several tributaries to the Nenana River. It crosses the GVEA line 1-1/2 miles north of Bear Creek, the Alaska Railroad and the Nenana River at A.R.R. Mile 383, and the Parks Highway. The route then parallels the GVEA line. The corridor crosses the Tanana River at the Tanana P.I. and follows the Tanana River flood plain for several miles until the route again crosses the highway where it travels on the west side of the Bonanza Creek Experimental Forest. The route parallels the GVEA right-of-way the rest of the way to Ester. The Healy to Ester portion of the route passes through some private lands (mining claims, homesteads, etc.), as well as near the towns of Healy, Lignite, and Nenana. An archeological site exists near Dry Creek. Portions of the corridor are heavily forested and provide habitat for moose, caribou, and bear. Poorly drained areas in this corridor are subject to potential permafrost degradation and frost heaving.

B. Environmental Impacts

Construction and maintenance of other Alaskan transmission systems has shown that most negative environmental impacts caused by a transmission system can be minimized. Golden Valley Electric Association, Matanuska Electric Association, and Chugach Electric Association have constructed and are operating several lines on poor soils and under harsh climatic conditions. Except for anticipated slight visual impacts, most environmental impacts caused by a transmission system would be far less than those of many transportation and communication systems. Specific areas to be impacted are discussed below.

1. Ecosystems - The major positive impact will be on human environment, while adverse effects to the other ecosystems will be minimal. The route has been selected to avoid adverse impacts on these ecosystems wherever possible. The human environment will be benefited by the provision of energy, vital to the growing state of Alaska. The development of many potential renewable energy resources will be made feasible by the Anchorage-Fairbanks intertie. The project will contribute to the reduction in costs of electrical energy, improvement in reliability of electrical service, and enhancement of opportunities for renewable energy resources (such as hydro and wind) to displace non-renewable energy resources (such as gas and oil) for the generation of electricity.

Alteration of vegetation patterns will affect wildlife. This corridor traverses many areas of moose concentrations, and moose should benefit from the introduction of brush resulting from regrowth on the clearing. Since the clearing must be maintained, this brush area will last for the lifetime of the project. Animals such as squirrels will suffer loss and displacement. However, their faster reproductive rates will allow their populations to adjust rapidly.

Construction itself will affect wildlife. Larger mammals may temporarily leave the area to return after the construction activity. Smaller animals will suffer individual losses, but should recuperate rapidly once construction is completed. The density of forest in portions of the corridor will allow animals to move only a short distance to avoid contact with construction activities.

Vegetation suppression, by whatever method, will periodically remove cover from along the right-of-way. However, due to the surrounding cover of the uncleared forests, this impact will be insignificant.

2. Recreation - The corridor will approach several recreational and wayside areas in the lower Susitna Valley. The largest of these is the Nancy Lake Recreational Area. The corridor will also approach the Denali State Park, but will be separated from the Park by the Susitna River.

This corridor will provide access to areas previously difficult to reach. The largest such area is that south of Nancy Lake to Point MacKenzie. Dense forest and muskeg limit travel.

Further north the corridor parallels the east border of Mt. McKinley National Park, being separated by the Parks Highway, the Nenana River, and the Alaska Railroad.

3. Cultural Resources - The National Register of Historical and Archaeological Sites lists the following sites which will be approached by the transmission corridor: Knik Village, Dry Creek, and the Tangle Lake Archaeological District. The line will be routed to bypass these areas.

During construction and preconstruction surveys, other archaeological sites may be discovered which may be eligible for nomination to the National Register. This is a positive benefit of the corridor, as archaeological and other cultural resources are often difficult to find in the great Alaska wilderness.

4. <u>Scenic Resources</u> - The southern portion of the corridor does not traverse any areas of good or high quality scenic values. The northern portion is, however, more scenic than the southern portion. In the northern portion the fairly continuous, moderately dense forest will provide ample screening from transportation routes. Further south, the forests are more intermingled with open muskeg. Glimpses of the transmission line will be seen from the highway or railroad through these muskeg areas. South of Nancy Lake the transmission corridor and the transportation corridors diverge, and although cover becomes more sporadic, the line will no longer be visible from the transportation routes. The transmission line will not be visible from most of the Nancy Lake Recreation Area.

As the Alaska Railroad and the transmission corridor approach Gold Creek, the valley becomes more confined, and screening becomes more difficult. However, it appears that the line can be concealed through most of this portion.

The corridor passes through an area recognized as being of good to high scenic quality from Devil Canyon to Healy. The possibility of screening throughout this area varies from moderate in the southern portion around Chulitna, to minimal in the Broad Pass and the upper and lower canyons of the Nenana River. Scenic quality will be impacted, the impact being a function of existing scenic quality and the opportunity for screening. The proposed line design will incorporate weathering tubular steel towers which blend well into the environment. Non-specular conductors might be used where light reflection from the line would cause unacceptable adverse visual impact. Impact in the Nenana Canyon will be high; impact on Broad Pass will be moderate to high; impact elsewhere will be moderate. Two favorable factors mitigate the impact somewhat: 1) the corridor is not visually intact as the Alaska Railroad and the Anchorage-Fairbanks Highway have already reduced scenic quality somewhat; and 2) the major views south of the canyons are to the west, toward the Mt. McKinley massif, whereas the transmission line corridor lies to the east of the transportation routes.

5. Social - Some economic impact can be expected, as flying services, motels, restaurants, and entertainment facilities receive business, not only from the transmission line workers, but from related personnel. Due to the high cost of a low-load tap on a high voltage line, the likelihood of use of the energy by small communities along the corridor is remote. However, in places where the demand could justify such a tap, it would provide a reliable source of electrical energy for growing communities.

C. Special Impact Mitigation Efforts During Construction

Right-of-way clearing will be accomplished by approved methods such as the hydro axe, and chips will be spread along the right-of-way. The line will be screened wherever possible. The towers will be designed to blend into the environment, thereby reducing visual impact.

Movement of men and equipment during construction will be scheduled to avoid excessive damage to the ground cover. This is generally accomplished by winter construction. The tower design will allow movement of men and equipment along the right-of-way centerline, thereby eliminating the need for an access road in addition to the transmission line clearing.

Major river crossings will be required over the Talkeetna River, Tanana River, Healy Creek, and the Susitna River. Minor stream crossings may be made either by fording or ice crossings. Special efforts will be made to avoid siltation of fish streams. Oil will be carefully handled to avoid spillage. Where larger quantities of oil are to be stockpiled, dikes will be constructed to protect against spills.

Since most of the construction will occur far from communities, noise is not anticipated to be a problem. Suitable muffling devices will be used to protect men and wildlife from excessive noise.

Prior to and during construction, special efforts will be made to consult with State historical and archaeological authorities, the Soil Conservation Service, the Bureau of Land Management, the Alaska Department of Fish and Game, and the U.S. Forest and Wildlife Service, and any other agencies having jurisdiction over the construction area, in an effort to ensure sound environmental practices.

4.6 REFERENCES

1. Robert W. Retherford Associates, North Slope Natural Gas Transport Systems and Their Potential Impact on Electric Power Supply and Uses in Alaska, March 1977.

2. U.S. Army Corps of Engineers, Southcentral Railbelt Area, Alaska, Upper Susitna River Basin Interim Feasibility Report, (Appendix I, Part II (G) Marketability Analysis, (H) Transmission System, (I) Environmental Assessment for Transmission Systems, December 1975.

3. Kozak, Edwin, under the direction of J. R. Eaton, Performance Characteristics of a 350-Mile Electric Power Transmission Line (Fairbanks to Anchorage), A project in EE 494, Department of Electrical Engineering, University of Alaska, June 1973.

4. Ch2M-Hill, Electric Generation and Transmission Intertie System for Interior and Southcentral Alaska, 1972.

5. Federal Power Commission, Alaska Power Survey, 1969.

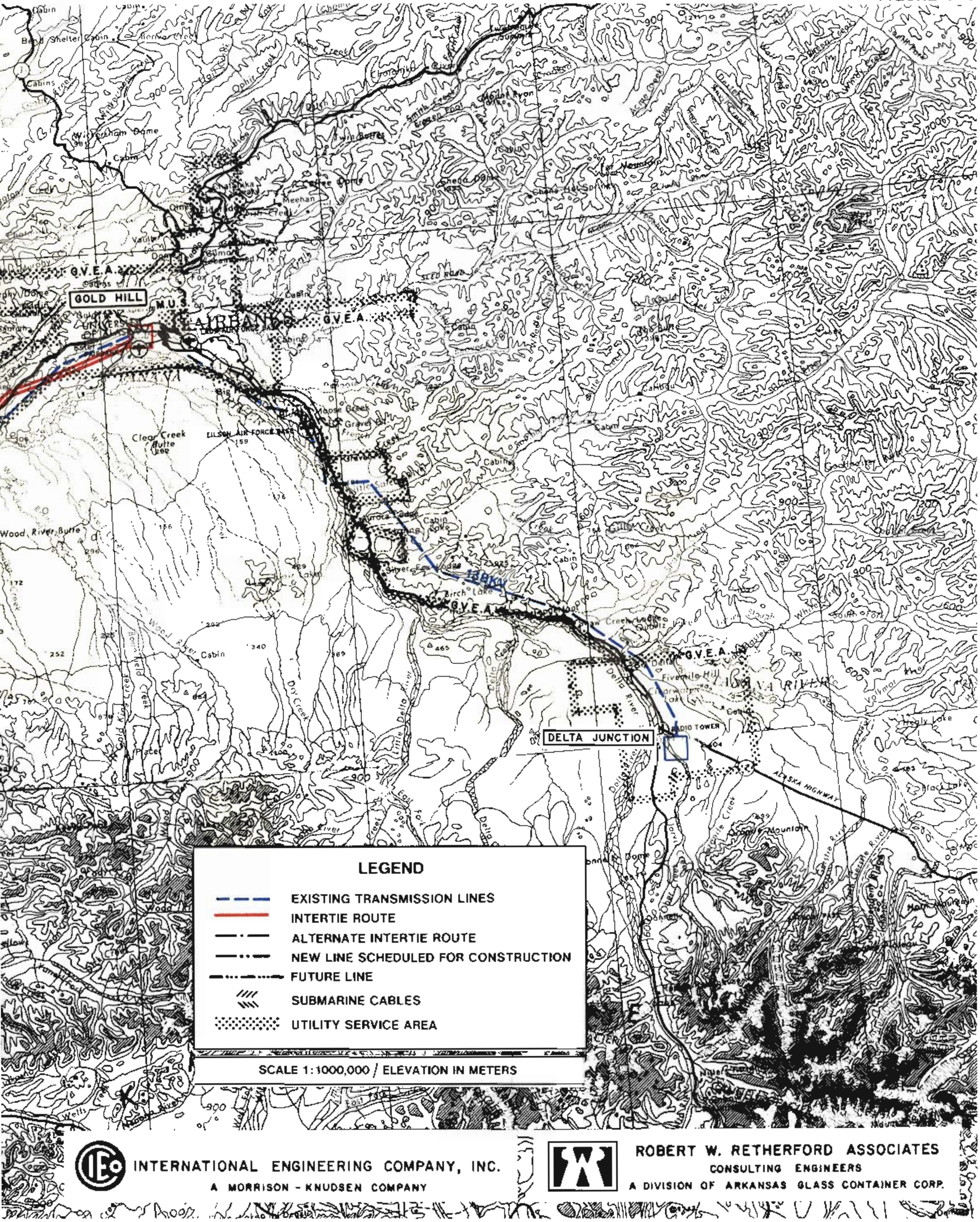
6. Alaska Power Administration, Alaska Railbelt Transmission System, working paper, December 1967.

7. The Ralph M. Parsons Company, Central Alaska Power Study, undated.

8. The Ralph M. Parsons Company, Alaska Power Feasibility Study, 1962.

TANANA
Cabin
Indian Village
WINTER TRAIL
Cabins
Placer
Baker Creek
Sawtooth Mountain
Eureka Dome
Roughtop Mountain
Applegate Creek
SLED ROAD
Manley Hot Springs
Hot Springs Landing
Minto
Tolovana
Mooseheart Mountain
Toklat
Wein Lake
North Nenana
NENANA
APPROXIMATE ALIGNMENT
G.V.E.A.
Kuskokwim River
UNSURVEYED
Bearpaw Mountain
Nineteenmile
Roosevelt
Diamond
Glacier
Kantishna
Wonder Lake
Camp
McKinley River
Slippery Creek
Birch Creek
Herron River
Clearwater Creek
MT. McKINLEY NATIONAL PARK
Rex
Jumbo Dome
HEALY

FIGURE 4-1



NENANA-FAIRBANKS-TANANA TRANSMISSION SYSTEM

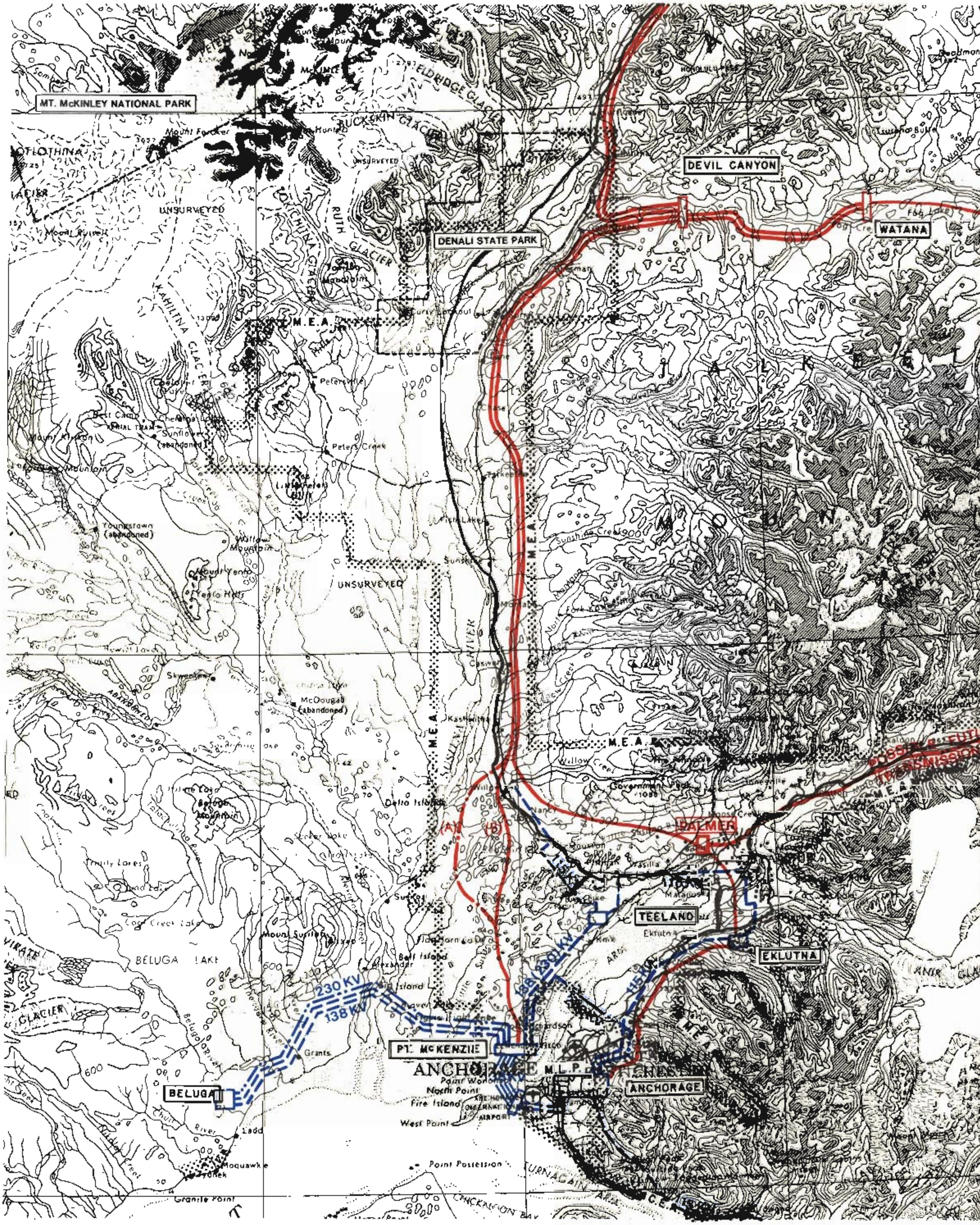
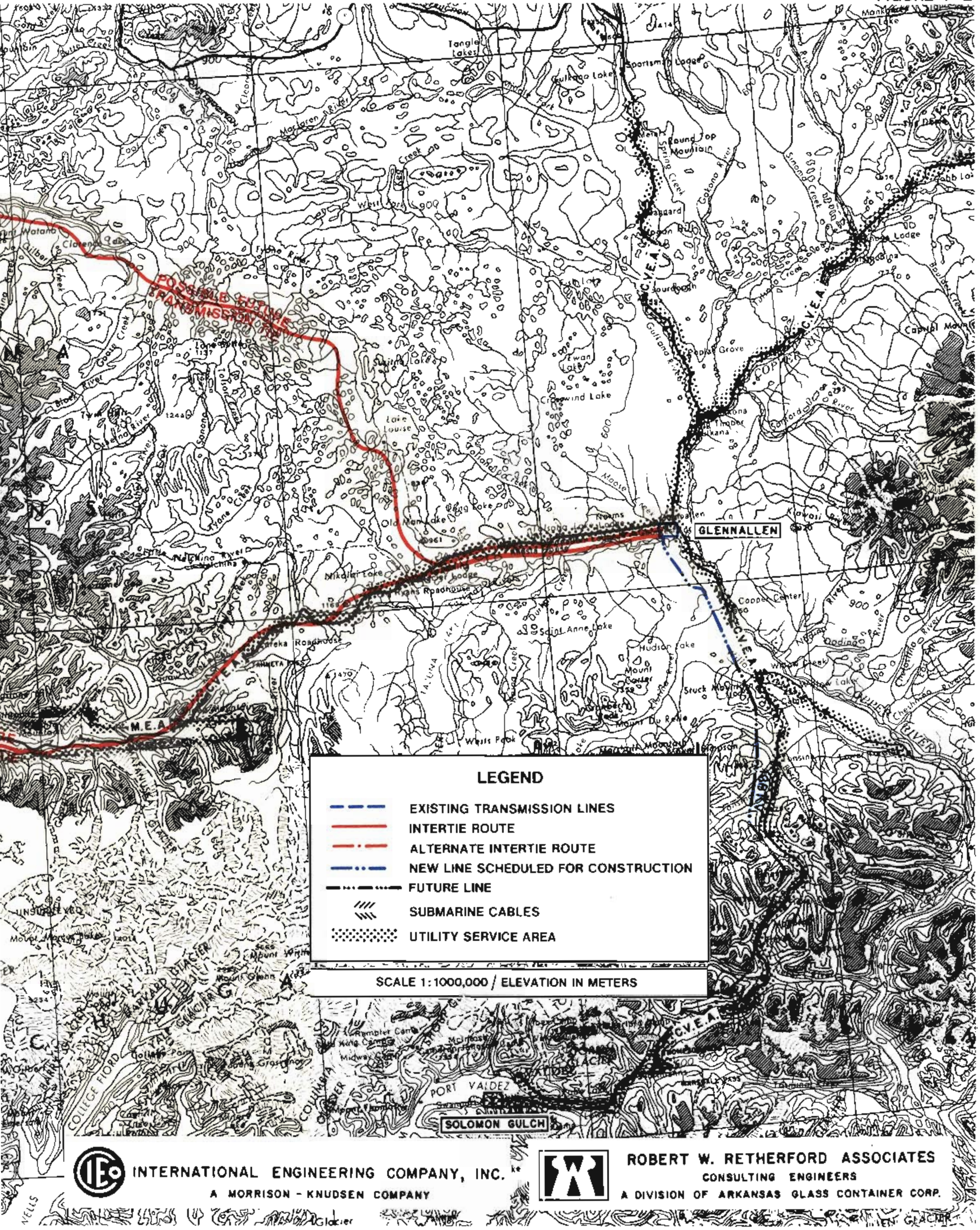

MT. McKINLEY NATIONAL PARK
DEVIL CANYON
WATANA
DENALI STATE PARK
UNSURVEYED
RUTH GLACIER
KAHILTNA GLACIER
ELDRIDGE GLACIER
BUCKSKIN GLACIER
M.E.A.
Petersville
Peters Creek
UNSURVEYED
TALKEETNA MOUNTAINS
PALMER
TEELAND
EKLUTNA
ANCHORAGE
PT. McKENZIE
BELUGA
M.L.P.
230 KV
138 KV
115 KV
BELUGA LAKE
Point Possession
TURNAGAIN ARM
C.E.A.
(A)
(B)
SUSITNA RIVER
POSSIBLE FUTURE TRANSMISSION

FIGURE 4–2



ANCHORAGE–MATANUSKA–SUSITNA–GLENNALLEN–VALDEZ TRANSMISSION SYSTEM

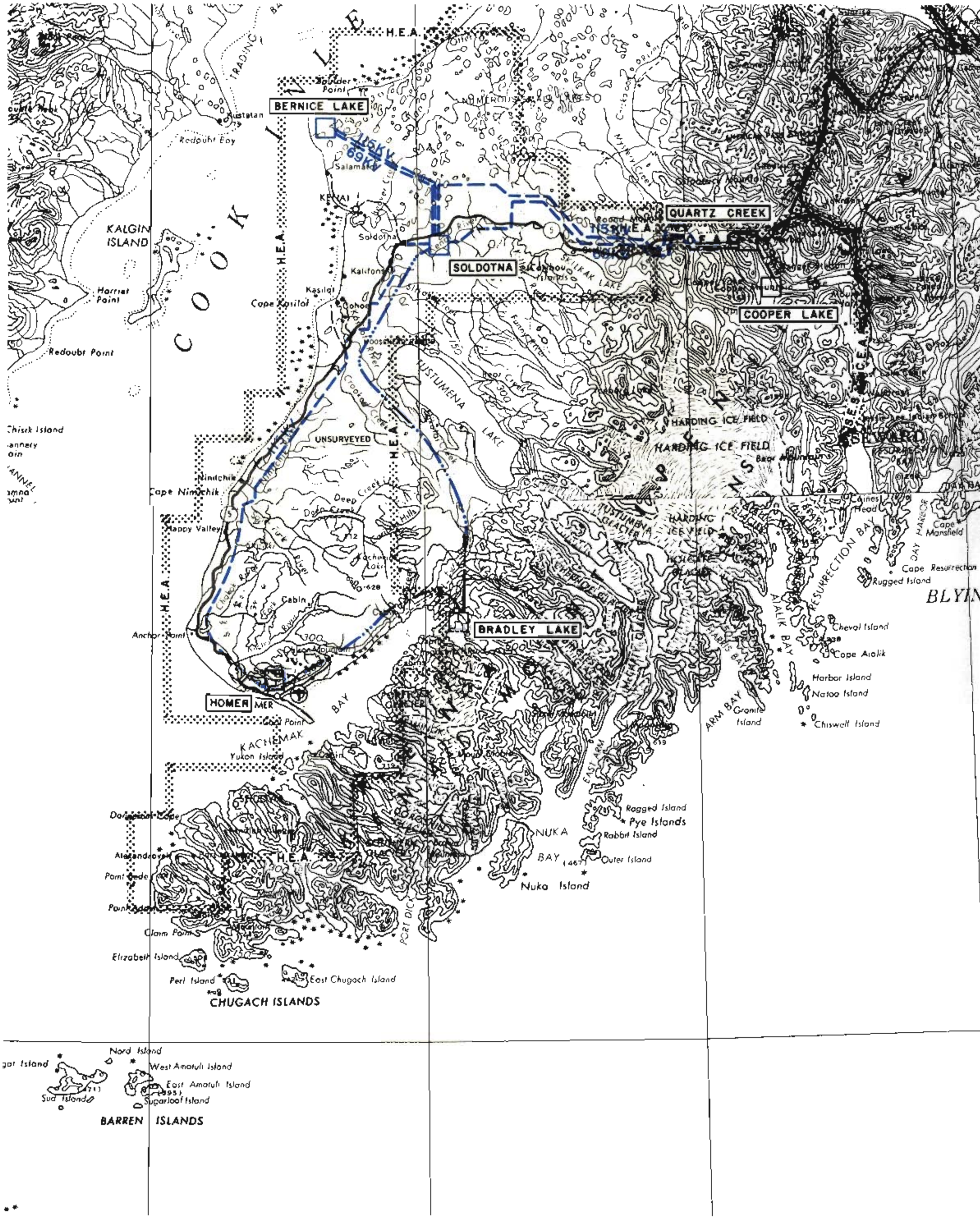
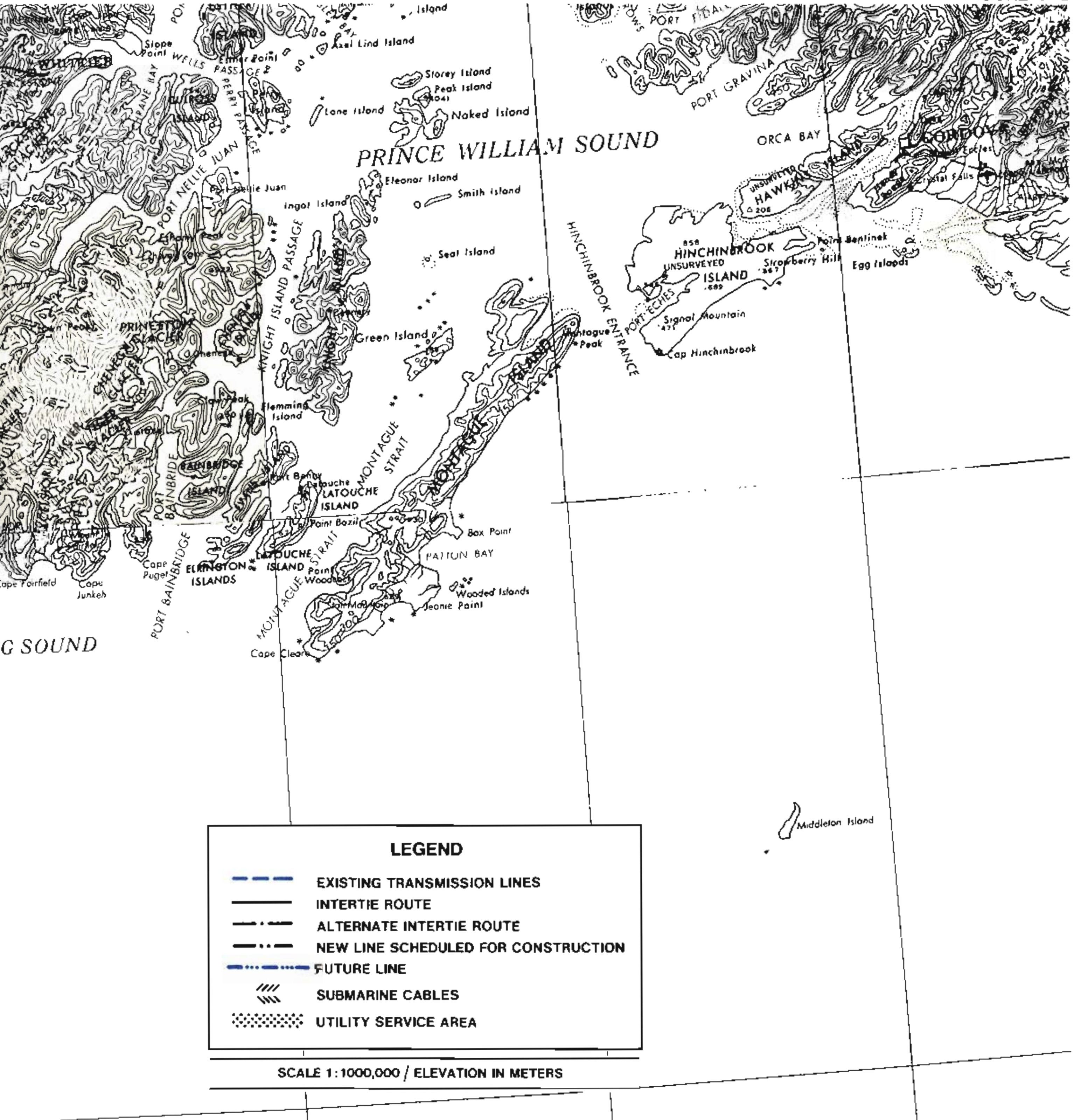

BERNICE LAKE
115KV
69KV
QUARTZ CREEK
SOLDOTNA
COOPER LAKE
BRADLEY LAKE
HOMER
H.E.A.
COOK INLET
KALGIN ISLAND
Harriet Point
Redoubt Point
Redoubt Bay
Cape Kasilof
Kasilof
Kenai
Salamatof
Soldotna
Ninilchik
Cape Ninilchik
Happy Valley
Anchor Point
Tustumena Lake
Harding Ice Field
Tustumena Glacier
UNSURVEYED
Deep Creek
Kachemak Bay
Yukon Island
Dangerous Cape
Point Adam
Elizabeth Island
Perl Island
East Chugach Island
CHUGACH ISLANDS
Nuka Bay
Nuka Island
Pye Islands
Ragged Island
Rabbit Island
Outer Island
Seward
Resurrection Bay
Cape Resurrection
Rugged Island
Chevol Island
Cape Aialik
Harbor Island
Natoa Island
Chiswell Island
Aialik Bay
Arm Bay
Granite Island
Nord Island
West Amatuli Island
East Amatuli Island
Sugarloaf Island
Sud Island
BARREN ISLANDS

FIGURE 4–3



INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON - KNUDSEN COMPANY

ROBERT W. RETHERFORD ASSOCIATES
CONSULTING ENGINEERS
A DIVISION OF ARKANSAS GLASS CONTAINER CORP.

COOK INLET – KENAI PENINSULA TRANSMISSION SYSTEM

CHAPTER 5

TRANSMISSION LINE DESIGN

CHAPTER 5

TRANSMISSION LINE DESIGN

5.1 BASIC DESIGN REQUIREMENTS

Experience in Alaska with both wood-pole H-frame, aluminum lattice guyed-X towers, and tubular steel guyed-X towers with high-strength conductors (such as Drake 795 kcmil ACSR) has demonstrated the excellent performance of lines designed with relatively long spans and flexible structures. This general philosophy has been followed in establishing the input parameters for the Transmission Line Cost Analysis Program (TLCAP) used to optimize line designs for the Anchorage-Fairbanks Intertie study. Sample outputs of TLCAP and descriptions of the program methodology are found in Appendix B.

The results of this computer analysis for 230-kV lines favor relatively long spans (1300 ft) and high-strength conductors (such as Cardinal 954 kcmil ACSR). This confirms the previous Alaskan experience and contributes substantially to a more economical design, as Chapter 7 will illustrate.

5.2 SELECTION OF TOWER TYPE USED IN THE STUDY

Due to rather unique soil conditions in Alaska, with extensive regions of muskeg and permafrost, conventional self-supporting or rigid towers will not provide a satisfactory performance or solution for the proposed intertie. Permafrost and seasonal changes in the soil are known to cause large earth movements at some locations, requiring towers with a high degree of flexibility and capability for handling relatively large foundation movements without appreciable loss of structural integrity.

The guyed tower is exceptionally well suited for these type of conditions. Therefore, the final choice of tower for this study was the hinged-guyed X-type design, which has been considered for both the 230-kV and 345-kV alternatives. These towers are essentially identical in design to towers presently used on some lines in Alaska, which have proven themselves during more than ten years of service. The design features include hinged connections between the leg members and the foundations which, together with the longitudinal guy system, provides for large flexibility combined with excellent stability in the direction of the line. Transverse stability is provided by the wide leg base which also accounts for relatively small and manageable footing reactions.

The foundations are pile-type, consisting of heavy H-pile beams driven to an expected depth of 20 to 30 feet depending upon the soil conditions.

Tower outlines with general dimensions for the two voltage levels are shown on Figures 5-1 and 5-2.

5.3 DESIGN LOADING ASSUMPTIONS

According to available information and experience on existing lines, heavy icing is not a serious problem in most parts of Alaska. NESC Heavy Loading is presently used for all line designs throughout the Railbelt region. However, there are locations where Light Loading probably could be used. Some line failures have occurred due to exceptionally heavy wind combined with very little or no ice. Such locations should be identified and carefully investigated prior to the final line design.

In this study, NESC Heavy Loading or heavy wind on bare conductor (corresponding to NESC Light Loading) was used, whichever is more severe.

5.4 TOWER WEIGHT ESTIMATION

In order to arrive at realistic tower weights and material costs for the study, actual tower designs for both the 230-kV and the 345-kV alternatives were obtained from Meyer Industries of Red Wing, Minnesota (Ref. 1). This company has designed similar towers for other lines in Alaska.

Based on these reference designs and additional manual calculations, tower weight formulas were developed to account for variations in tower weight due to changes in tower height and load as a function of the type of conductor used.

5.5 CONDUCTOR SELECTION

Conductor size (see Table 5-1) was selected by the use of the Transmission Line Cost Analysis Program (TLCAP) which was specially developed by IECO for this type of study. Given an appropriate range of conductor types and sizes, span lengths, and other pertinent data, TLCAP determines the most economical conductor-span combination.

The program includes a sag-tension routine which calculates the conductor sag and tension for a given set of criteria. Using this information, the tower height and loads are then determined for each discrete span length. These values are then applied to the tower weight formula with the pertinent overload factors included.

In the process of this analysis, the program also evaluated the effect of the cost of the power losses over a specified number of years. The power losses were minimized by varying the sending and receiving end voltages by ± 10% and by providing required shunt compensation at both line terminals. Applicable material and labor costs, together with projected escalation rates, were included to enable the program to calculate the total installed cost of the line. A discount rate of 7% per annum was used for the determination of the present worth of transmission line losses.

For this particular study, material and labor costs were obtained from "as built" cost information realized on recently completed (138-kV and 230-kV) lines in Alaska.

5.6 POWER TRANSFER CAPABILITIES

Preliminary transmission line capabilities, based on surge impedance loading (SIL) criteria, were obtained from the National Power Survey Report (Ref. 2). Additional investigations indicate that for the 230-kV alternatives (Cases IA, IB, and ID), the calculated intertie power angle is near 30 degrees. To improve the 230-kV intertie's steady state and transient transmission capability, series capacitors will be necessary. Interconnected power system studies should be performed to determine the final series and shunt compensation requirements. Such studies are outside the scope of this work.

5.7 HVDC TRANSMISSION SYSTEM

Because of its asynchronous nature, the interconnection of two isolated alternating current (ac) systems by a point-to-point HVDC transmission link provides the desired power exchange without being prone to inherent stability problems. Furthermore, HVDC transmission can provide stabilizing power, and be very effective in damping system oscillations. While the state-of-the-art in HVDC technology is advancing, the resulting developments are keeping pace with inflation.

Preliminary investigations have shown that HVDC transmission, using 180-kV mono-polar transmission and ground return, is competitive with single-circuit 230-kV ac transmission in the transfer 130 MW of power over 323 miles. However, if the point-to-point transmission link is required to supply intermediate locations with power (either initially or in the future) then it is unlikely that dc transmission can be competitive with an ac alternative.

5.8 REFERENCES

1. Letter from ITT Meyer Industries to Robert W. Retherford Associates, Anchorage, Alaska, January 15, 1979.

2. FPC Advisory Committee Report No. 6, National Power Survey, Vol. II, p. IV2-12, 1964.

TABLE 5-1

CONDUCTOR SIZE SELECTION CRITERIA

Case and Alternative[1/]	Interconnection	Voltage (kV + 10%)	Line Length (miles)	Optimum ACSR Conductor (kcmil)	Load[2/] Per Circuit (MW)
I A & B	Anchorage-Ester	230 s/c	323	1/c - 954	130
I C	Anchorage-Ester	345 s/c	323	2/c - 715	380
I D	Anchorage-Palmer Healy-Ester	230 s/c	323	2/c - 954	130
II A	Anchorage-Devil Canyon	345 s/c[3/]	155	2/c - 954	600
	Devil Canyon-Ester	230 s/c[3/]	189	1/c - 954	185
	Watana-Devil Canyon	230 s/c[3/]	27	1/c - 2156	488

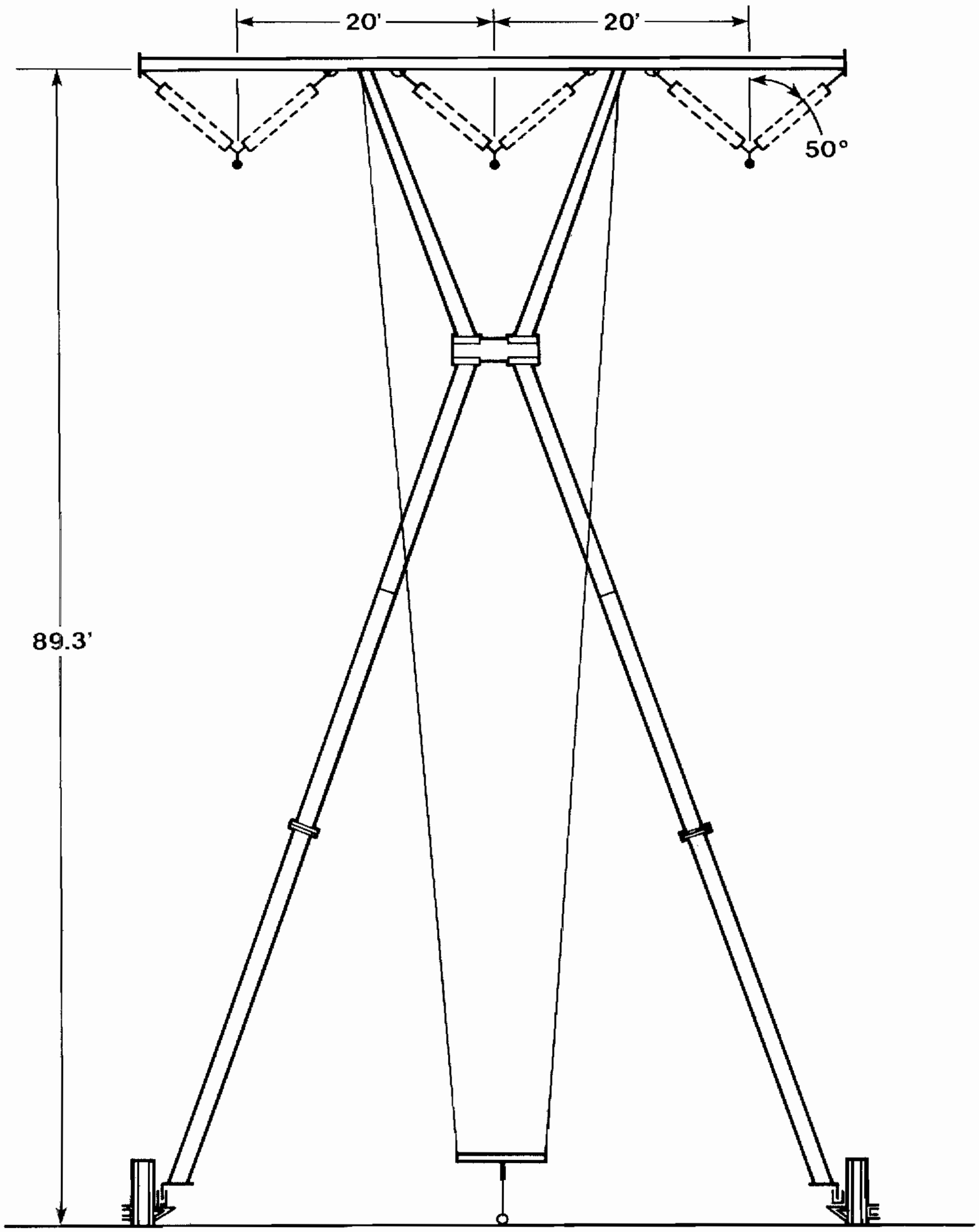
1/ Case I Alternatives exclude the proposed Susitna Project; Case II Alternative A includes the Susitna Project.

2/ 100% voltage support at both ends.

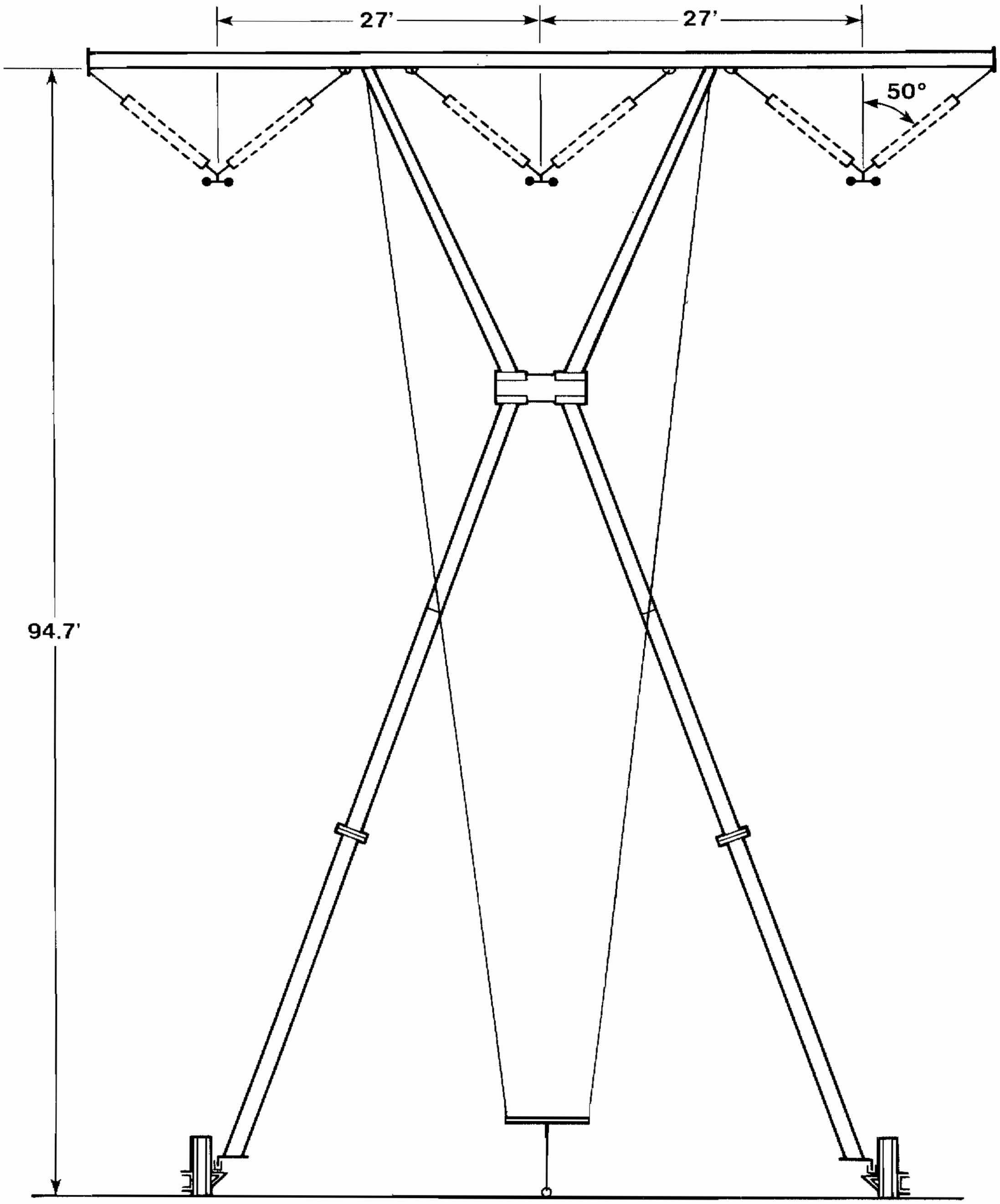
3/ Two single-circuit lines on the same right-of-way.

Note: s/c = single circuit; 1/c = single conductor; 2/c = two conductor bundle.

FIGURE 5–1



230KV TANGENT TOWER



345KV TANGENT TOWER

CHAPTER 6

SYSTEM EXPANSION PLANS

CHAPTER 6
SYSTEM EXPANSION PLANS

One benefit of transmission interconnection between two independent power systems is the reduction in the installed generating capacity that is possible, while maintaining the same electric power supply (generation) reliability level for both the independent and interconnected power systems. To calculate this reduction in installed generating plant capacity (megawatts), generation expansion plans had to be developed for both the independent and the interconnected power systems.

This chapter describes the actual process used in the generation expansion planning for the independent power systems of the Anchorage and Fairbanks areas, and for an interconnected Anchorage - Fairbanks power system. Generation expansion planning is a rather complex process. A brief description of the somewhat simplified method used in this Economic Feasibility Study is described below.

6.1 GENERATION PLANNING CRITERIA

A. Generating Unit Data

Existing generating unit data were obtained from the Battelle (Ref. 1) and University of Alaska, August 1976 (Ref. 2) reports. These available data were reviewed and updated using new information obtained by IECO-RWRA engineers during interviews with the managers of the Railbelt utilities. The updated existing generation unit data is presented in Tables 6-1 and 6-2.

Preliminary information on near future (1979-1986) generation expansion planning, including probable generation capacity requirements, for the AML&P and CEA systems was obtained directly from the two utilities. More detailed information on GVEA generation expansion plans was available in the review copy of the report Power Supply Study - 1978 (Ref. 3) and the Report on FMUS/GVEA Net Study (Ref. 4).

B. Installed Reserve Capacity

At the present time, there is apparently no uniform policy as to the required installed generation reserve margins for Alaskan electric power utilities. By definition, the installed generation reserve capacity includes spinning reserve, "hot" and "cold" standby reserves, and generating units on maintenance and overhaul work. No effort is made in this study to separate the installed reserve capacity into spinning and other types of reserves. Utilities in Alaska currently keep spinning reserves to the very minimum, mainly because of the no-load fuel cost incurred by the spinning reserves, and because most generating units in Alaska's Railbelt are quick starting, combustion turbine-type units. This situation may change in the future when new larger, slow starting, thermal power plants are constructed, exceptions being hydro plant units which can be started rather rapidly.

To develop alternative generation expansion plans for this study, a criterion for installed reserve generation capacity had to be established. A 20% reserve margin or the largest single unit at the time of peak system load was decided on as the installed generation reserve criterion. In general, the 20% value is close to the installed reserve goals of most U.S.A. utilities. Recently, the Department of Energy's Economic Regulatory Administration reported the following for the 1978 winter peak load of the lower 48 states:

> "According to the forecast, total available power resources for the lower 48 states will total nearly 500,000 MW. Peak demand is anticipated at 380,000 MW, for a reserve of nearly 120,000 MW or 31.5 percent. The lowest reserve - the 21.1 percent - will occur for the southeastern Electric Reliability Council, the DOE said, with the Mid-Atlantic Council experiencing the highest reserve margin at 45.1 percent" (Ref. 5).

C. Unit Retirement

Except for the Knik Arm Power Plant (CEA), no other generating units were reported for retirement by the Railbelt utilities during the 1980-1992 period. Later, to include the effect of the proposed Susitna Hydroelectric Project and to obtain a better economic analysis, this study period was extended through 1997. An assumption was made that the generating units available from 1980-1992 will also be available from 1993 through 1997. Many of them, however, will serve as system standby reserve units.

D. Generation Expansion Planning

To program the economic feasibility study and to establish transmission line interconnection benefits, generation expansion plans for the 1980-1997 period were developed for:

- Independent Anchorage area system.
- Independent Fairbanks area system.
- Interconnected Anchorage-Fairbanks system (intertie for reserve sharing only).
- Interconnected Anchorage-Fairbanks system (intertie for reserve sharing and power transfer).
- Interconnected Anchorage-Fairbanks system (with Susitna Hydroelectric Project).

Basically, generation planning includes three aspects: forecasting future loads (previously described in Chapter 3); developing generation reserve and reliability criteria (discussed later in this chapter); and determining when, how much, and what type of generation capacity is needed (which is discussed below).

Generation timing and capacity were determined by the most probable load forecasts for the Anchorage, Fairbanks, and combined Anchorage-Fairbanks areas, as described in Chapter 3.

Unit sizes for the alternative system expansion plans were determined by the ability of the power system to withstand the loss of a generating unit (or units) and still maintain reasonable system generation reliability. In determining unit sizes, due consideration was given to the valuable generation expansion planning data for the 1979-1986 period which was obtained by IECO-RWRA engineers from the Railbelt area utilities.

IECO-RWRA engineers determined the type of generation mix for the expansion plans based on:

- Preliminary planning information obtained through interviews with Railbelt utilities.
- Information available in the Battelle Report and Alaska Power Administration's January 1979 report draft (Ref. 6).
- The judgment of IECO-RWRA power system planners.

Most of the planned generation additions are baseload-type thermal steam power plants burning coal, gas, or oil as fuel. They are mixed with a few additional peaking-type combustion turbine generating units using natural gas or oil as fuel. It is assumed that in the later years of this study many existing combustion turbine generating units, presently used as baseload or intermediate units, will become peaking or standby units.

6.2 MULTI-AREA RELIABILITY STUDY

A. Purpose

The PTI Multi-Area Reliability (MAREL) Computer Program is used for alternative generation expansion planning, mainly for its ability to maintain a nearly constant level of generation supply reliability in all cases. This approach provides a nearly equal reliability level as far as generation ability to meet the load is concerned. The MAREL program gives reliability equivalence to both individual area and interconnected system generation planning alternatives. The MAREL program manual (Ref. 7) introduces this program with the following:

> "The PTI Multi-Area Reliability Program MAREL determines the reliability of multi-area power systems. It has been written in FORTRAN IV for use on a PRIME 400 time-sharing computer. Reliability indices computed by the program include system loss of load probability (LOLP), LOLP values for the individual areas, probability of various failure conditions and probability that each transmission (intertie) link is limiting in the transfer of generation reserves from one area to another."

MAREL program results helped determine the effectiveness of a transmission line intertie between the Anchorage and Fairbanks areas, and established the amount of generating capacity needed to give the individual areas approximately the same LOLP as for the interconnected system. MAREL study results are also applicable to the alternative which includes the Upper Susitna Project. In this instance the study became a three area reliability study with the Susitna area having only net generation and no load.

B. Reliability Index

To perform individual and interconnected system reliability studies (MAREL), it was necessary to select a reference system generation reliability index. As described above, the MAREL program uses LOLP calculation techniques for each study case. For each load condition the program user adjusts input data, specifically generator unit sizes, generator types, location of generating plants, and intertie capacities, to obtain generation expansion plans of near equal reliability for various alternatives. The LOLP method is very much the adapted method used by U.S.A. utilities during the last 30 years. According to the IEEE/PES Working Group on

Performance Records for Optimizing System Design, Power System Engineering Committee (Ref. 8):

> "This (LOLP reliability) index is defined as the long run average number of days in a period of time that load exceeds the available installed capacity. The index may be expressed in any time units for the period under consideration and, in general, can be considered as the expected number of days that the system experiences a generating capacity deficiency in the period. This index is commonly, but mistakenly, termed the "loss of load probability, (LOLP)". A year is generally used as the period of consideration. In this case, the LOLP index is the long-run number of days/year that the hourly integrated daily peak load exceeds the available installed capacity."

There is no standard value of LOLP which is used throughout the electric power industry. However, one day in ten years is a very much accepted value by the lower 48 utilities. Since to the authors' knowledge, LOLP index has not previously been used in Alaska, it was decided to use one day in ten years as LOLP index in this study. The use of this LOLP index may imply larger generation reserve margins than are presently used in Alaska, but an equal or even lower LOLP index is justifiable for Alaska for at least the following reasons:

- In very cold climatic zones the loss of electric power may be more critical than in more temperate climates.

- There is very little information on existing generation and transmission outage rates in Alaska. Therefore, there is more uncertainty about the study input data.

- At present, most of the power systems in Alaska are independently operated. In case of emergency, utilities cannot rely on help from neighboring utilities or power pools as can most of utilities in the lower 48. Therefore, a lower LOLP reliability index is justifiable.

- Higher planned generation reserves may be needed to provide protection against possible unplanned delays in construction of new larger thermal units.

C. Program Methodology

A general description of the MAREL computer program methodology is contained in Appendix C. The particular program application to this study is "Planning of interconnections to achieve regional integration and more widespread sharing of generation reserves" (Ref. 7). Briefly, the program models each area as a one-bus system to which all generators and loads are connected. Transmission interties between areas are modeled as having limited power transfer capabilities and specified line outage rates. The method assumes that each area takes care of its own internal transmission needs.

D. Load Model

Annual load models were developed for the Anchorage and Fairbanks areas. Daily peak load data for 1975 were obtained from AML&P, CEA, FMUS, and GVEA. The Railbelt utility representatives agreed that 1975 was a typical year with normal weather conditions. The 1975 load models were converted into per unit system for the MAREL program. The computer program multiplied this 1975 load model (input) by the respective study year peak loads to obtain annual load models for each year of the study. Forecasted annual peak loads and the per unit annual load models for the Anchorage and Fairbanks areas are shown in Tables 6-3 and 6-4. Annual demand curves indicating biweekly non-coincident peaks are shown on Figure 6-1. Figure 6-1 also indicates that there is very little diversity between the loads of the Anchorage and Fairbanks areas.

E. Generating Unit Data

Information on existing generating unit data, as indicated in Tables 6-1 and 6-2, was used in the study. Unit base ratings were rounded off to the nearest megawatt in the study. Sizes for new generating units used in the expansion plans are indicated on Figures 6-2, 6-3, 6-4, and 6-5.

Generating unit outage rates, which are required for calculating LOLP indexes, were obtained from the most recent Edison Electric Institute (EEI) report on equipment availability (Ref. 9). The rates for combustion turbines were obtained from the actual operating experience of CEA and GVEA at the Beluga and Zehnder Power Plants. The EEI publication defines the forced outage rate as:

$$\text{Forced Outage Rate} = FOH/(SH + FOH) \times 100$$

Where FOH represents forced outage hours and SH represents service hours. Generating unit outage rates used in the MAREL study are indicated below:

Unit Designation	Forced Outage Rate (%)
Combustion Turbine*	5.5
Hydroelectric Plant	1.6
Thermal Steam Plant (small units)	5.9
Thermal Steam Plant (100-200 MW)	5.7
Thermal Steam Plant (300 MW)	7.9

* The Forced Outage Rate for combustion turbines was based on the following information:

- CEA experience at Beluga during 1977-1978 period, six units base loaded.

Unit availability	87% of the time
Scheduled maintenance	8% of the time
Forced outage	5% of the time

Therefore, the calculated Forced Outage Rate equals 5.4%.

- In 1975 GVEA experience at Zehnder Station, Units No. 1 and 2 provides calculated Forced Outage Rates of 4.2% and 4%, respectively; however, these units were basically standby units.

F. Generating Unit Maintenance

The MAREL program automatically schedules generating unit maintenance within the specified restrictions. For the purpose of this study, it was assumed that no unit maintenance will be scheduled during the November-March winter season.

G. Intertie Data

The MAREL program models the transmission intertie by limiting intertie transfer capabilities and considering intertie outage rates. No load loss sharing method was used. This means that one area will share its generating reserves only up to the limit of intertie transfer capability or available reserves in the other area, whichever is limiting. The forced outage rates (on a per year basis) used in the study for transmission and line terminal equipment are indicated below:

Line Voltage (kV)	Forced Outage Rate (per unit/100 miles)
230	0.00113
345	0.00225

Note: The following outage rate was used for both 230-kV and 345-kV line terminals: 36 hours/10 years.

6.3 SYSTEM EXPANSION PLANS

A. Planning Study Period

Based on generation planning criteria and the results of the MAREL reliability study (previously described in this chapter), alternative generation expansion plans were developed. The 1984-1997 period was selected for the alternative expansion plans for the following reasons:

- 1984 is the earliest year when the interconnected system can be operational.

- The 1992-1997 period includes the Upper Susitna Hydroelectric Project, based on the optimistic assumption that Watana Unit No. 1 will be on-line in January 1992.

- The study period is long enough for the present worth economic analysis method, and includes most of the costs and benefits obtainable by the introduction of an intertie in 1984.

To close the gap between the existing generation systems and the first study year (1984) of the intertie economic feasibility study, generation expansion plans for the independent Anchorage and Fairbanks areas for 1980 through 1983 were developed. Information on planned generation additions supplied by the generating utilities in the Railbelt area was used for this purpose.

B. Independent System Expansion Plans

Generation expansion plans for the independent Anchorage and Fairbanks systems were also needed to calculate economic benefits of the interconnection. The planned generation additions consist of thermal base load and peaking units. They do not include the Upper Susitna Project (Watana and Devil Canyon Hydro Plants), which are only included in the interconnected system expansion plans. The independent Anchorage and Fairbanks generation expansion plans are indicated on Figure 6-2.

C. Interconnected System Expansion Plans

Two cases of system interconnection were studied - Case I, direct interconnection between Anchorage and Fairbanks (Ester), and Case II, interconnection between Watana-Devil Canyon with Anchorage and Fairbanks systems. Under Case I four alternatives were developed as follows:

- Case IA includes a single-circuit 230-kV transmission line having 130-MW power transfer capability allocated for reserve sharing only. This plan is shown on Figures 6-3 and 6-6.

- Case IB includes one single-circuit 230-kV transmission line (1984-1991) and two single-circuit 230-kV transmission lines (1992-1997) having the following generation reserve sharing capabilities: 100 MW (1984-1987), 130 MW (1989-1991) and 190 MW (1992-1997). In addition, this alternative has a firm power transfer capability of 30 MW (1984-1987) and 70 MW (1992-1997). This plan is shown on Figures 6-4 and 6-6.

- Case IC includes one single-circuit 345-kV transmission line having a 130-MW power transfer capability allocated for generation reserve sharing and a 250-MW capacity available for firm power transfer. This case was developed for comparative cost information purposes only without generation expansion plans (MAREL study) and is presented on Figure 6-7.

- Case ID is the same as Case IA, except with intermediate switching stations at Palmer and Healy. This plan is shown on Figures 6-3 and 6-8.

Under Case II, only one solution was studied: two single-circuit 230-kV transmission lines from Watana to Devil Canyon; two single-circuit 230-kV lines from Devil Canyon to Ester (Fairbanks); and two single-circuit 345-kV lines from Devil Canyon to Anchorage.

D. Reliability Indexes

The results of the MAREL study show loss of load probability (LOLP) indexes for independent system expansion plans and plans for an interconnected system (with and without the Upper Susitna Project), and are indicated in Tables 6-7, 6-8, and 6-9. As previously discussed in Subsection 6.2B, the LOLP index of one day in ten years (0.1 day/year) or lower was maintained throughout the study.

6.4 REFERENCES

1. Battelle Pacific Northwest Laboratories, Alaskan Electric Power, An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, Vol. I, March 1978.

2. University of Alaska, Institute for Social and Economic Research, Electric Power in Alaska, 1976 - 1995, August 1976.

3. Stanley Consultants, Power Supply Study - 1978 for Golden Valley Electric Association, Inc.

4. Alaska Resource Sciences Corporation, Report FMUS/GVEA Net Study, Vol. 1, May 1978.

5. Electric Light and Power, Capacity Can Meet Winter Peaks - DOE, November 1978.

6. Alaska Power Administration, Upper Susitna River Project, POWER MARKET ANALYSES, Draft, January 1979.

7. Power Technologies, Inc. PTI Multi-Area Reliability Program (MAREL), Computer Program Manual, September 1978.

8. "Reliability Indices for Use in Bulk Power Supply Adequacy Evaluation", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-97, No. 4, July/August 1978.

9. Edison Electric Institute, Report on Equipment Availability for the Ten-Year Period 1967-1976, December 1977.

TABLE 6-1

EXISTING GENERATION SOURCES
ANCHORAGE - COOK INLET AREA

Name/Location	Unit Reference	Year of Installation	Type	Unit Rating Base (kW)	Unit Rating Peak (kW)	Dependable Capacity (kW)	Remarks
ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)							
Anchorage			Diesel	2,200			Black start unit
Anchorage	Unit 1		SCGT	15,130	18,000		
Anchorage	Unit 2		SCGT	15,130	18,000		
Anchorage	Unit 3	1968	SCGT	18,650	21,000		
Anchorage	Unit 4	1972	SCGT	31,700	35,000		
Anchorage	Unit 5	1975	SCGT	36,800	40,000		Combined cycle installation
Anchorage	Unit 6	1979	HRST	12,000			
CHUGACH ELECTRIC ASSOCIATION (CEA)							
Beluga	Unit 1		SCGT	15,150	18,700		
Beluga	Unit 2		SCGT	15,150	18,700		
Beluga	Unit 3		RCGT	53,500	67,000		
Beluga	Unit 4		SCGT	9,300	10,000		
Beluga	Unit 5		RCGT	53,500	67,000		
Beluga	Unit 6		SCGT	67,810	72,900		
Beluga	Unit 7	1978	SCGT	67,810	72,900		
Bernice Lake	Unit 1		SCGT	8,200	16,500		
Bernice Lake	Unit 2		SCGT	19,600	20,500		
Bernice Lake	Unit 3	1978	SCGT	24,000			
International	Unit 1		SCGT	14,530	16,500		
International	Unit 2		SCGT	14,530	16,500		
International	Unit 3		SCGT	18,600	21,500		
Cooper Lake	Unit 1		Hydro	7,500	9,600		
Cooper Lake	Unit 2		Hydro	7,500	9,600	16,500	
Knit Arm	Several		ST	14,500	17,700		To be retired in 1985
MATANUSKA ELECTRIC ASSOCIATION (MEA)							
Talkeetna			Diesel	600			Standby
HOMER ELECTRIC ASSOCIATION (HEA)							
English Bay			Diesel	100			
Homer-Kenai			Diesel	300			Leased to CEA
Homer			SCGT	7,000			Leased from GVEA (1977-1979)
Port Graham			Diesel	200			
Seldovia			Diesel	1,648		1,500	
SEWARD ELECTRIC SYSTEM (SES)							
Seward	Unit 1		Diesel	1,500			
	Unit 2		Diesel	1,500	1,500	5,500	Standby
	Unit 3		Diesel	2,500	3,000		
ALASKA POWER ADMINISTRATION (APA)							
Eklutna	Unit 1		Hydro	30,000	35,000	30,000	

TABLE 6-2

EXISTING GENERATION SOURCES

FAIRBANKS - TANANA VALLEY AREA

Name/Location	Unit Reference	Year of Installation	Type	Unit Rating Base (kW)	Unit Rating Peak (kW)	Dependable Capacity (kW)	Remarks
FAIRBANKS MUNICIPAL UTILITIES SYSTEM (FMUS)							
Fairbanks	Chena 1	1954	ST	5,000			
Fairbanks	Chena 2	1952	ST	2,000			
Fairbanks	Chena 3	1952	ST	1,500			
Fairbanks	Chena 4	1963	ST	20,000			
Fairbanks	Chena 5	1970	SCGT	5,350	7,000		
Fairbanks	Chena 6	1976	SCGT	23,500			
Fairbanks	Diesel 1	1967	Diesel	2,665			
Fairbanks	Diesel 2	1968	Diesel	2,665			
Fairbanks	Diesel 3	1968	Diesel	2,665			
GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)							
Zehnder Sub.	Unit 1	1971	SCGT	17,553	20,000	17,400	Peaking Service
Zehnder Sub.	Unit 2	1972	SCGT	17,553	20,000	17,400	
Zehnder Sub.	Unit 3	1975	SCGT			3,500	Leased to HEA (1977-1979)
Zehnder Sub.	Unit 4	1975	SCGT			3,500	
Zehnder Sub.	Units 1-7	1970	Diesel			12,900	
Healy	Unit-1	1967	ST			26,200	
Healy			Diesel	2,500			
Northpole	Unit 1	1976	SCGT	64,800	70,000		
Northpole	Unit 2	1977	SCGT	64,800	70,000		
U. of Alaska	Units 7&8		Diesel			5,100	
Delta			Diesel			500	Mobile Unit

TABLE 6-4

LOAD MODEL DATA
FAIRBANKS AREA

ANNUAL PEAK LOAD IN MW
(1983 - 1996)

```
196.  212.  231.  249.  270.  291.  313.  338.  362.  390.
416.  446.  477.  511.
```

INTERVAL PEAK LOADS IN P.U. OF ANNUAL PEAK LOAD
(26 INTERVALS / YEAR)

```
0.87590.69900.73710.76040.57490.59710.56630.51110.43240.41150.38330.37470.3587
0.35380.38080.41770.42010.43730.46190.53190.57490.89190.93370.93491.00000.7690
```

DAILY PEAK LOADS IN P.U. OF INTERVAL PEAK LOAD
(260 WEEK DAYS / YEAR)

```
1.00000.97480.94670.94670.94530.93130.89480.86540.84290.8177
1.00000.93670.92790.92790.90510.89980.88050.85940.82790.7891
1.00000.99330.96670.94830.94000.92330.90330.88000.86670.8267
1.00000.97580.96120.94510.86910.83200.82390.81100.79000.6769
1.00000.98500.98290.95940.95300.94660.91880.90810.90170.8825
1.00000.99790.99590.98770.97940.95880.93620.90530.89300.8827
1.00000.98480.95010.93710.91970.89370.88070.87200.86120.8091
1.00000.96870.96150.95190.93510.91590.88700.88220.87980.8558
1.00000.99150.99150.99150.97160.96870.93180.89200.88920.8693
1.00001.00000.96120.93130.92840.92840.92240.90750.90450.8955
1.00000.99040.99040.94550.92310.91990.91670.91350.87820.8558
1.00000.96720.95410.92790.92460.90490.89840.89510.87870.8721
1.00000.96920.96920.95890.95890.94520.94520.93150.92120.9041
1.00000.98960.97220.96870.95830.94790.93400.92360.92010.8507
1.00000.96770.93870.93230.91290.90320.90320.90320.87100.8677
1.00000.87350.87060.86760.86460.85880.84710.84410.83820.8059
1.00000.94440.90640.90640.89470.82750.82750.82460.81870.8012
1.00000.99720.97750.96350.96350.94940.93820.93820.91010.8904
1.00000.99470.96810.93090.92820.90960.90690.90160.88830.8856
1.00000.98850.93300.91450.90990.89610.88910.88450.86370.8568
1.00000.99150.98080.97650.94020.92950.92740.91880.91450.9017
1.00000.96690.91180.89260.88840.79890.73970.64460.61020.6088
1.00000.97710.91050.90790.90790.89340.88950.88550.86320.8434
1.00000.97110.86330.83050.81870.79630.79240.74510.73320.7201
1.00000.99510.98160.97300.97170.95580.91650.88450.82430.6818
1.00000.99840.93930.92010.89940.88980.88500.84820.81310.7971
```

TABLE 6-5

LOSS OF LOAD PROBABILITY INDEX (LOLP)1/
FOR
STUDY CASES IA & ID2/

Study Year	Anchorage Independent Expansion	Anchorage Interconnected Expansion	Fairbanks Independent Expansion	Fairbanks Interconnected Expansion
1984	0.0262	0.0063	0.8193	0.0066
1985	0.0123	0.0275	0.1446	0.0242
1986	0.0293	0.0178	0.2868	0.0268
1987	0.0288	0.0255	0.6766	0.0575
1988	0.0482	0.0799	0.1140	0.0300
1989	0.0330	0.0677	0.2318	0.0394
1990	0.0265	0.0680	0.0593	0.0670
1991	0.0193	0.0633	0.1550	0.0130
1992	0.0189	0.0286	0.0276	0.0275
1993	0.0546	0.0316	0.0586	0.0606
1994	0.0427	0.0321	0.1583	0.1365
1995	0.0326	0.0652	0.0373	0.0426
1996	0.0931	0.0586	0.0899	0.1021

1/ LOLP in days per year.

2/ 230 kV s/c, 130 MW reserve sharing only.

TABLE 6-6

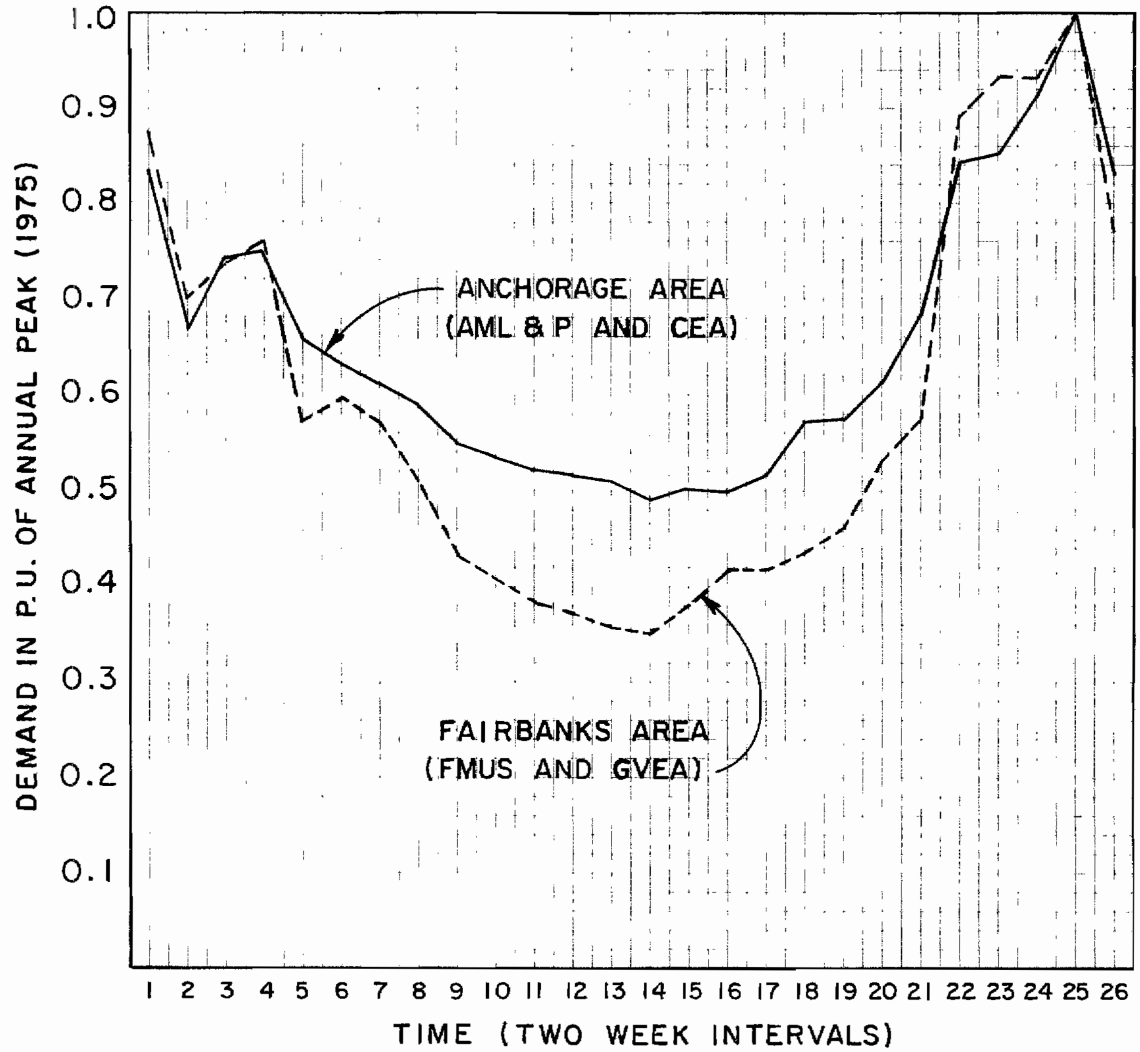
LOSS OF LOAD PROBABILITY INDEX (LOLP)[1/]
FOR
CASE IB[2/]

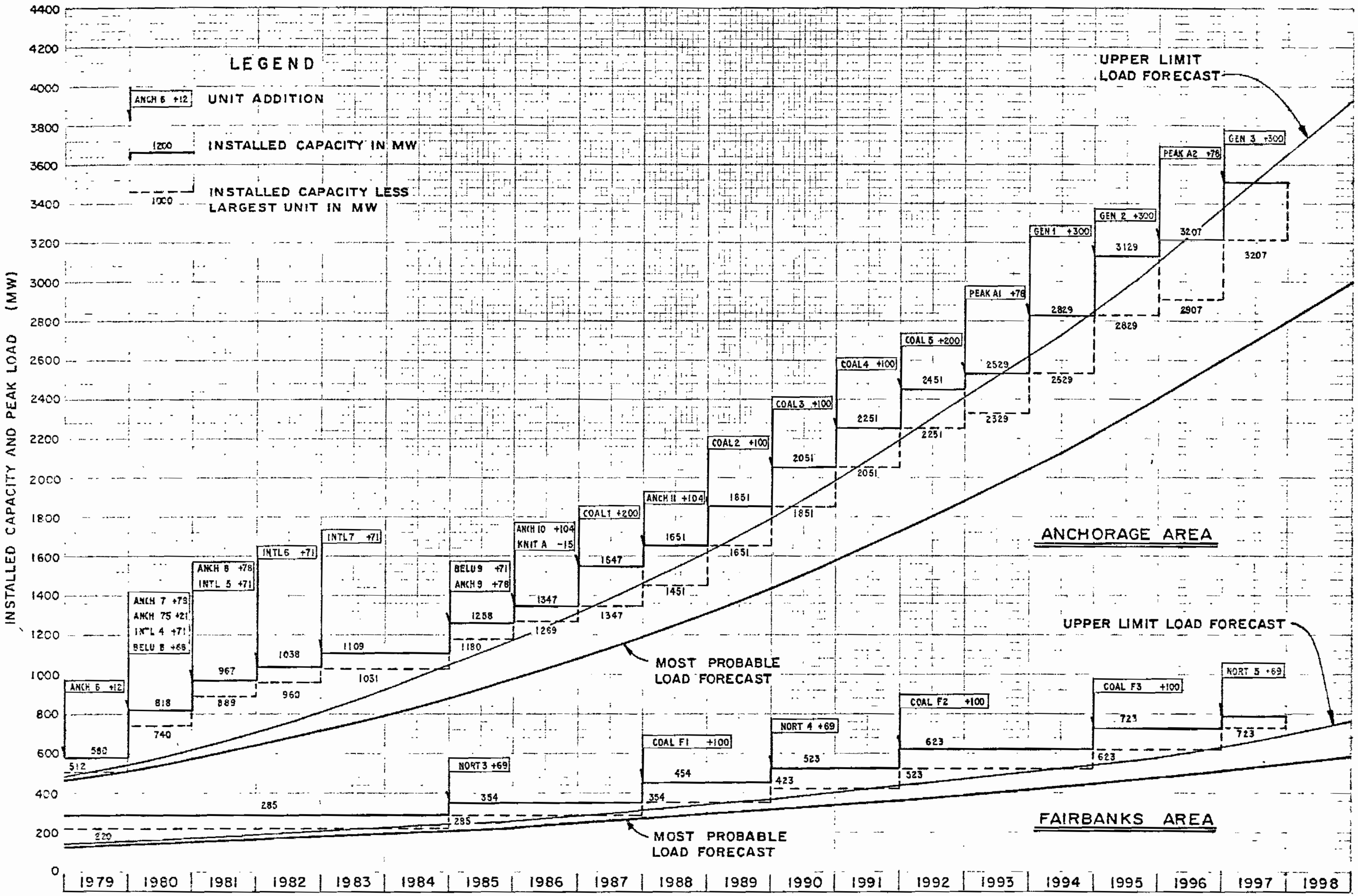
Study Year	Anchorage Independent Expansion	Anchorage Interconnected Expansion	Fairbanks Independent Expansion	Fairbanks Interconnected Expansion
1984	0.0262	0.0077	0.8193	0.0018
1985	0.0123	0.0329	0.1446	0.0096
1986	0.0293	0.0220	0.2868	0.0152
1987	0.0288	0.0306	0.6766	0.0299
1988	0.0482	0.0799	0.1140	0.0300
1989	0.0330	0.0677	0.2318	0.0394
1990	0.0265	0.0680	0.0593	0.0670
1991	0.0193	0.0633	0.1550	0.0130
1992	0.0189	0.0359	0.0276	0.0143
1993	0.0546	0.0703	0.0586	0.0354
1994	0.0427	0.0550	0.1583	0.0654
1995	0.0326	0.0991	0.0373	0.0369
1996	0.0931	0.0838	0.0899	0.0506

1/ LOLP in days per year.

2/ 230-kV transmission system with reserve sharing and firm power transfer capability.

NON-COINCIDENT 1975 PEAK DEMANDS
ANCHORAGE AND FAIRBANKS AREAS





INDEPENDENT SYSTEM EXPANSION PLANS
ANCHORAGE AND FAIRBANKS AREAS

FIGURE 6-2

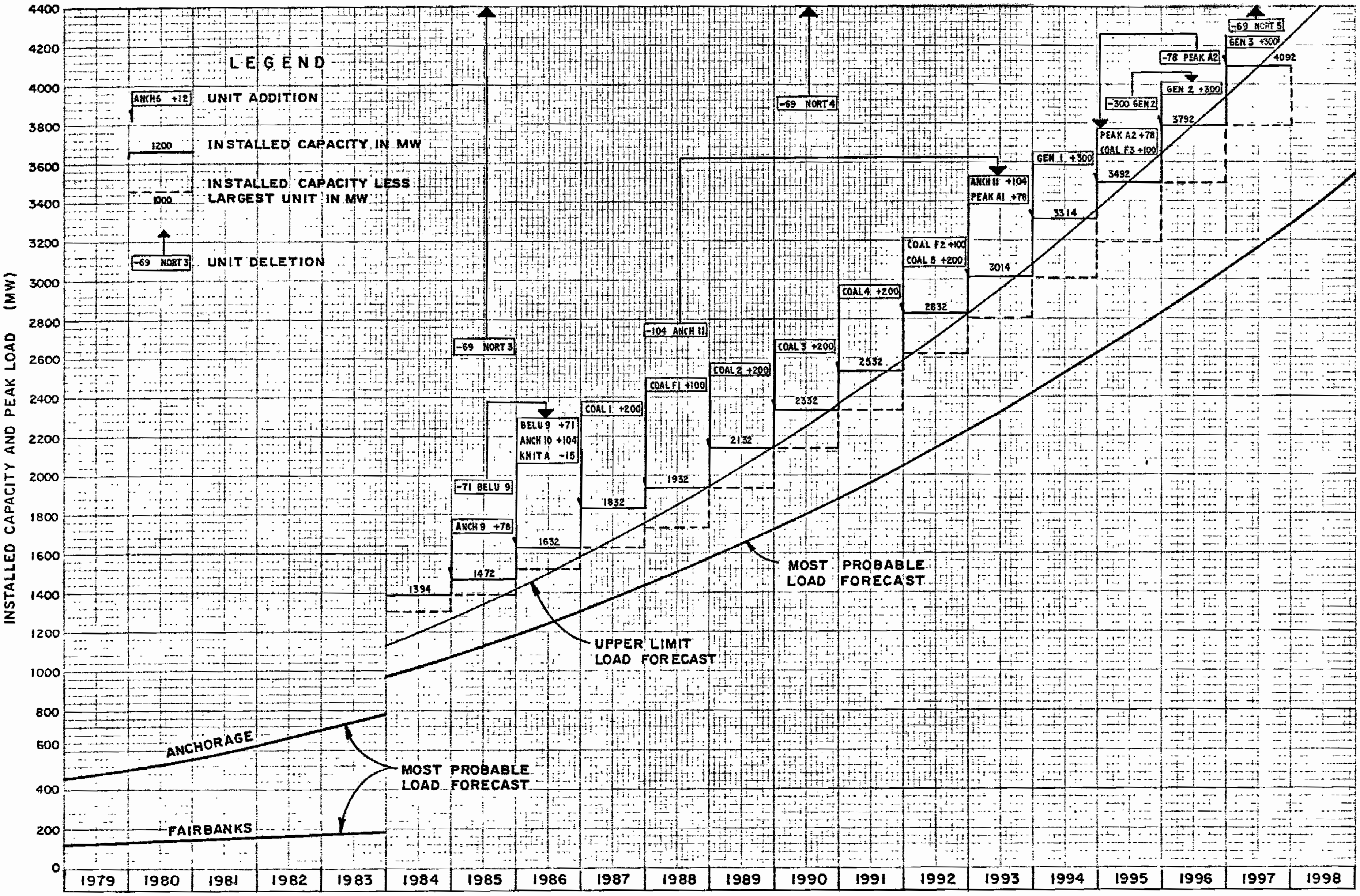
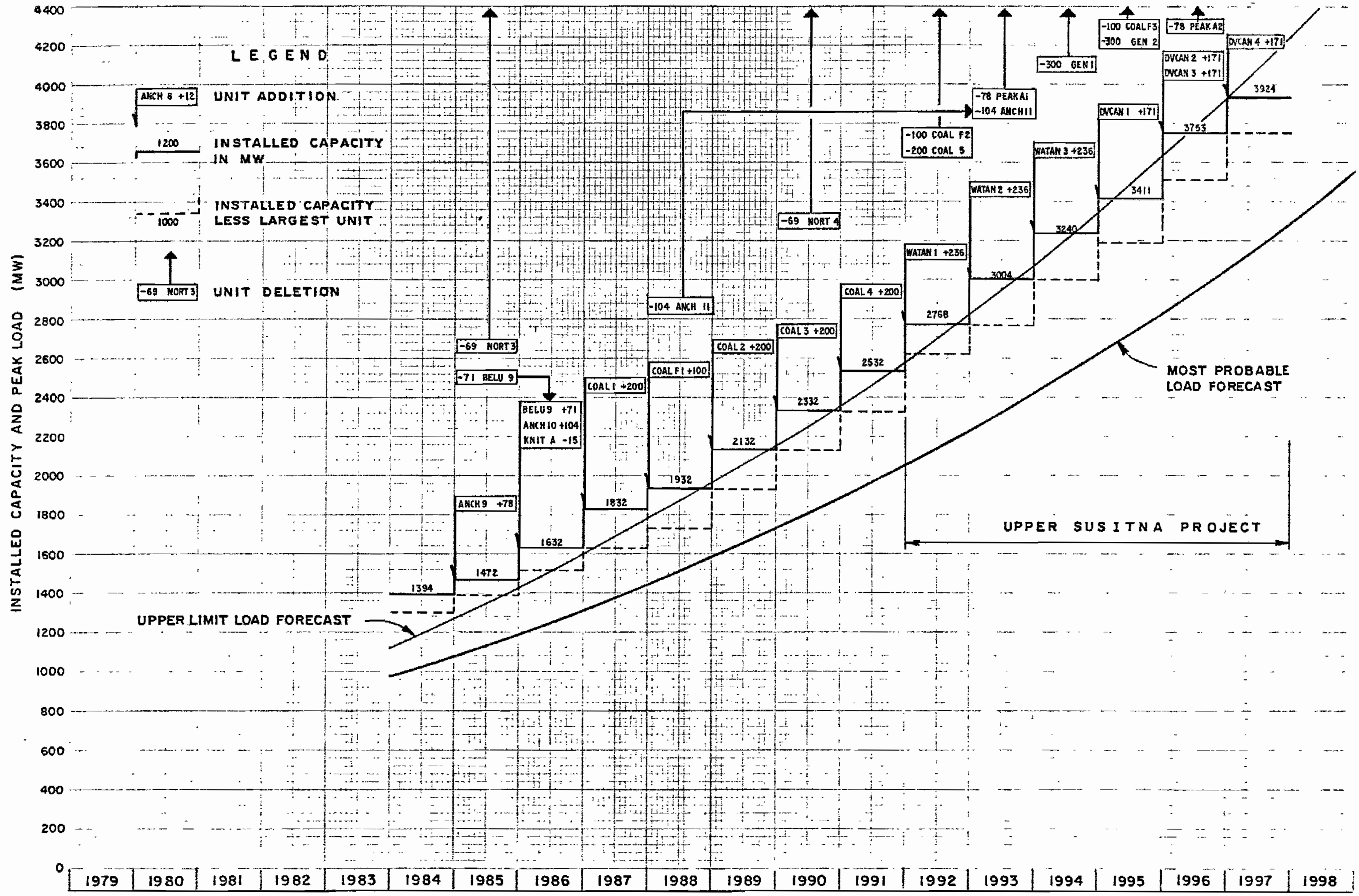


FIGURE 6-3

INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITHOUT SUSITNA PROJECT



INTERCONNECTED SYSTEM EXPANSION PLAN
ANCHORAGE - FAIRBANKS AREA
WITH UPPER SUSITNA PROJECT

FIGURE 6-5

FIGURE 6-6

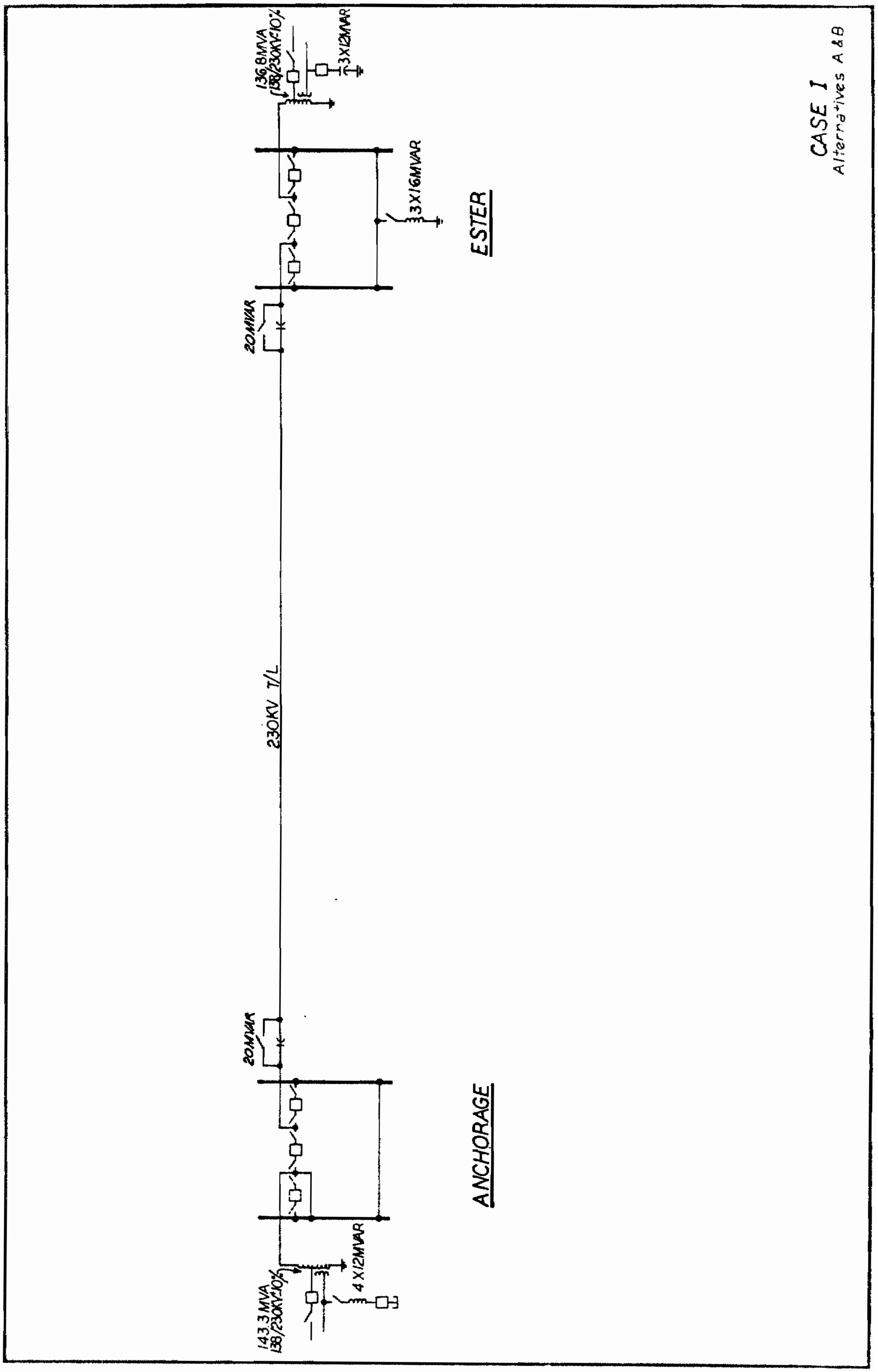

CASE I
Alternatives A & B
ESTER
3X16MVAR
3X12MVAR
136.8MVA
138/230KV-10%
20MVAR
230KV T/L
20MVAR
ANCHORAGE
4 X12MVAR
143.3 MVA
138/230KV-10%

FIGURE 6-7

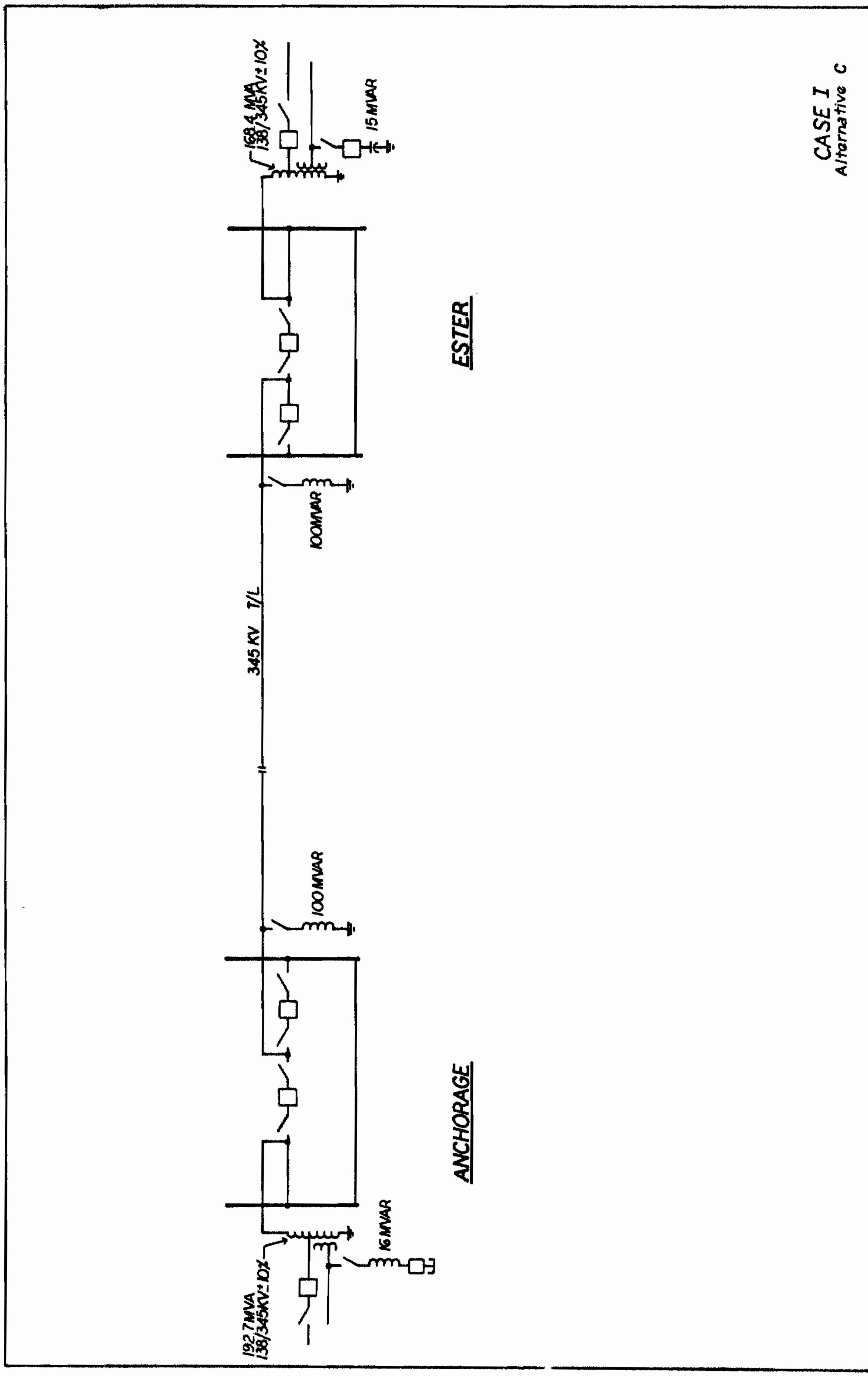

CASE I
Alternative C
168.4 MVA
138/345KV±10%
15 MVAR
ESTER
100MVAR
345 KV T/L
100 MVAR
ANCHORAGE
16 MVAR
192.7 MVA
138/345KV±10%

FIGURE 6-8

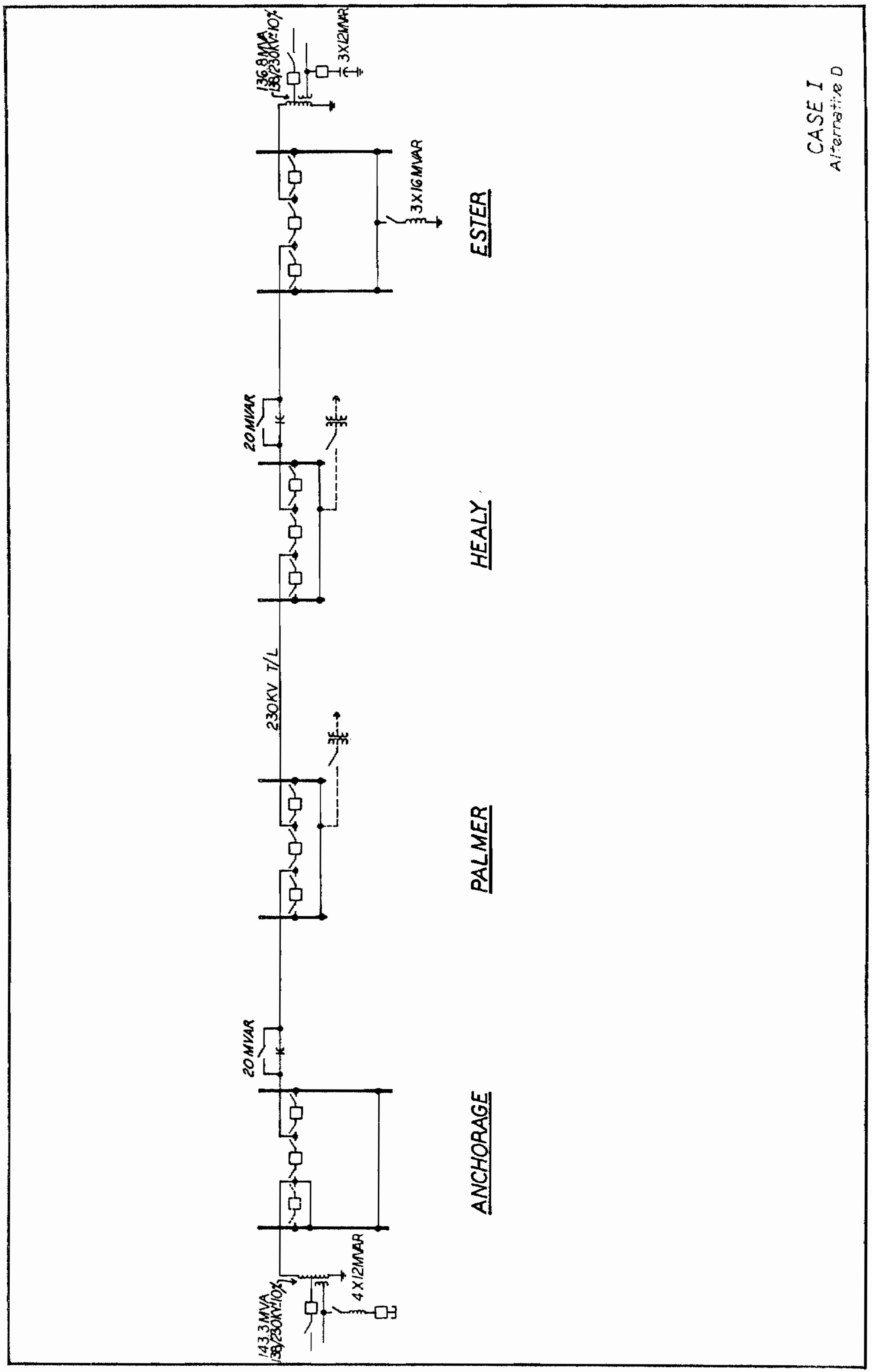
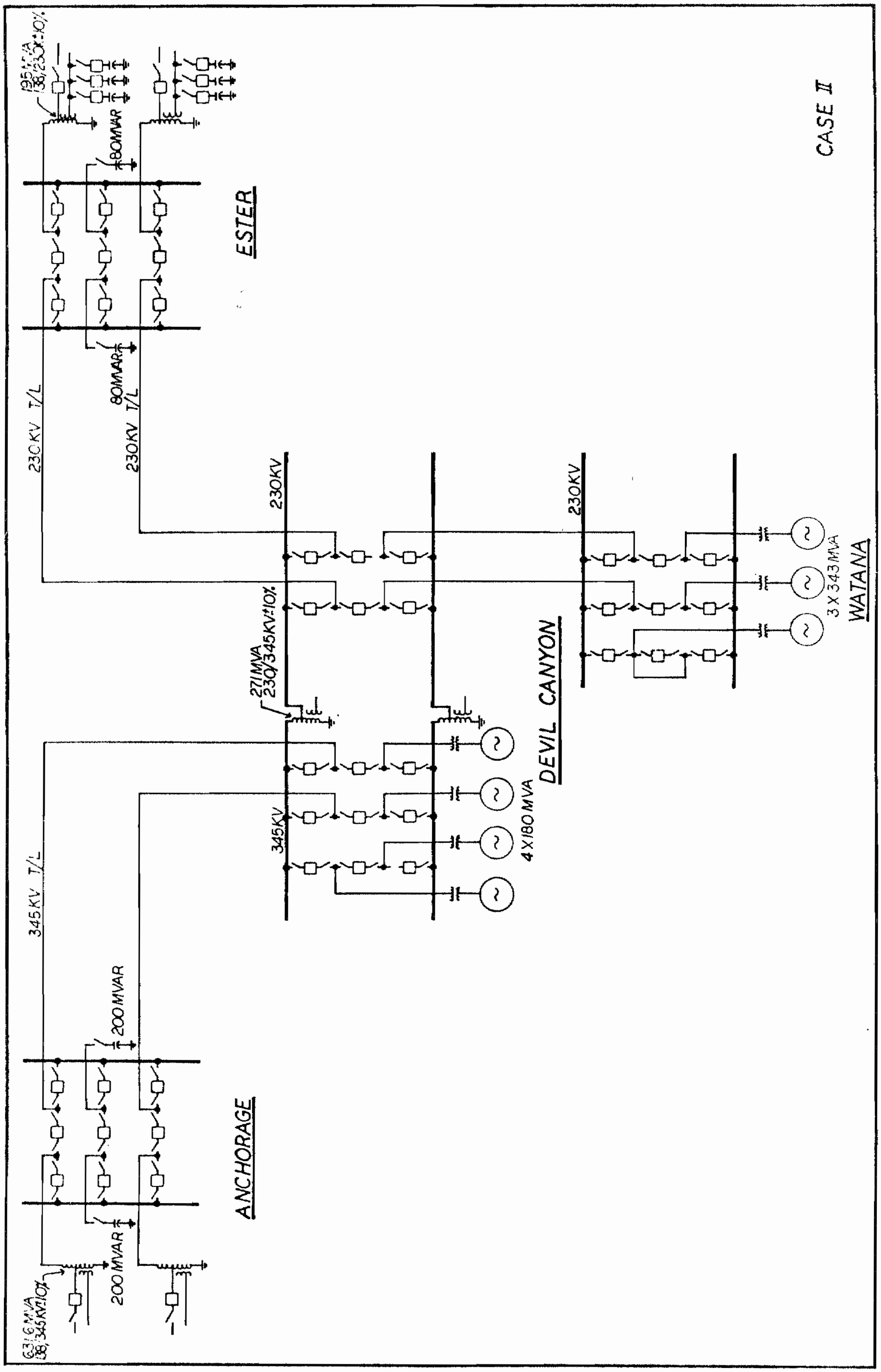

CASE I
Alternative D
ANCHORAGE
PALMER
HEALY
ESTER
230KV T/L
20MVAR
20MVAR
3X16MVAR
3X12MVAR
4X12MVAR
136.8MVA
143.3MVA

FIGURE 6-9


CASE II
ESTER
80MVAR
80MVAR
230KV T/L
230KV T/L
230KV
230KV
271MVA
230/345KV±10%
DEVIL CANYON
WATANA
3 X 343 MVA
4 X 180 MVA
345KV
345KV T/L
200 MVAR
200 MVAR
ANCHORAGE

CHAPTER 7
FACILITY COST ESTIMATES

CHAPTER 7

FACILITY COST ESTIMATES

7.1 TRANSMISSION LINE COSTS

The transmission line costs were obtained from past and current experience of the Consultants with the design and construction of transmission lines in Alaska. Cost data was escalated to 1979 levels and a factor of 1.46 (AVF = Average Value Factor) was applied to total costs to give an average value for construction in the area. The AVF includes a 10% addition for anticipated difficulty with the constraints associated with the selected line route.

A. Alaskan Experience

Facility cost estimates for alternative transmission intertie designs are based on an in-depth analysis of pertinent Alaskan transmission lines that have been built and are now in successful operation. Analyses were made based on actual experience to develop material and man-hour costs, together with specific installation requirements for structures, conductors, and footing assemblies. In addition, typical right-of-way clearance costs and other costs associated with the solicitation and obtention of right-of-way easements, permits, and environmental reviews were gathered to provide representative costs for estimating component items for the Anchorage-Fairbanks Intertie.

The first Alaskan transmission line capable of operating at voltages as high as 230 kV was the Beluga Line. It was constructed for Chugach Electric Association (CEA) in 1967 by City Electric, Inc. of Anchorage. This line traverses about 42.5 miles of undeveloped land, of which about 65% was muskeg swamp. No roads existed to connect the line right-of-way to any highway or railroad, requiring that access be by water (Cook Inlet - Susitna River), by air (helicopter), or by ORV (off-road vehicle). One major river crossing was required along the transmission line route.

The Beluga Line was constructed of aluminum lattice, X-shape, hinged-guyed towers and Drake (795 kcmil ACSR) conductor by the Contractor. Using one tower assembly yard at Anchorage, the Contractor made extensive use of helicopter delivery of men and materials with ORV equipment during winter weather to construct the line. This project was completed at a cost of about $50,000 per mile, including right-of-way clearance.

The hinged-guyed, X-shaped tower proved successful and has since been used for the following lines described below.

1. Knik Arm Transmission Line - 230 kV (Aluminum Lattice Towers, 795 kcmil Drake ACSR Conductor), 1975. This line was built using Owner-furnished material by force account and contract methods. The Owner (CEA) installed the piling and anchors, and contracted for the right-of-way clearing, tower erection, and wire stringing. Piling and anchors were installed using ORV equipment to carry the power tool for installing anchors and the Del Mag-5 diesel hammer and welding equipment for the piling work. City Electric, Inc. accomplished the tower erection and wire stringing using helicopter and ORV equipment.

Summary of Actual Costs:	$/Mile
Construction Cost	87,294
Right-of-way Clearing Cost	19,049
Right-of-way Solicitation Cost	7,706
TOTAL (w/o Engineering)	114,049

2. Willow Transmission Line - 115 kV (Tubular Steel Towers, 556.5 kcmil Dove ACSR Conductor), 1978. This line was built by contract using Owner-furnished material. Right-of-way clearing was accomplished by one contractor and line construction by another (Rogers Electric - an experienced Alaska contractor). This line contractor used a vibratory driver to install the 8" H-pile with great success. (This driver has since been used to drive 10" H-pile for another line. In one case, the tool drove a 14" H-pile for a sign support. The contractors are preparing

to drive more 14" piles for a new CEA line.) The introduction of the vibratory pole-driving technique, together with the application of the tubular steel, hinged-guyed, X-tower is expected to realize substantial cost savings on future transmission line projects.

Summary of Actual Costs:	\$/Mile
Construction Cost	73,863
Right-of-way Clearing Cost	10,312
Right-of-way Solicitation Cost	4,909
TOTAL (w/o Engineering)	89,084

B. Material Costs

The estimated cost for the tower steel, as well as the physical characteristics were obtained from ITT Meyer Industries (Ref. 1). The cost of steel, therefore, has 1979 as the reference year. A 10 percent addition to the material cost was included to account for the 1.46 AVF explained above.

The cost of foundation steel was taken to be \$0.31 per lb for WG Beam. This value is somewhat conservative, as the current market price is \$0.22 per lb.

Prices for insulators and conductors have a reference year of 1977; thereafter, the price was escalated at 7 percent per year through 1979. The cost of right-of-way was based on actual average values paid by utilities in the same area as the proposed lines. Other factors used, that provide good indication of projected costs for the transmission line are:

- Terrain Factor - This factor is used to correct the number of calculated towers per mile to actual towers per mile.

- Line Angle Factor - This factor is used to increase the effective transversal load on the tower, and accounts for the 3^{o} design-angle for the towers.

- Tower Weight Factor - This factor is used to increase the total estimated tower weight, to account for heavy angle and dead-end towers.

C. Labor Costs

Labor costs were obtained from actual construction experience, obtained by the Consultants' construction records for transmission lines built in Alaska. This information included the cost of labor and a detailed breakdown of the man-hours required for every specific task included in the construction program. A multiplier of 2 was applied to the estimated cost of labor for this period, in order to obtain the 1.46 AVF indicated above.

D. Transportation Costs

An estimated unit cost of $100 per ton was taken to represent the transportation and shipping costs from the Pacific Northwest to the line route staging depot, including loading and unloading (Ref. 2).

7.2 SUBSTATIONS COSTS

For this report, the facility costs for substations were obtained from the U.S. Department of Energy 1978 version of the previous FPC publication "Hydroelectric Power Evaluation" (Ref. 3). As the values included in the publication are list prices, with 1977 as reference year, they were adjusted to 1979 values by using the U.S. Bureau of Reclamation Index (Ref. 4). The cost of the substations includes the shunt compensation, required at both ends, for operation from no-load to full-load. No reactive power (VAR) compensation support from the source generators was considered in this study.

7.3 CONTROL AND COMMUNICATIONS SYSTEM COSTS

Control and communications sytems costs are included in the intertie cost estimates. The system is necessary to provide effective control of power system operations, and economic energy dispatch throughout the interconnected Anchorage-Fairbanks area. The cost estimates include a power line carrier type communications system, a digital supervisory control and data acquisition (SCADA) system, and automatic generation control equipment.

7.4 TRANSMISSION INTERTIE FACILITY COSTS

As previously discussed in Chapter 5, transmission line costs were calculated using TLCAP. Computer printout sheets indicating input data and the calculated results for all five intertie alternatives are shown in Appendix B. Costs for substation facilities and the control and communications system were added to the transmission line costs, thus obtaining the investment cost for the total intertie facilities. A cost summary for each of the five alternatives studied is presented in Table 7-1. Detailed cost estimates and supporting data are included in Appendix D.

7.5 COST OF TRANSMISSION LOSSES

The Transmission Line Optimization Program (TLCAP) for the selection of the optimum span-conductor combination, includes the cost of demand and energy losses for long transmission lines. The loss components are optimized by varying the voltages at the receiving and sending ends. The program assumes 100 percent volt support at both ends. Table 7-2 presents the present worth (1979) costs of calculated transmission line energy and demand losses.

7.6 BASIS FOR GENERATING PLANT FACILITY COSTS

Cost estimates were prepared for all new generating plants (five gas-turbine units and five coal-fired steam plants), and associated substation and transmission facilities which will be affected by the transmission interconnection. The costs for the facilities are summarized in Table 7-3.

The most recent cost data and estimates available for both gas-turbine and coal-fired steam plants planned for the Railbelt area was used as a basis for the generating plant estimates. The three principal sources of cost data and information are included in the references at the end of this chapter. The Battelle study report (Ref. 2) provided background information and specific factors to determine applicable Alaskan construction cost location adjustement factors. The Stanley Consultants report to GVEA (Ref. 5) provided detailed cost estimates for both the 104-MW coal-fired plant at Healy and combustion turbines at the Northpole substation in Fairbanks. These estimates were then used to derive reference costs for other gas-turbine and coal-fired units of different capacity at other Railbelt sites. The nomogram developed by Arkansas Power & Light Company (Ref. 6) was used to determine the 100-MW reference cost estimate from reported costs relevant to the 104-MW coal-fired plant at Healy. The same nomogram was then used to determine plant costs for unit ratings of 200 and 300 MW, taking into consideration economies of scale. Subsequently, the Alaskan construction cost location adjustment factors were applied to derive site specific cost estimates.

Cost estimates for the associated transmission facilities were obtained from cost data developed during this study for the transmission intertie, the Stanley Consultants report (Ref. 5), and typical costs experienced in recent Alaskan transmission projects.

The cost estimates and supporting data are contained in Appendix D.

7.7 GENERATING PLANT FUEL COSTS

Benefits in addition to those resulting from generation reserve capacity sharing will result from the supply of firm power over the intertie. An analysis was made of the relative generation costs for both independent and interconnected system expansions to determine the comparative economic advantage of firm power interchange. The fuel cost component of operating expenses is the salient factor which affects the economic comparison of alternative system expansions. Therefore, a year-by-year analysis of alternative modes of generation was completed for each period during which firm power transfer over the intertie is possible, as follows:

			Transmission Intertie Firm Power Transfer			
From	To	Duration	Capacity	% Power Loss 1/	Energy 2/	% Energy Loss 1/
1984	1987	4 yrs.	30 MW	6.9	145 GWh	1.05
1992	1996	5 yrs.	70 MW	6.9	337 GWh	1.05

1/ Case IB.

2/ Annual Transmission Capacity Factor of 0.55 assumed for analysis.

Fuel costs were estimated utilizing the trend curves from the Battelle report for future natural gas and coal prices in the Railbelt area. The energy loss component of firm power transfer over the intertie was considered, in estimating the total cost of fuel required to generate sufficient energy in one area to displace a block of energy otherwise generated by a local plant in an independently supplied area.

A year-by-year analysis of the comparative cost of generation is given in Appendix D. Table 7-4 summarizes these costs. Although this analysis is germane to the confirmation of salient considerations regarding the economic feasibility of the intertie, this level of study of fuel costs is in no way a definitive substitution for a detailed year-by-year analysis of production costing for the multi-area interconnection.

7.8 MEA UNDERLYING SYSTEM COSTS

The construction of transmission intertie with the intermediate substation at Palmer (Case ID) provides an opportunity for Matanuska Electric Association (MEA) to purchase power at the intermediate substation at Palmer. Information in the System Planning Report (Ref. 8) indicates the following MEA system expansion investment cost for transmission lines and substation facilities with and without the intertie:

Interconnected System	$1,356,000 (1987)
Independent System	$6,646,000 (1987)
Independent System	$2,004,000 (1992)

The above costs are in 1979 dollars, values were escalated by 10% from 1978 to 1979 level. These values were used in an economic analysis to obtain additional benefits for Case ID.

7.9 CONSTRUCTION POWER COSTS FOR THE UPPER SUSITNA PROJECT

Completion of the transmission interconnection, prior to the development of the Watana and Devil Canyon sites of the Upper Susitna Project will enable the supply of electrical energy for construction power. A temporary wood-pole line to the sites will be supplied from a transmission tap along the intertie route, near the junction of the site access road with the main highway between Anchorage and Fairbanks. Generally, isolated diesel generation is used at such remote hydropower plant sites.

A comparison was made of the relative costs of isolated diesel generation and energy supply to the sites via the tap-line. Table 7-5 shows alternative cost streams through the construction period corresponding to the introduction of the Watana and Devil Canyon units to the interconnected Railbelt generation expansion, shown on Figure 6-5. The construction schedule, as outlined on page 94 of the Interim Feasibility Report (Ref. 7), was followed to establish the time frame for economic comparison of alternative modes of construction power supply. Results of the economic comparison indicate a clear advantage for utilizing the intertie as a source of construction power.

7.10 REFERENCES

1. Letter from ITT Meyer Industries to R. W. Retherford Associates, Anchorage, Alaska, January 15, 1979.

2. Battelle Pacific Northwest Laboratories, Alaska Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, March 1978.

3. DOE, Federal Energy Regulatory Commission, Hydroelectric Power Evaluation (Final Draft), August 1978.

4. U.S. Bureau of Reclamation, "BuRec Construction Costs", Engineering News Record, 22 March 1979.

5. Stanley Consultants, Power Supply Study - 1978, Review Copy of Report to Golden Valley Electric Association, Inc.

6. Power Engineering, "Nomogram calculates economy of scale in power plants", Volume 83, February 1979.

7. U.S. Army Corps of Engineers, South-Central Railbelt Area, Alaska, Upper Susitna River Basin Interim Feasibility Report, December 1975.

8. Robert W. Retherford Associates, System Planning Report, Matanuska Electric Association, Inc., January 1979.

TABLE 7-1

COST SUMMARY FOR INTERTIE FACILITIES

	Total Cost at 1979 Levels ($1000)				
	Case IA	Case IB	Case IC	Case ID	Case II
1. Transmission Line:					
Eng'g. & Constr. Supv.	3,012	3,012	4,043	3,012	8,079
Right-of-Way	8,837	8,837	9,080	8,837	20,973
Foundations	8,445	8,445	12,160	8,445	22,966
Towers	21,615	21,615	33,719	21,615	64,088
Hardware	477	477	477	477	1,096
Insulators	503	503	755	503	1,396
Conductor	10,761	10,761	16,708	10,761	32,886
Subtotal	53,650	53,650	76,942	53,650	151,484
2. Substations:					
Eng'g. & Constr. Supv.	1,352	1,352	1,855	2,816	6,902
Land	57	57	46	81	185
Transformers	1,703	1,703	3,291	1,703	11,917
Circuit Breakers	1,093	1,093	1,323	1,953	6,410
Station Equipment	1,223	1,223	1,933	1,345	4,375
Structures & Accessories	3,628	3,628	3,978	4,026	16,411
Subtotal	9,056	9,056	12,426	11,924	46,200
3. Control and Communications:					
Eng'g. & Constr. Supv.	125	125	125	165	200
Equipment	2,375	2,375	2,375	3,135	3,600
Subtotal	2,500	2,500	2,500	3,300	3,800
Total Baseline 1979 Costs	65,206	65,206	91,868	68,874	201,484

TABLE 7-2

PRESENT WORTH OF INTERTIE LINE LOSSES
1984-1996 STUDY PERIOD[1/]

Case	$ x 1000 (1979)	
IA & ID (230 kV)	10,530	
IB (230 kV)	11,582	
IC (345 kV)	7,341	
II A (230 & 345 kV)		
Anchorage - Devil Canyon	28,027	
Devil Canyon - Ester	14,816	$\left.\right\}$ $49,125
Watana - Devil Canyon	6,282	

1/ Cost of losses, energy, and demand, escalated at 7% per year.

TABLE 7-3

COST SUMMARY FOR GENERATING FACILITIES
(Costs at 1979 Levels[1/])

Unit Name	Code [2/]	Type[3/]	MW	Installed Cost Thousand $	Installed Cost $/kW	Total Cost[4/] Thousand $	Total Cost[4/] $/kW
Northpole #3	NORT 3	SCGT	69	24,385	353	27,934	405
Beluga #9	BELU 9	SCGT	71	33,548	473	42,498	598
Northpole #4	NORT 4	SCGT	69	24,385	353	25,185	365
Anchorage	PEAK A2	SCGT	78	22,620	290	23,400	300
Northpole #5	NORT 5	SCGT	69	24,385	353	25,185	365
Anchorage #11	ANCH 11	Coal	104	99,084	953	105,636	1016
Unit F2	COAL F2	Coal	100	130,000	1300	151,980	1520
Unit No. 5	COAL 5	Coal	200	200,000	1000	212,245	1061
Unit No. 6	COAL 6	Coal	300	274,000	913	292,250	974
Unit No. 2	GEN 2	Coal	300	274,000	913	292,250	974

1/ Investment costs adjusted to January 1979 levels, excluding IDC.

2/ Code name used in MAREL study.

3/ SCGT - Simple cycle combustion turbine, includes NO_x removal equipment.
COAL - Steam turbine, coal-fired with FGD equipment.

4/ Total cost includes substation and transmission costs.

TABLE 7-4

SUMMARY
OF
ALTERNATIVE GENERATING PLANT FUEL COSTS

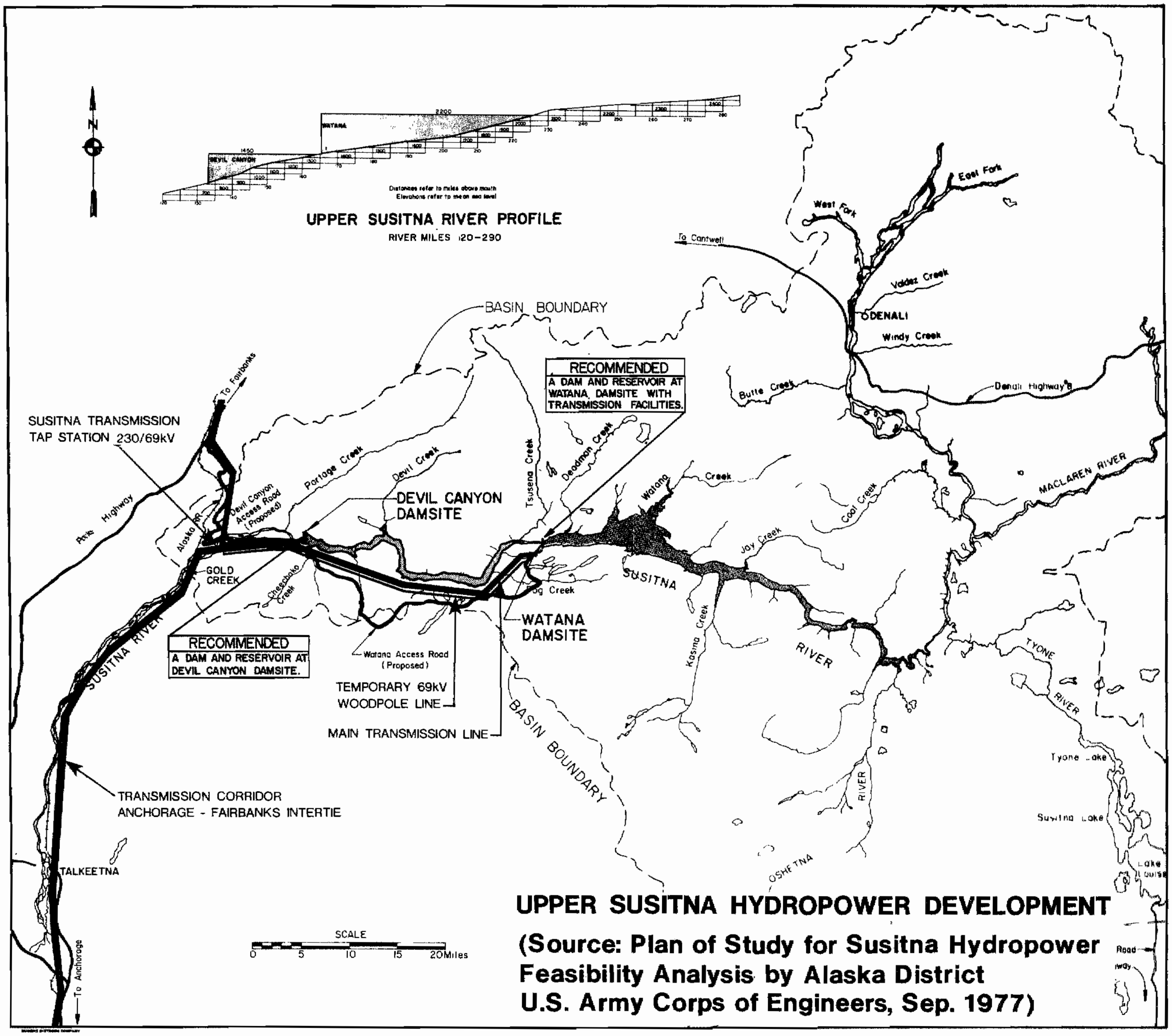
Year	$ 1000 (Escalated) Independent System Operation	Interconnected System Operation	
1984	-	-	
1985	8,468	7,648	30 MW 145 GWh Firm Power Transfer
1986	9,324	8,498	
1987	10,267	9,029	
1992	6,851	8,324	70 MW 337 GWh Firm Power Transfer
1993	7,212	8,654	
1994	7,933	8,016	
1995	8,654	8,745	
1996	9,015	9,109	

TABLE 7-5

ALTERNATIVE COSTS FOR CONSTRUCTION POWER SUPPLY
TO
WATANA AND DEVIL CANYON HYDROPOWER SITES
DURING
CONSTRUCTION OF UPPER SUSITNA PROJECT

	1979 Baseline Costs - $1000	
Year	Isolated Diesel Generation at Site	Tapline Supply From Intertie
1985	2,835	267
1986	695	483
1987	697	481
1988	696	478
1989	3,055	752
1990	1,324	902
1991	187	734
1992	623	430
1993	623	419
1994	-500 1/	304

1/ Negative sign indicates that resale value of generating plant exceeds cost of generation in final year.



CONSTRUCTION PLAN FOR UPPER SUSITNA PROJECT:

Ref. Interim Feasibility Report - P.94, US Army Corps of Engineers, 12 Dec. 1975

Construction Period for Selected Projects:

Watana Dam - 6 Years
Devil Canyon Dam - 5 Years
Total Period - 10 Years (1 Year Overlap)

SUGGESTED REVISED SCHEDULE:

Ref. Chapter 6, Figure 6-5

First Unit On-Line at Watana - Beginning Year 1992
Last Unit On-Line at Devil Canyon - End of Year 1996
Period of Overlap in Construction - 2 Years
Due to Introduction of First Unit at Devil Canyon in 1994

CHAPTER 8

ECONOMIC FEASIBILITY ANALYSIS

CHAPTER 8
ECONOMIC FEASIBILITY ANALYSIS

An economic feasibility analysis was performed to determine which system expansion plan provides the best use of available resources for supplying electrical power to the Railbelt area. Alternative system expansion plans and facility cost estimates were developed in Chapters 6 and 7. In this chapter, the results of the economic feasibility analysis are presented.

8.1 METHODOLOGY

This economic analysis uses the conventional present-worth model. Annual capital disbursement tables, on a year-by-year basis, were prepared for independent and interconnected system expansion plans. To evaluate these plans on an equal basis all capital disbursements were discounted to the 1979 base year and then totalized for each plan to obtain a single 1979 present-worth value. This approach does not include additional capital disbursements after 1996. Such disbursements will be required later to replace retired facilities. However, the extension of the present-worth model over the whole life of the proposed intertie will not significantly affect the results of this feasibility study. The year 1996 was chosen as the final year of the study period to include the last unit of Upper Susitna Hydropower Project (Devil Canyon Unit No. 4).

Figures 6-2 thru 6-5 in Chapter 6 show that many facility costs for both independent and interconnected system expansion plans do not vary. Therefore, in this economic analysis facility costs for the new generating plants not affected by the introduction of the intertie are eliminated. Also excluded from the analysis are plant fixed operation and maintenance costs. The exclusion of these O&M costs will somewhat favor the independent system expansion alternatives.

Only capital costs are used to evaluate generation reserve capacity sharing benefits. This simplification is based on the assumption that an average operating cost of generation for reserve sharing is approximately the same in the Anchorage and Fairbanks areas. To account for generating plant operating costs with reasonable accuracy, a multi-area production cost study would be needed. The multi-area production cost model simulates an economic dispatching of generating units in the system and computes expected fuel and variable O&M costs based on the energy (MWh) output for each unit, taking into consideration intertie transfer limits. Since such a study is outside the scope of the present work, a somewhat simplified method was used in this feasibility study. It is recommended that a multi-area production cost study be performed at a later time.

8.2 SENSITIVITY ANALYSIS

A computer program was developed by IECO to analyze the sensitivity of different escalation and discount rates on the capital costs of various alternatives. This program, the Transmission Line Economics Analysis Program (TLEAP), provides the following outputs:

- Cost disbursement tables for alternative system expansion plans.
- Discounted cost ratio (independent/interconnected) tables for system expansion alternatives.
- Tables indicating independent minus interconnected system costs.
- Separate tables indicating the discounted value of base year (1979) costs for the independent and interconnected systems.

Computer printout sheets indicating input data and calculated results for all alternatives included in this economic feasibility analysis are found in Appendix E.

8.3 ECONOMIC ANALYSIS

Tables included in this chapter and in Appendix E indicate economic analyses for a range of annual escalation rates of 4% to 12%, and a range of discount rates from 8% to 12%. In the analysis of the results below, a long-term average annual escalation rate of 7% and a 10% discount rate are used. The 10% discount rate is now required by the Office of Management and Budget for federal projects.

A. Benefits due to Generation Reserve Capacity Sharing

Two cases were investigated to determine intertie benefits due to generation reserve capacity sharing alone: the 230-kV single circuit intertie and 345-kV single circuit intertie between Anchorage and Fairbanks. In both cases 130 MW of power transfer capacity was allocated for generation reserve capacity sharing purposes (Cases IA and IC in Chapter 6). The economic analysis results indicate:

230 kV	PW (1979 Costs x 1000)
Independent Systems	$406,853
Interconnected System	388,355
Benefit	18,498
Less cost of line losses	10,530
Net Benefit	$ 7,968

The above results indicate that the 230-kV intertie is economically feasible based on generation reserve capacity sharing only.

345 kV	PW (1979 Costs x $1000)
Independent Systems	$406,853
Interconnected System	412,338
Benefit	-5,485
Less cost of line losses	-7,341
Net Benefit	$-12,826

The above results indicate that the 345-kV intertie is not economically feasible based on 130 MW power transfer capacity. To analyze the 345-kV intertie with different (higher) power transfer capacities allocated to generation reserve capacity sharing would require development of additional expansion plans and new MAREL studies.

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-1 and 8-2. Computer printouts, indicating cost disbursements, discounted cost ratios, and discounted value tables, are included in Appendix E (Economic Analyses Nos. 1 and 7).

B. Benefits due to Firm Power Transfer and Generation Reserve Capacity Sharing

One case was investigated to determine combined 230-kV intertie benefits due to both firm power transfer and generation reserve capacity sharing (Case IB in Chapter 6). This study case has one 230-kV single circuit line during the 1984-1991 period and two single circuit 230-kV lines during the 1992-1996 period. The economic analysis results indicate:

	PW (1979 Costs x $1000)
Independent Systems	$707,534
Interconnected System	681,364
Benefit	26,171
Less cost of line losses	11,582
Net Benefit	$ 14,589

The above intertie benefits can be combined with additional benefits due to supply of construction power to the Upper Susitna Hydropower Project sites (see Section 7.9).

	PW (1979 Costs x $1000)
Independent Systems	$715,566
Interconnected System	685,295
Benefit	30,271
Less cost of line losses 1/	12,740
Net Benefit	$ 17,531

The increase in net benefits due to supply of construction power to the Upper Susitna Hydropower Project sites is $2,942,000 or approximately 20 percent.

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-3 and 8-4. Computer printouts, indicating cost disbursements, discounted cost ratios and discounted value tables, are included in Appendix E (Economic Analyses Nos. 2 and 8).

C. 230-kV Intertie with Intermediate Substations

Two cases were investigated to determine additional benefits due to supply of power to the MEA System at Palmer substation, and construction power to the Upper Susitna Hydropower Project (Case ID, Chapter 6). These cases include a 230-kV single circuit line between Anchorage and Fairbanks (Ester), with intermediate substations at Palmer and Healy. The economic analysis results indicate:

1/ Losses were increased by 10% to account for construction power.

Supply to MEA Only	PW (1979 Costs x $1000)
Independent Systems	$413,579
Interconnected System	392,984
Benefit	20,595
Less cost of line losses	10,530
Net Benefit	$ 10,065

Supply to MEA & Susitna	PW (1979 Costs x $1000)
Independent Systems	$421,610
Interconnected System	396,914
Benefit	24,696
Less cost of line losses[2/]	11,583
Net Benefit	13,113

Comparing the above calculated benefits with the results for Case IA (as described in Subsection 8.3A) we obtain the following comparison:

Study Case	Net Benefits PW (1979 Costs x $1000)	
IA (Reserve sharing only)	$ 7,968	(100%)
ID (Plus supply to MEA)	10,065	(126%)
ID (Plus constr. power supply)	13,113	(165%)

Sensitivity of the results to variations in escalation and discount rates are indicated in Tables 8-5 and 8-6. Computer printouts, indicating cost disbursements, discounted cost ratios and discounted value tables, are included in Appendix E (Economic Analyses Nos. 5 and 3).

D. Intertie with Upper Susitna Hydropower Project

Only system reliability (MAREL) analyses and facility cost estimates were developed for this alternative system expansion plan (Case II, Chapter 6). The economic feasibility analysis was not performed for this alternative because:

- The methodology of this economic analysis is more appropriate for thermal generation systems. It is not applicable to large mixed hydro/thermal generation systems. A multi-area production cost study, involving extensive analyses of optimum hydro operations in conjunction with thermal plants, would be required to obtain accurate results.

- A draft copy of the Upper Susitna project report prepared by the Alaska Power Administration (Ref. 1) was received by the Consultants in the course of this study. It includes revisions to unit ratings for the Upper Susitna Project used in the MAREL analyses (as described in Chapter 6). The new total installed capacity is 1573 MW, versus the 1392 MW installaed capacity used in development of the expansion plans analyzed in this report.

A study should be performed to accommodate the above revisions to the Susitna power ratings and change to the production economics due to major hydro substitution for thermal energy. The study should examine in detail the economic feasibility of Susitna hydropower, due to the displacement of large increments of thermal power.

For reference, Figure 6-5 in Chapter 6 indicates the initial expansion plan developed for this study. This figure also indicates the thermal generating unit displacement by Upper Susitna Hydropower units.

MAREL study results indicate the following intertie requirements for maintaining the study criteria of equal reliability system expansion with introduction of Uppwer Susitna power:

Period	Requirement
1992	One 345-kV S/C line to Anchorage One 230-kV S/C line to Fairbanks
1993	One 345-kV S/C line to Anchorage Two 230-kV S/C lines to Fairbanks
1994-1996	Two 345-kV S/C lines to Anchorage Two 230-kV S/C lines to Fairbanks

8.4 REFERENCES

1. Alaska Power Administration, Upper Susitna Project Power Market Report (Draft), February 1979.

5 APRIL 79

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	19,512	18,560	17,215	15,417	13,098	10,183	6,590	2,226	-3,011
8.25	19,688	18,825	17,584	15,907	13,729	10,977	7,572	3,423	-1,567
8.50	19,845	19,066	17,925	16,365	14,322	11,727	8,502	4,560	-193
8.75	19,983	19,286	18,240	16,791	14,878	12,433	9,381	5,639	1,114
9.00	20,104	19,483	18,529	17,187	15,398	13,098	10,213	6,662	2,357
9.25	20,207	19,661	18,794	17,554	15,885	13,724	10,998	7,632	3,537
9.50	20,295	19,819	19,036	17,894	16,340	14,311	11,740	8,550	4,659
9.75	20,367	19,959	19,256	18,208	16,764	14,863	12,439	9,420	5,723
10.00	20,425	20,082	19,455	18,498	17,158	15,380	13,098	10,242	6,733
10.25	20,469	20,188	19,634	18,763	17,525	15,864	13,718	11,019	7,691
10.50	20,500	20,278	19,794	19,005	17,864	16,316	14,301	11,753	8,598
10.75	20,519	20,352	19,936	19,226	18,178	16,738	14,848	12,445	9,457
11.00	20,525	20,413	20,060	19,426	18,467	17,130	15,362	13,098	10,270
11.25	20,521	20,460	20,168	19,607	18,732	17,495	15,842	13,713	11,039
11.50	20,506	20,494	20,260	19,768	18,975	17,834	16,292	14,291	11,766
11.75	20,481	20,515	20,337	19,912	19,197	18,147	16,712	14,834	12,451
12.00	20,446	20,525	20,400	20,038	19,398	18,436	17,103	15,344	13,098

TABLE 8-1

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

TABLE 8-2

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-3,562	-5,375	-7,604	-10,311	-13,564	-17,438	-22,016	-27,391	-33,665
8.25	-3,183	-4,899	-7,016	-9,594	-12,698	-16,400	-20,781	-25,932	-31,950
8.50	-2,825	-4,449	-6,459	-8,912	-11,872	-15,409	-19,602	-24,536	-30,308
8.75	-2,488	-4,024	-5,931	-8,265	-11,086	-14,465	-18,475	-23,201	-28,736
9.00	-2,171	-3,622	-5,430	-7,649	-10,338	-13,564	-17,399	-21,925	-27,232
9.25	-1,873	-3,243	-4,956	-7,065	-9,627	-12,705	-16,372	-20,705	-25,792
9.50	-1,594	-2,885	-4,507	-6,510	-8,949	-11,887	-15,392	-19,539	-24,414
9.75	-1,331	-2,548	-4,082	-5,984	-8,306	-11,108	-14,456	-18,426	-23,097
10.00	-1,086	-2,230	-3,681	-5,485	-7,694	-10,365	-13,564	-17,361	-21,836
10.25	-856	-1,932	-3,302	-5,012	-7,112	-9,658	-12,713	-16,345	-20,631
10.50	-641	-1,651	-2,944	-4,564	-6,560	-8,986	-11,902	-15,375	-19,479
10.75	-441	-1,387	-2,607	-4,141	-6,036	-8,346	-11,128	-14,448	-18,377
11.00	-254	-1,140	-2,289	-3,740	-5,539	-7,737	-10,392	-13,564	-17,324
11.25	-80	-909	-1,989	-3,361	-5,068	-7,159	-9,690	-12,720	-16,318
11.50	80	-693	-1,708	-3,003	-4,621	-6,610	-9,022	-11,916	-15,358
11.75	229	-491	-1,443	-2,665	-4,198	-6,088	-8,386	-11,149	-14,440
12.00	367	-302	-1,195	-2,347	-3,798	-5,592	-7,781	-10,417	-13,564

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	27,096	26,190	24,824	22,926	20,414	17,198	13,177	8,242	2,268
8.25	27,259	26,456	25,212	23,456	21,110	18,086	14,288	9,608	3,927
8.50	27,400	26,695	25,567	23,948	21,760	18,921	15,337	10,902	5,503
8.75	27,519	26,908	25,891	24,402	22,367	19,705	16,325	12,127	6,998
9.00	27,617	27,096	26,185	24,820	22,932	20,440	17,257	13,285	8,417
9.25	27,695	27,259	26,450	25,205	23,456	21,127	18,133	14,379	9,761
9.50	27,754	27,400	26,687	25,557	23,943	21,770	18,957	15,412	11,035
9.75	27,795	27,519	26,899	25,879	24,393	22,370	19,731	16,387	12,241
10.00	27,820	27,618	27,086	26,171	24,808	22,929	20,457	17,306	13,382
10.25	27,828	27,697	27,250	26,434	25,189	23,448	21,136	18,171	14,460
10.50	27,821	27,757	27,391	26,671	25,539	23,930	21,772	18,984	15,479
10.75	27,799	27,800	27,511	26,883	25,859	24,376	22,366	19,749	16,440
11.00	27,764	27,826	27,611	27,070	26,149	24,788	22,919	20,466	17,347
11.25	27,715	27,836	27,691	27,234	26,412	25,167	23,434	21,138	18,201
11.50	27,655	27,831	27,753	27,376	26,649	25,515	23,911	21,767	19,005
11.75	27,583	27,811	27,797	27,497	26,860	25,833	24,354	22,355	19,760
12.00	27,499	27,778	27,825	27,598	27,048	26,123	24,763	22,903	20,470

TABLE 8-3

5 APRIL 79

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	30,913	30,276	29,194	27,595	25,399	22,515	18,844	14,275	8,685
8.25	31,014	30,476	29,511	28,050	26,015	23,319	19,865	15,546	10,243
8.50	31,094	30,649	29,796	28,467	26,586	24,070	20,824	16,746	11,720
8.75	31,153	30,798	30,051	28,848	27,115	24,771	21,725	17,878	13,117
9.00	31,192	30,922	30,278	29,195	27,604	25,425	22,571	18,945	14,440
9.25	31,212	31,024	30,477	29,509	28,053	26,033	23,363	19,950	15,689
9.50	31,214	31,104	30,650	29,793	28,466	26,597	24,104	20,895	16,870
9.75	31,199	31,164	30,798	30,046	28,844	27,120	24,796	21,783	17,985
10.00	31,169	31,204	30,923	30,271	29,188	27,604	25,442	22,617	19,035
10.25	31,123	31,225	31,025	30,470	29,500	28,049	26,042	23,398	20,025
10.50	31,063	31,229	31,106	30,642	29,781	28,458	26,601	24,130	20,957
10.75	30,990	31,216	31,166	30,791	30,033	28,832	27,118	24,813	21,833
11.00	30,903	31,188	31,208	30,916	30,258	29,174	27,596	25,451	22,655
11.25	30,805	31,144	31,231	31,019	30,455	29,483	28,037	26,045	23,427
11.50	30,695	31,086	31,236	31,100	30,628	29,763	28,443	26,597	24,149
11.75	30,575	31,015	31,226	31,162	30,777	30,014	28,814	27,110	24,824
12.00	30,444	30,932	31,199	31,205	30,902	30,238	29,154	27,583	25,455

TABLE 8-4

5 APRIL 79

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	21,225	20,637	19,694	18,339	16,509	14,133	11,132	7,418	2,896
8.25	21,319	20,810	19,960	18,715	17,014	14,787	11,958	8,443	4,149
8.50	21,397	20,962	20,202	19,062	17,483	15,399	12,736	9,412	5,337
8.75	21,458	21,095	20,420	19,381	17,920	15,973	13,469	10,328	6,464
9.00	21,503	21,209	20,616	19,673	18,324	16,509	14,157	11,193	7,531
9.25	21,534	21,305	20,790	19,939	18,699	17,009	14,804	12,008	8,541
9.50	21,551	21,385	20,943	20,180	19,044	17,475	15,410	12,777	9,496
9.75	21,554	21,448	21,078	20,399	19,361	17,908	15,978	13,501	10,400
10.00	21,545	21,496	21,193	20,595	19,652	18,310	16,509	14,181	11,253
10.25	21,525	21,529	21,291	20,770	19,918	18,682	17,005	14,821	12,058
10.50	21,493	21,548	21,372	20,924	20,159	19,025	17,467	15,421	12,817
10.75	21,450	21,555	21,438	21,060	20,378	19,342	17,897	15,983	13,532
11.00	21,398	21,549	21,488	21,177	20,574	19,632	18,296	16,509	14,205
11.25	21,336	21,531	21,523	21,277	20,750	19,897	18,666	17,001	14,837
11.50	21,265	21,502	21,545	21,360	20,905	20,138	19,007	17,459	15,431
11.75	21,185	21,462	21,554	21,427	21,042	20,357	19,322	17,886	15,988
12.00	21,098	21,413	21,551	21,479	21,161	20,554	19,611	18,282	16,509

TABLE 8-5

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	25,042	24,722	24,063	23,008	21,494	19,450	16,798	13,451	9,313
8.25	25,074	24,829	24,259	23,309	21,918	20,019	17,534	14,381	10,465
8.50	25,090	24,916	24,431	23,582	22,309	20,548	18,224	15,256	11,554
8.75	25,091	24,985	24,581	23,828	22,668	21,039	18,869	16,079	12,583
9.00	25,078	25,036	24,709	24,048	22,996	21,494	19,472	16,853	13,554
9.25	25,051	25,070	24,817	24,243	23,296	21,915	20,034	17,579	14,469
9.50	25,011	25,089	24,906	24,416	23,567	22,302	20,557	18,260	15,332
9.75	24,958	25,092	24,976	24,566	23,812	22,659	21,043	18,897	16,143
10.00	24,895	25,081	25,029	24,696	24,032	22,985	21,494	19,493	16,906
10.25	24,820	25,057	25,066	24,805	24,228	23,283	21,911	20,048	17,623
10.50	24,735	25,020	25,087	24,895	24,401	23,553	22,296	20,566	18,295
10.75	24,641	24,971	25,093	24,968	24,552	23,797	22,649	21,047	18,924
11.00	24,537	24,910	25,084	25,023	24,682	24,017	22,974	21,494	19,513
11.25	24,425	24,839	25,063	25,061	24,793	24,213	23,270	21,907	20,063
11.50	24,305	24,757	25,029	25,084	24,885	24,386	23,539	22,289	20,575
11.75	24,177	24,666	24,982	25,093	24,959	24,538	23,783	22,640	21,052
12.00	24,042	24,566	24,925	25,087	25,015	24,669	24,002	22,962	21,494

TABLE 8-6

CHAPTER 9

FINANCIAL PLANNING CONCEPTS

CHAPTER 9

FINANCIAL PLANNING CONCEPTS

The approach taken in this study towards the financial planning for the intertie facilities represents the preliminary conceptual structuring of the ultimate financial package needed to implement the Railbelt transmission system expansion on a progressive basis. This approach seeks to be demonstrative of the methodology employed, rather than an attempt to arrive at specific recommendations. The acceptance of debt allocations by participants to the Alaskan Intertie Agreement (AIA) will require individual financial positions to be evaluated, prior to negotiations on specific portions of the total debt for which a particular participant will ultimately agree to sign. Therefore, what follows is an initial exploration of possible financial arrangements, and will serve as a starting point for successive evaluations by each potential participant to the AIA.

9.1 SOURCES OF FUNDS

An initial appraisal of viable sources of funds has been made to determine the combination which will represent the most financially advantageous terms and also will reflect the projected allocation of financial responsibility that may be acceptable to each of the participants.

The following principal sources were examined:

- State of Alaska revenue bonds floated by APA.
- REA loans negotiated by APA and participants.
- CFC loans negotiated in conjunction with REA loans.
- FFB loans negotiated by APA and participants.
- Municipal bond issues by Anchorage and Fairbanks.

The conditions under which each of the above sources would be negotiable are dependent upon the ability to generate revenue to make repayment.

A. State of Alaska Revenue Bonds

Of these sources, the issue of State of Alaska bonds would require the most complex formula for revenue generation, to arrive at an acceptable agreement to ensure complete payback through time on a steady cash flow basis. It is thought that the issue of State bonds should be deferred from present consideration, until such time as a combined generation and transmission project is ready for funding. Within the confines of the Railbelt development, this would be appropriate when consideration is given to the financing of the first hydropower development of the Upper Susitna Project, together with its associated transmission facilities. Accordingly, although programmatic inclusion of APA bonds is retained in the Transmission Line Financial Analysis Program (TLFAP), for present analytical purposes, consideration has been given only to the remaining sources for analysis of initial financial plans for the intertie. The transmission intertie facilities represent what may be regarded as the first stage development of the ultimate transmission system that will be required for the Watana and Devil Canyon hydropower plants of the Upper Susitna Project. Only the financial sources discussed in the following sections were then considered for initial funding of the Anchorage-Fairbanks Interconnection.

B. Rural Electrification Administration (REA)

The principal participants, with the exception of the Anchorage and Fairbanks municipal systems, are all REA utilities of the Alaska District. Therefore, REA funding is assumed for the maximum amount of total project financial requirements. In accordance with REA stipulations, the loan ceiling is normally 70 percent of total project costs. Thus, a maximum of the full amount under the 70 percent ceiling was considered for the prime source of funds, at an interest rate of 5 percent over a repayment period of 35 years.

Although not considered at this first level of financial planning, REA also makes guaranteed loans, which normally are made for prevailing interest rates of the order of 8-1/2 percent.

OMB restrictions are expected to reflect through future REA commitments for project funding. Therefore, with the large capital outlay necessary for the intertie, it may be necessary to consider alternative sources of supplementary capital to structure a complementary loan package for the project. The Consultants have accordingly considered the CFC and FFB as part of financial contingency plans.

C. National Rural Utilities Cooperative Finance Corporation (CFC)

The CFC makes loans to REA utilities to supplement REA funds, with loans that are currently carrying an interest rate of 8.75 percent, with a repayment period of 35 years. To structure a loan package for the balance of project costs, CFC funds would be drawn on to the extent justifiable under the primary criteria of providing the most advantageous overall financial terms.

D. Federal Finance Bank (FFB)

The FFB also provides supplementary funding, complementary to CFC as a financial source, with loans that bear interest at a higher rate than that to be obtained from CFC. Currently, the interest rate for FFB loans is 9.375 percent for project funding, with a repayment period of 35 years.

E. Municipal Bonds

Anchorage and Fairbanks municipalities both have the authority to arrange financing for a portion of the project by the issuance of tax-exempt, general obligation bonds. For purposes of analysis, the interest rate was assumed to be 7.5 percent under prevailing market conditions, with a maturity period of 35 years. These terms are to be construed as conservative under present market conditions. In practice some measure of improvement can be anticipated depending upon prevailing economic and financial considerations at the time of entry to the bond market. For purposes of illustration, a final interest rate of 7.25 percent was assumed to simulate the progressive improvement of terms anticipated for this project.

Thirty percent of the total project costs are assumed to be funded by municipal bonds, which is deemed reasonably reflective of the participation of the municipal systems in the Alaskan Intertie Agreement. It also is the complementary portion of total project costs that would meet the ceiling of the maximum REA loan available to member utilities.

9.2 PROPORTIONAL ALLOCATIONS BETWEEN SOURCES

In the ultimate financial package for the transmission intertie, the final negotiated amounts for debt financing and bonding will be agreed to by APA and AIA participants. To arrive at the proportional allocation of total project costs between possible sources will require protracted effort on the part of APA and AIA participants, in the successive negotiations with REA and other federal funding agencies, together with the officials responsible for decisions relating to issuance of municipal bonds.

To assist with an evaluation of financial positions in relation to possible agreement on resolution of questions pertaining to proportional allocations between sources, the Consultants offer the following approach for initial consideration:

- REA funds would be used to the limit of the normal 70 percent ceiling, as a proportion of project costs. If due to budgetary restraints REA is not amenable to funding the full proportion, supplementary loans would be sought from a combination of CFC and FFB.

- The balance of funding, 30 percent of projects costs, would be obtained through a joint issue of general obligation bonds, by the municipalities of Anchorage and Fairbanks.

In preparing a financial plan to follow this approach the following analysis was completed using computer programs TLFAP and COMPARE.

1. An initial run of TLFAP was made with the following allocations and assumptions for funding terms and conditions:

   - 70% funding by REA loan, at 5% interest rate.
   - 30% funding by general obligation municipal bonds, with equal division of obligation between Anchorage and Fairbanks. A conservative rate of 7.5% was assumed for this issue.
   - 35-year repayment period for both sources.

2. On the assumption that REA funds would have to be supplemented by loans arranged jointly with CFC and FFB, an analysis was made of a 20% portion of the total REA allocation, to illustrate the capability of minimizing total financial obligations through judicious combinations within the package. This was accomplished using program COMPARE, which derives the present value of future payments for up to three loan sources under varying loan terms. To simplify the procedure, a similar repayment period of 35 years was assumed with base case and sensitivity runs, as follows:

   - Equal division 10/10% between CFC and FFB, with interest rates of 8.75% and 9.375%, respectively.
   - Sensitivity runs of ±5% for both CFC and FFB, in converse proportion, at the same interest rates.

3. The best of the three test-cases, selected on the basis of least present value to borrower, was then substituted in TLFAP, with the following modifications to previous input of 1. above.

   - 50% allocation to REA funding @ 5% interest rate.
   - 20% source allocation; divided between CFC and FFB according to the results of the COMPARE analysis:

     - 15% of total by CFC loan at 8.75% interest rate
     - 5% of total by FFB loan at 9.375% interest rate

   This combination results in the lowest present value of the three alternative divisions, presented on Sheets F-7, F-8 and F-9 of Appendix F.

- 30 % source allocation to municipal bonds at an improved interest rate of 7.25%, to indicate possible positive offset to the higher composite rate resulting from the combination of loans from CFC and FFB.

The results of this analysis are contained in Appendix F.

9.3 ALLOCATED FINANCIAL RESPONSIBILITY FOR PARTICIPANTS

A. Basis for Assumption of Financial Obligation

Once the source allocations are determined, the next step involving discussions, evaluations, and negotiations between the participants is the determination of the allocated responsibility for debt assumption and subsequent service over the repayment period. The approach followed was to match percentage of total funds to the AIA participants on the basis of service jurisdictions, potential benefits from facilities, and a certain judgement in relation to the acceptability, or otherwise, of certain allocations to individual participants. A degree of tokenism was also judged to be appropriate at this initial stage, to allow for minimum funding participation by utilities without major generating plants.

This enables all utilities, that are directly affected by the interconnection to take a major or minor share of the responsibility for debt service of the total facility costs in support of the project.

The only utility which is not an immediate direct beneficiary of the intertie is CVEA. Although TLFAP contains a provision for later participation by this utility, it is not anticipated that CVEA will exercise this option prior to the connection of the Glennallen-Valdez system to the intertie, at or before completion of the first stage development of the Upper Susitna Project.

B. Allocation of Total Project Costs

Table 9-1 provides a division of total project costs on a percentage basis and a subsequent allocation between participants. This preliminary set of debt service allocations was used for the financial planning projections contained in Appendix F. These may be used by individual participants as a starting point for their own analysis and evaluation of the impact of their assumed obligation on their own financial operations.

The allocation of costs was aided by considering the logical division of the total facility into three sections:

Section	From	To	Distance (Miles)
I	Anchorage	Palmer	40
II	Palmer	Healy	191
III	Healy	Ester	92

The costs included in Table 9-1 pertain to Case ID transmission facilities, single-circuit 230 kV transmission line with intermediate switching at Palmer and Healy. This also allows the realization of investment participation by MEA in the AIA to the extent indicated in Table 9-1. Although the benefits of the interconnection are more indirect for HEA, a small percentage participation in the intertie project is included for this utility.

C. Effect of Sinking Fund on Total Revenue Requirements

In evaluating the revenue requirements for each participant to the AIA, the cumulative effect of the municipal bond sinking fund on the allocated debt repayment should be noted. The total revenue required from each participant is indicated on pages F-8, F-9, and F-10 and F-19, F-20, and F-21 of Appendix F, and includes both debt service and sinking fund payments over the 35-year period, to full loan amortization and bond maturity.

9.4 FINANCIAL PLAN FOR STAGED DEVELOPMENT

The following is intended as one possible view of future plans for financing successive expansions and extensions of the initial interconnection of Railbelt utilities.

A. Interconnection Extension between Systems

The implementation of the Anchorage-Fairbanks Transmission Intertie will cause Railbelt utilities to examine their system expansions in relation to those of other utilities, to determine mutual benefits of additional transmission facilities to firm ties between adjacent systems. The cost of associated facilities could be financed on a comprehensive basis, possibly on more advantageous terms than if attempted by individual utilities or municipalities. The cost of such additions to utility systems could be met from a revolving fund administered by APA, on behalf of the participants.

One possibility for application of major funds for system extension would be the interconnection of the CVEA system to the Anchorage end of the intertie. The participation of CVEA in the AIA would then be desirable, with possibly a token allocation, prior to the determination of the timing and cost of the facilities to link the initial interconnection with the CVEA system at Glennallen. This could be implemented on a separate basis, or as part of an integrated plan for the transmission system associated with the development of Susitna hydropower.

B. Expansion of a Susitna Transmission System

The implementation of the Susitna Hydropower Project would require that a comprehensive financial plan be followed for funding the generation project and associated transmission facilities. The large increments of firm power possible from the Susitna development would require the expansion of the initial intertie, to receive the energy blocks for transmission to Anchorage and Fairbanks.

As part of the comprehensive financial plan, the funding of transmission line and substation facility expansion through time could be arranged on the basis of total incremental funding, with partition of costs and financial obligations between participants, on a similar basis to that used for this initial approach to first stage financing of the transmission system interconnection via the Railbelt.

9.5 REFERENCES

1. International Engineering Company, Inc.
   Financial Planning Model

2. Moody's Bond Record
   'Tax Exempt Bond Yields by Ratings'
   'Tax Exempts Vs. Governments and Corporates'
   January 1979

TABLE 9 - 1

ALLOCATION OF TOTAL PROJECT COSTS BETWEEN PARTICIPANTS
TO
ALASKAN INTERTIE AGREEMENT
A I A

SECTIONAL INTERCONNECTION DIVISIONS

	Anchorage	Section I (40 M)	Palmer	Section II (191 M)	Healy	Section III (92 M)	Ester	
INTERTIE COMPONENTS				PROJECT COSTS - 1979 $1000 (%)				TOTAL FACILITY
Transmission Line		6644 (10)		31,726 (46)		15,282 (22)		53,652 (78)
Substations:								
Anchorage	3976 (6)							3,976 (6)
Palmer			717 (1) 717 (1)					1,434 (2)
Healy					717 (1) 717 (1)			1,434 (2)
Ester							5,080 (7%)	5,080 (7)
Control & Communications		1,450 (2)		400 (1)		1,450 (2)		3,300 (5)
TOTAL		12,787 (19)		33,560 (49)		22,529 (32)		68,876 (100)
AIA PARTICIPANTS				ALLOCATIONS OF TOTAL PROJECT COSTS (%)				
AM&LP		(5)		(10)				(15)
CEA		(10)		(20)				(30)
HEA		(1)						(1)
MEA		(3)						(3)
CVEA				(9)		(27)		(36)
FMUS				(10)		(5)		(15)

CHAPTER 10
INSTITUTIONAL CONSIDERATIONS

CHAPTER 10
INSTITUTIONAL CONSIDERATIONS

The Intertie Advisory Committee has proven itself most useful during this study. It has enabled initial discussions to be held between potential participants in the projected interconnection of Railbelt utilities via the Anchorage-Fairbanks Transmission Intertie. This committee represents a sure, first step towards the formation of a continuing, viable, cohesive entity, through which the intertie can be built and the resulting benefits realized by the continued expansion and operation of the interconnected utility systems in the Railbelt.

10.1 PRESENT INSTITUTIONS AND RAILBELT UTILITIES

The predominant pattern of ownership management and operating responsibility by public power organizations in Alaska is exemplified by the prospective participants to an Alaskan Intertie Agreement (AIA). In addition to REA and municipal utilities in the Railbelt, it is anticipated that both the Alaska Power Administration and the Alaska Power Authority would be parties to the AIA. The probable composition of institutions and participating utilities is anticipated to be:

- Alaska Power Authority
- Anchorage Municipal Light and Power
- Chugach Electric Association, Inc.
- Homer Electric Association, Inc.
- Matanuska Electric Association, Inc.
- Golden Valley Electric Association, Inc.
- Fairbanks Municipal Utility System
- Alaska Power Administration

The above group of utilities may be joined by Copper Valley Electric Association, Inc. at a later date, to extend the interconnected facilities to the Glennallen-Valdez system.

A. Statutes and Limitations

The enabling legislation for the Alaska Power Authority (APA) is contained in HB 442 for the Legislature of the State of Alaska. It provides for the establishment of power projects and the authorization to proceed with developments that will serve "to supply power at the lowest reasonable cost to the state's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumers of the state, as well as to supply existing or future industrial needs".

APA would mainly act on behalf of the municipal and rural electric utilities as a party to the AIA. Therefore, it is not presently anticipated that the authorized "powers to construct, acquire, finance, and incure debt" would be required for the Intertie Project. Rather APA could integrate and coordinate the efforts of the other participants to the AIA, to ensure that an expeditious approach is maintained during the course of the project.

APA is in an excellent position to coordinate regional programs with its state-wide involvement. For example, such coordination may assist in the process of securing an abridgement of the two county rule for the transmission intertie. Left unresolved, such existing statutes may otherwise constitute a roadblock to the realization of the benefits to be achieved by interconnection of systems of participating utilities over the large geographical area encompassed.

B. Jurisdiction and Service Territories

The Alaska Power Authority exercises jurisdiction over power projects in Alaska as a State entity. It parallels the Alaska Power Administration, which has federal jurisdiction in Alaska for the United States Department of Energy in Washington, D.C.

Both State and Federal entities have statewide responsibility in Alaska.

The service territories of the municipal and rural electric utilities are shown on the maps of Figures 4-1, 4-2, and 4-3 in Chapter 4. The confines of the Railbelt result in elongated geographical service areas. Such areas are particularly appropriate in relation to the transmission corridor for the intertie and enable the delineation of easements along the route to be made relative to existing transmission and distribution facilities in the area.

10.2 ALASKAN INTERCONNECTED UTILITIES

To provide an identity for the utility participants to the AIA, it is suggested that the name Alaskan Interconnected Utilities (AIU) be adopted by the existing Railbelt utilities to be included in the institutional and management plan for the implementation and operation of the intertie.

A. Present Arrangements and Future Requirements

To a certain extent, the operating utilities in the Anchorage and Fairbanks areas have already evolved mutual interests. These interests now need to be augmented, to satisfy future operating requirements.

Prior to interconnection, there would be a need to coordinate revised planning for system expansion, the scheduled construction of facilities, and the separate building programs of each utility. A Planning Subcommittee of the Intertie Advisory Committee, composed of technical staff from AIU, would be desirable in the near future if this program is implemented. This planning subcommittee could be empowered to resolve joint planning problems affecting participating members.

Later on, an Operating Subcommittee would be required to determine operating procedures and coordinate system planning policy, working towards centralized economic dispatch for the interconnected system. The need for improved communications facilities will also need to be addressed, together with the mode of overall system control and data acquisition for interconnected facilities.

B. Evolution of Institutional Framework

In any approach toward projecting institutional requirements for the establishment of the necessary framework to support the Anchorage-Fairbanks Transmission Intertie, it is essential to preserve a sense of perspective towards the future and allow for the possibility of integrating the presently conceived plans and concepts within a larger and more comprehensive institutional structure. This is particularly appropriate to the task of system interconnection, when successive expansions are necessary to accommodate the incremental additions associated with major generating plants.

In the case of the Railbelt, the possible implementation of the major hydropower developments of the Upper Susitna Project, would require that the institutional structure required for the transmission intertie be compatible with future institutional needs of the Susitna developments. Thus, whatever institutional changes would be brought about by a program of hydropower development of the Susitna should represent only a transition between organizational requirements keyed to transmission system expansion without the impact of the Susitna developments and with the addition of major hydropower sources, such as Watana and Devil Canyon.

The evolutionary approach to effecting this transition is preferable over an abrupt change of institutional structures and it is thought that with the acceptance of a pattern of multiple participation in the planning, financing, implementation, and operation of the Intertie, a suitable mode of proportionate involvement can also be considered for applicability to other transmission facilities required for the Susitna Project. This division of fiscal and managerial responsibility can also be extended into the operation of the system.

In this way a maximum of local utility participation can be achieved, with a financially beneficial allocation of total project costs between funding sources to arrive at a least financial cost package to multiple borrowers having pre-arranged sharing of debt-service obligations.

10.3 REFERENCES

1. Battelle Pacific Northwest Laboratories, Alaska Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region, March 1978.

2. University of Alaska, Institute for Social and Economic Research, Electric Power in Alaska 1976-1995, August 1976.

3. House Bill 442 in the Legislature of the State of Alaska, Finance Committee, Tenth Legislature - Second Session.

APPENDIX A

NOTES ON FUTURE USE OF ENERGY IN ALASKA

APPENDIX A

NOTES ON FUTURE USE OF ENERGY IN ALASKA

Power requirements studies analyzing historical data and forecasting future trends have been regularly accomplished for the REA-financed electric utilities in Alaska since they began operation. These studies and their forecasts over the years provide an interesting perspective as to the changes in use of electricity and the change in numbers of users, but do not fully account for the forces that produce these changes.

It is observed that electrical uses increase as the dreary, manual routines of everyday life are displaced by the equivalent electrically-powered devices. This allows the human effort to be directed elsewhere or eliminated. Electric lighting, water pumping (many Alaska homes have their own water systems) and heating, clothes washing, refrigerator, freezer, vacuum cleaner, dishwasher, cooking aids, radio and TV (education and recreation), lawn mower, chain saw, etc., all direct electrical energy toward improving the quality of life and making human effort more productive.

The typical Alaskan family is becoming more productive as a unit through an increasing percentage of the family partners entering the community group of wage earners. Increasing income allows the family to seek out new means of improving the quality of living.

There are on the horizon a number of technological triumphs that will undoubtedly find uses in those communities where the families can assign some of their resources to enhancing their lives. The home computer with its implications of many more "robots" to come and the electric car are just two of such items nearing the scene.

These considerations certainly support the trends of electrical energy use that are being forecast and could well result in the forecasts being exceeded, if the rising standards of Alaskan life are maintained into the future.

The following paragraphs are a direct excerpt from a system planning report (see Ref. 7 in Section 3) completed in early 1979 for the Matanuska Electric Association, Inc. of Palmer, Alaska. This electric system is the oldest REA-financed system in Alaska and the statistics cited which relate the use of electrical energy to the average family earnings over a period of 35 years of actual history and a forecast of 15 to 25 years are interesting indeed.

*INTRODUCTION

The accomplishment of long-range planning requires that data be estimated for future conditions and that technical answers for those conditions be evaluated in a prudent manner. Technical answers to a defined set of conditions can be readily developed using state-of-the-art methods. An occasional set of conditions prompts innovation when conventional methods appear limited; but, it is demonstrably clear that the <u>estimate of future conditions</u> is the single most significant factor affecting the ultimate value of a long-range plan.

It will be noted in the following System Planning Report a great effort was made to provide <u>accurate and detailed historical data</u>. A better understanding of the nature of electrical consumers and their actual performance amidst the set of observed environmental restraints (political and natural) is bound to be enhanced by such data. It is believed that forecasts of future conditions will also benefit in sufficient measure to make the effort a bargain.

---

* Excerpted from MEA System Planning Report, January 1979 - see Chapter 3, Ref. 7.

The understanding of a long-range plan in the context of the whole growth of a community or region and in terms more useful to the consumer of electricity and his representatives is believed extra difficult today because of environmental concerns, high inflation and other cost aberrations.

To provide some perspective that is intended to illuminate the broad impact and position of the MEA electric supply system on its service area a tabular listing of significant MEA statistics is included herewith on the following page, Table A-1.

This table contains the 35-year history of MEA and a 20-year forecast based on the data in the Long-Range Plan. The numbers listed may surprise the reader at first inspection but this simple listing of historic factual data and related future estimates serves to demonstrate the powerful influence of electricity on the quality of life and the productivity of the MEA service area.

MEA STATISTICAL SUMMARY - PAST, PRESENT AND FORECAST

Year	Ave. No. Served / Average kWh/Mo.	Ave. No. (w/o LP) / Average kWh/Mo.	Miles of Line Dist. / Trans.	Const. Per Mile Dist.	Ave. Cost Purch. Power $/kWh	Average Revenue Total Sales $/kWh	Average Revenue (w/o LP) $/kWh	Average Bill/Const. (w/o LP) $/Mo.	Average Family Income $/Mo.	Portion of Income Percent
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1942	210 / 142	188 / 47	90 / 0	2.3	0.020	0.0628	0.1074	5.07	175	2.9
1954	1401 / 533	1393 / 335	313 / 0	4.5	0.0196	0.0450	0.0531	17.82	590	3.02
1966	3134 / 951	3113 / 694	708 / 63	4.4	0.0114	0.0348	0.0366	25.40	885	3.9
1977	9434 / 1578	9352 / 1318	1430 / 97	6.6	0.0128	0.0359	0.0368	48.50	2248	2.4
See Footnotes										
Level I ('82-85')	16693 / 2100	16510 / 1785	2212 / 241	7.5	0.0187	0.0546	0.0559	99.78	3303	3.02
Level II ('87-'92)	30510 / 2799	30060 / 2488	2705 / 269	11.3	0.0348	0.0692	0.0705	175.30	4853	3.60
Level III ('92-'99)	55744 / 3714	54956 / 3494	3041 / 293	18.3	0.0488	0.0829	0.0837	292.45	7131	4.10

The basic historical data was taken from the REA From 7. Each column is explained as follows:

(1) The year of operation - MEA first energized its system on January 19, 1942. Level I, II, and III refer to the Load Levels of the December 1978 Long Range Plan. The years in parenthesis are estimated dates when these levels might be reached.

(2) The total average number of consumers with LPs and their average monthly energy (kWh) use.

(3) The average number of consumers (w/o LPs) and their average monthly energy (kWh) use.

(4) Miles of line at year end.

(5) Average number of consumers served per mile of distribution line - Columns (2) divided by Column (4).

(6) Cost of purchased power - at Levels I, II and III these are estimates developed by RWR from miscellaneous sources. These forecast are believed to be consistent with other elements of the forecast.

(7), (8), and (9) For levels I, II and III the figures resulted from a generalized forecast of costs using the investments indicated by the Long Range Plan escalated at 7% per year, the operating costs per consumer escalated @ 7% per year and the purchased power costs of Column (6). It was also assumed that there would be 10% losses of energy and that MEA margins would be 10% of Gross Revenue.

(10) The estimated average family income is developed from old payroll records, the "Statistical Abstract of the U.S." (Public by Bureau of the Census) 1977, and "The Alaska Economy, Year-End Performance Report 1977" (Published by Alaska Department of Commerce and Economic Development). Future income estimates made by escalating 1977 numbers at 1.08 per year which is the approximate average growth rate of income for the last 35 years.

(11) Column (9) divided by Column (10) multiplied by 100.

TABLE A-1

APPENDIX B
TRANSMISSION LINE COST ANALYSIS PROGRAM (TLCAP)

TRANSMISSION LINE COST ANALYSIS PROGRAM (TLCAP)

B.1 GENERAL DESCRIPTION

The Transmission Line Cost Analysis Program (TLCAP) calculates the installation, operation, and maintenance costs of a transmission line using a detailed unit cost model. It also automatically determines the "optimum" span and conductor size combination. Applications include the following:

- Voltage Selection - TLCAP examines the relative economics of various voltage levels.
- Span and Conductor Optimization - Span and conductor are optimized simultaneously to provide a matrix of present worth costs. Sensitivity of present worth costs to assumed discount rate is also automatically included.
- Tower Type Selection - TLCAP compares the cost impact of alternate tower types.

B.2 COMPUTER PROGRAM APPLICATIONS FOR OPTIMUM TRANSMISSION LINE COSTS

Choosing the most economical voltage level and other line parameters for any projected transmission line is a complex problem. It requires the simultaneous consideration of a multitude of interrelated factors, each of which will have a decided influence on line performance and the installed and operational costs of both the line and the overall system. The installed cost of a line increases rapidly with the voltage used. For typical single-circuit ac lines, the cost increase is approximately in direct proportion to the increase in voltage. On the other hand, the load carrying capacity of a line increases with the square of the voltage, but this is partially offset by the increase in phase spacing and the resultant increase of line impedance.

Another factor affecting the load carrying capacity and line cost is the size of the conductor and the number of conductors per phase. Since the installed cost of the conductors may constitute as much as 28% of the total line cost, the selection of the conductor is an important decision in any line design.

For EHV lines, conductor size selection is first governed by two basic electrical requirements - the current carrying capacity and the corona performance in terms of corona loss radio interference (R.I.) and television interference (T.V.I.). As the line voltage increases, the corona performance becomes more and more the governing factor in selecting conductor size and bundle configuration.

If consideration is given to the electrical aspects alone, there is an optimum solution as to the size and number of conductors for each voltage level and load carrying requirement. However, the size of the conductor affects the loads on the structures supporting it, as well as the sag, tension, span length, and tower height and weight. All such factors influence the total cost and economics of the line. Hence, both the electrical and mechanical aspects must be considered together in order to arrive at a truly optimized overall line cost. Often a solution which is entirely satisfactory from the electrical viewpoint alone will be in conflict with the mechanical requirements. This is particularly true at locations where heavy ice loading is encountered. For example, a small conductor in a bundle of three may meet all the electrical requirements but may be entirely unsatisfactory mechanically due to excessive sag and overstress. This results in higher towers or shorter spans with more towers per unit length of line than would a larger conductor in a bundle of two. A large number of conductor and phase configurations must usually be tried before an optimum solution is found for a specific voltage level.

The voltage level for any given line should be chosen on the basis of its effect on the system to which it will be connected. This may require medium- or long-range estimation of load flow. For example, it may be more advantageous to build a single 750-kV line instead of two 400-kV lines. Each solution has its own impact on the system with respect to reliability, stability, switching over-voltages, transfer of power, and possibly the cost of future expansion. In other words, the line should be custom designed to meet present and future needs of the system within which it is to operate. It should also provide for the lowest overall cost in terms of investment and operation. Without proper attention to future needs, the "lowest initial cost solution" for a line between two given points may not necessarily be the most desirable or satisfactory one.

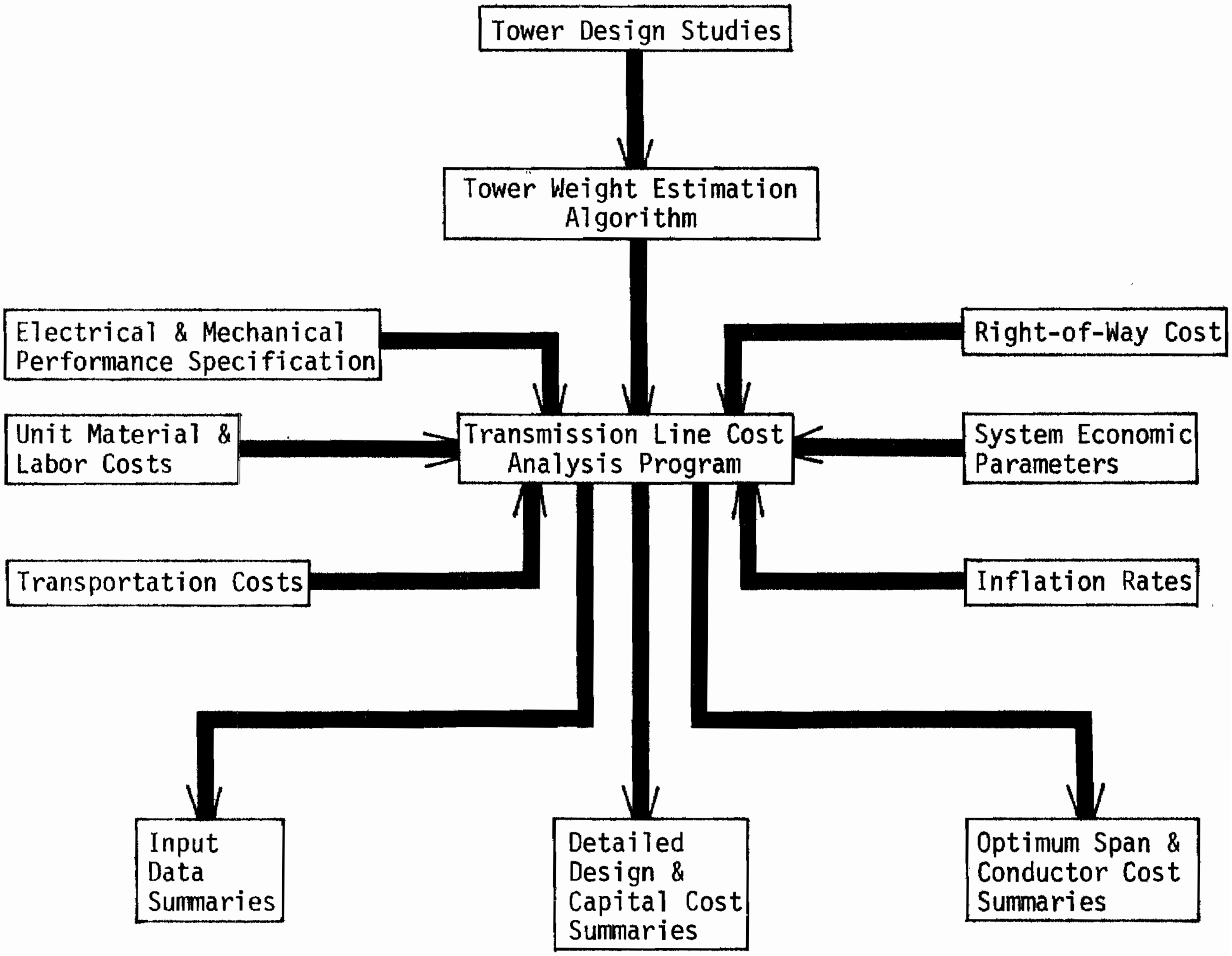
In addition to the variables mentioned above, there are numerous other line parameters that must be considered to properly evaluate and compare the various solutions. A few of the more important ones are:

- Conductor material, size, and stranding.
- Tower types, such as rigid or guyed, single or double-circuit, ac or dc, metal or wood.
- Foundation costs.
- Wind and ice load criteria, and their effect on tower cost through transverse, vertical, broken-wire, and/or construction loads.
- Number and strength of insulators.
- Insulator swing and air gap.
- Applicable material and labor costs.
- Investment charges, demand, and annual energy loss charges.

To accurately assess all the complexities and interrelationships, and to integrate them into a totally coordinated design that will produce a line of required performance at minimum cost, a carefully engineered computer program was developed by IECO. Program methodology of TLCAP is shown on Figure C-1. Briefly, program elements include:

TRANSMISSION LINE COST ANALYSIS PROGRAM (TLCAP)

METHODOLOGY



- Conductor Selection - A large variety of conductor sizes and strandings are on file for automatic use by the program. Depending upon line voltage and load, the program determines the minimum power and energy losses for each conductor studied.

- Insulation Selection - The program calculates the incremental cost differences caused by changes in the insulator length, which together with other studies of system performance indicates the best insulation for each voltage level. To ensure maximum transmission capacity, the minimum possible phase spacing is used with each type of tower, considering clearance to tower steel and insulator swing.

- Tower Selection and Span Optimization - The installed cost of towers represents a large portion of the total line cost. Therefore, this item is given special and careful consideration in the calculations. The installed cost of a tower is usually a function of the weight of the steel used. A considerable difference in weight between different tower configurations can be experienced, even in cases where the loads are identical. If to this variable, the variations in loads due to conductor size, bundling, and climatic criteria are added, it becomes evident that correct tower weights can only be determined by an actual tower design in which all the variables are properly considered. Therefore, the optimization program is complemented with a tower design program. Appropriate foundation and insulation costs are added to each tower solution to obtain the total installed cost per tower location. This information is then used by the optimization program to determine the optimum span length (the span that results in the lowest tower cost per unit length of line) for each conductor configuration being considered.

In processing these criteria, including a present worth evaluation of annual energy loss and other time-related charges, the optimization program arrives at a long-range minimum cost solution for each voltage level investigated. However, as previously mentioned, the final evaluation of the adequacy of a line should be based upon its present and future effect on the system as a whole. Therefore, the lowest cost solution for a select number of conductor configurations, with their specific electrical characteristics, should be tried in a few additional system study runs to obtain a proper basis for a final decision.

B.3 TLCAP SAMPLE OUTPUTS

Sample outputs of the TLCAP computer program are shown on the following pages. The output cases are listed below:

- Anchorage - Fairbanks, 230 kV (Case IA).
- Anchorage - Fairbanks, 230 kV (Case IB).
- Anchorage - Fairbanks, 345 kV (Case IC).
- Anchorage - Devil Canyon, 345 kV (Case II-1).
- Devil Canyon - Ester, 230 kV (Case II-2A).
- Watana - Devil Canyon, 230 kV (Case II-3A).

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979,

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

```
******************
*                *
*   INPUT DATA   *
*                *
******************
```

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	136.8 MVA	1992
AVERAGE CIRCUIT LOADING	41.0 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

****
*   *
*   INPUT DATA *
*   *
****

CONDUCTOR DATA

NUMBER PER PHASE	1	
CONDUCTOR SPACING	0.0	IN
VOLTAGE	230	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	0.00	KW/MI
LINE LENGTH	323.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1200.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

```
******************
*                *
*   INPUT DATA   *
*                *
******************
```

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

B-9

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

```
TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912  KIPS
```

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

****
*   INPUT DATA   *
****

CONDUCTOR SUMMARY

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
24	GROSBEAK	636.0	26/ 7	0.8750	0.9900	0.5809	11.00	10.3
25	EGRET	636.0	30/19	0.9880	1.0190	0.6134	11.30	9.7
26	FLAMINGO	666.0	24/ 7	0.8590	1.0000	0.5914	10.55	10.7
27	GANNET	666.0	26/ 7	0.9180	1.0140	0.6087	11.00	10.3
28	STILT	715.0	24/ 7	0.9210	1.0360	0.6348	10.55	10.7
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9

ANCHORAGE-FAIRBANKS INTERTIE   CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 9:29:47

****
INPUT DATA
****

CONDUCTOR SUMMARY

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
24	GROSBEAK	25000.0	0.0335	0.628/1977	790.	0.1452	0.4118	2.6347
25	EGRET	31500.0	0.0351	0.609/1977	870.	0.1447	0.4060	2.6136
26	FLAMINGO	23700.0	0.0335	0.640/1977	810.	0.1399	0.4118	2.6294
27	GANNET	26200.0	0.0343	0.609/1977	820.	0.1373	0.4092	2.6347
28	STILT	25500.0	0.0347	0.627/1977	840.	0.1320	0.4066	2.6400
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816

ANCHORAGE-FAIRBANKS INTERTIF CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

```
*****************
*               *
*   INPUT DATA  *
*               *
*****************
```

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	68147.	3834.	84796.	9328.	166104.	32600.	3284.	201988.
35	795.	1300.	64664.	3721.	82616.	9088.	160089.	39120.	3151.	202359.
35	795.	1400.	65375.	3684.	82031.	9023.	160113.	39120.	3161.	202394.
37	900.	1300.	67299.	3772.	84608.	9307.	164986.	34543.	3257.	202784.
39	954.	1400.	69552.	3828.	84673.	9314.	167367.	32600.	3322.	203288.
37	900.	1400.	68697.	3766.	84494.	9294.	166251.	34543.	3294.	204088.
35	795.	1500.	66879.	3689.	82176.	9039.	161784.	39120.	3206.	204109.
32	795.	1300.	65558.	3685.	83893.	9228.	162364.	39523.	3195.	205082.
30	715.	1300.	63510.	3615.	82301.	9053.	158478.	44166.	3112.	205756.
30	715.	1400.	64204.	3576.	81729.	8990.	158498.	44166.	3122.	205787.
34	795.	1300.	65807.	3659.	84359.	9279.	163104.	39599.	3209.	205913.
32	795.	1400.	66784.	3669.	83683.	9205.	163342.	39523.	3226.	206091.
39	954.	1500.	71843.	3870.	85337.	9387.	170437.	32600.	3397.	206433.
38	954.	1300.	70136.	3831.	86787.	9547.	170300.	32997.	3371.	206667.
39	954.	1200.	70386.	4033.	87082.	9579.	171080.	32600.	3385.	207065.
37	900.	1500.	70983.	3807.	85172.	9369.	169331.	34543.	3369.	207242.
34	795.	1400.	67235.	3653.	84298.	9273.	164459.	39599.	3248.	207306.
35	795.	1600.	69124.	3735.	82979.	9128.	164966.	39120.	3282.	207367.
30	715.	1500.	65702.	3580.	81896.	9009.	160187.	44166.	3167.	207520.
35	795.	1200.	66889.	3916.	85020.	9352.	165176.	39120.	3254.	207549.
37	900.	1200.	69631.	3977.	86926.	9562.	170096.	34543.	3361.	207999.
29	715.	1300.	64091.	3593.	83683.	9205.	160573.	44804.	3150.	208527.
24	636.	1200.	58648.	3345.	82481.	9073.	153548.	52193.	2975.	208715.
32	795.	1500.	68883.	3701.	84257.	9268.	166109.	39523.	3295.	208926.
36	900.	1300.	69499.	3780.	86682.	9535.	169496.	36096.	3351.	208942.

ANCHORAGE-FAIRBANKS INTERTIE CASE IA
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:29:47

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 39
954. KCMIL 1300. FT SPAN 87.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840.	FT	14086.	9.73	973.	18257.	33316.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	207.	UNITS	1313.	1.14	244.		1557.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	38870.	20.31	2031.	26019.	66921.
FOUNDATIONS	4.3	UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13.	ACRES	9120.			18241.	27361.
IDC/ENGINEERING			9328.				9328.
TOTALS			68147.	31.65	3834.	84796.	166104.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	24588.	7992.	32580.
CORONA LOSSES	0.	19.	19.
TOTALS	24588.	8011.	32600.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979,

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

```
*****************
*               *
*  INPUT DATA   *
*               *
*****************
```

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	136.8 MVA	1992
AVERAGE CIRCUIT LOADING	49.2 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

INPUT DATA

CONDUCTOR DATA

NUMBER PER PHASE	1	
CONDUCTOR SPACING	0.0	IN
VOLTAGE	230	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	0.00	KW/MI
LINE LENGTH	323.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1200.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

INPUT DATA

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
24	GROSBEAK	636.0	26/ 7	0.8750	0.9900	0.5809	11.00	10.3
25	EGRET	636.0	30/19	0.9880	1.0190	0.6134	11.30	9.7
26	FLAMINGO	666.0	24/ 7	0.8590	1.0000	0.5914	10.55	10.7
27	GANNET	666.0	26/ 7	0.9180	1.0140	0.6087	11.00	10.3
28	STILT	715.0	24/ 7	0.9210	1.0360	0.6348	10.55	10.7
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

****
* INPUT DATA *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
24	GROSBEAK	25000.0	0.0335	0.628/1977	790.	0.1452	0.4118	2.6347
25	EGRET	31500.0	0.0351	0.609/1977	870.	0.1447	0.4060	2.6136
26	FLAMINGO	23700.0	0.0335	0.640/1977	810.	0.1399	0.4118	2.6294
27	GANNET	26200.0	0.0343	0.609/1977	820.	0.1373	0.4092	2.6347
28	STILT	25500.0	0.0347	0.627/1977	840.	0.1320	0.4066	2.6400
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816

ANCHORAGE-FAIRBANKS INTERTIE   CASE 1B
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 9:37:07

```
*****************
*               *
*   INPUT DATA  *
*               *
*****************
```

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS

REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS

TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	68147.	3834.	84796.	9328.	166104.	35856.	3284.	205244.
37	900.	1300.	67299.	3772.	84608.	9307.	164986.	37993.	3257.	206235.
35	795.	1300.	64664.	3721.	82616.	9088.	160089.	43028.	3151.	206267.
35	795.	1400.	65375.	3684.	82031.	9023.	160113.	43028.	3161.	206302.
39	954.	1400.	69552.	3828.	84673.	9314.	167367.	35856.	3322.	206545.
37	900.	1400.	68697.	3766.	84494.	9294.	166251.	37993.	3294.	207538.
35	795.	1500.	66879.	3689.	82176.	9039.	161784.	43028.	3206.	208017.
32	795.	1300.	65558.	3685.	83893.	9228.	162364.	43468.	3195.	209027.
39	954.	1500.	71843.	3870.	85337.	9387.	170437.	35856.	3397.	209689.
34	795.	1300.	65807.	3659.	84359.	9279.	163104.	43545.	3209.	209858.
38	954.	1300.	70136.	3831.	86787.	9547.	170300.	36293.	3371.	209963.
32	795.	1400.	66784.	3669.	83683.	9205.	163342.	43468.	3226.	210036.
30	715.	1300.	63510.	3615.	82301.	9053.	158478.	48561.	3112.	210151.
30	715.	1400.	64204.	3576.	81729.	8990.	158498.	48561.	3122.	210182.
39	954.	1200.	70386.	4033.	87082.	9579.	171080.	35856.	3385.	210321.
37	900.	1500.	70983.	3807.	85172.	9369.	169331.	37993.	3369.	210693.
34	795.	1400.	67235.	3653.	84298.	9273.	164459.	43545.	3248.	211251.
35	795.	1600.	69124.	3735.	82979.	9128.	164966.	43028.	3282.	211275.
37	900.	1200.	69631.	3977.	86926.	9562.	170096.	37993.	3361.	211450.
35	795.	1200.	66889.	3916.	85020.	9352.	165176.	43028.	3254.	211457.
30	715.	1500.	65702.	3580.	81896.	9009.	160187.	48561.	3167.	211915.
36	900.	1300.	69499.	3780.	86682.	9535.	169496.	39701.	3351.	212547.
38	954.	1400.	72348.	3861.	87234.	9596.	173039.	36293.	3440.	212771.
32	795.	1500.	68883.	3701.	84257.	9268.	166109.	43468.	3295.	212871.
29	715.	1300.	64091.	3593.	83683.	9205.	160573.	49222.	3150.	212944.

ANCHORAGE-FAIRBANKS INTERTIE CASE IB
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:37:07

****
COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT
****

CONDUCTOR NUMBER = 39
954. KCMIL 1300. FT SPAN 87.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840.	FT	14086.	9.73	973.	18257.	33316.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	207.	UNITS	1313.	1.14	244.		1557.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	38870.	20.31	2031.	26019.	66921.
FOUNDATIONS	4.3	UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13.	ACRES	9120.			18241.	27361.
IDC/ENGINEERING			9328.				9328.
TOTALS			68147.	31.65	3834.	84796.	166104.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	24588.	11249.	35837.
CORONA LOSSES	0.	19.	19.
TOTALS	24588.	11268.	35856.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979,

ANCHORAGE-FAIRBANKS INTERTIE   CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 10:10:52

****
*   *
*   INPUT DATA   *
*   *
****

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	168.4 MVA	1992
AVERAGE CIRCUIT LOADING	58.9 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-FAIRBANKS INTERTIE   CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 10:10:52

INPUT DATA

CONDUCTOR DATA

NUMBER PER PHASE	2	
CONDUCTOR SPACING	18.0	IN
VOLTAGE	345	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	1.70	KW/MI
LINE LENGTH	323.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1000.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

****
* INPUT DATA *
****

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

B-25

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	27.0 FEET	D1	27.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	27.00 FT
GROUND CLEARANCE	32.0 FEET	D3	54.00 FT
NO. OF INSULATORS PER TOWER	72	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	9.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 10: 345KV TOWER

TW = 0.00043*TH**2 - 0.992111*TH**0.6000 - 0.10371*EFFVDL -
0.27365*EFFTDL + 0.00503*TH*EFFTDL + 0.00181*TH*EFFVDL +
20.77701 KIPS

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

****
* INPUT DATA *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9
40	ORTOLAN	1033.0	45/ 7	1.1650	1.2130	0.8678	9.40	11.5

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

****
*   *
*   INPUT DATA   *
*   *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816
40	ORTOLAN	28900.0	0.0401	0.670/1977	1020.	0.0924	0.3902	2.4658

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

```
*****************
*               *
*   INPUT DATA  *
*               *
*****************
```

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
30	715.	1300.	105622.	6261.	113812.	12519.	238214.	22728.	4821.	265762.
35	795.	1300.	108253.	6486.	114488.	12594.	241821.	19629.	4908.	266357.
30	715.	1400.	107324.	6256.	112903.	12419.	238902.	22728.	4854.	266483.
35	795.	1400.	110039.	6487.	113599.	12496.	242620.	19629.	4944.	267192.
30	715.	1200.	105232.	6340.	115902.	12749.	240223.	22728.	4843.	267793.
35	795.	1200.	107799.	6561.	116571.	12823.	243753.	19629.	4929.	268310.
29	715.	1300.	105955.	6203.	115588.	12715.	240461.	23923.	4857.	269240.
30	715.	1500.	110237.	6320.	113036.	12434.	242026.	22728.	4939.	269692.
29	715.	1200.	104868.	6250.	117221.	12894.	241233.	23923.	4852.	270008.
32	795.	1300.	109255.	6399.	116128.	12774.	244556.	20589.	4960.	270105.
35	795.	1500.	113021.	6554.	113739.	12511.	245825.	19629.	5031.	270485.
32	795.	1200.	108121.	6443.	117764.	12954.	245282.	20589.	4955.	270825.
34	795.	1300.	109378.	6341.	116691.	12836.	245246.	21069.	4972.	271286.
29	715.	1400.	108480.	6237.	115211.	12673.	242600.	23923.	4922.	271445.
34	795.	1200.	107991.	6373.	118160.	12998.	245522.	21069.	4956.	271546.
32	795.	1400.	111805.	6435.	115732.	12731.	246703.	20589.	5026.	272318.
37	900.	1300.	112812.	6583.	117342.	12908.	249645.	17916.	5082.	272642.
37	900.	1200.	111385.	6612.	118824.	13071.	249892.	17916.	5065.	272872.
30	715.	1100.	106343.	6506.	119395.	13133.	245378.	22728.	4931.	273036.
35	795.	1100.	108831.	6723.	120046.	13205.	248805.	19629.	5014.	273448.
34	795.	1400.	112220.	6390.	116486.	12813.	247910.	21069.	5049.	274027.
29	715.	1100.	105362.	6388.	120302.	13233.	245285.	23923.	4916.	274124.
39	954.	1300.	114706.	6714.	117754.	12953.	252127.	16883.	5143.	274153.
39	954.	1200.	113228.	6740.	119225.	13115.	252308.	16883.	5125.	274315.
31	795.	1200.	109517.	6440.	119187.	13111.	248254.	21550.	5016.	274820.

ANCHORAGE-FAIRBANKS INTERTIE CASE I-C
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:10:52

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 30
715. KCMIL 1300. FT SPAN 90.1 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	31680.	FT	24661.	17.60	1760.	25306.	51727.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	310.	UNITS	1970.	1.70	366.		2336.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	63399.	33.12	3312.	37681.	104393.
FOUNDATIONS	4.3	UNITS	4791.		775.	32083.	37648.
RIGHT OF WAY	13.	ACRES	9371.			18742.	28114.
IDC/ENGINEERING			12519.				12519.
TOTALS			105622.	52.90	6261.	113812.	238214.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	9670.	3735.	13405.
CORONA LOSSES	2088.	7235.	9323.
TOTALS	11758.	10970.	22728.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979.

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

****
*   *
*   INPUT DATA   *
*   *
****

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	631.6 MVA	1992
AVERAGE CIRCUIT LOADING	347.4 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

****
*   *
*   INPUT DATA   *
*   *
****

CONDUCTOR DATA

NUMBER PER PHASE	2	
CONDUCTOR SPACING	18.0	IN
VOLTAGE	345	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	1.70	KW/MI
LINE LENGTH	155.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1000.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

```
******************
*                *
*   INPUT DATA   *
*                *
******************
```

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

B-33

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	27.0 FEET	D1	27.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	27.00 FT
GROUND CLEARANCE	32.0 FEET	D3	54.00 FT
NO. OF INSULATORS PER TOWER	72	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	9.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 10: 345KV TOWER

TW = 0.00043*TH**2 - 0.992111*TH**0.6000 - 0.10371*EFFVDL -
0.27365*EFFTDL + 0.00503*TH*EFFTDL + 0.00181*TH*EFFVDL +
20.77701 KIPS

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9
40	ORTOLAN	1033.0	45/ 7	1.1650	1.2130	0.8678	9.40	11.5

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

****
* INPUT DATA *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816
40	ORTOLAN	28900.0	0.0401	0.670/1977	1020.	0.0924	0.3902	2.4658

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

INPUT DATA

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS

REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS

TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

ANCHORAGE-DEVIL CANYON CASE II-1

345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 12 APR 79 TIME: 10:25:33

AUTOMATIC CONDUCTOR SELECTION

ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	114706.	6714.	117754.	12953.	252127.	90411.	5143.	347681.
39	954.	1200.	113228.	6740.	119225.	13115.	252308.	90411.	5125.	347843.
40	1033.	1200.	117782.	6840.	121885.	13407.	259913.	84621.	5295.	349829.
37	900.	1300.	112812.	6583.	117342.	12908.	249645.	95660.	5082.	350386.
39	954.	1400.	117620.	6769.	117532.	12928.	254849.	90411.	5222.	350482.
37	900.	1200.	111385.	6612.	118824.	13071.	249892.	95660.	5065.	350616.
39	954.	1100.	113373.	6859.	122168.	13438.	255838.	90411.	5176.	351425.
40	1033.	1100.	116899.	6910.	124193.	13661.	261664.	84621.	5307.	351591.
40	1033.	1300.	120420.	6869.	121120.	13323.	261732.	84621.	5358.	351711.
37	900.	1400.	115679.	6635.	117111.	12882.	252308.	95660.	5159.	353126.
38	954.	1200.	114994.	6662.	121202.	13332.	256189.	91853.	5204.	353246.
35	795.	1300.	108253.	6486.	114488.	12594.	241821.	107119.	4908.	353847.
37	900.	1100.	111580.	6734.	121780.	13396.	253490.	95660.	5118.	354268.
35	795.	1400.	110039.	6487.	113599.	12496.	242620.	107119.	4944.	354683.
38	954.	1300.	117510.	6684.	120390.	13243.	257827.	91853.	5262.	354942.
38	954.	1100.	114231.	6738.	123557.	13591.	258117.	91853.	5220.	355190.
35	795.	1200.	107799.	6561.	116571.	12823.	243753.	107119.	4929.	355800.
39	954.	1500.	121880.	6899.	118425.	13027.	260230.	90411.	5357.	355998.
40	1033.	1400.	124683.	6989.	121712.	13388.	266772.	84621.	5488.	356881.
35	795.	1500.	113021.	6554.	113739.	12511.	245825.	107119.	5031.	357975.
32	795.	1300.	109255.	6399.	116128.	12774.	244556.	108934.	4960.	358450.
37	900.	1500.	119895.	6762.	117998.	12980.	257634.	95660.	5293.	358587.
32	795.	1200.	108121.	6443.	117764.	12954.	245282.	108934.	4955.	359170.
36	900.	1200.	113498.	6552.	120883.	13297.	254229.	100106.	5156.	359491.
34	795.	1300.	109378.	6341.	116691.	12836.	245246.	109437.	4972.	359654.

ANCHORAGE-DEVIL CANYON CASE II-1
345 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 10:25:33

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 39
954. KCMIL 1300. FT SPAN 94.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	31680.	FT	28172.	19.47	1947.	25870.	55989.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	310.	UNITS	1970.	1.70	366.		2336.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	68496.	35.79	3579.	40104.	112179.
FOUNDATIONS	4.3	UNITS	4791.		775.	32083.	37648.
RIGHT OF WAY	14.	ACRES	9848.			19697.	29545.
IDC/ENGINEERING			12953.				12953.
TOTALS			114706.	57.43	6714.	117754.	252127.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	44314.	39493.	83807.
CORONA LOSSES	2088.	4517.	6604.
TOTALS	46401.	44010.	90411.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979,

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

```
******************
*                *
*   INPUT DATA   *
*                *
******************
```

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	194.7 MVA	1992
AVERAGE CIRCUIT LOADING	107.1 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

```
*****************
*               *
*  INPUT DATA   *
*               *
*****************
```

CONDUCTOR DATA

NUMBER PER PHASE	1	
CONDUCTOR SPACING	0.0	IN
VOLTAGE	230	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	0.00	KW/MI
LINE LENGTH	189.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1200.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

```
******************
*                *
*   INPUT DATA   *
*                *
******************
```

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

B-41

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

****
*   *
*   INPUT DATA *
*   *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEF. ALPHA*E-6 PER DEG F
24	GROSBEAK	636.0	26/ 7	0.8750	0.9900	0.5809	11.00	10.3
25	EGRET	636.0	30/19	0.9880	1.0190	0.6134	11.30	9.7
26	FLAMINGO	666.0	24/ 7	0.8590	1.0000	0.5914	10.55	10.7
27	GANNET	666.0	26/ 7	0.9180	1.0140	0.6087	11.00	10.3
28	STILT	715.0	24/ 7	0.9210	1.0360	0.6348	10.55	10.7
29	STARLING	715.0	26/ 7	0.9850	1.0510	0.6535	11.00	10.3
30	REDWING	715.0	30/19	1.1110	1.0810	0.6901	11.30	9.7
31	CUCKOO	795.0	24/ 7	1.0240	1.0920	0.7053	10.55	10.7
32	DRAKE	795.0	26/ 7	1.0940	1.1080	0.7261	11.00	10.3
33	TERN	795.0	45/ 7	0.8960	1.0630	0.6676	9.40	11.5
34	CONDOR	795.0	54/ 7	1.0240	1.0930	0.7053	10.85	10.9
35	MALLARD	795.0	30/19	1.2350	1.1400	0.7668	11.30	9.7
36	RUDDY	900.0	45/ 7	1.0150	1.1310	0.7069	9.40	11.5
37	CANARY	900.0	54/ 7	1.1590	1.1620	0.7985	10.85	10.9
38	RAIL	954.0	45/ 7	1.0750	1.1650	0.8011	9.40	11.5
39	CARDINAL	954.0	54/ 7	1.2290	1.1960	0.8464	10.85	10.9

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

INPUT DATA

CONDUCTOR SUMMARY

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
24	GROSBEAK	25000.0	0.0335	0.628/1977	790.	0.1452	0.4118	2.6347
25	EGRET	31500.0	0.0351	0.609/1977	870.	0.1447	0.4060	2.6136
26	FLAMINGO	23700.0	0.0335	0.640/1977	810.	0.1399	0.4118	2.6294
27	GANNET	26200.0	0.0343	0.609/1977	820.	0.1373	0.4092	2.6347
28	STILT	25500.0	0.0347	0.627/1977	840.	0.1320	0.4066	2.6400
29	STARLING	28100.0	0.0355	0.608/1977	850.	0.1294	0.4050	2.6453
30	REDWING	34600.0	0.0372	0.612/1977	860.	0.1288	0.3992	2.5661
31	CUCKOO	27100.0	0.0366	0.636/1977	900.	0.1214	0.3992	2.5502
32	DRAKE	31200.0	0.0375	0.622/1977	910.	0.1172	0.3992	2.5450
33	TERN	22900.0	0.0352	0.677/1977	890.	0.1188	0.4060	2.5766
34	CONDOR	28500.0	0.0368	0.635/1977	900.	0.1172	0.4002	2.5555
35	MALLARD	38400.0	0.0392	0.599/1977	910.	0.1162	0.3928	2.5186
36	RUDDY	25400.0	0.0374	0.676/1977	935.	0.1082	0.3928	2.5080
37	CANARY	32300.0	0.0392	0.633/1977	950.	0.1040	0.3928	2.5027
38	RAIL	26900.0	0.0385	0.671/1977	970.	0.0998	0.3949	2.5027
39	CARDINAL	34200.0	0.0404	0.632/1977	990.	0.0987	0.3902	2.4816

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

```
******************
*                *
*   INPUT DATA   *
*                *
******************
```

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

DEVIL CANYON-ESTER CASE II-2A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:45:19

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
39	954.	1300.	68147.	3834.	84796.	9328.	166104.	36988.	3284.	206376.
37	900.	1300.	67299.	3772.	84608.	9307.	164986.	39195.	3257.	207436.
35	795.	1300.	64664.	3721.	82616.	9088.	160089.	44359.	3151.	207598.
35	795.	1400.	65375.	3684.	82031.	9023.	160113.	44359.	3161.	207633.
39	954.	1400.	69552.	3828.	84673.	9314.	167367.	36988.	3322.	207676.
37	900.	1400.	68697.	3766.	84494.	9294.	166251.	39195.	3294.	208739.
35	795.	1500.	66879.	3689.	82176.	9039.	161784.	44359.	3206.	209348.
32	795.	1300.	65558.	3685.	83893.	9228.	162364.	44830.	3195.	210389.
39	954.	1500.	71843.	3870.	85337.	9387.	170437.	36988.	3397.	210821.
38	954.	1300.	70136.	3831.	86787.	9547.	170300.	37456.	3371.	211126.
34	795.	1300.	65807.	3659.	84359.	9279.	163104.	44915.	3209.	211228.
32	795.	1400.	66784.	3669.	83683.	9205.	163342.	44830.	3226.	211398.
39	954.	1200.	70386.	4033.	87082.	9579.	171080.	36988.	3385.	211453.
30	715.	1300.	63510.	3615.	82301.	9053.	158478.	50049.	3112.	211639.
30	715.	1400.	64204.	3576.	81729.	8990.	158498.	50049.	3122.	211669.
37	900.	1500.	70983.	3807.	85172.	9369.	169331.	39195.	3369.	211894.
35	795.	1600.	69124.	3735.	82979.	9128.	164966.	44359.	3282.	212607.
34	795.	1400.	67235.	3653.	84298.	9273.	164459.	44915.	3248.	212621.
37	900.	1200.	69631.	3977.	86926.	9562.	170096.	39195.	3361.	212651.
35	795.	1200.	66889.	3916.	85020.	9352.	165176.	44359.	3254.	212788.
30	715.	1500.	65702.	3580.	81896.	9009.	160187.	50049.	3167.	213402.
36	900.	1300.	69499.	3780.	86682.	9535.	169496.	40968.	3351.	213814.
38	954.	1400.	72348.	3861.	87234.	9596.	173039.	37456.	3440.	213934.
32	795.	1500.	68883.	3701.	84257.	9268.	166109.	44830.	3295.	214233.
38	954.	1200.	71305.	3980.	88398.	9724.	173407.	37456.	3431.	214293.

DEVIL CANYON-ESTER CASE II-2A

230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION

DATE: 12 APR 79 TIME: 9:45:19

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 39

954. KCMIL 1300. FT SPAN 87.7 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY		MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840.	FT	14086.	9.73	973.	18257.	33316.
GROUNDWIRE	0.	FT	0.	0.00	0.	0.	0.
INSULATORS	207.	UNITS	1313.	1.14	244.		1557.
HARDWARE			1429.	0.47	47.		1477.
TOWERS	4.3	UNITS	38870.	20.31	2031.	26019.	66921.
FOUNDATIONS	4.3	UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13.	ACRES	9120.			18241.	27361.
IDC/ENGINEERING			9328.				9328.
TOTALS			68147.	31.65	3834.	84796.	166104.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	19547.	17422.	36969.
CORONA LOSSES	0.	19.	19.
TOTALS	19547.	17441.	36988.

INTERNATIONAL ENGINEERING CO. INC
SAN FRANCISCO CALIFORNIA

TRANSMISSION LINE COST ANALYSIS PROGRAM
VERSION 1: 23 FEB 1979,

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

****
*   *
*   INPUT DATA   *
*   *
****

SYSTEM ECONOMIC FACTORS	INPUT VALUE	REFERENCE YEAR FOR INPUT
STARTING YEAR OF STUDY	1979	
ENDING YEAR OF STUDY	1996	
BASE YEAR FOR ESCALATION	1977	
MAXIMUM CIRCUIT LOADING	514.0 MVA	1992
AVERAGE CIRCUIT LOADING	282.7 MVA	1992
DEMAND COST FACTOR	73.0 $/KW	1979
ENERGY COST FACTOR	13.0 MILLS/KWH	1979
VAR COST FACTOR	0.0 $/KVAR	1984
CAPITAL COST/DISCOUNT RATE:		
MINIMUM	7.0 PERCENT	1984
MAXIMUM	10.0 PERCENT	1984
NUMBER OF INTERVALS	1	
O&M COST FACTOR	1.5 % CAP.COST	1979
RIGHT OF WAY COST FACTOR	715.0 $/ACRE	1979
RIGHT OF WAY CLEARING COST	1430.0 $/ACRE	1979
INTEREST DURING CONSTRUCTION	0.00 % INST.CST	
ENGINEERING FEE	11.00 % INST.CST	

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

****
* INPUT DATA *
****

CONDUCTOR DATA

NUMBER PER PHASE	1	
CONDUCTOR SPACING	0.0	IN
VOLTAGE	230	KV
VOLTAGE VARIATION	10.00	PCT
LINE FREQUENCY	60	CPS
FAIRWEATHER LOSSES	0.00	KW/MI
LINE LENGTH	27.00	MILES
POWER FACTOR	0.95	

GROUNDWIRE DATA

NUMBER PER TOWER	0	
DIAMETER	0.00	IN
WEIGHT	0.0000	LBS/FT

SPAN DATA

MINIMUM	1200.	FT
MAXIMUM	1600.	FT
INTERVAL	100.0	FT

WEATHER DATA

MAXIMUM RAINFALL RATE	1.18	IN/HR
MAXIMUM RAINFALL DURATION	1	HRS/YR
AVERAGE RAINFALL RATE	0.03	IN/HR
AVERAGE RAINFALL DURATION	636	HRS/YR
MAXIMUM SNOWFALL RATE	1.87	IN/HR
MAXIMUM SNOWFALL DURATION	1	HRS/YR
AVERAGE SNOWFALL RATE	0.13	IN/HR
AVERAGE SNOWFALL DURATION	264	HRS/YR
RELATIVE AIR DENSITY	1.000	

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

****
*   *
*   INPUT DATA   *
*   *
****

SAG/TENSION DESIGN FACTORS

EVERYDAY STRESS TEMPERATURE	40. DEGREES F	ICE AND WIND TENSION (PCT UTS)	50. PERCENT
ICE AND WIND TEMPERATURE	0. DEGREES F	HIGH WIND TENSION (PCT UTS)	50. PERCENT
HIGH WIND TEMPERATURE	40. DEGREES F	EXTREME ICE TENSION (PCT UTS)	70. PERCENT
EXTREME ICE TEMPERATURE	30. DEGREES F	ICE THICKNESS WITH WIND	0.50 INCHES
MAX DESIGN TEMP FOR GND CLEARANCE	120. DEGREES F	WIND PRESSURE WITH ICE	4.00 LBS/SQ.FT.
EDS TENSION (PCT UTS)	20. PERCENT	HIGH WIND	9.0 LBS/SQ.FT.
NESC CONSTANT	0.31 LBS/FT		
		EXTREME ICE	0.50 INCHES

B-49

TOWER DESIGN

TOTAL NUMBER OF PHASES	3	DISTANCE BETWEEN PHASES:	
PHASE SPACING	20.0 FEET	D1	20.00 FT
CONDUCTOR CONFIGURATION FACTOR	1.02	D2	20.00 FT
GROUND CLEARANCE	28.0 FEET	D3	40.00 FT
NO. OF INSULATORS PER TOWER	48	D4	0.00 FT
INSULATOR SAFETY FACTOR	2.50	D5	0.00 FT
STRING LENGTH	6.5 FEET	D6	0.00 FT
I, VEE, OR COMBINATION	3		
FOUNDATION TYPE	4		
TERRAIN FACTOR	1.06 PER UNIT		
LINE ANGLE FACTOR	.0864		
TOWER GROUNDING	0		
TRANSVERSE OVERLOAD FACTOR	2.50		
VERTICAL OVERLOAD FACTOR	1.50		
LONGITUDINAL LOAD	1000. LBS		
MISCELLANEOUS HARDWARE WEIGHT	0.11 TONS/TOWER		
TOWER WEIGHT FACTOR	1.02		

TOWER WEIGHT ESTIMATION ALGORITHM

TOWER TYPE 9: 230KV TOWER

TW = 0.00016*TH**2 - 3.09797*TH**0.3333 - 0.08943*EFFVDL -
0.27367*EFFTDL + 0.00510*TH*EFFTDL + 0.00160*TH*EFFVDL +
18.37912 KIPS

WATANA-DEVIL CANYON   CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79   TIME: 9:02:43

****
*   *
*   INPUT DATA   *
*   *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	SIZE(KCM)	STRANDING (AL/ST)	UNIT WEIGHT (LBS/FT)	OUT.DIAM. (INCHES)	TOTAL AREA (SQ.IN.)	MODULUS (EF/E6 PSI)	TEMP.COEFF. ALPHA*E-6 PER DEG F
52	NUTHATCH	1510.0	45/ 7	1.7020	1.4660	1.2680	9.40	11.5
53	PARROT	1510.0	54/19	1.9420	1.5060	1.3366	10.30	10.8
54	LAPWING	1590.0	45/ 7	1.7920	1.5020	1.3350	9.40	11.5
55	FALCON	1590.0	54/19	2.0440	1.5450	1.4076	10.30	10.8
56	CHUKAR	1780.0	84/19	2.0740	1.6020	1.5120	9.05	11.3
57	BLUEBIRD	2156.0	84/19	2.5120	1.7620	1.8280	9.05	11.3
58	KIWI	2167.0	72/ 7	2.3040	1.7370	1.7760	9.25	12.0

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

****
*   INPUT DATA   *
****

CONDUCTOR SUMMARY
****

ID NUMBER	NAME	ULT.TENS. STRENGTH(LBS)	GEOM.MEAN RADIUS(FT)	PRICE($/LB)	THERM.LIMIT (AMPERES)	AC RESIST. AT 25 DEG C (OHMS/MILE)	IND.REACT. (OHMS/MILE)	CAP.REACT. (MOHM-MILES)
52	NUTHATCH	41600.0	0.0485	0.664/1977	1300.	0.0649	0.3670	2.3126
53	PARROT	53200.0	0.0508	0.630/1977	1320.	0.0602	0.3622	2.2862
54	LAPWING	43800.0	0.0497	0.660/1977	1340.	0.0623	0.3638	2.2915
55	FALCON	56000.0	0.0521	0.636/1977	1360.	0.0612	0.3580	2.2704
56	CHUKAR	53600.0	0.0534	0.675/1977	1440.	0.0560	0.3548	2.2387
57	BLUEBIRD	63400.0	0.0588	0.673/1977	1610.	0.0475	0.3443	2.1648
58	KIWI	50900.0	0.0570	0.699/1977	1600.	0.0480	0.3480	2.1806

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

****
*   *
*   INPUT DATA   *
*   *
****

UNIT MATERIALS COSTS	INPUT VALUE	REFERENCE YEAR FOR INPUT
PRICE OF TOWER MATERIAL	0.957 $/LB	1979
PRICE OF CONCRETE	0.00 $/CU.YD.	1977
PRICE OF GROUND WIRE	0.000 $/LB	1977
INSTALLED COST OF GROUNDING SYSTEM	0.00 $/TOWER	1977
TOWER SETUP	1751. $	1979
TOWER ASSEMBLY	0.455 $/LB	1979
FOUNDATION SETUP	0. $	1979
FOUNDATION ASSEMBLY	4140.00 $/TON	1979
FOUNDATION EXCAVATION	0.00 $/CU.YD.	1979
PRICE OF MISCELLANEOUS HARDWARE	290.00 $/TOWER	1977

UNIT LABOR COSTS		
REFERENCE YEAR LABOR COST	24.00 $/MANHOUR	1979
STRING GROUND WIRE	0.0 $/MILE	1977
STRING LABOR MARKUP	4.2 PER UNIT	

UNIT TRANSPORTATION COSTS	
TOWER	100.0 $/TON
FOUNDATION CONCRETE	100.0 $/YD
FOUNDATION STEEL	100.0 $/TON
CONDUCTOR	100.0 $/TON
GROUND WIRE	100.0 $/TON
INSULATOR	100.0 $/TON OR $/M**3
HARDWARE	100.0 $/TON

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

AUTOMATIC CONDUCTOR SELECTION
ALL QUANTITIES PER MILE

CAPITAL COST/DISCOUNT RATE OF 7.00 PERCENT

CONDUCTOR			INSTALLED COST					PRESENT WORTH		
								LINE LOSSES	O&M COST	LINE COST
NO.	KCM	SPAN(FT)	MATERIALS	TRANSPORTATION	INSTALLATION	ENG/IDC	SUBTOTAL	SUBTOTAL	SUBTOTAL	TOTAL
57	2156.	1300.	89569.	5105.	90521.	9957.	195153.	116334.	3992.	315478.
57	2156.	1200.	90137.	5217.	92027.	10123.	197504.	116334.	4033.	317870.
57	2156.	1400.	92123.	5160.	90934.	10003.	198219.	116334.	4071.	318623.
58	2167.	1300.	92415.	5125.	93237.	10256.	201033.	117583.	4114.	322730.
58	2167.	1200.	92234.	5204.	94210.	10363.	202012.	117583.	4125.	323720.
57	2156.	1500.	95769.	5268.	92163.	10138.	203339.	116334.	4194.	323866.
56	1780.	1300.	82764.	4678.	88729.	9760.	185931.	137630.	3767.	327327.
58	2167.	1400.	95989.	5226.	94328.	10376.	205919.	117583.	4233.	327734.
56	1780.	1400.	84951.	4714.	88966.	9786.	188417.	137630.	3833.	329879.
56	1780.	1200.	83451.	4796.	90292.	9932.	188471.	137630.	3812.	329912.
53	1510.	1300.	77500.	4479.	87032.	9573.	178584.	148218.	3590.	330391.
57	2156.	1600.	100185.	5423.	94144.	10356.	210108.	116334.	4350.	330792.
53	1510.	1400.	79192.	4490.	86974.	9567.	180224.	148218.	3637.	332078.
56	1780.	1500.	88068.	4799.	90008.	9901.	192776.	137630.	3937.	334342.
53	1510.	1200.	79083.	4642.	89077.	9798.	182601.	148218.	3669.	334486.
55	1590.	1300.	79058.	4570.	87330.	9606.	180565.	150744.	3640.	334949.
58	2167.	1500.	100672.	5386.	96330.	10596.	212984.	117583.	4397.	334964.
53	1510.	1500.	81760.	4550.	87688.	9646.	183644.	148218.	3721.	335582.
55	1590.	1400.	80792.	4584.	87283.	9601.	182260.	150744.	3688.	336692.
52	1510.	1200.	72903.	4188.	87159.	9587.	173837.	160117.	3459.	337413.
55	1590.	1200.	80560.	4729.	89344.	9828.	184460.	150744.	3716.	338920.
55	1590.	1500.	83400.	4646.	88008.	9681.	185734.	150744.	3773.	340251.
56	1780.	1600.	92071.	4932.	91788.	10097.	198888.	137630.	4079.	340596.
54	1590.	1300.	79970.	4495.	89119.	9803.	183387.	153527.	3692.	340605.
53	1510.	1600.	85158.	4653.	89108.	9802.	188721.	148218.	3840.	340778.

WATANA-DEVIL CANYON CASE II-3A
230 KV TRANSMISSION LINE COST ANALYSIS AND CONDUCTOR OPTIMIZATION
DATE: 12 APR 79 TIME: 9:02:43

COST OUTPUT PER MILE
PRESENT VALUE RATE
7.00 PERCENT

CONDUCTOR NUMBER = 57
2156. KCMIL 1300. FT SPAN 87.4 FT TOWER

INSTALLED COST BREAKDOWN	QUANTITY	MATERIAL COST($)	TONNAGE	TRANSPORTATION COST($)	INSTALLATION COST($)	TOTAL COST($)
CONDUCTOR	15840. FT	30659.	19.90	1990.	21730.	54378.
GROUNDWIRE	0. FT	0.	0.00	0.	0.	0.
INSULATORS	207. UNITS	1313.	1.14	244.		1557.
HARDWARE		1429.	0.47	47.		1477.
TOWERS	4.3 UNITS	43756.	22.86	2286.	28342.	74384.
FOUNDATIONS	4.3 UNITS	3327.		538.	22280.	26145.
RIGHT OF WAY	13. ACRES	9085.			18170.	27255.
IDC/ENGINEERING		9957.				9957.
TOTALS		89569.	44.37	5105.	90521.	195153.

PRESENT VALUE ($)

LOSS ANALYSIS	DEMAND LOSSES	ENERGY LOSSES	TOTAL LOSSES
RESISTANCE LOSSES	61516.	54818.	116334.
CORONA LOSSES	0.	0.	0.
TOTALS	61516.	54818.	116334.

APPENDIX C

MULTI-AREA RELIABILITY PROGRAM (MAREL)

POWER TECHNOLOGIES INC

P.O. BOX 1058 SCHENECTADY, NEW YORK 12301 518 374-1220

MULTI AREA RELIABILITY PROGRAM (MAREL)

BULLETIN PTI/103 Page 1 of 3

SUMMARY

The Multi-Area Reliability Program (MAREL) computes the Loss of Load Probability (LOLP) reliability index for electric generating systems of several areas interconnected by a transmission network without any restrictions on the network topology. The program permits the study of large power pools and reliability councils as well as individual utilities imbedded in an extensive interconnection. The program is intended to be used in the design and analysis of generation systems and the interconnection capability requirements needed to share reserves among the interconnected areas. The program may be used for as many as six or seven interconnected areas modeled directly. A greater number may be accommodated by developing equivalent systems. The output includes area and total system LOLP indices as well as data or the probable causes of failures and their locations in the network. The program structure is flexible so that load and capacity models may be as detailed as required and at the same time, the complex evaluation of the individual area reliability levels may be performed with efficiency.

PROGRAM ELEMENTS AND MODELS

The structure of MAREL is shown in block form on Figure 1. Input data may be provided for each case or partially supplied by saved case files. The program structure is set up to analyze one year at a time under the control of the user. This facilitates the development of system expansions interactively or with a series of runs on a batch basis without the risk of the possibility of using excessive computer time.

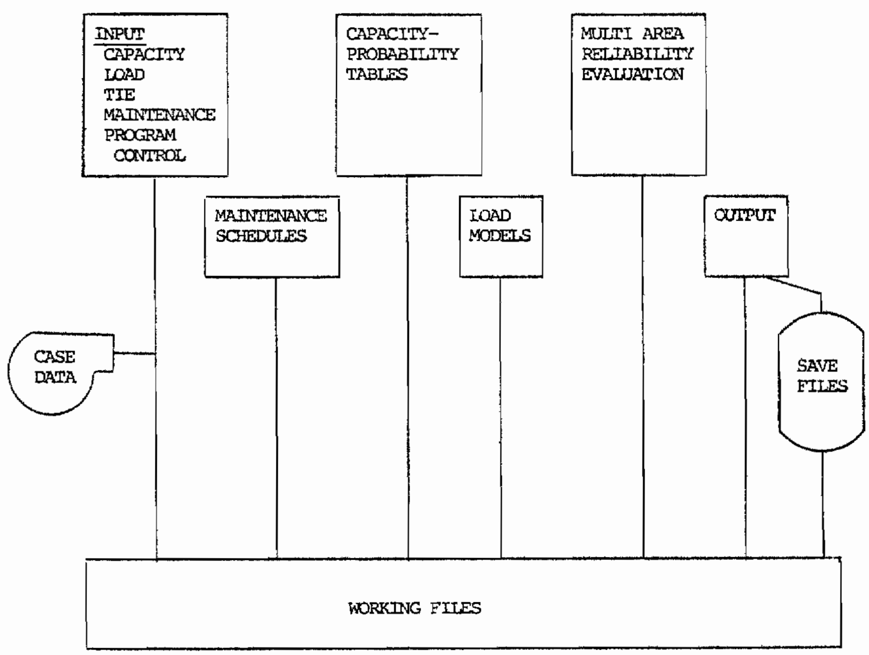


FIGURE 1

STRUCTURE OF MULTI AREA RELIABILITY PROGRAM

- Loads are modeled by area with distributions of peak loads for each 'season' of the year. A season may be of whatever length is appropriate for the study, weeks, months, or longer intervals.

- Capacity Models are developed for each area for each season of the year and are available capacity-probability density tables.

- Maintenance Outages are simulated either by adding the capacity on outage to the appropriate area and season load model or by modification of the proper capacity-probability table. Maintenance may be prescheduled and input or done automatically within MAREL by an algorithm designed to level available area generation reserves over the year.

- Transmission Interconnections are modeled by the use of a linear flow network which models the limitations on individual tie line transfer capabilities considering their forced outage rates (if desired) without restrictions on the network configuration or topology.

- Program Controls are set by the user to establish the fineness with which the loads and capcities are represented and to set tolerance levels on the LOLP computations to save unnecessary computer effort and cost.

- Program Output may include area load and capacity models as well as maintenance schedules, three sets of both seasonal and annual area and system LOLP indices, the probabilities of various failure modes. That is, the program automatically calculates area LOLP values as though the area were isolated and then two separate LOLP values with the actual interconnection. These two LOLP indices represent the extremes of possible operating policies concerning the sharing of generation reserves, (1) sharing only available reserves, and (2) sharing load losses up to the transfer limitations imposed by the network. Failure mode probabilities show the probabilities and locations of failures caused by generation shortages or transmission limitations as well as combinations and indicate the probabilities that each individual tie may be limiting. These data are useful in developing reliable system designs.

- System Size is not restricted except by limits on acceptable computational effort and cost. Past PTI system studies have included two interconnected reliability councils represented by nine or ten areas and incorporating approximately 500 units for a total of 100,000 mw of generation.

PROGRAM APPLICATIONS

- Generation reliability level analysis which includes the effects of the interconnected system for the expansion planning of individual utilities and power pools.

- Planning of interconnections to achieve regional integration and more widespread sharing of generation reserves.

- Evaluation of the reliability benefits of strengthening ties vis-a-vis additions to generation reserves.

- Assistance in locating weak portions of a system in order to locate new bulk power facilities for maximum reliability improvement.
- Analysis of the reliability benefits of new jointly-owned plants located remotely or within one system's territory.
- Evaluation of the ability of individual utilities to reliably survive the postponement of new plant additions in their own and interconnected systems.

AVAILABILITY AND SUPPORT

MAREL is available for use at PTI for studies by individual utilities or groups of systems. It may also be leased for installation on a client's computer. The lease entitles the user to:

- Complete set of source code for all modules including all MAREL activities and subroutines.
- Engineering and program reference manuals.
- Installation on a suitable PRIME 400 computer at the client's site and a training seminar.

Installation on other computers is feasible but will only be done on the basis of charging for the time and expense required.

Since PTI is a consulting engineering organization and uses MAREL in studies for clients, the program is continually being enhanced and updated.

While updates are not included in the MAREL lease price, PTI will offer all significant MAREL improvements to lessees at add-on prices.

PTI can assist MAREL users in the development of system equivalents where their use is attractive to the user.

FOR FURTHER INFORMATION

Contact: C.K. Pang, Senior Engineer
or
A.J. Wood, Principal Engineer
Power Technologies, Inc.
P.O. Box 1058
Schenectady, N.Y. 12301

Tel. (518) 374-1220
Telex 145498 POWER TECH SCH

1/78

MULTI-AREA RELIABILITY PROGRAM (MAREL)

SAMPLE OUTPUT SHEETS
FOR
TWO-AREA RELIABILITY STUDY - YEAR 1989

Note: The following other output sheets (35 cases) are on file with Alaska Power Authority under a separate cover:

- Independent System Expansion Plans (years 1984 through 1996)

- Interconnected System Expansion Plans (years 1984 through 1996)

- Interconnected System Expansion, Three-Area Realiability Study with Susitna (years 1992 through 1996)

- Interconnected System Expansion Plans, with Firm Power Transfer (years 1984 through 1987 and 1992 through 1996)

IECREL *TIE89 01/18/79 11:01 PRT018

```
 WWW   WWWWW   WWW   WWWW   WWWWW  W
  W    W      W   W  W   W  W      W
  W    W      W      W   W  W      W
  W    WWWW   W      WWWW   WWWW   W
  W    W      W      W W    W      W
  W    W      W   W  W  W   W      W   W
 WWW   WWWWW   WWW   W   W  WWWWW  WWWWW


         WWWWW   WWW   WWWWW   WWW    WWW
W W W      W      W    W      W   W  W   W
 WWW       W      W    W      W   W  W   W
WW WW      W      W    WWWW    WWW    WWWW
 WWW       W      W    W      W   W      W
W W W      W      W    W      W   W     W
           W     WWW   WWWWW   WWW   WWW
```

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM:

---- MULTI-AREA RELIABILITY PROGRAM - MAREL ----

---- VERSION : NOVEMBER 15, 1978 ----

---- POWER TECHNOLOGIES, INC. ----

```
**********************
**                  **
**  01 - 18 - 1979  **
**                  **
**********************
```

S T U D Y   C A S E:

```
******************************************************************************
**                                                                          **
**   ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY      **
**                                                                          **
**   2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979      **
**                                                                          **
******************************************************************************
```

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

```
****************************************************************************
**                                                                        **
**   ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY    **
**                                                                        **
**   2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979    **
**                                                                        **
****************************************************************************
```

YEAR OF STUDY = 1989

PROBABILITY THRESHOLD = 0.10E-07

FAILURE PROB. THRESHOLD = 0.20E-08

PROB. RATIO FOR LOAD LEV.= 0.0100

ROUNDING MW STEP SIZE = 1

MAX. NO. OF AREAS WITH NEGATIVE
MARGIN TO BE EXAMINED = 2

MAX. OF CAPACITY STEPS = 50

----- SYSTEM DATA -----

NO. OF AREAS OR BUSES = 2

NO. OF AREAS WITH GENERATION = 2

NO. OF AREAS WITH LOADS = 2

NO. OF LINES WITH OUTAGES = 1

NO. OF FIRM LINES = 0

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

----- DATA FOR LINES WITH OUTAGES -----
--- AVAILABLE CAPACITY PROBABILITY ---

LINE NO. 1, LINK NO. 3
TIE FROM AREA 1 ANCHOR -TO- AREA 2 FAIRBA

LEVEL	CAP(FOR)	CAP(REV)	PROBABILITY
1	0	0	0.004000
2	130	130	0.996000

----- TIME USED IN CPUS : INCREMENT = 2, ELAPSED = 2

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

SUMMARY ON CAPACITY, PEAK LOAD AND MAINTENANCE : AREA ANCHOR

SEASON		1	2	3	4	5	6	7	8	9
INSTALLED CAPACITY (MW)		1747	1747	1747	1747	1747	1747	1747	1747	1747
PEAK LOAD (MW)		1200	882	789	752	729	725	826	886	1441
INSTALLED RESERVES :										
	MW	547	865	958	995	1018	1022	921	861	306
	PERCENT	45.58	98.07	121.42	132.31	139.64	140.97	111.50	97.18	21.24
CAPACITY ON MAINTENANCE (MW)		0	135	227	256	286	287	188	122	0
RESERVES AFTER MAINTENANCE :										
	MW	547	730	731	739	732	735	733	739	306
	PERCENT	45.58	82.77	92.65	98.27	100.41	101.38	88.74	83.41	21.24

UNIT RETIREMENTS AND INSTALLATIONS :

NO.	UNIT	CAP(MW)	F.O.R.	RET/INST	SEASON	DATE
1	COAL 2	200	0.057	INST	1	1/1989

*** MAINTENANCE FOR SEASONS :   1   9 ***

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

SUMMARY ON CAPACITY, PEAK LOAD AND MAINTENANCE : AREA FAIRBA

SEASON		1	2	3	4	5	6	7	8	9
INSTALLED CAPACITY (MW)		385	385	385	385	385	385	385	385	385
PEAK LOAD (MW)		274	177	135	119	112	130	136	166	313
INSTALLED RESERVES :										
	MW	111	208	250	266	273	255	249	219	72
	PERCENT	40.51	117.51	185.19	223.53	243.75	196.15	183.09	131.93	23.00
CAPACITY ON MAINTENANCE (MW)		0	14	55	72	100	65	54	25	0
RESERVES AFTER MAINTENANCE :										
	MW	111	194	195	194	173	190	195	194	72
	PERCENT	40.51	109.60	144.44	163.03	154.46	146.15	143.38	116.87	23.00

UNIT RETIREMENTS AND INSTALLATIONS :

NO.	UNIT	CAP(MW)	F.O.R.	RET/INST	SEASON	DATE

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

SUMMARY ON CAPACITY AND PEAK LOAD BY AREA

AREA	ANCHOR	FAIRBA
PEAK LOAD SEASON	9	9
INSTALLED CAPACITY (MW) AT ANNUAL PEAK	1747	385
ANNUAL PEAK LOAD (MW)	1441	313
INSTALLED RESERVES (MW)	306	72
RESERVES IN PERCENT OF ANNUAL PEAK LOAD	21.24	23.00
AREA WEIGHTED AVERAGE UNIT FOR (PERCENT)	5.46	7.42
AREA ANNUAL AVERAGE MAINTENANCE(PERCENT)	9.55	11.11

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

-----SUMMARY BY AREAS-----

	AREA	NO.OF UNITS	CAP.(MW)
1	ANCHOR	36	1747
2	FAIRBA	24	385

SEASONAL RESERVES IN PERCENT OF PEAK LOADS
AFTER MAINTENANCE OF UNITS FOR THE TOTAL SYSTEM

SEASON	RESERVES	ORDER	SEASON	RESERVES
1	44.6404	1	9	21.5507
2	87.2521	2	1	44.6404
3	100.2164	3	2	87.2521
4	107.1182	4	8	88.6882
5	107.6100	5	7	96.4657
6	108.1871	6	3	100.2164
7	96.4657	7	4	107.1182
8	88.6882	8	5	107.6100
9	21.5507	9	6	108.1871

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
TWO AREA SYSTEM JANUARY 15 1979

MAINTENANCE SUMMARY BY MW AND PERCENT OF TOTAL AREA CAPACITY :

SEASON	AREA ANCHOR		AREA FAIRBA	
1	0	0.00	0	0.00
2	135	7.73	14	3.64
3	227	12.99	55	14.29
4	256	14.65	72	18.70
5	286	16.37	100	25.97
6	287	16.43	65	16.88
7	188	10.76	54	14.03
8	122	6.98	25	6.49
9	0	0.00	0	0.00

AREA EFOR 5.4550 7.4169

SYSTEM EFOR = 5.8093

EFOR : WEIGHTED EFFECTIVE FORCED OUTAGE RATE IN PERCENT.

*** END OF PROGRAM MNTCE ***

------ TIME USED IN CPUS : INCREMENT = 2, ELAPSED = 4

------ TIME USED IN CPUS : INCREMENT = 0, ELAPSED = 4

*** AREA 1 ANCHOR HAS NO UNITS ON ***
*** MAINTENANCE FOR SEASONS : 1 9 ***

*** AREA 2 FAIRBA HAS NO UNITS ON ***

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- LOSS OF LOAD PROBABILITY AT VARIOUS AREAS ---

AT	AREA	PROBABILITY ISOLATED	PROBABILITY WITH LLS	PROBABILITY WITHOUT LLS
1	ANCHOR	0.149268E+00	0.798471E-01	0.676829E-01
2	FAIRBA	0.190494E+01	0.909675E-01	0.394379E-01
	SYSTEM		0.915377E-01	0.915377E-01

NOTE : LLS = LOAD LOSS SHARING

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- PROBABILITY OF MINIMAL CUTS ---

CUT	PROBABILITY	CUT MEMBERS(LINKS)
1	0.792771E-01	1 2
2	0.570032E-03	1 3
3	0.116904E-01	2 3

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- MINIMAL CUTS AND DEFICIENT NODES(AREAS) ---

CUT	PROBABILITY	NODES(AREAS) IN DEFICIENT REGION
1	0.792771E-01	1 ANCHOR 2 FAIRBA
2	0.570032E-03	1 ANCHOR
3	0.116904E-01	2 FAIRBA

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- PROBABILITY THAT EACH LINE IS LIMITING ---

LINE	LINK	DESCRIPTION A R E A	TO	A R E A	TOTAL PROBABILITY	FORWARD DIRECTION	REVERSE DIRECTION
1	3	1 ANCHOR	TO	2 FAIRBA	0.122604E-01	0.116904E-01	0.570032E-03

***** ALL PROBABILITIES ARE IN DAYS/PERIOD *****

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

ISOLATED SITUATION - SUMMARY :

AREA LOLP IN DAYS/PERIOD BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.0021	0.3096
2	0.0000	0.0071
3	0.0000	0.0000
4	0.0000	0.0000
5	0.0000	0.0000
6	0.0000	0.0000
7	0.0000	0.0000
8	0.0000	0.0000
9	0.1472	1.5882
YEAR	0.1493	1.9049

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

ISOLATED SITUATION - SUMMARY :

EXPECTED MW-DAYS LOSS BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.09	7.45
2	0.00	0.14
3	0.00	0.00
4	0.00	0.00
5	0.00	0.00
6	0.00	0.00
7	0.00	0.00
8	0.00	0.00
9	8.87	44.23
YEAR	8.9548	51.8097

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

ISOLATED SITUATION - SUMMARY :

EXPECTED MW DEFICIENCY BY SEASON.

SEASON	AREA ANCHOR	AREA FAIRBA
1	42.38	24.04
2	13.57	19.22
3	0.00	0.00
4	0.00	0.00
5	0.00	0.00
6	0.00	0.00
7	0.00	0.00
8	0.00	0.00
9	60.24	27.85

INDICES FOR THE YEAR :

MW-DAYS	8.95	51.81
LOLP-DAYS	0.15	1.90
E(MW)	59.99	27.20

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

INTERCONNECTED WITH LOAD LOSS SHARING :

AREA LOLP IN DAYS/PERIOD BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.0004	0.0020
2	0.0000	0.0000
3	0.0000	0.0000
4	0.0000	0.0000
5	0.0000	0.0000
6	0.0000	0.0000
7	0.0000	0.0000
8	0.0000	0.0000
9	0.0794	0.0890
YEAR	0.0798	0.0910

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

INTERCONNECTED WITH NO LOAD LOSS SHARING :

AREA LOLP IN DAYS/PERIOD BY SEASONS.

SEASON	AREA ANCHOR	AREA FAIRBA
1	0.0003	0.0017
2	0.0000	0.0000
3	0.0000	0.0000
4	0.0000	0.0000
5	0.0000	0.0000
6	0.0000	0.0000
7	0.0000	0.0000
8	0.0000	0.0000
9	0.0673	0.0378
YEAR	0.0677	0.0394

POWER TECHNOLOGIES, INC.
MULTI-AREA RELIABILITY PROGRAM

ANCHORAGE - FAIRBANKS TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
2-AREA RELIABILITY STUDY - YEAR 1989 : INTERCONNECTED - 1/15/1979

--- SYSTEM RESULT SUMMARY IN PER UNIT ---

PROBABILITY OF SUCCESS EVENTS	=	0.999648E+00
PROBABILITY OF FAILURE EVENTS	=	0.352068E-03
PROBABILITY OF NEGLECTED UNSPECIFIED EVENTS	=	0.270125E-08
SUM OF THE ABOVE 3 PROBABILITIES	=	0.100000E+01
PROBABILITY OF UNCLASSIFIED FAILURE EVENTS	=	0.620649E-09

```
*************************************************
*** NOTE: THE SUM OF THE FIRST 3 MUST BE 1.0000 ***
***       WITHIN REASONABLE TOLERANCE.          ***
*************************************************
```

DEFINITION OF EVENTS :

SUCCESS : ALL LOADS SATISFIED.

FAILURE : ONE OR MORE AREA LOADS NOT SATISFIED.

UNSPECIFIED : NOT IDENTIFIED AS EITHER SUCCESS OR FAILURE.

UNCLASSED FAILURE : CAUSE OF FAILURE NOT ESTABLISHED.
CAUSE OF FAILURE IS INDICATED BY MINIMAL CUTS.

TOTAL ELAPSED TIME IN CPUS = 20

***** END OF PROGRAM MAREL *****

```
   ANCHORAGE - FAIRBANKS  TRANSMISSION INTERTIE ECONOMIC FEASIBILITY
   2-AREA RELIABILITY STUDY - YEAR 1996 : INTERCONNECTED - 1/15/1979
    2    1    0    0    0    0    0    0    0    0
    0    0    0    0    1    0    0    0    0    0
    0    0    0    0    0    0
    1    1    1    4
 1996
   0.1E-07   0.2E-07   0.5E-05
 0.01 0.10
    2    1   50
    2    1    0    2    2
ANCHORFAIRBA
         1    2    2
    1    0    0  0.004000
    2  130  130  0.996000
   LOAD DATA IN PER UNIT INTERVAL DURATION CURVE
   TWO AREA SYSTEM          JANUARY 15 1979
    1    1    1
    2   10   26    9   14 1983
    1 0.01 1.00    0
 1 1 1 1 1 1 2 2 3 3 4 4 5 5 6 6 7 7 8 8 9 9 9 9 9 9
 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
  1  ANCHOR  20         0.0
  789.  877.  977. 1080. 1196. 1313. 1441. 1581. 1724. 1881.
 2041. 2215. 2402. 2591.
 .8333 .6667 .7404 .7500 .6571 .6346 .6122 .5865 .5481 .5353 .5224 .5160 .5064
 .4904 .5032 .4968 .5160 .5737 .5769 .6154 .6827 .8429 .8526 .91351.0000 .8301
1.0000 .9769 .9731 .9538 .9500 .9462 .8962 .8731 .8577 .8423
1.0000 .9893 .9663 .9663 .9615 .9615 .9519 .9519 .9423 .9375
1.0000 .9913 .9784 .9827 .9697 .9654 .9437 .9307 .9221 .8918
1.0000 .9829 .9487 .9359 .9017 .8889 .8889 .8846 .8333 .8934
1.0000 .9512 .9317 .9171 .9171 .9073 .9073 .9024 .9024 .8976
1.0000 .9848 .9798 .9747 .9646 .9495 .9444 .9343 .9293 .9141
1.0000 .9686 .9634 .9529 .9529 .9476 .9424 .9372 .9058 .9058
1.0000 .9781 .9727 .9617 .9563 .9563 .9344 .9344 .9071 .9071
1.0000 .9883 .9883 .9825 .9825 .9708 .9708 .9649 .9591 .9415
1.0000 .9940 .9820 .9701 .9581 .9461 .9401 .9341 .9281 .9162
1.0000 .9939 .9877 .9571 .9571 .9509 .9509 .9448 .9202 .8589
1.0000 .9938 .9814 .9689 .9565 .9379 .9379 .9379 .9255 .9255
1.0000 .9810 .9684 .9620 .9494 .9494 .9430 .9367 .9304 .9177
1.0000 .9804 .9739 .9739 .9673 .9608 .9542 .9542 .9477 .8824
1.0000 .9873 .9745 .9554 .9490 .9490 .9427 .9427 .9299 .9299
1.00001.0000 .9935 .9871 .9806 .9742 .9677 .9613 .9548 .9484
1.0000 .9938 .9814 .9689 .9627 .9565 .9565 .9441 .9441 .9379
1.0000 .9777 .9609 .9441 .9274 .9106 .8883 .8715 .8715 .8045
1.0000 .9944 .9944 .9722 .9722 .9722 .9611 .9278 .9222 .9222
1.0000 .9948 .9896 .9896 .9687 .9583 .9531 .9375 .9323 .8802
1.0000 .9859 .9484 .9437 .9390 .9296 .9249 .9202 .9155 .9014
1.0000 .9962 .9658 .9468 .9468 .9087 .7985 .7757 .7719 .8555
1.00001.0000 .9887 .9662 .9549 .9511 .9474 .9398 .9361 .9323
1.0000 .9754 .8632 .8596 .8421 .8386 .8336 .8386 .8326 .8175
1.0000 .9840 .9679 .9519 .9359 .9327 .9327 .9135 .8654 .8045
1.0000 .9730 .9730 .9614 .9614 .9575 .9575 .9537 .9421 .8340
  2  FAIRBA  20         0.0
  196.  212.  231.  249.  270.  291.  313.  338.  362.  390.
```

```
  416.  446.  477.  511.
0.67390.69900.73710.76040.57490.59710.56630.51110.43240.41150.38330.37470.3587
0.35300.38080.41770.42010.43730.46190.53190.57490.89190.93370.93491.00000.7690
1.00000.97420.94670.94670.94530.93130.89480.86540.84290.8177
1.00000.93670.92790.92790.90510.89980.88950.85940.82790.7891
1.00000.99330.96670.94830.94000.92330.90330.88800.86670.8267
1.00000.97530.96120.94510.86910.83200.82390.81100.79000.6769
1.00000.98560.98290.95940.95300.94660.91880.90810.90170.8825
1.00000.99790.99590.98770.97940.95820.93620.90530.89300.8827
1.00000.98480.95010.93710.91970.89370.88070.87200.86120.8091
1.00000.96870.96150.95190.93510.91590.88700.88220.87980.8558
1.00000.99150.99150.99150.97160.96870.93180.89200.88920.8693
1.00001.00000.96120.93130.92840.92840.92240.90750.90450.8955
1.00000.99040.99040.94350.92310.91990.91670.91350.87820.8558
1.00000.96720.95410.92790.92460.90490.89840.89510.87870.8721
1.00000.96920.96920.95890.95890.94520.94520.93150.92120.9041
1.00000.98960.97220.96870.95830.94790.93400.92360.92010.8507
1.00000.96770.93870.93230.91290.90320.90320.90320.87100.8677
1.00000.87350.87060.86760.86460.85880.84710.84410.83820.8059
1.00000.94440.90640.90640.89470.82750.82750.82460.81870.8012
1.00000.99720.97750.96350.96350.94940.93820.93820.91010.8904
1.00000.99470.96810.93090.92820.90960.90690.90160.88830.8856
1.00000.93530.93300.91450.90990.89610.88910.88450.86370.8568
1.00000.99150.98980.97650.94020.92950.92740.91880.91450.9017
1.00000.96690.91180.89260.88840.79890.73970.64460.61020.6088
1.00000.97710.91050.90790.90790.89340.88950.88550.86320.8434
1.00000.97110.86330.83050.81870.79630.79240.74510.73320.7201
1.00000.99510.98160.97300.97170.95580.91650.88450.82430.6818
1.00000.99840.93920.92010.89940.88980.88300.84820.81310.7971
  GENERATOR UNIT DATA FOR ANCHORAGE-FAIRBANKS STUDY
  TWO AREA SYSTEM                            JANUARY 15 1979
   1     1     1
   2     1    1.0E-12
     ANCHOR    44    12
 1.0
  1 ANCH 1    15 0.055
  2 ANCH 2    15 0.055
  3 ANCH 3    19 0.055
  4 ANCH 4    32 0.055
  5 ANCH 5    37 0.055
  6 ANCH 6    12 0.055
  7 ANCH 7    78 0.055
  8 ANCH7S    21 0.055
  9 ANCH 8    78 0.055
 10 BELU 1    15 0.055
 11 BELU 2    15 0.055
 12 BELU 3    54 0.055
 13 BELU 4     9 0.055
 14 BELU 5    54 0.055
 15 BELU 6    68 0.055
 16 BELU 7    68 0.055
 17 BELU 8    68 0.055
 18 BERN 1     8 0.055
 19 BERN 2    20 0.055
 20 BERN 3    24 0.055
```

```
 21 INTL 1    14 0.055
 22 INTL 2    14 0.055
 23 INTL 3    19 0.055
 24 COOP 1     8 0.016
 25 COOP 2     8 0.016
 26 KNIT A    15 0.059 R  1/1986
 27 INTL 4    71 0.055
 28 INTL 5    71 0.055
 29 INTL 6    71 0.055
 30 INTL 7    71 0.055
 31 HOMER      7 0.055
 32 EKLUTN    30 0.016
 33 BELU 9    71 0.055 N  1/1986
 34 ANCH 9    78 0.055 N  1/1985
 35 ANCH10   104 0.057 N  1/1986
 36 COAL 1   200 0.057 N  1/1987
 37 ANCH11   104 0.057 N  1/1993
 38 COAL 2   200 0.057 N  1/1989
 39 COAL 3   200 0.057 N  1/1990
 40 COAL 4   200 0.057 N  1/1991
 41 COAL 5   200 0.057 N  1/1992
 42 PEAKA1    78 0.055 N  1/1993
 43 GEN  1   300 0.079 N  1/1994
 44 GEN  2   300 0.079 N  1/1996
 45 PEAKA2    78 0.055 N  1/1995
-99
    COOP 1
    COOP 2
    EKLUTN
-99
  1
  9
-99
   ,FAIRBA    26    12
 1.0
  1 CHEN 1     5 0.059
  2 CHEN 2     2 0.059
  3 CHEN 3     2 0.059
  4 CHEN 4    20 0.059
  5 CHEN 5     5 0.055
  6 CHEN 6    24 0.055
  7 DIES 1     3 0.295
  8 DIES 2     3 0.295
  9 DIES 3     2 0.295
 10 ZEHN 1    17 0.055
 11 ZEHN 2    17 0.055
 12 ZEHN 3     4 0.055
 13 ZEHN 4     4 0.055
 14 ZEHND1     3 0.295
 15 ZEHND2     3 0.295
 16 ZEHND3     3 0.295
 17 ZEHND4     2 0.295
 18 ZEHND5     2 0.295
 19 HEAL 1    26 0.059
 20 HEAL D     3 0.295
```

```
 21 NORT 1    65 0.055
 22 NORT 2    65 0.055
 23 UALASK     5 0.295
 25 COALF1   100 0.057 N  1/1988
 27 COALF2   100 0.057 N  1/1992
 28 COALF3   100 0.057 N  1/1995
-99
-99
  1
  9
-99
```

APPENDIX D

DATA AND COST ESTIMATES FOR TRANSMISSION INTERTIE AND GENERATING PLANTS

APPENDIX D

DATA AND COST ESTIMATES FOR

TRANSMISSION INTERTIE AND GENERATING PLANTS

D.1 DATA AND COST ESTIMATES FOR TRANSMISSION INTERTIE

A. Cost Summary and Disbursements for Intertie Facilities

	Total Cost at 1979 Levels - $1000				
	Case IA	Case IB	Case IC	Case ID	Case II
1. Transmission Line:					
Eng'g. & Constr. Supv.	3,012	3,012	4,043	3,012	8,079
Right-of-Way	8,837	8,837	9,080	8,837	20,973
Foundations	8,445	8,445	12,160	8,445	22,966
Towers	21,615	21,615	33,719	21,615	64,088
Hardware	477	477	477	477	1,096
Insulators	503	503	755	503	1,396
Conductor	10,761	10,761	16,708	10,761	32,886
Subtotal	53,650	53,650	76,942	53,650	151,484
2. Substations:					
Eng'g. & Constr. Supv.	1,352	1,352	1,855	2,816	6,902
Land	57	57	46	81	185
Transformers	1,703	1,703	3,291	1,703	11,917
Circuit Breakers	1,093	1,093	1,323	1,953	6,410
Station Equipment	1,223	1,223	1,933	1,345	4,375
Structures & Accessories	3,628	3,628	3,978	4,026	16,411
Subtotal	9,056	9,056	12,426	11,924	46,200
3. Control and Communications:					
Eng'g. & Constr. Supv.	125	125	125	165	200
Equipment	2,375	2,375	2,375	3,135	3,600
Subtotal	2,500	2,500	2,500	3,300	3,800
Total Baseline 1979 Costs	65,206	65,206	91,868	68,874	201,484

Capital disbursements for each of the above cases are given on following computation sheets, these being identical to those later used for financial planning purposes with selected alternative.

CAPITAL INVESTMENT DISBURSMENTS FOR TRANSMISSION INTERTIE
CASES IA & IB

	1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION SUPERVISION	452	753	0	392	693	723	3012
RIGHT OF WAY	0	2209	6628	0	0	0	8837
FOUNDATIONS	0	0	0	2280	6165	0	8445
TOWERS	0	0	0	0	9727	11888	21615
HARDWARE	0	0	0	0	72	405	477
INSULATORS	0	0	0	0	75	428	503
CONDUCTOR	0	0	0	0	1614	9147	10761
SUB-TOTAL	452	2962	6628	2672	18346	22591	53650
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION SUPERVISION	270	270	270	270	135	135	1352
LAND	57	0	0	0	0	0	57
TRANSFORMERS	0	0	341	596	596	170	1703
CIRCUIT BREAKERS	0	0	219	383	383	109	1093
STATION EQUIPMENT	0	0	245	428	428	122	1223
STRUCTURES & ACCESSORIES	0	0	726	1451	1451	0	3628
SUB-TOTAL	327	270	1800	3128	2993	537	9056
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION SUPERVISION	0	0	0	0	54	71	125
EQUIPMENT	0	0	0	0	950	1425	2375
SUB-TOTAL	0	0	0	0	1004	1496	2500
TOTAL	779	3233	8428	5800	22342	24624	65206
TOTAL FOR YEAR	0	4012	0	14228	0	46967	65206

CAPITAL INVESTMENT DISBURSMENTS FOR TRANSMISSION INTERTIE
CASE IC

	1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION SUPERVISION	606	1011	0	526	930	970	4043
RIGHT OF WAY	0	2270	6810	0	0	0	9080
FOUNDATIONS	0	0	0	3283	8877	0	12160
TOWERS	0	0	0	0	15174	18545	33719
HARDWARE	0	0	0	0	72	405	477
INSULATORS	0	0	0	0	113	642	755
CONDUCTOR	0	0	0	0	2506	14202	16708
SUB-TOTAL	606	3281	6810	3809	27671	34765	76942
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION SUPERVISION	371	371	371	371	186	186	1855
LAND	46	0	0	0	0	0	46
TRANSFORMERS	0	0	658	1152	1152	329	3291
CIRCUIT BREAKERS	0	0	265	463	463	132	1323
STATION EQUIPMENT	0	0	387	677	677	193	1933
STRUCTURES & ACCESSORIES	0	0	796	1591	1591	0	3978
SUB-TOTAL	417	371	2476	4254	4068	840	12426
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION SUPERVISION	0	0	0	0	54	71	125
EQUIPMENT	0	0	0	0	950	1425	2375
SUB-TOTAL	0	0	0	0	1004	1496	2500
TOTAL	1023	3652	9286	8062	32743	37101	91868
TOTAL FOR YEAR	0	4675	0	17348	0	69844	91868

CAPITAL INVESTMENT DISBURSMENTS FOR TRANSMISSION INTERTIE
CASE ID

		1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION							
SUPERVISION	452	753	0	392	693	723	3012
RIGHT OF WAY	0	2209	6628	0	0	0	8837
FOUNDATIONS	0	0	0	2280	6165	0	8445
TOWERS	0	0	0	0	9727	11888	21615
HARDWARE	0	0	0	0	72	405	477
INSULATORS	0	0	0	0	75	428	503
CONDUCTOR	0	0	0	0	1614	9147	10761
SUB-TOTAL	452	2962	6628	2672	18346	22591	53650
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION							
SUPERVISION	563	563	563	563	282	282	2816
LAND	81	0	0	0	0	0	81
TRANSFORMERS	0	0	341	596	596	170	1703
CIRCUIT BREAKERS	0	0	391	684	684	195	1953
STATION EQUIPMENT	0	0	269	471	471	135	1345
STRUCTURES & ACCESSORIES	0	0	805	1610	1610	0	4026
SUB-TOTAL	644	563	2369	3924	3642	782	11924
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION							
SUPERVISION	0	0	0	0	71	94	165
EQUIPMENT	0	0	0	0	1254	1881	3135
SUB-TOTAL	0	0	0	0	1325	1975	3300
TOTAL	1096	3525	8996	6596	23313	25348	68874
TOTAL FOR YEAR	0	4621	0	15592	0	48661	68874

CAPITAL INVESTMENT DISBURSEMENTS FOR TRANSMISSION INTERTIE
CASE II

	1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
1. TRANSMISSION LINE							
ENGINEERING AND CONSTRUCTION							
SUPERVISION	1212	2020	0	1050	1858	1939	8079
RIGHT OF WAY	0	5243	15730	0	0	0	20973
FOUNDATIONS	0	0	0	6201	16765	0	22966
TOWERS	0	0	0	0	28840	35248	64088
HARDWARE	0	0	0	0	164	932	1096
INSULATORS	0	0	0	0	209	1187	1396
CONDUCTOR	0	0	0	0	4933	27953	32886
SUB-TOTAL	1212	7263	15730	7251	52770	67259	151484
2. SUBSTATIONS							
ENGINEERING & CONSTRUCTION							
SUPERVISION	1380	1380	1380	1380	690	690	6902
LAND	185	0	0	0	0	0	185
TRANSFORMERS	0	0	2383	4171	4171	1192	11917
CIRCUIT BREAKERS	0	0	1282	2244	2244	641	6410
STATION EQUIPMENT	0	0	875	1531	1531	438	4375
STRUCTURES & ACCESSORIES	0	0	3282	6564	6564	0	16411
SUB-TOTAL	1565	1380	9203	15890	15200	2960	46200
3. CONTROL AND COMMUNICATIONS							
ENGINEERING AND INSTALLATION							
SUPERVISION	0	0	0	0	86	114	200
EQUIPMENT	0	0	0	0	1440	2160	3600
SUB-TOTAL	0	0	0	0	1526	2274	3800
TOTAL	2777	8643	24933	23142	69496	72493	201484
TOTAL FOR YEAR	0	11421	0	48074	0	141989	201484

B. Case IA & IB, Anchorage-Fairbanks Intertie, 230 kV s/c Transmission System, 323 Miles

1. Cost Summary

T/L Cost @ $166,104 per mile	$53,652,000
Anchorage Substation	3,976,000
Ester Substation	5,080,000
Control and Communications System	2,500,000
TOTAL	$65,208,000

2. Anchorage Substation Costs

1	138-kV Circuit Breaker	$ 86,000
	Structures and Accessories	108,000
1	138-kV Air Disconnect Switch	11,000
	Structures and Accessories	38,000
4	13.8-kV, 12-MVAR Shunt Reactor Bank	420,000
	Structures and Accessories	315,000
4	13.8-kV Circuit Breaker	154,000
	Structures and Accessories	119,000
4	13.8-kV Air Disconnect Switch	31,000
	Structures and Accessories	64,000
4	1Ø - 48 MVA, 138/230-kV Autotransformer	1,020,000
	Structures and Accessories	538,000
2	230-kV Circuit Breakers	338,000
	Structures and Accessories	407,000
4	230-kV Air Disconnect Switch	70,000
	Structures and Accessories	234,000
	Land 2 acres	23,000
	TOTAL	$3,976,000

3. Ester Substation Costs

1	138-kV Circuit Breaker Structures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
3	13.8-kV, 12-MVAR Shunt Capacitor Bank Structures and Accessories	265,000 198,000
3	13.8-kV Circuit Breaker Structures and Accessories	116,000 89,000
4	1Ø, 46 MVA, 138/230-kV Autotransformer Structures and Accessories	984,000 516,000
3	230-kV Circuit Breaker Structures and Accessories	507,000 613,000
9	230-kV Air Disconnect Switch Structures and Accessories	157,000 528,000
3	230-kV, 16-MVAR Reactor Structures and Accessories	474,000 356,000
	Land 3 acres	34,000
	TOTAL	$5,080,000

C. Case IC, Anchorage-Fairbanks Intertie, 345 kV s/c Transmission System, 323 miles

1. Cost Summary

T/L Cost @ $238,214 per mile	$76,943,000
Anchorage Substation	6,195,000
Ester Substation	6,231,000
Control and Communications System	2,500,000
TOTAL	$91,868,000

2. Anchorage Substation Costs

1	138-kV Circuit Breaker Structures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
1	13.8-kV 16-MVAR Shunt Reactor Bank Structures and Accessories	112,000 84,000
1	13.8-kV Circuit Breaker Structures and Accessories	39,000 30,000
1	13.8-kV Air Disconnect Switch Structures and Accessories	8,000 16,000
4	1Ø - 48-MVA, 138/345-kV Autotransformer Structures and Accessories	1,936,000 725,000
2	345-kV Circuit Breaker Structures and Accessories	653,000 340,000
5	345-kV Air Disconnect Switch Structures and Accessories	114,000 330,000
4	1Ø - 33-1/3-MVAR, 345-kV Shunt Reactor Structures and Accessories	882,000 660,000
	Land 2 acres	23,000
	TOTAL	$6,195,000

3. Ester Substation Cost

1	138-kV Circuit Breaker Structures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
1	13.8-kV, 15-MVAR Shunt Capacitor Structures and Accessories	132,000 100,000
1	13.8-kV Circuit Breaker Structures and Accessories	39,000 30,000
1	13.8-kV Air Disconnect Switch Structures and Accessories	8,000 16,000

3. Ester Substation Cost (Continued)

4	1Ø - 48 MVA, 138/345-kV Autotransformer	$1,936,000
	Structures and Accessories	725,000
2	345-kV Circuit Breaker	653,000
	Structures and Accessories	340,000
5	345-kV Air Disconnect Switch	114,000
	Structures and Accessories	330,000
4	1Ø - 33-1/3-MVAR, 345-kV Shunt Reactor	882,000
	Structures and Accessories	660,000
	Land 2 acres	23,000
	TOTAL	$6,231,000

D. Case ID, Anchorage-Fairbanks Intertie, 230 kV s/c Transmission System, 323 miles

1. Cost Summary

T/L Cost @ $166,104 per mile	$53,652,000
Anchorage Substation	3,976,000
Palmer Substation	1,434,000
Healy Substation	1,434,000
Ester Substation	5,080,000
Control and Communications System	3,300,000
TOTAL	$68,876,000

2. Anchorage-Palmer, 230 kV s/c Transmission System, 40 miles

T/L Cost @ $166,104 per mile	$ 6,644,000
Anchorage Substation	3,976,000
Palmer Substation	717,000
Control and Communications System	1,450,000
TOTAL	$12,787,000

3. Palmer-Healy, 230 kV s/c Transmission System, 190.5 miles

T/L Cost @ $166,104 per mile	$31,726,000
Palmer Substation	717,000
Healy Substation	717,000
Control and Communications System	400,000
TOTAL	$33,560,000

4. Healy-Ester, 230 kV s/c Transmission System, 92 miles

T/L Cost @ $166,104 per mile	$15,282,000
Healy Substation	717,000
Ester Substation	5,080,000
Control and Communications System	1,450,000
TOTAL	$22,529,000

5. Anchorage Substation Costs

1	138-kV Circuit Breaker	$ 86,000
	Structures and Accessories	108,000
1	138-kV Air Disconnect Switch	11,000
	Structures and Accessories	38,000
4	13.8-kV, 12-MVAR Shunt Reactor Bank	420,000
	Structures and Accessories	315,000
4	13.8-kV Circuit Breaker	154,000
	Structures and Accessories	119,000
4	13.8-kV Air Disconnect Switch	31,000
	Structures and Accessories	64,000
4	1Ø - 48-MVA, 138/230-kV Autotransformer	1,020,000
	Structures and Accessories	538,000
2	230-kV Circuit Breakers	338,000
	Structures and Accessories	407,000
4	230-kV Air Disconnect Switch	70,000
	Structures and Accessories	234,000
	Land 2 acres	23,000
	TOTAL	$ 3,976,000

6. Palmer Substation - (One Line Bay)

1.5	230-kV Circuit Breaker Structures and Accessories	$ 253,000 305,000
2	230-kv Air Disconnect Switch Structures and Accessories	36,000 117,000
	Land	6,000
	TOTAL	$ 717,000

7. Healy Substation - (One Line Bay)

1.5	230-kV Circuit Breaker Structures and Accessories	253,000 305,000
2	230-kV Air Disconnect Switch Structures and Accessories	36,000 117,000
	Land	6,000
	TOTAL	$ 717,000

8. Ester Substation Costs

1	138-kV Circuit Breaker Sturctures and Accessories	$ 86,000 108,000
1	138-kV Air Disconnect Switch Structures and Accessories	11,000 38,000
3	13.8-kV, 12-MVAR Shunt Capacitor Bank Structures and Accessories	265,000 198,000
3	13.8-kV Circuit Breaker Structures and Accessories	116,000 89,000
4	1Ø - 46-MVA, 138/230-kV Autotransformer Structures and Accessories	984,000 516,000
3	230-kV Circuit Breaker Structures and Accessories	507,000 613,000

8. <u>Ester Substation Costs</u> (Continued)

9	230-kV Air Disconnect Switch	$ 157,000
	Structures and Accessories	528,000
3	230-kV, 16-MVAR Reactor	474,000
	Structures and Accessories	356,000
	Land 3 acres	34,000
	TOTAL	$5,080,000

E. <u>Case II, Anchorage - Upper Susitna - Fairbanks Intertie</u>

<u>345 kV 2-s/c Anchorage-Devil Canyon 155 miles</u>

<u>230 kV 2-s/c Devil Canyon-Ester 189 miles</u>

<u>230 kV 2-s/c Watana-Devil Canyon 27 miles</u>

1. <u>Cost Summary</u>

Anchorage - Devil Canyon T/L @ $504,254 per mile*	$ 78,159,000
Devil Canyon - Ester T/L @ $332,208 per mile*	62,787,000
Watana - Devil Canyon T/L @ $390,306 per mile*	10,538,000
Anchorage Substation	23,160,000
Devil Canyon Substation	10,109,000
Ester Substation	11,339,000
Watana Substation	1,596,000
Control and Communications System	3,800,000
TOTAL	$201,488,000

* Includes two single-circuit lines.

2. Anchorage Substation Cost

2	138-kV Circuit Breaker	$ 172,000
	Structures and Accessories	216,000
2	138-kV Air Disconnect Switch	23,000
	Structures and Accessories	76,000
7	1Ø - 210.5-MVA, 138/345-kV Autotransformer	8,516,000
	Structures and Accessories	3,404,000
9	345-kV Circuit Breaker	2,938,000
	Structures and Accessories	1,528,000
18	345-kV Air Disconnect Switch	408,000
	Structures and Accessories	1,191,000
2	345-kV, 200-MVAR Shunt Capacitor	2,647,000
	Structures and Accessories	1,984,000
	Land 5 acres	57,000
	TOTAL	$23,160,000

3. Devil Canyon Substation Cost

3	345-kV Circuit Breaker	$ 981,000
	Structures and Accessories	509,000
6	345-kV Air Disconnect Switch	138,000
	Structures and Accessories	399,000
7	1Ø - 90.3-MVA, 230/345-kV Autotransformer	3,418,000
	Structures and Accessories	1,466,000
6	230-kV Circuit Breaker	1,015,000
	Structures and Accessories	1,224,000
12	230-kV Air Disconnect Switch	210,000
	Structures and Accessories	703,000
	Land 4 acres	46,000
	TOTAL	$10,109,000

4. Ester Substation Cost

2	138-kV Circuit Breaker Structures and Accessories	$ 172,000 216,000
2	138-kV Air Disconnect Switch Structures and Accessories	23,000 76,000
7	1Ø - 65-MVA, 138/345-kV Autotransformer Structures and Accessories	2,086,000 1,253,000
6	13.8-kV Air Disconnects Structures and Accessories	46,000 96,000
6	13.8-kV Circuit Breaker Structures and Accessories	232,000 181,000
6	13.8-kV, 6-MVAR Capacitor Structures and Accessories	264,000 200,000
9	230-kV Circuit Breaker Structures and Accessories	1,523,000 1,838,000
18	230-kV Air Disconnect Switch Structures and Accessories	314,000 1,055,000
2	230-kV, 80-MVAR Capacitor Structures and Accessories	968,000 727,000
	Land 6 acres	69,000
	TOTAL	$11,339,000

5. Watana Substation Cost

3	230-kV Circuit Breakers Structures and Accessories	$ 508,000 613,000
6	230-kV Disconnect Switch Structures and Accessories	106,000 352,000
	Land	17,000
	TOTAL	$ 1,596,000

D.2 DATA AND COST ESTIMATES FOR GENERATING PLANTS

B. Cost Estimates and Disbursements for Generating Plants

Note: Only specific units affected by interconnection of Anchorage and Fairbanks systems are considered:

1. Northpole #3 (NORT 3) 69 MW SCGT in Fairbanks Area.

   This unit is necessary for independent system expansion. Will not be required if interconnection assured.

   Rating - 68.6 MW (net) Combustion Turbine
   Fuel - Distillate from North Pole Refinery

   Ref. Table B-1, Appendix B of Stanley Consultants Review Report

   For 1983 Installation:

Unit Cost =	$31,482,000		
NO_x Cost	1,387,000		
Subtotal	$32,869,000	or	$476/kW
Assoc. Transm.1/	4,783,000		
TOTAL	$37,652,000	or	$546/kW

See Also: P. 45 of GVEA Power Supply Study - 1978 by Stanley Consultants & P. 28 - Table 10 Escalation Rates.

Period	GNP Deflators Labor (·/. 20%)	Material (·/. 80%)	Composite
1983-1980	1.085	1.07	1.075
1980-1979	1.095	1.08	1.085

Summary of Costs:

Facility	1979 Baseline Costs		
Gas-Turbine Unit	$24,385,000	or	$353/kW
Assoc. Transm.	3,549,000		
Total Capital Investment	$27,934,000	or	$405/kW

Disbursements - $1000 Pre-Operational Period	1st Year (1983)		2nd Year (1984)	
Gas-Turbine Unit	7,315	(30%)	17,070	(70%)
Assoc. Transm.	355	(10%)	3,194	(90%)
Total Facilities	$7,670		$20,264	

1/ Relocation of facilities and expansion of existing Northpole substation.

2. Beluga #9 (BELU 9) 71 MW RCGT in Anchorage Area.

This unit will be postponed for one year by interconnection, from beginning year 1985 to 1986.

This unit will draw on Beluga gas reserves for fuel supply. Design of unit is assumed to be simple-cycle, similar to existing units on Chugach System - Ref. Beluga Units 1, 2, 4, 6, & 7.

Estimated Cost of Unit:

From Reference Cost Estimate for NORT 3 at Fairbanks

Cost at Bus-bar of 69 MW unit = \$353/kW

By comparison for 71 MW unit = \$350/kW

Now applying Alaskan construction cost location factors from Battelle Report, Table 6.3, P. 6.12

Applicable factor from Fairbanks to Beluga = $\frac{1.62}{1.2}$ = 1.35

Estimated Cost = \$473/kW or \$33,548,000

Disbursements:

Pre-Operational Period	1st Year	2nd Year
Independent Expansion	1983	1984
Interconnected Expansion	1984	1985
Proportion of Total	30%	70%
Investment - \$1000	10,064	23,484

Associated Transmission Facilities:

Transmission Line (allow 50 miles) @ \$126,000/mile

Total Cost of Line Facilities = \$6,300,000

Substation Additions at Beluga and Knik Arm = \$2,650,000

Total Transmission Line and Substation Facilities = \$8,950,000

Disbursements:

	1979 Baseline Costs		
Pre-Operational Period	1st Year	2nd Year	
Independent Expansion	1983	1984	
Interconnected Expansion	1984	1985	
Proportion of Total	10%	90%	
Investment - \$1000 Transm. & Substations	895	8,055	
Total Facilities			\$42,490,000

3. Northpole #4 (NORT 4) 69 MW SCGT in Fairbanks Area.

This unit is necessary for independent system expansion.
Will not be required with an interconnected system.

Scheduled In-Service Beginning Year 1990

Unlike NORT 3, no transmission additions will be required, with completion of relocation and expansion of the substation.

Considering only cost of unit with assoc. transf. and swgr.

For 1979 Baseline Cost Levels:

Total Capital Investment = $25,185,000 or $365/kW

Disbursements:

Pre-Operational Period	1st Year (1988)	2nd Year (1989)
GT unit, transf. & swgr.	7,555 (30%)	17,630 (70%)

4. Anchorage Peaking Unit #2 (PEAK A2) 78 MW SCGT

This unit is required for both independent and interconnected systems but in-service date is advanced one year with intertie.

Basing cost of addition on Northpole Unit 4 installation - i.e. SCGT unit with associated transformer and switching. Estimated cost based on rating, with allowance for scale.

For 1979 Baseline Cost Levels:

69 MW GT Unit Total Cost = $25,185,000 or $365/kW

78 MW GT Unit Total Cost = $28,080,000 or $360/kW

Now applying Alaskan construction cost location adjustment factor from Battelle Report Table 6.3 P. 6.12

Applicable factor from Fairbanks to Anchorage = 1/1.2 = 0.83

Total Capital Investment = $23,400,000 or $300/kW

Disbursements:

Year	Independent	Interconnected	% Total	Cost - $1000
1	1994	1993	30	7,020
2	1995	1994	70	16,380

5. Northpole #5 (NORT 5) 69 SCGT in Fairbanks Area.

This unit is necessary for independent system expansion. Will not be required with an interconnected system.

Scheduled In-Service Beginning Year 1997

The addition of this unit completes the expansion for the independent systems of the Railbelt Area, the time frame is such that for interconnected expansion, with the staged increments of hydro capacity from the Susitna development, the last unit at Devil Canyon would be on-line beginning year 1997.

Similar to NORT 4, no transmission additions are assumed to be required, such that power would be delivered from the expanded Northpole Substation to the existing system.

Considering only cost of unit, with associated transf. and swgr.

For 1979 Baseline Cost Levels:

Total Capital Investment = $25,185,000 or $365/kW

Disbursements:

	($1000)	
Pre-Operational Period:	1st Year (1995)	2nd Year (1996)
GT unit, transf. & swgr.	7,555 (30%)	17,630 (70%)

6. Anchorage #11 (ANCH 11) 104 MW Coal-Fired Steam-Electric Plant.

This unit will be required for independent system expansion but will be postponed, with interconnection, from in-service 1988 to 1993.

Cost estimate for this plant is based on Healy Unit 2 estimate prepared by Stanley Consultants, with applicable Alaskan construction cost location adjustment factor.

From Stanley Consultants Report to GVEA, Appendix A, P. A-1.

For 1984 Installation Date (1978 Cost Levels):

Healy Unit 2 Plant (Without FGD):

Plant and Equipment	$102,924,000	or	$ 990/kW
Contingency	3,088,000		
Total Construction Cost	$107,012,000	or	$1029/kW
Eng'g., Legal & Overhead	14,982,000		
TOTAL	$121,994,000	or	$1173/kW
Escalating @ 10% to 1979 Cost Level	. . . .		$1290/kW
Total Baseline 1979 Cost without FGD =	$134,160,000		

Now Including Cost of Desulphurization:

Plant and Equipment	$111,174,000	or	$1069/kW
Contingency	3,335,000		
Total Construction Cost	$114,509,000	or	$1101/kW
Eng'g., Legal & Overhead	16,031,000		
TOTAL	$130,540,000	or	$1255/kW
Escalating @ 10% to 1979 Cost Level	. . . .		$1380/kW
Total Baseline 1979 Cost with FGD =	$143,520,000		

Associated Transmission Facilities:

Assuming relatively short transmission line with substation facilities required, for connection to existing AML&P transmission system in Anchorage area.

Cost Estimate for Transmission Line:

Transmission Line (allow 30 miles) @ $126,000/mile

Total Cost of Line Facilities = $3,780,000

Cost Estimate for Substation Facilities:

Equipment	$2,700,000
Contingency	203,000
Total Construction Cost	$2,903,000
Eng'g., Legal & Overhead	377,000
TOTAL	$3,280,000
Escalating @ 10% to 1979 Cost Level	
Total 1979 Baseline Cost	$3,608,000

Summary of Costs:

	WO/FGD	W/FGD
Coal-Fired Plant (104 MW)	$134,160,000	$143,520,000
Transmission Line	3,780,000	3,780,000
Substation Facilities	3,608,000	3,608,000
TOTAL	$141,548,000	$150,908,000

Now applying Alaskan construction cost location adjustment factor from Table 6.3 P. 6.12 of Battelle Study Report:

From Healy to Anchorage - Location Factor = 1.7/2.42 = 0.70

		WO/FGD	W/FGD
Applying this factor, Total Costs	=	$99,084,000	$105,636,000
or	=	$953/kW	$1016/kW

Disbursements - $1000

Coal-Fired Plant (ANCH 11)

Pre-Operational Year:			1979 Baseline Costs % Total	WO/FGD	W/FGD
	Independent	Interconnected			
1.	1982	1987	2	1,878	2,009
2.	1983	1988	8	7,513	8,037
3.	1984	1989	30	28,174	30,139
4.	1985	1990	37	34,747	37,172
5.	1986	1991	20	18,783	20,093
6.	1987	1992	3	2,817	3,014

Associated Transmission Facilities

5.	1986	1991	20	1,034	1,034
6.	1987	1992	80	4,138	4,138

7. Coal-Fired Unit F2 (COAL F2) 100 MW in Fairbanks Area.

This unit will be required for both the independent and interconnected system expansions, with generation reserve sharing only. However, with both reserve sharing and firm power transfer, it is replaced, together with COAL 5, by a 300 MW unit (COAL 6).

This unit will be very similar to ANCH 11, which in turn was based on the Healy Unit 2 Plant, as reported by Stanley Consultants. The unit costs will be increased proportionately, to allow for the change of unit size from 104 MW to 100 MW. This has been economically scaled using the nomograph (Figures D-1 and D-2) in this appendix.

For Generating Plant COAL F2:

Plant Cost Estimates:	1979 Baseline Cost Levels		
Without FGD	$120,000,000	or	$1200/kW
With FGD	$130,000,000	or	$1300/kW

Associated Transmission Facilities:

Assuming a plant site location at or near Healy, the transmission line and substation requirements are similar to those required for Healy Unit 2. Reference Stanley Consultants Review Report to GVEA, Appendix A, P. A-1:

Transmission Facility Costs:

	1979 Cost Levels (1.1 x 1978 Costs)	
	Transmission Line	Substation Facilities
Equipment and Material	$15,510,000	$3,348,000
Contingency	465,000	100,000
Construction Cost	$15,975,000	$3,448,000
Eng'g., Legal & Overhead	2,455,000	102,000
TOTAL	$18,430,000	$3,550,000

Disbursements - $1000

Coal-Fired Unit (COAL F2):

Pre-Operational Year:		1979 Baseline Costs % Total	WO/FGD	W/FGD
1.	1986	2	2,400	2,600
2.	1987	8	9,600	10,400
3.	1988	30	36,000	39,000
4.	1989	37	44,400	48,100
5.	1990	20	24,000	26,000
6.	1991	3	3,600	3,900
Associated Transmission Facilities:				
5.	1990	20	4,400	4,400
6.	1991	80	17,580	17,580

8. Coal-Fired Unit 5 (COAL 5) 200 MW in Anchorage Area.

This unit will be required for both the independent and interconnected system expansions, with generation reserve sharing only. However, with both reserve sharing and firm power transfer, it is replaced, together with COAL F2, by a 300-MW unit (COAL 6).

The cost estimate for this generating plant was obtained by scaling costs from a base reference of 100 MW to 200 MW, using the nomograph (Figures D-1 and D-2) contained in this Appendix. Then Alaskan construction cost location adjustment factors were used to determine the cost relevant to the Beluga site in the Anchorage Area.

From Healy to Beluga - Location Factor = 2.75/2.42 = 1.14

For Generating Plant COAL 5

Plant Cost Estimates:

	1979 Baseline Cost Levels ($1000) Healy Site	Beluga Site
Without FGD	$165,000 or $825/kW	$188,000 or $ 940/kW
With FGD	$175,000 or $875/kW	$200,000 or $1000/kW

Associated Transmission Facilities:

Assuming a section of transmission line and substation facilities, for connection to existing transmission system in Anchorage area.

Transmission Line (allow 50 miles) @		$174,000/mile
Total Cost of Line Facilities	=	$ 8,700,000
Substation Terminal at Knik Arm	=	3,545,000
Total Transmission Facilities		$12,245,000

Disbursements - $1000

Coal-Fired Unit (COAL 5)

Pre-Operational Year:		1979 Baseline Costs % Total	WO/FGD	W/FGD
1.	1986	2	3,760	4,000
2.	1987	8	15,040	16,000
3.	1988	30	56,400	60,000
4.	1989	37	69,560	74,000
5.	1990	20	37,600	40,000
6.	1991	3	5,640	6,000
Associated Transmission Facilities:				
5.	1990	20	2,450	2,450
6.	1991	80	9,795	9,795

9. Coal-Fired Unit 6 (COAL 6) 300 MW in Anchorage Area.

This unit will not be required either for independent or interconnected system expansion for generation reserve sharing only. However, with reserve capacity sharing and firm power transfer, it will replace both COAL F2 and COAL 5.

The cost estimate for this plant has been derived from the cost for the reference 100 MW plant, using the nomograph (Figures D-1 and D-2) contained in this Appendix. This enabled consideration of economies of scale obtained when the unit capacity is changed from 100 to 300 MW and the differential costs associated with the two sites, according to the Alaskan construction cost location adjustment factor, similar to that developed for COAL 5.

Plant Cost Estimates:

	1979 Baseline Cost Levels ($1000)	
	Healy Site	Beluga Site
Without FGD	$200,000 or $667/kW	$228,000 or $760/kW
With FGD	$240,000 or $800/kW	$274,000 or $913/kW

Associated Transmission Facilities:

Assuming a section of transmission line and substation facilities, for connection to existing transmission system in Anchorage area.

Transmission Line (allow 50 miles) @	$240,000/mile
Total Cost of Line Facilities =	$12,000,000
Substation Terminal at Knik Arm =	6,250,000
Total Transmission Facilities	$18,250,000

Disbursements - $1000

Coal-Fired Unit (COAL 6)

Pre-Operational Year:	1979 Baseline Costs % Total	WO/FGD	W/FGD
1. 1986	2	4,560	5,480
2. 1987	8	18,240	21,920
3. 1988	30	68,400	82,200
4. 1989	37	84,360	101,380
5. 1990	20	45,600	54,800
6. 1991	3	6,840	8,220
Associated Transmission Facilities:			
5. 1990	20	3,650	3,650
6. 1991	80	14,600	14,600

10. Coal-Fired Unit 2 (GEN 2) 300 MW at New Site in Anchorage Area. This unit is required for both independent and interconnected systems but in-service date postponed one year with intertie.

For Generating Plant COAL 6:
It is assumed that site will be near to previous plant location at Beluga, in sufficient proximity to assume cost basis to be identical, with difference only in the time frame for construction.

Cost estimate for plant and associated transmission facilities are then identical to that for COAL 6.

Disbursements - $1000

Coal-Fired Unit (GEN 2)

Pre-Operational Year:			1979 Baseline Costs		
	Independent	Interconnected	% Total	WO/FGD	W/FGD
1.	1989	1990	2	4,560	5,480
2.	1990	1991	8	18,240	21,920
3.	1991	1992	30	68,400	82,200
4.	1992	1993	37	84,360	101,380
5.	1993	1994	20	45,600	54,800
6.	1994	1995	3	6,840	8,220
Associated Transmission Facilities:					
5.	1993	1994	20	3,650	3,650
6.	1994	1995	80	14,600	14,600

D.3 DATA AND COST ESTIMATES FOR SUPPLY OF CONSTRUCTION POWER TO UPPER SUSITNA PROJECT SITES

The requirements of the combined Railbelt area generation expansion, with inclusion of both Watana and Devil Canyon power from the Susitna development, schedules Unit 1 from Devil Canyon in January 1995, only 3 years after the first unit goes on line at Watana Damsite. Assuming as a first construction schedule that of the U.S. Army Corps of Engineers, the construction periods are 6 and 5 years, respectively, for Watana earthfill dam and the concrete arch dam at Devil Canyon. Thus, with the generation staging of the plan for interconnection, the total construction period would be 11 years, with pre-operational construction periods of 6 years for Watana and 5 years for Devil Canyon. There would be concurrent construction during 2 years.

Prior to the first unit on-line at Watana, construction power would be required for 6 years at Watana and 2 years at Devil Canyon. It is assumed, for purposes of analysis, that separate provision would need to be made for the full construction power needs at both sites. From estimates by the Consultants:

Connected Load

Watana	4000 kW (estimated at 3750 kW)
Devil Canyon	3400 kW (estimated at 3350 kW)

Operational Assumptions for Both Sites:

6 months/yr intensive operation	@ 0.65 LF
6 months/yr light loading	@ 0.30 LF

Corresponding to construction planning assumptions of U.S. Corps of Engineers.

Figure 7-1 of Chapter 7 shows the recommended sites at Watana and Devil Canyon for the Susitna development and the routing of the tap line to the sites from the transmission tap station, located on the main transmission corridor for the Anchorage-Fairbanks Intertie. The tap line can later be used also for a subtransmission circuit for distribution in the area, following the completion of the construction program.

A. <u>Alternative 1 - Cost of Construction Power by Diesel Generation</u>
(This will constitute benefits for B/C analysis)

Basic Assumptions:

1. Diesel units purchased for Watana will be used for a period of 6 years and then sold at depreciated value.

2. Diesel units purchased for Devil Canyon will be used for a period of 5 years and then sold at depreciated value.

3. No provision will be made at Devil Canyon for tapping 230-kV line from Watana once energized, due to prior purchase of diesel units for construction power.

4. Diesel units will be installed in multiples of 675 kW net/unit.
   - 6 units at Watana — 4050 kW net capacity
   - 5 units at Devil Canyon — 3375 kW net capacity

From previous construction power estimates for diesel unit installations:

1979 Cost = $700/kW

Installation for Watana construction power units would be made in 1985, ready for service in January 1986.

Escalating @ 7% through 1985 - Cost Level = $1050/kW.

Installation for Devil Canyon construction power units would be made in 1989, ready for service in January 1990.

Escalating @ 7% through 1989 - Cost Level = $1377/kW.

Cost of Diesel Installations:

Watana = $1050 x 4050 = $4,252,500
Devil Canyon = $1377 x 3355 = $4,647,375

This capital investment would be disbursed in 1985 and 1989, respectively, for Watana and Devil Canyon.

Cost of Diesel Operation During Construction

Basic Assumption: Maximum Coincident Demand = Connected Load

This, incidentally, introduces a measure of maximum loading which tends to compensate for an initial lower estimate of construction power requirements by a factor equivalent to projected diversity.

Average Energy Usage Per Year:

Watana $3750\ (0.65 + 0.30)\ \frac{8760}{2}$ kWh = 15,603,750 kWh

Say 15.60 GWh/yr for 6 yrs.

Devil Canyon $3350\ (0.65 + 0.30)\ \frac{8760}{2}$ kWh = 13,939,350 kWh

Say 13.94 GWh/yr for 5 yrs.

Operating Characteristics of Diesel Units:

Fuel Rate Assumed	- 13 kWh/gal (diesel fuel)
Base Price for Diesel Fuel	- 41.2 ¢/gal (1977 actual)
Plus 5% Allowance for Lube Oil	- 43.3 ¢/gal

To be escalated @ 11% to 1980 and 7% thereafter.

O&M for diesel units estimated at 5% of total cost of incremental generation.

Year	Watana Dam	Year	Devil Canyon
1986	$1,118,500		
1987	1,198,100		
1988	1,280,800		
1989	1,371,200		
1990	1,468,000	1990	$1,311,800
1991	1,569,400	1991	1,402,400
		1992	1,501,300
		1993	1,607,300
		1994	1,708,800

DIESEL GENERATION OPERATING COSTS

Year	Diesel Fuel Including Lube Oil ¢/gal	Diesel Fuel Including Lube Oil mills/kWh	O&M (mills/kWh)	Total Operating Cost (mills/kWh)
1977	43.3	33.3	1.7	35.0
1978	48.1	37.0	1.9	38.9
1979	53.3	41.0	2.1	43.1
1980	59.2	45.5	2.3	47.8
1981	63.3	48.7	2.4	51.1
1982	67.8	52.2	2.6	54.8
1983	72.5	55.8	2.8	58.6
1984	77.6	59.7	3.0	62.7
1985	83.0	63.8	3.2	67.0
1986	88.8	68.3	3.4	71.7
1987	95.1	73.2	3.6	76.8
1988	101.7	78.2	3.9	82.1
1989	108.8	83.7	4.2	87.9
1990	116.5	89.6	4.5	94.1
1991	124.6	95.8	4.8	100.6
1992	133.3	102.5	5.2	107.7
1993	142.7	109.8	5.5	115.3
1994	152.6	117.4	5.9	123.3

Depreciated Value of Diesel Units:

Basic Assumption of 15-Year Service Life.

Assume Straight-Line Depreciation

1. Watana Installation

   Installed Cost (new) = $4,252,500 (1985)
   Depreciation/Year = 283,500
   Depreciated Value (1991) 6-Year Period = $2,551,500

2. Devil Canyon Installation

   Installed Cost (new) = $4,647,375 (1989)
   Depreciation/Year = 309,825
   Depreciated Value (1994) 5-Year Period = $3,098,250

Discounted Value of Benefits (Diesel Generation Alternative)

Base Year 1979 (Discounted @ 7%)

Year	PWF'	Construction Cost ($)	Operating Cost ($)	Total Cost ($)	Present Value ($)
1979	1.00000				
1985	0.66634	4,252,500		4,252,500	2,833,611
1986	0.62274		1,118,500	1,118,500	696,535
1987	0.58200		1,198,100	1,198,100	697,294
1988	0.54393		1,280,800	1,280,800	696,666
1989	0.50834	4,647,375	1,371,200	6,018,575	3,059,482
1990	0.47509		2,779,800	2,779,800	1,320,655
1991	0.44401	-2,551,500	2,971,800	420,300	186,617
1992	0.41496		1,501,300	1,501,300	622,979
1993	0.38781		1,607,300	1,607,300	623,327
1994	0.36244	-3,098,250	1,718,800	-1,379,450	-499,968
				TOTAL PW'	10,237,198

(- sign denotes assumed resale value)

B. <u>Alternative 2 - Cost of Construction Power by Temporary Tapline</u>
(This will represent costs for B/C analysis)

Basic Assumptions:

1. Same loading conditions and time frame as per Alternative 1.

2. Sequence of temporary construction as per previous assumptions.

3. Reuse of substation equipment possible after construction program completed but no salvage value on line material. (Note: Possible reuse as distribution line to recreational areas.) Assume resale value of substation equipment to be depreciated value based on 25-year life of facilities.

4. Cost of power based on wholesale rates in Railbelt area. From previous estimates for line and substation facilities:

Construction Costs:

69-kV subtransmission line - $3,200,000 (1985 level)
Susitna tap station + Watana substation facilities
Baseline cost level = $26.50/kVA (1979)
Escalating @ 7% to 1985 (6 yrs)
Construction Cost = $40/kVA (1985)
Total Construction Cost = $400,000

69/4.16 kW, 5 MVA, Substation at Devil Canyon (1979 levels)
Transformer - $45,000 fob factory (Virginia)
Allowing 5% for shipping and handling, etc.

At jobsite cost	=	$47,250
Fused Disc. Sw.	=	2,750
Structure, Conc, pad, etc.	=	5,000
TOTAL		$55,000

Construction Costs:

Equipment	60%	$55,000
Labor	30%	28,000
Design	10%	9,000
TOTAL		$92,000 or $18.4/kVA (1979)

Substation would be installed in 1989.

Escalated at 7% from 1979 levels.

1989 Construction Cost = $36.2/kVA
Total Construction Cost = $181,000

O&M For Temporary Construction Power Line Maintenance

69 kV Wood Pole line - Approximately 40 miles long (11 + 29 M)

	Year	$/M	Total O&M Costs ($)
40 M Total	1986	330	13,200
	1987	345	13,800
	1988	360	14,400
	1989	380	15,200
	1990	400	16,000
	1991	420	16,800
29 M Total	1992	440	12,800
	1993	460	13,300
	1994	485	14,000

Note: That due to overlap in construction schedules for Watana and Devil Canyon the capacity of the Susitna tap station will need to be doubled by addition of second 5 MVA transfer. This will be moved to spares inventory after 2 years.

Cost of Construction Power Supplied over Temporary Line Facility

Based on information from RWRA 2/1/79

Wholesale rates for Railbelt area, with combination of Susitna Hydropower and large coal-fired plant feeding interconnection.

Year	Rate of Change	Wholesale Rate (mills/kWh)	Cost of Energy (mills/kWh) Bus-Bar	Substation
			Note:	1977 Cost Levels
1979	10%	17		
1980		18		
1981		20		
1982		22		
1983	8%	24		
1984		26		
1985		28		
1986		30	27.3	30.2
1987		32		
1988	7%	34		
1989		37		
1990		39	31.0	33.5
1991		42		
1992		45		
1993	5%	47		
1994		50		
1995			33.2	36.6
2000			36.2	39.1

Conversion of Total Energy Rate to 2-Part Tariff

Assumption: 100 MW Power Transfer at 0.6 LF is 525.6 GWh/yr.

Year	Bulk Rate (mills/kWh)	Total Revenue for Bulk Rate ($1000)	50/50 Revenue From: Demand ($1000)	Energy ($1000)	Equivalent Tariff Demand Rate ($/kWh)	Energy Rate (mills/kWh)
1979	17	8,935.2	4,467.6		74.5	8.5
1980	18	9,460.8	4,730.4		78.8	9.0
1981	20	10,512.0	5,256.0		87.6	10.0
1982	22	11,563.2	5,781.6		96.4	11.0
1983	24	12,614.4	6,307.2		105.1	12.0
1984	26	13,665.6	6,832.8		113.9	13.0
1985	28	14,716.8	7,358.4		122.6	14.0
1986	30	15,768.0	7,884.0		131.4	15.0
1987	32	16,819.2	8,409.6		140.2	16.0
1988	34	17,870.4	8,935.2		148.9	17.0
1989	37	19,447.2	9,723.6		162.1	18.5
1990	39	20,498.4	10,249.2		170.8	19.5
1991	42	22,075.2	11,037.6		184.0	21.0
1992	45	23,652.0	11,826.0		197.1	22.5
1993	47	24,703.2	12,351.6		205.9	23.5
1994	50	26,280.0	13,140.0		219.0	25.0

Allow 5% adder for line and substation losses - assume the resulting rates are applicable to price construction power.

Cost Estimate for Construction Power

Assuming same loading as for diesel generation alternative.

1. Watana Damsite (3750 kW, 15.6 GWh/yr)

Year	Demand Rate ($/kW)	Energy Rate (mills/kWh)	Construction Power Costs Demand ($)	Energy ($)	Total ($)
1986	138.0	15.8	517,500	246,480	763,980
1987	147.2	16.8	552,000	262,080	814,080
1988	156.3	17.9	586,125	279,240	865,365
1989	170.2	19.4	638,250	302,640	940,890
1990	179.3	20.5	672,375	319,800	992,175
1991	193.2	22.1	724,500	344,760	1,069,260

2. Devil Canyon Damsite (3350 kW, 13.94 GWh/yr)

Year	Demand Rate ($/kW)	Energy Rate (mills/kWh)	Construction Power Costs Demand ($)	Energy ($)	Total ($)
1990	179.3	20.5	600,655	285,770	886,425
1991	193.2	22.1	647,220	308,074	955,294
1992	207.0	23.6	693,450	328,984	1,022,434
1993	216.2	24.7	724,270	344,318	1,068,588
1994	230.0	26.3	770,500	366,622	1,137,122

Depreciated Value of Substation Facilities

Basic Assumption of 25-Year Service Life

Assume Straight Line Depreciation

1. Watana Substation

Installed Cost (new)	=	$ 27.6/kVA (1985)
	=	$138,000
Depreciation/Year	=	$ 5,520
Depreciated Value	=	$104,880 (1991) (6-year period)

2. Devil Canyon Substation

Installed Cost (new)	=	$ 36.2/kVA (1989)
	=	$ 181,000
Depreciation/Year	=	$ 7,240
Depreciated Value	=	$ 144,800 (1994) (5-year period)

3. Susitna Tap Station/Watana Bus Tap

Installed Cost (new)	=	$ 262,000 (1985)
Depreciation/Year	=	$ 10,480
Depreciated Value	=	$ 167,680 (1994) (7-year period)

To transfer 5 MVA facility from Susitna Tap to Watana.

Cost of removal and transfer = $30,000 (1991)

Cost of second 5 MVA step-down facility at Susitna tap.

In 1989 for Supplementary power to Devil Canyon = $343,400

Depreciated value after 2 years = $315,900

Discounted Value of Costs (Sub-Transmission Tapline Alternative)

Base Year 1979 (Discounted @ 7%)

Year	PWF'	Construction Cost ($)	O&M ($)	Cost of Power ($)	Total Cost ($)	Present Value ($)
1979	1.00000					
1985	0.66634	400,000			400,000	266,536
1986	0.62274		13,200	763,980	777,180	483,981
1987	0.58200		13,800	814,080	827,880	481,826
1988	0.54393		14,400	865,365	879,765	478,531
1989	0.50834	524,400	15,200	940,890	1,480,490	752,592
1990	0.47509		16,000	1,878,600	1,894,600	900,106
1991	0.44401	-390,780*	16,800	2,024,554	1,650,574	732,871
1992	0.41496		12,800	1,022,434	1,035,234	429,581
1993	0.38781		13,300	1,068,588	1,081,888	419,567
1994	0.36244	-312,480	14,000	1,137,122	838,642	303,957
					TOTAL PW'	5,249,548

* Including one-time cost of transfer of tap facilities and resale value of 5-MVA substation.

B/C Ratio for Construction Power Supply by Tapline.

$$\text{B/C Ratio} = \frac{\text{Discounted Cost of Diesel Generation Alternative}}{\text{Discounted Cost of Tapline Alternative}}$$

$$= \frac{10,237,198}{5,249,548}$$

$$= \underline{1.95}$$

DERIVATION

OF

INPUT COST DATA FOR ECONOMIC ANALYSIS

TO OBTAIN

BASELINE COSTS ASSOCIATED WITH THE TWO CONSTRUCTION POWER ALTERNATIVES

		Alternative I Diesel Generation		Alternative II Tapline Supply	
Year	7% Deflator	Escalated	Deflated	Escalated	Deflated
1979	1.00				
1980	1.07				
1981	1.14				
1982	1.23				
1983	1.31				
1984	1.40				
1985	1.50	4,252,500	2,835,000	400,000	266,670
1986	1.61	1,118,500	694,720	777,180	482,720
1987	1.72	1,198,100	696,570	827,880	481,330
1988	1.84	1,280,800	696,090	879,765	478,130
1989	1.97	6,018,575	3,055,110	1,480,490	751,520
1990	2.10	2,779,800	1,323,710	1,894,600	902,190
1991	2.25	420,300	186,800	1,650,574	733,590
1992	2.41	1,501,300	622,950	1,035,234	429,560
1993	2.58	1,607,300	622,980	1,081,888	419,340
1994	2.76	-1,379,450	-499,800	838,642	303,860

SUMMARY

BASELINE COSTS (1979)

ASSOCIATED WITH TWO CONSTRUCTION POWER ALTERNATIVES

	$1000 (1979)	
	(Independent)	(Interconnected)
	Diesel	Tapline
Year	Generation	Supply
1985	2,835	267
1986	695	483
1987	697	481
1988	696	478
1989	3,055	752
1990	1,324	902
1991	187	734
1992	623	430
1993	623	419
1994	-500[1/]	304

1/ Negative sign indicates net resale value predominates over costs.

D.4 ALTERNATIVE GENERATING PLANT FUEL COSTS

The year-by-year analysis of comparative fuel costs follows:

A. First Period (1984-87) - Firm Power Transfer of 30 MW, 145 GWh

Year	Interconnected System Expansion	Independent System Expansion
1984	The number and type of generating plants is identical to that for each system operating independently.	Each independent system would be supplied by operational units on basis of economic dispatch to meet individual area needs.

The determination of relative economic advantage to either system, of a firm power transfer, would require a detailed analysis, necessitating production costing of economically dispatched units for the Anchorage and Fairbanks systems. It is a reasonable measure to delete the comparison of marginal advantages accruing for this year of operation.

Year	Interconnected System Expansion	Independent System Expansion
1985	ANCH 9 - 78 MW SCGT is added to AML&P system, obviating the need for both NORT 3 and BELU 9.	Two units are required in Anchorage area, ANCH 9 - 78 MW SCGT and BELU 9 - 71 MW RCGT, together with NORT 3 - 69 MW SCGT unit at the Northpole Station in Fairbanks.

As a first approximation, the relative generation cost advantage may be determined by estimating the respective fuel costs associated with the generation of 145 GWh of energy by either ANCH 9 or NORT 3, taking into consideration different primary fuel costs and thermal efficiencies. The unit ratings are sufficiently close to justify this analytical approach, on the basic assumption that equivalent energy would be generated during the year by the two units. An adjustment would then be made to allow for the differential cost of supplying line losses in the transmission intertie, which would amount to 1.5 GWh/yr.

Comparative Fuel Costs:

ANCH 9 - 78 MW SCGT

From Battelle Report (see Figure D-3)
See Figure D-1
Trend Curve for HR8444 New Gas
with 8% inflation and escalation
1985 Fuel Cost = \$3.60/MBTU
Net Heat Rate = 14,500 BTU/kWh
Annual Cost of Fuel (ACF)
to generate 145 GWh:
ACF @ 0.21 PCF[2/] = \$3.60 x 145 x 14,500
= \$7,569,000

NORT 3 - 69 MW SCGT

From Stanley Consultants Report P. 21
1978 Fuel Cost = \$1.98/MBTU
Escalating @ 10% per year[1/]:
1985 Fuel Cost = \$3.86/MBTU
For distillate from North Pole refinery
From Table 6, P. 22:
Net Heat Rate = 15,130 BTU/kWh
Annual Cost of Fuel (ACF)
to generate 145 GWh:
ACF @ 0.24 PCF[2/] = \$3.86 x 145 x 15,130
= \$8,468,000

The total cost comparison is in favor of ANCH 9 generation to supply Fairbanks. Total cost of generation, including loss component = \$7,648,000.

1986 BELU 9 - 71 MW SCGT is added to CEA system, the interconnection having served to delay the in-service of the combustion turbine by one year. It is assumed that this unit will be operated for supply to CEA system only during first year of operation.

ANCH 10 - 104 MW coal-fired plant is added to AML&P system for both independent and interconnected system expansions. KNIK A - 15 MW thermal power plant (CEA) is also retired from both expansions.

The relative economic advantage is attributable to the fuel cost differential between distillate for NORT 3 generation and Beluga gas for generation by either ANCH 9 or BELU 9. Selecting ANCH 9 as in the previous analysis for 1985:

1/ 7% inflation + 3% escalation.
2/ PCF = Plant Capacity Factor.

Comparative Fuel Costs:

ANCH 9 - 79 MW SCGT	NORT 3 - 69 MW SCGT
1986 Fuel Cost = $4.00/MBTU	1986 Fuel Cost = $4.25/MBTU
Net Heat Rate = 14,500 BTU/kWh	Net Heat Rate = 15,130 BTU/kWh
Annual Cost of Fuel (ACF) to generate 145 GWh:	Annual Cost of Fuel (ACF) to generate 145 GWh:
ACF @ 0.21 PCF = $8,410,000	ACF @ 0.24 PCF = $9,324,000

The cost comparison is once again in favor of ANCH 9 generation to supply the equivalent amount of energy over intertie, as would otherwise be generated locally in Fairbanks.

Total cost of ANCH 9 generation, including transmission loss = $8,498,000.

1987 This is the first year of operation of COAL 1 - 200 MW coal-fired plant on the Anchorage system. As this would be the first year of operation for the first major coal-fired plant in the Railbelt, for either independent or interconnected expansions, it would be thus common to the two alternatives. The relative cost advantages would then again be determined by consideration of the relative generation cost for ANCH 9 and NORT 3.

Comparative Fuel Costs:

ANCH 9 - 79 MW SCGT	NORT 3 - 69 MW SCGT
1987 Fuel Cost = $4.25/MBTU	1987 Fuel Cost = $4.68/MBTU
Net Heat Rate = 14,500 BTU/kWh	Net Heat Rate = 15,130 BTU/kWh
Annual Cost of Fuel (ACF) to generate 145 GWh:	Annual Cost of Fuel (ACF) to generate 145 GWh:
ACF @ 0.21 PCF = $8,936,000	ACF @ 0.21 PCF = $10,267,000

Total cost of ANCH 9 generation, including transmission loss = $9,029,000.

B. Second Period (1992-96) - Firm Power Transfer of 70 MW, 337 GWh

Year	Interconnected System Expansion	Independent System Expansion
1992	Interconnected operation obviates the need for COAL 5 - 200 MW unit in Anchorage area and COAL F2 - 100 MW unit in Fairbanks area. Comparable generation is maintained by COAL 6 - 300 MW unit in Anchorage area.	COAL 5 would have to be added to Anchorage system and COAL F2 to Fairbanks.

Comparative economic advantage is determined by relative magnitude of fuel costs, for either COAL 6 or COAL F2, to generate same energy.

Comparative Fuel Costs:

	• COAL 6 - 300 MW	• COAL F2 - 100 MW
From Battelle Report (see Figure D-4)		
Fuel Cost in 1992	\$2.60/MBTU	\$1.90/MBTU
Net Heat Rate	9,500 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	\$8,324,000	\$6,851,000

The comparative advantage in this case moves to the use of Healy coal. However, as with interconnection, the unit COAL F2 will be eliminated in favor of the economies of scale associated with the COAL 6 unit. Without production costing, it is not possible to determine the overall economic advantage of introducing COAL 6, so for present analysis it is assumed that no economic energy transfer is possible. However, as a first approximation, the fuel costs for this year will be entered into economic analysis to consider the effect of the differential.

1993	ANCH 11 - 104 MW coal-fired unit added to AML&P system in this year for interconnected expansion, after an interval of five years following the in-service date for same unit with independent expansion. PEAK A1 - 78 MW combustion turbine also in-service from beginning of year.	PEAK A1 - 78 MW combustion turbine in-service from beginning of year, for independent expansion of Anchorage system.

Of interest in this year is a comparison between the cost of energy generation for ANCH 11 and COAL F2 using the same source of fuel, Healy coal. Thus, the relative advantage of either generating at the existing plant site at Healy or in the vicinity of Anchorage may be examined for similar capacity units having the same thermal efficiency, to determine the economies of energy transfer by intertie.

Comparative Fuel Costs:

	• ANCH 11	• COAL F2
Cost of Healy coal in 1993	\$2.4/MBTU[1/]	\$2.00/MBTU[2/]
Net Heat Rate	10,700 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	\$8,654,000	\$7,212,000

Once again the comparative advantage lies with the generation of energy at the Healy site. However, with interconnection the need for COAL F2 disappears in favor of the economies of scale attendant on COAL 6. It may be noted that the cost differential in favor of Healy disappears if the COAL F2 site would be moved away from Healy for environmental reasons to say Nenana. In this case, the cost of generation would be approximately the same whether coal were transported either to Anchorage or Nenana, as the transmission loss, associated with ANCH 11 (104 MW) generation and transfer over the intertie, would be compensated for by the slightly higher heat rate to be expected with the 100 MW unit of COAL F2.

1/ Delivered to Anchorage plant site.

2/ Delivered to Healy plant site.

1994 As GEN 1 - 300 MW coal-fired generating plant added for both independent and interconnected system expansions, the previous combination of ANCH 11 and COAL F2 can again be examined to determine the differential cost of fuel.

Comparative Fuel Costs:

	• ANCH 11	• COAL F2
Cost of Healy coal in 1994 (Minemouth Generation, FOB Tipple)	\$2.5/MBTU	\$2.2/MBTU
Net Heat Rate	10,700 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	\$9,015,000	\$7,933,000

It may be noted that due to divergence of fuel cost trends after 1993, for coal delivered to either Anchorage or Nenana, rather than minemouth, the economic advantage moves progressively towards generation at an Anchorage location, with transfer of the equivalent energy over the intertie. However, in 1994, it is possible to transmit energy generated economically at Healy to Anchorage over the intertie.

Total cost of COAL F2 generation, including transmission loss = \$8,016,000.

1995 COAL F3 - 100 MW coal-fired plant is introduced to the Fairbanks area and PEAK A2 - 78 MW combustion turbine is added to the AML&P system. Interconnection results in the postponement by one year of the 300 MW GEN 2 in the Anchorage area.

GEN 2 - 300 MW coal-fired plant is introduced to the Anchorage area with independent system expansion but the 78 MW combustion turbine PEAK A2 is not required in addition to the large coal-fired plant. COAL F3 is added to the system in the Fairbanks area.

As COAL F3 is common to both the independent and interconnected system expansions, it is of interest whether the gas-fired PEAK A2 in Anchorage could economically displace the equivalent energy generated by the coal-fired unit COAL F3 in the Fairbanks area.

Comparative Fuel Costs:

	• PEAK A2	• COAL F3
Cost of New Gas in 1995 (HR 8444 - 8% infl. + esc.)	$7.70/MBTU	
Cost of Healy Coal in 1995 (Minemouth Plant, FOB Tipple)		$2.40/MBTU
Net Heat Rate	14,500 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	$37,626,000	$8,654,000

There is a definite economic advantage to coal generation at Healy and energy transfer over the intertie to displace gas-fired generation in Anchorage.

Total cost of COAL F3 generation, including transmission loss = $8,745,000.

1996 GEN 2 - 300 MW coal-fired plant is introduced to the Anchorage area, the interconnection serving to postpone its in-service date by one year.

PEAK A2 - 78 MW combustion turbine is introduced to the AML&P system in Anchorage.

In this final year of analysis, it is of interest to compare the relative economic advantages of coal-fired generation at either the Fairbanks (Healy) or Anchorage (Beluga) sites.

Comparative Fuel Costs:

	• GEN 2	• COAL F3
Cost of Beluga Coal in 1996	$3.3/MBTU	
Cost of Healy Coal in 1996		2.5/MBTU
Net Heat Rate	9,500 BTU/kWh	10,700 BTU/kWh
ACF to generate 337 GWh	$10,565,000	$9,015,000

Once again it is more economical to generate in the Fairbanks area and transfer energy south over the intertie to Anchorage.

Total cost of COAL F3 generation, including transmission loss = $9,109,000.

Nomogram calculates economy of scale in power plants

By JAMES McALISTER, Arkansas Power & Light Co.

Historically, the per unit cost of larger power plants has been less than that of smaller plants. The proportionality was examined in some detail in the article "Economy of Scale in Power Plants" in the August 1977 issue of POWER ENGINEERING Magazine, p. 51.

The basic equation is:

$$(C_1/C_2) = (MW_1/MW_2)^P$$

Where:

C_1 = cost of plant 1
C_2 = cost of plant 2
MW_1 = capability of plant 1
MW_2 = capability of plant 2
P = proportionality factor

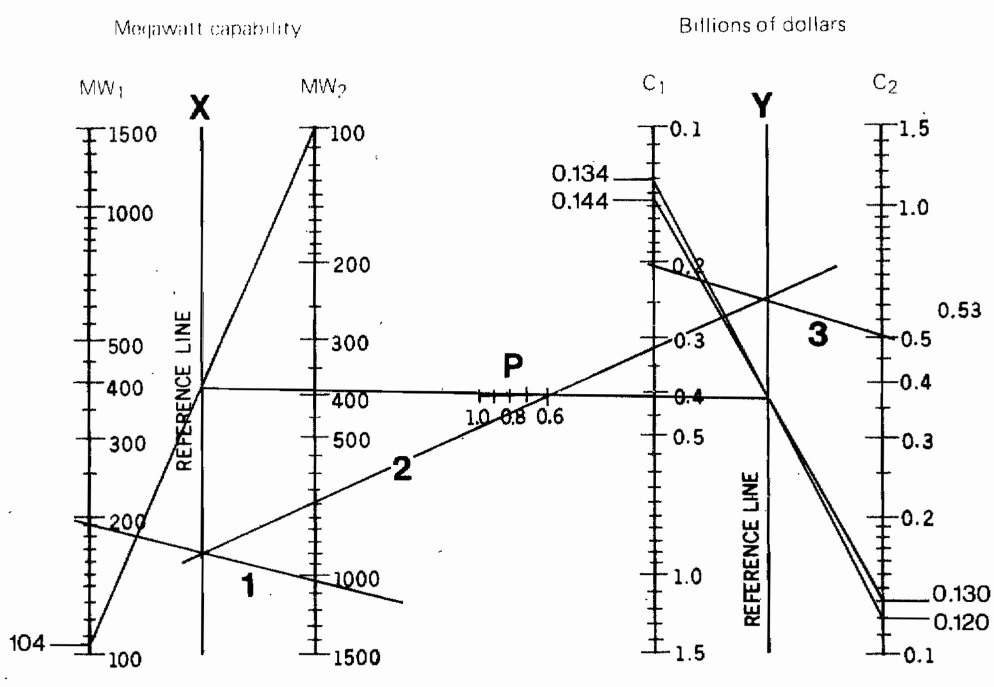
For many years, this proportionality factor averaged about 0.6, which led to the so-called "Six-tenths Power Law." However, as explained in the article referred to above, extended project schedules and inflation cause the factor to increase

This nomogram solves the equation and permits a cost comparison of plants of different sizes. It assumes, of course, that they are essentially identical in construction technique, design and time frame, and that the only significant difference is in size.

Example: A 200-MW plant can be built for $200 million. Find the cost of a similar 1000-MW plant.

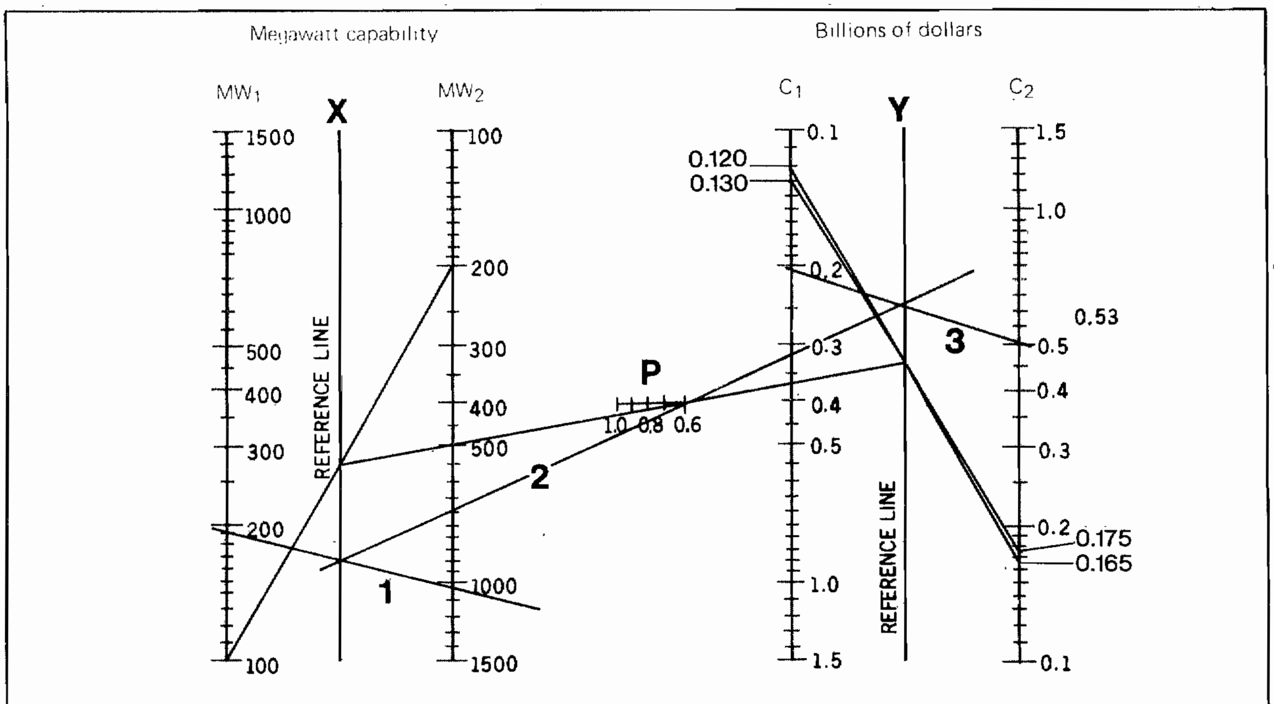
Solution: (1) Connect unit ratings of 200 MW and 1000 MW on the MW_1 and MW_2 scales, and mark intersection with Reference Line X. (2) Align this point with assumed scaling factor P = 0.6 and extend to cut Reference Line Y. (3) Connect this point with 0.2 on C_1 scale and extend to C_2 scale. Read answer as $0.53 billion. **END**

To obtain an extra copy of this article, circle 206 on Reader Service Card

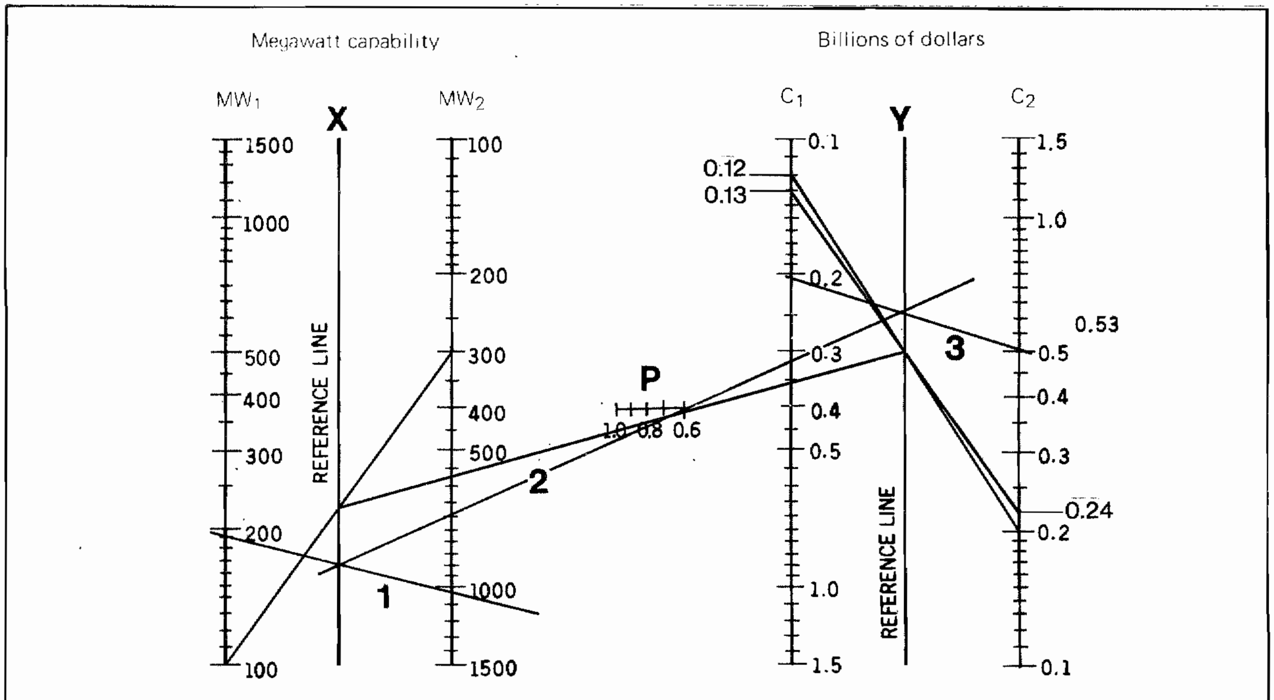


$$\frac{C_2}{C_1} = \left(\frac{MW_2}{MW_1}\right)^P$$

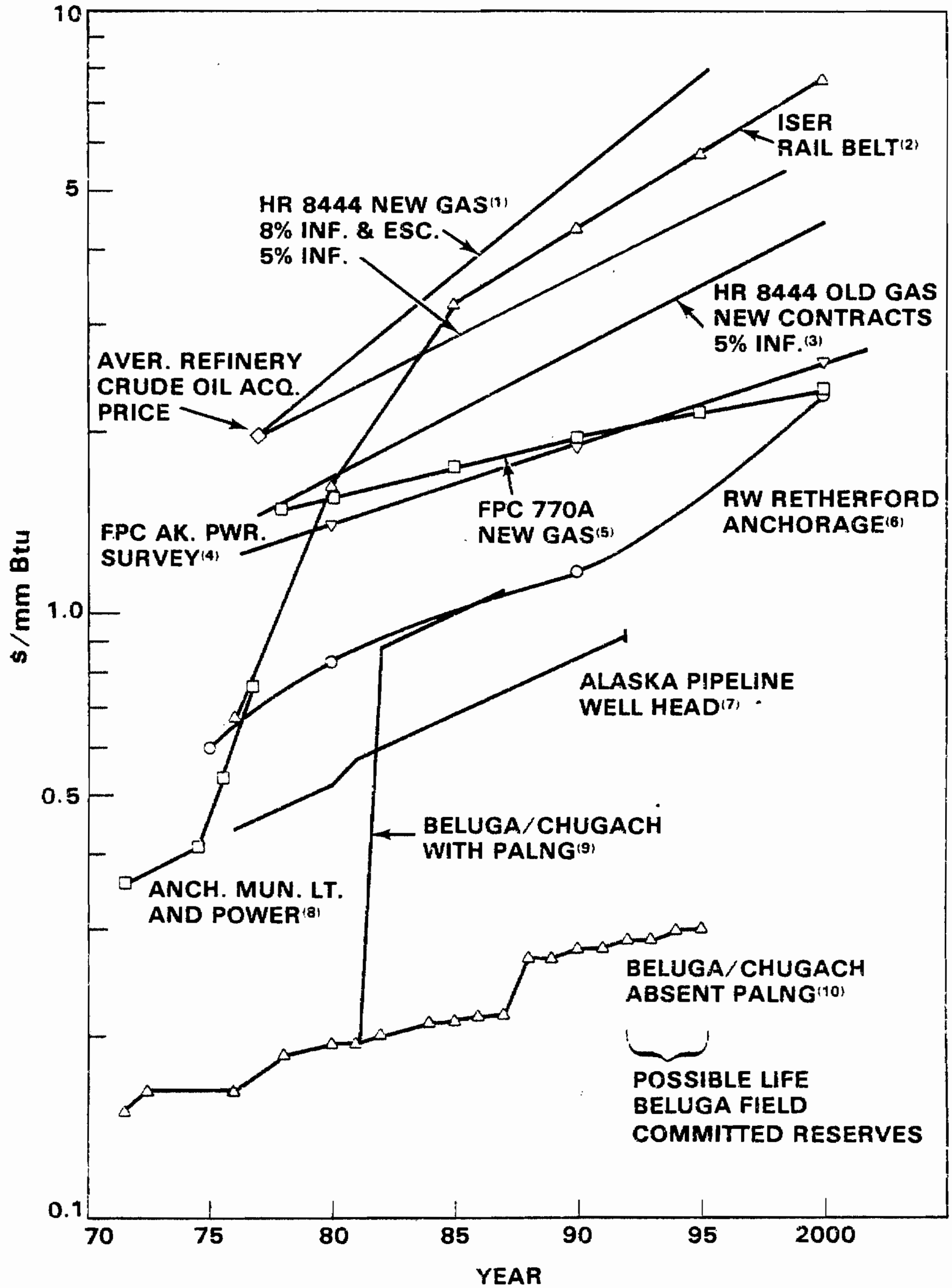
FIGURE D-2



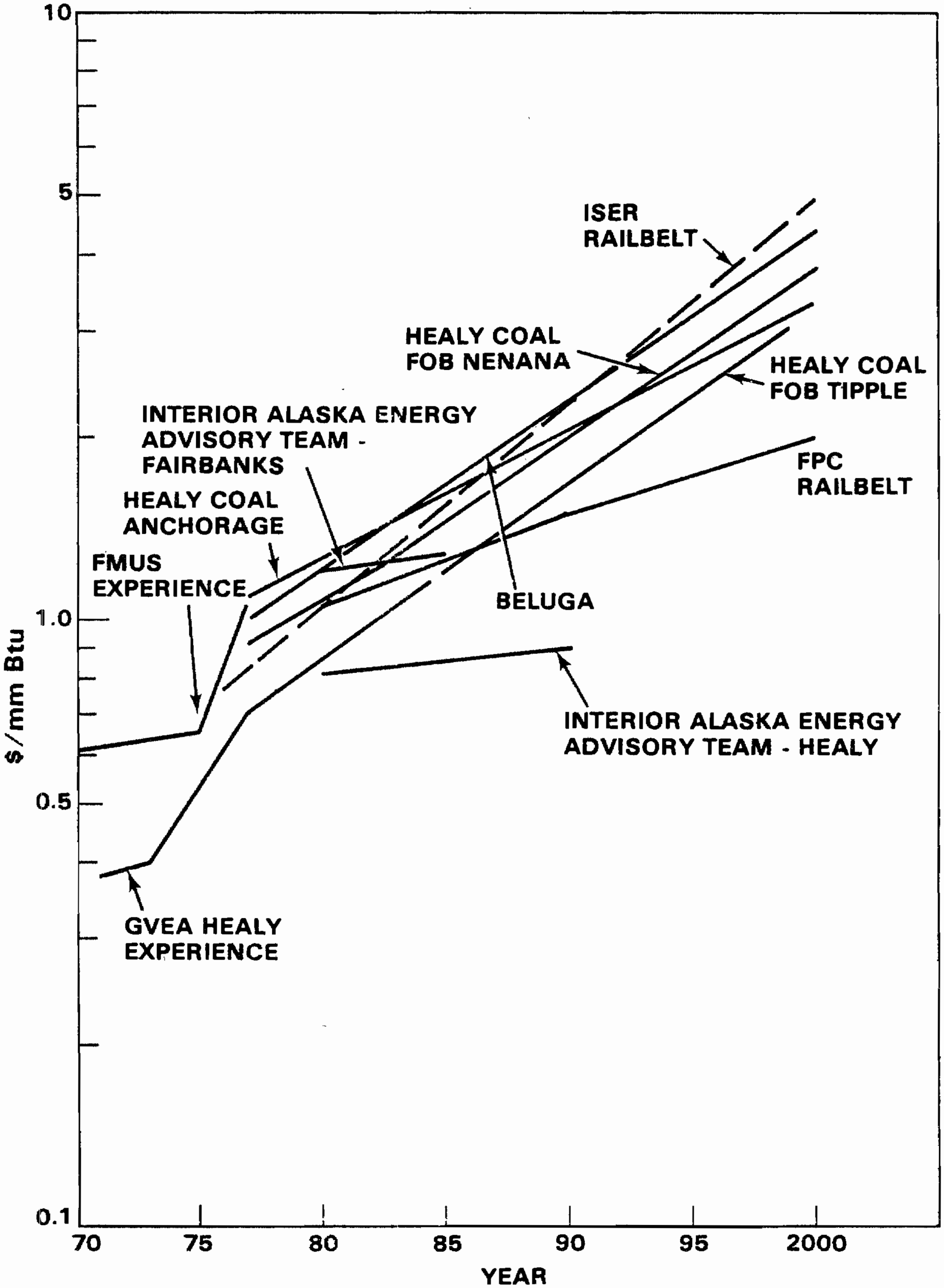
$$\frac{C_2}{C_1} = \left(\frac{MW_2}{MW_1}\right)^P$$



$$\frac{C_2}{C_1} = \left(\frac{MW_2}{MW_1}\right)^P$$



ESTIMATES OF FUTURE NATURAL GAS PRICES
(Source: Battelle Final Report 'Alaskan Electric Power', March 1978/Figure 6-6)



ESTIMATES OF FUTURE COAL PRICES
(Source: Battelle Final Report 'Alaskan Electric Power', March 1978/Figure 6-7)

APPENDIX E

TRANSMISSION LINE ECONOMIC ANALYSIS PROGRAM (TLEAP)

APPENDIX E
TRANSMISSION LINE ECONOMIC ANALYSIS PROGRAM (TLEAP)

The following pages contain TLEAP computer printout sheets for economic analyses 1, 2, 3, 5, 7, and 8.

ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,011		
1982	2,009	14,228		
1983	26,666	46,967		
1984	81,942	10,959		
1985	37,172	31,539		
1986	21,127			
1987	7,152	2,009		
1988	7,555	8,037		
1989	23,110	30,139		
1990	21,920	42,652		
1991	82,200	43,047		
1992	101,380	89,352		
1993	58,450	108,400		
1994	29,840	74,830		
1995	23,935	22,820		
1996	17,630			

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992				
1993				
1994				
1995				
1996				

DISCOUNTED COST RATIOS FOR RANGE OF BASE YEAR (1979) COSTS
ESCALATED OVER EXPANSION PERIOD - 1979 TO 1996

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	1.056	1.048	1.040	1.032	1.025	1.017	1.010	1.003	.996
8.25	1.058	1.050	1.042	1.034	1.027	1.019	1.012	1.005	.998
8.50	1.060	1.052	1.044	1.036	1.029	1.021	1.014	1.007	1.000
8.75	1.062	1.054	1.046	1.038	1.030	1.023	1.016	1.008	1.001
9.00	1.064	1.056	1.048	1.040	1.032	1.025	1.017	1.010	1.003
9.25	1.066	1.058	1.050	1.042	1.034	1.027	1.019	1.012	1.005
9.50	1.068	1.060	1.052	1.044	1.036	1.028	1.021	1.014	1.007
9.75	1.069	1.061	1.054	1.046	1.038	1.030	1.023	1.016	1.009
10.00	1.071	1.063	1.055	1.048	1.040	1.032	1.025	1.017	1.010
10.25	1.073	1.065	1.057	1.050	1.042	1.034	1.027	1.019	1.012
10.50	1.075	1.067	1.059	1.051	1.044	1.036	1.028	1.021	1.014
10.75	1.077	1.069	1.061	1.053	1.046	1.038	1.030	1.023	1.016
11.00	1.079	1.071	1.063	1.055	1.047	1.040	1.032	1.025	1.018
11.25	1.081	1.073	1.065	1.057	1.049	1.042	1.034	1.027	1.019
11.50	1.082	1.075	1.067	1.059	1.051	1.043	1.036	1.028	1.021
11.75	1.084	1.076	1.069	1.061	1.053	1.045	1.038	1.030	1.023
12.00	1.086	1.078	1.070	1.063	1.055	1.047	1.040	1.032	1.025

$$\text{COST RATIOS} = \frac{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INDEPENDENT EXPANSION}}{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INTERCONNECTED EXPANSION}}$$

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

	ESCALATION RATES								
DISCOUNT RATE	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	19,512	18,560	17,215	15,417	13,098	10,183	6,590	2,226	-3,011
8.25	19,688	18,825	17,584	15,907	13,729	10,977	7,572	3,423	-1,567
8.50	19,845	19,066	17,925	16,365	14,322	11,727	8,502	4,560	-193
8.75	19,983	19,286	18,240	16,791	14,878	12,433	9,381	5,639	1,114
9.00	20,104	19,483	18,529	17,187	15,398	13,098	10,213	6,662	2,357
9.25	20,207	19,661	18,794	17,554	15,885	13,724	10,998	7,632	3,537
9.50	20,295	19,819	19,036	17,894	16,340	14,311	11,740	8,550	4,659
9.75	20,367	19,959	19,256	18,208	16,764	14,863	12,439	9,420	5,723
10.00	20,425	20,082	19,455	18,498	17,158	15,380	13,098	10,242	6,733
10.25	20,469	20,188	19,634	18,763	17,525	15,864	13,718	11,019	7,691
10.50	20,500	20,278	19,794	19,005	17,864	16,316	14,301	11,753	8,598
10.75	20,519	20,352	19,936	19,226	18,178	16,738	14,848	12,445	9,457
11.00	20,525	20,413	20,060	19,426	18,467	17,130	15,362	13,098	10,270
11.25	20,521	20,460	20,168	19,607	18,732	17,495	15,842	13,713	11,039
11.50	20,506	20,494	20,260	19,768	18,975	17,834	16,292	14,291	11,766
11.75	20,481	20,515	20,337	19,912	19,197	18,147	16,712	14,834	12,451
12.00	20,446	20,525	20,400	20,038	19,398	18,436	17,103	15,344	13,098

E - 5

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	367,521	404,713	445,907	491,538	542,088	598,088	660,126	728,848	804,970
8.25	359,139	395,342	435,430	479,820	528,991	583,447	643,759	710,556	784,529
8.50	350,998	386,242	425,258	468,454	516,283	569,243	627,885	692,818	764,711
8.75	343,088	377,404	415,382	457,417	503,949	555,461	612,487	675,615	745,495
9.00	335,403	368,819	405,791	446,703	491,979	542,088	597,548	658,929	726,861
9.25	327,936	360,480	396,476	436,299	480,358	529,110	583,054	642,744	708,789
9.50	320,678	352,377	387,429	426,196	469,077	516,512	568,988	627,041	691,260
9.75	313,624	344,503	378,639	416,384	458,123	504,284	555,338	611,804	674,255
10.00	306,766	336,850	370,099	406,853	447,486	492,412	542,088	597,018	657,757
10.25	300,098	329,412	361,801	397,594	437,154	480,884	529,226	582,668	641,748
10.50	293,615	322,182	353,736	388,598	427,119	469,689	516,738	568,739	626,213
10.75	287,309	315,152	345,898	379,856	417,370	458,817	504,613	555,217	611,134
11.00	281,177	308,316	338,278	371,361	407,898	448,256	492,837	542,088	596,498
11.25	275,211	301,669	330,869	363,104	398,694	437,996	481,401	529,340	582,289
11.50	269,407	295,203	323,666	355,077	389,749	428,028	470,292	516,960	568,494
11.75	263,759	288,914	316,661	347,273	381,055	418,341	459,499	504,936	555,098
12.00	258,263	282,795	309,847	339,686	372,604	408,928	449,014	493,256	542,088

DISCOUNTED VALUE OF BASE YEAR (1979)INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	348,009	386,153	428,691	476,121	528,990	587,905	653,536	726,623	807,981
8.25	339,451	376,517	417,845	463,917	515,262	572,469	636,187	707,133	786,095
8.50	331,153	367,176	407,333	452,090	501,961	557,516	619,383	688,257	764,903
8.75	323,105	358,119	397,142	440,627	489,072	543,028	603,105	669,976	744,381
9.00	315,300	349,336	387,262	429,516	476,580	528,990	587,335	652,267	724,505
9.25	307,729	340,819	377,683	418,745	464,473	515,386	572,055	635,112	705,252
9.50	300,383	332,557	368,393	408,302	452,737	502,201	557,248	618,490	686,601
9.75	293,257	324,543	359,383	398,175	441,359	489,421	542,898	602,384	668,532
10.00	286,341	316,768	350,645	388,355	430,327	477,032	528,990	586,776	651,024
10.25	279,629	309,225	342,167	378,831	419,630	465,020	515,508	571,649	634,057
10.50	273,115	301,904	333,942	369,592	409,255	453,374	502,437	556,986	617,614
10.75	266,791	294,799	325,962	360,630	399,192	442,079	489,764	542,771	601,677
11.00	260,651	287,903	318,217	351,934	389,432	431,125	477,476	528,990	586,228
11.25	254,690	281,209	310,701	343,497	379,962	420,500	465,558	515,627	571,250
11.50	248,901	274,710	303,405	335,309	370,774	410,194	454,000	502,669	556,728
11.75	243,278	268,399	296,323	327,362	361,859	400,194	442,788	490,102	542,646
12.00	237,817	262,271	289,447	319,647	353,206	390,492	431,911	477,912	528,990

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,011		
1982	2,009	14,228		
1983	26,666	46,967		
1984	81,942	10,959		
1985	37,172	31,539	8,468	7,648
1986	27,727	5,480	9,324	8,498
1987	33,552	23,929	10,267	9,029
1988	106,555	90,237		
1989	145,210	135,530		
1990	94,760	115,330		
1991	119,475	112,834		
1992	101,380	89,352	6,851	8,324
1993	58,450	108,400	7,212	8,654
1994	29,640	74,830	7,933	8,016
1995	23,935	22,820	8,654	8,745
1996	17,630		9,015	9,109

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992				
1993				
1994				
1995				
1996				

DISCOUNTED COST RATIOS FOR RANGE OF BASE YEAR (1979) COSTS
ESCALATED OVER EXPANSION PERIOD - 1979 TO 1996

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	1.044	1.038	1.033	1.028	1.022	1.017	1.012	1.007	1.002
8.25	1.045	1.040	1.034	1.029	1.024	1.018	1.013	1.008	1.003
8.50	1.046	1.041	1.036	1.030	1.025	1.020	1.015	1.009	1.004
8.75	1.048	1.042	1.037	1.032	1.026	1.021	1.016	1.011	1.006
9.00	1.049	1.044	1.038	1.033	1.028	1.022	1.017	1.012	1.007
9.25	1.050	1.045	1.040	1.034	1.029	1.024	1.018	1.013	1.008
9.50	1.052	1.046	1.041	1.036	1.030	1.025	1.020	1.015	1.010
9.75	1.053	1.048	1.042	1.037	1.032	1.026	1.021	1.016	1.011
10.00	1.054	1.049	1.044	1.038	1.033	1.028	1.022	1.017	1.012
10.25	1.056	1.050	1.045	1.040	1.034	1.029	1.024	1.019	1.013
10.50	1.057	1.052	1.046	1.041	1.036	1.030	1.025	1.020	1.015
10.75	1.058	1.053	1.048	1.042	1.037	1.032	1.026	1.021	1.016
11.00	1.060	1.054	1.049	1.044	1.038	1.033	1.028	1.023	1.017
11.25	1.061	1.056	1.050	1.045	1.040	1.034	1.029	1.024	1.019
11.50	1.062	1.057	1.052	1.046	1.041	1.036	1.030	1.025	1.020
11.75	1.063	1.058	1.053	1.048	1.042	1.037	1.032	1.027	1.021
12.00	1.065	1.059	1.054	1.049	1.044	1.038	1.033	1.028	1.023

$$\text{COST RATIOS} = \frac{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INDEPENDENT EXPANSION}}{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INTERCONNECTED EXPANSION}}$$

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	27,096	26,190	24,824	22,926	20,414	17,198	13,177	8,242	2,268
8.25	27,259	26,456	25,212	23,456	21,110	18,086	14,288	9,608	3,927
8.50	27,400	26,695	25,567	23,948	21,760	18,921	15,337	10,902	5,503
8.75	27,519	26,908	25,891	24,402	22,367	19,705	16,325	12,127	6,998
9.00	27,617	27,096	26,185	24,820	22,932	20,440	17,257	13,285	8,417
9.25	27,695	27,259	26,450	25,205	23,456	21,127	18,133	14,379	9,761
9.50	27,754	27,400	26,687	25,557	23,943	21,770	18,957	15,412	11,035
9.75	27,795	27,519	26,899	25,879	24,393	22,370	19,731	16,387	12,241
10.00	27,820	27,618	27,086	26,171	24,808	22,929	20,457	17,306	13,382
10.25	27,828	27,697	27,250	26,434	25,189	23,448	21,136	18,171	14,460
10.50	27,821	27,757	27,391	26,671	25,539	23,930	21,772	18,984	15,479
10.75	27,799	27,800	27,511	26,883	25,859	24,376	22,366	19,749	16,440
11.00	27,764	27,826	27,611	27,070	26,149	24,788	22,919	20,466	17,347
11.25	27,715	27,836	27,691	27,234	26,412	25,167	23,434	21,138	18,201
11.50	27,655	27,831	27,753	27,376	26,649	25,515	23,911	21,767	19,005
11.75	27,583	27,811	27,797	27,497	26,860	25,833	24,354	22,355	19,760
12.00	27,499	27,778	27,825	27,598	27,048	26,123	24,763	22,903	20,470

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	646,867	708,932	777,234	852,386	935,064	1,026,007	1,126,021	1,235,993	1,356,889
8.25	632,139	692,645	759,218	832,456	913,013	1,001,606	1,099,020	1,206,114	1,323,827
8.50	617,813	676,806	741,701	813,080	891,578	977,892	1,072,784	1,177,086	1,291,712
8.75	603,877	661,401	724,667	794,242	870,742	954,844	1,047,287	1,148,882	1,260,512
9.00	590,320	646,415	708,101	775,923	850,484	932,439	1,022,507	1,121,474	1,230,199
9.25	577,128	631,838	691,987	758,109	830,787	910,658	998,420	1,094,838	1,200,744
9.50	564,292	617,654	676,312	740,783	811,632	889,481	975,006	1,068,948	1,172,120
9.75	551,799	603,854	661,063	723,929	793,004	868,888	952,241	1,043,783	1,144,300
10.00	539,640	590,424	646,225	707,534	774,885	848,863	930,107	1,019,317	1,117,258
10.25	527,804	577,353	631,787	691,583	757,260	829,386	908,583	995,530	1,090,971
10.50	516,282	564,630	617,737	676,063	740,113	810,441	887,650	972,400	1,065,414
10.75	505,063	552,246	604,061	660,959	723,430	792,011	867,290	949,907	1,040,564
11.00	494,139	540,188	590,749	646,260	707,196	774,081	847,485	928,031	1,016,399
11.25	483,501	528,448	577,791	631,952	691,398	756,635	828,218	906,752	992,899
11.50	473,141	517,016	565,174	618,025	676,022	739,658	809,472	886,052	970,041
11.75	463,049	505,883	552,889	604,467	661,056	723,136	791,231	865,913	947,807
12.00	453,218	495,040	540,925	591,265	646,486	707,055	773,480	846,318	926,177

DISCOUNTED VALUE OF BASE YEAR (1979)INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	619,771	682,743	752,410	829,460	914,651	1,008,809	1,112,844	1,227,751	1,354,622
8.25	604,879	666,189	734,006	809,000	891,903	983,520	1,084,732	1,196,506	1,319,900
8.50	590,413	650,110	716,134	789,133	869,818	958,971	1,057,447	1,166,184	1,286,209
8.75	576,359	634,492	698,776	769,840	848,375	935,139	1,030,962	1,136,755	1,253,514
9.00	562,703	619,320	681,916	751,103	827,552	911,999	1,005,250	1,108,189	1,221,783
9.25	549,434	604,579	665,537	732,904	807,330	889,530	980,267	1,080,458	1,190,963
9.50	536,538	590,255	649,625	715,226	787,690	867,711	956,048	1,053,536	1,161,085
9.75	524,004	576,335	634,164	698,051	768,611	846,518	932,510	1,027,396	1,132,059
10.00	511,821	562,806	619,139	681,364	750,077	825,934	909,650	1,002,011	1,103,876
10.25	499,977	549,656	604,537	665,149	732,071	805,938	887,447	977,359	1,076,511
10.50	488,461	536,873	590,345	649,391	714,574	786,511	865,878	953,416	1,049,935
10.75	477,264	524,446	576,550	634,076	697,571	767,635	844,924	930,158	1,024,123
11.00	466,376	512,362	563,139	619,190	681,047	749,293	824,566	907,564	999,052
11.25	455,786	500,612	550,099	604,718	664,986	731,468	804,784	885,613	974,698
11.50	445,486	489,186	537,421	590,649	649,373	714,143	785,560	864,284	951,037
11.75	435,466	478,072	525,091	576,970	634,196	697,303	766,877	843,558	928,047
12.00	425,719	467,261	513,100	563,668	619,439	680,932	748,717	823,415	905,708

ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,621		
1982	2,009	15,594		
1983	26,666	48,874		
1984	81,942	10,959		
1985	37,172	31,539		
1986	21,127			
1987	7,152	2,009		
1988	7,555	8,037		
1989	23,110	30,139		
1990	21,920	42,652		
1991	82,200	43,047		
1992	101,380	89,352		
1993	58,450	108,400		
1994	29,840	74,830		
1995	23,935	22,820		
1996	17,630			

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985			2,835	267
1986			695	483
1987	6,646	1,356	697	481
1988			696	478
1989			3,055	752
1990			1,324	902
1991			187	734
1992	2,004		623	430
1993			623	419
1994			-500	504
1995				
1996				

ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DISCOUNTED COST RATIOS FOR RANGE OF BASE YEAR (1979) COSTS
ESCALATED OVER EXPANSION PERIOD - 1979 TO 1996

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	1.070	1.063	1.055	1.047	1.040	1.032	1.025	1.018	1.011
8.25	1.072	1.065	1.057	1.049	1.042	1.034	1.027	1.020	1.013
8.50	1.074	1.066	1.059	1.051	1.044	1.036	1.029	1.022	1.015
8.75	1.076	1.068	1.061	1.053	1.045	1.038	1.031	1.024	1.017
9.00	1.078	1.070	1.062	1.055	1.047	1.040	1.033	1.025	1.018
9.25	1.080	1.072	1.064	1.057	1.049	1.042	1.034	1.027	1.020
9.50	1.081	1.074	1.066	1.059	1.051	1.044	1.036	1.029	1.022
9.75	1.083	1.076	1.068	1.060	1.053	1.045	1.038	1.031	1.024
10.00	1.085	1.077	1.070	1.062	1.055	1.047	1.040	1.033	1.025
10.25	1.087	1.079	1.072	1.064	1.057	1.049	1.042	1.034	1.027
10.50	1.088	1.081	1.073	1.066	1.058	1.051	1.043	1.036	1.029
10.75	1.090	1.083	1.075	1.068	1.060	1.053	1.045	1.038	1.031
11.00	1.092	1.084	1.077	1.070	1.062	1.055	1.047	1.040	1.033
11.25	1.094	1.086	1.079	1.071	1.064	1.056	1.049	1.042	1.034
11.50	1.095	1.088	1.081	1.073	1.066	1.058	1.051	1.043	1.036
11.75	1.097	1.090	1.082	1.075	1.067	1.060	1.053	1.045	1.038
12.00	1.099	1.091	1.084	1.077	1.069	1.062	1.054	1.047	1.040

$$\text{COST RATIOS} = \frac{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INDEPENDENT EXPANSION}}{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INTERCONNECTED EXPANSION}}$$

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	25,042	24,722	24,063	23,008	21,494	19,450	16,798	13,451	9,313
8.25	25,074	24,829	24,259	23,309	21,918	20,019	17,534	14,381	10,465
8.50	25,090	24,916	24,431	23,582	22,309	20,548	18,224	15,256	11,554
8.75	25,091	24,985	24,581	23,828	22,668	21,039	18,869	16,079	12,583
9.00	25,076	25,036	24,709	24,048	22,996	21,494	19,472	16,853	13,554
9.25	25,051	25,070	24,817	24,243	23,296	21,915	20,034	17,579	14,469
9.50	25,011	25,089	24,906	24,416	23,567	22,302	20,557	18,260	15,332
9.75	24,958	25,092	24,976	24,566	23,812	22,659	21,043	18,897	16,143
10.00	24,895	25,081	25,029	24,696	24,032	22,985	21,494	19,493	16,906
10.25	24,820	25,057	25,066	24,805	24,228	23,283	21,911	20,048	17,623
10.50	24,735	25,020	25,087	24,895	24,401	23,553	22,296	20,566	18,295
10.75	24,641	24,971	25,093	24,968	24,552	23,797	22,649	21,047	18,924
11.00	24,537	24,910	25,084	25,023	24,682	24,017	22,974	21,494	19,513
11.25	24,425	24,839	25,063	25,061	24,793	24,213	23,270	21,907	20,063
11.50	24,305	24,757	25,029	25,084	24,885	24,386	23,539	22,289	20,575
11.75	24,177	24,666	24,982	25,093	24,959	24,538	23,783	22,640	21,052
12.00	24,042	24,566	24,925	25,087	25,015	24,669	24,002	22,962	21,494

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	381,019	419,402	461,886	508,913	560,973	618,607	682,411	753,044	831,230
8.25	372,366	409,734	451,083	496,843	547,488	603,542	665,583	734,247	810,239
8.50	363,958	400,344	440,594	485,127	534,401	588,925	649,258	716,017	789,885
8.75	355,789	391,222	430,408	473,752	521,698	574,740	633,419	698,335	770,146
9.00	347,851	382,360	420,515	462,706	509,367	560,973	618,051	681,181	751,002
9.25	340,136	373,750	410,905	451,980	497,394	547,610	603,137	664,538	732,432
9.50	332,636	365,382	401,568	441,562	485,769	534,638	588,663	648,389	714,417
9.75	325,346	357,250	392,497	431,442	474,479	522,043	574,613	632,717	696,937
10.00	318,257	349,346	383,681	421,610	463,513	509,813	560,973	617,506	679,976
10.25	311,364	341,661	375,114	412,057	452,862	497,936	547,730	602,741	663,515
10.50	304,660	334,190	366,786	402,774	442,514	486,400	534,870	588,406	647,538
10.75	298,140	326,925	358,691	393,753	432,459	475,194	522,381	574,488	632,028
11.00	291,796	319,860	350,820	384,984	422,688	464,307	510,251	560,973	616,971
11.25	285,625	312,988	343,167	376,459	413,193	453,730	498,468	547,847	602,351
11.50	279,620	306,303	335,724	368,171	403,963	443,450	487,020	535,099	588,154
11.75	273,776	299,799	328,484	360,112	394,990	433,461	475,897	522,714	574,366
12.00	268,088	293,471	321,442	352,275	386,267	423,750	465,089	510,682	560,973

DISCOUNTED VALUE OF BASE YEAR (1979)INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	355,977	394,680	437,822	485,905	539,479	599,157	665,613	739,592	821,917
8.25	347,291	384,905	426,824	473,534	525,570	583,523	648,048	719,866	799,774
8.50	338,868	375,427	416,163	461,545	512,092	568,377	631,034	700,761	778,331
8.75	330,698	366,237	405,827	449,924	499,030	553,701	614,550	682,256	757,564
9.00	322,773	357,324	395,806	438,659	486,370	539,479	598,580	664,328	737,448
9.25	315,085	348,679	386,087	427,736	474,098	525,695	583,104	646,959	717,963
9.50	307,626	340,294	376,662	417,146	462,201	512,335	568,106	630,129	699,085
9.75	300,387	332,158	367,520	406,875	450,666	499,384	553,570	613,820	680,794
10.00	293,362	324,264	358,652	396,914	439,481	486,828	539,479	598,013	663,069
10.25	286,544	316,604	350,048	387,252	428,634	474,653	525,819	582,692	645,892
10.50	279,925	309,170	341,700	377,879	418,113	462,847	512,575	567,840	629,243
10.75	273,499	301,954	333,598	368,785	407,907	451,397	499,732	553,441	613,104
11.00	267,259	294,950	325,736	359,961	398,006	440,290	487,278	539,479	597,458
11.25	261,200	288,149	318,104	351,398	388,400	429,517	475,198	525,940	582,288
11.50	255,315	281,546	310,695	343,087	379,078	419,065	463,481	512,810	567,579
11.75	249,599	275,133	303,502	335,019	370,032	408,923	452,115	500,074	553,314
12.00	244,046	268,905	296,517	327,188	361,252	399,081	441,087	487,720	539,479

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,621		
1982	2,009	15,594		
1983	26,666	48,874		
1984	81,942	10,959		
1985	37,172	31,539		
1986	21,127			
1987	7,152	2,009		
1988	7,555	8,037		
1989	23,110	30,139		
1990	21,920	42,652		
1991	82,200	43,047		
1992	101,380	89,352		
1993	58,450	108,400		
1994	29,840	74,830		
1995	23,935	22,820		
1996	17,630			

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987	6,646	1,356		
1988				
1989				
1990				
1991				
1992	2,004			
1993				
1994				
1995				
1996				

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DISCOUNTED COST RATIOS FOR RANGE OF BASE YEAR (1979) COSTS
ESCALATED OVER EXPANSION PERIOD - 1979 TO 1996

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	1.060	1.053	1.045	1.038	1.031	1.024	1.017	1.010	1.004
8.25	1.062	1.055	1.047	1.040	1.033	1.026	1.019	1.012	1.005
8.50	1.064	1.056	1.049	1.042	1.034	1.027	1.020	1.014	1.007
8.75	1.066	1.058	1.051	1.044	1.036	1.029	1.022	1.015	1.009
9.00	1.067	1.060	1.053	1.045	1.038	1.031	1.024	1.017	1.010
9.25	1.069	1.062	1.054	1.047	1.040	1.033	1.026	1.019	1.012
9.50	1.071	1.063	1.056	1.049	1.042	1.034	1.027	1.020	1.014
9.75	1.072	1.065	1.058	1.051	1.043	1.036	1.029	1.022	1.015
10.00	1.074	1.067	1.060	1.052	1.045	1.038	1.031	1.024	1.017
10.25	1.076	1.069	1.061	1.054	1.047	1.040	1.033	1.026	1.019
10.50	1.078	1.070	1.063	1.056	1.049	1.042	1.034	1.027	1.021
10.75	1.079	1.072	1.065	1.058	1.050	1.043	1.036	1.029	1.022
11.00	1.081	1.074	1.067	1.059	1.052	1.045	1.038	1.031	1.024
11.25	1.083	1.075	1.068	1.061	1.054	1.047	1.040	1.033	1.026
11.50	1.084	1.077	1.070	1.063	1.056	1.049	1.041	1.034	1.027
11.75	1.086	1.079	1.072	1.065	1.057	1.050	1.043	1.036	1.029
12.00	1.087	1.080	1.073	1.066	1.059	1.052	1.045	1.038	1.031

$$\text{COST RATIOS} = \frac{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INDEPENDENT EXPANSION}}{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INTERCONNECTED EXPANSION}}$$

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

	ESCALATION RATES								
DISCOUNT RATE	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	21,225	20,637	19,694	18,339	16,509	14,133	11,132	7,418	2,896
8.25	21,319	20,810	19,960	18,715	17,014	14,787	11,958	8,443	4,149
8.50	21,397	20,962	20,202	19,062	17,483	15,399	12,736	9,412	5,337
8.75	21,458	21,095	20,420	19,381	17,920	15,973	13,469	10,328	6,464
9.00	21,503	21,209	20,616	19,673	18,324	16,509	14,157	11,193	7,531
9.25	21,534	21,305	20,790	19,939	18,699	17,009	14,804	12,008	8,541
9.50	21,551	21,365	20,943	20,180	19,044	17,475	15,410	12,777	9,496
9.75	21,554	21,448	21,078	20,399	19,361	17,908	15,978	13,501	10,400
10.00	21,545	21,496	21,193	20,595	19,652	18,310	16,509	14,181	11,253
10.25	21,525	21,529	21,291	20,770	19,918	18,682	17,005	14,821	12,058
10.50	21,493	21,548	21,372	20,924	20,159	19,025	17,467	15,421	12,817
10.75	21,450	21,555	21,438	21,060	20,378	19,342	17,897	15,983	13,532
11.00	21,398	21,549	21,488	21,177	20,574	19,632	18,296	16,509	14,205
11.25	21,336	21,551	21,523	21,277	20,750	19,897	18,666	17,001	14,837
11.50	21,265	21,502	21,545	21,360	20,905	20,138	19,007	17,459	15,431
11.75	21,185	21,462	21,554	21,427	21,042	20,357	19,322	17,886	15,988
12.00	21,098	21,413	21,551	21,479	21,161	20,554	19,611	18,282	16,509

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	373,662	411,407	453,201	499,483	550,738	607,502	670,367	739,985	817,076
8.25	365,154	401,898	442,573	487,603	537,460	592,662	653,783	721,456	796,376
8.50	356,889	392,663	432,253	476,072	524,575	578,265	637,698	703,487	776,307
8.75	348,859	383,693	422,233	464,878	512,069	564,295	622,094	686,059	756,845
9.00	341,057	374,980	412,501	454,009	499,930	550,738	606,954	669,154	737,972
9.25	333,474	366,514	403,049	443,455	488,145	537,580	592,264	652,754	719,666
9.50	326,104	358,289	393,867	433,205	476,704	524,808	578,007	636,843	701,909
9.75	318,940	350,295	384,947	423,250	465,593	512,408	564,170	621,402	684,682
10.00	311,975	342,526	376,279	413,579	454,803	500,369	550,738	606,417	667,966
10.25	305,203	334,973	367,856	404,183	444,322	488,678	537,698	591,873	651,746
10.50	298,618	327,631	359,669	395,054	434,142	477,325	525,037	577,754	636,004
10.75	292,213	320,492	351,711	386,182	424,250	466,297	512,742	564,047	620,723
11.00	285,983	313,550	343,975	377,559	414,640	455,584	500,801	550,738	605,890
11.25	279,922	306,799	336,453	369,178	405,300	445,176	489,202	537,814	591,489
11.50	274,025	300,232	329,138	361,030	396,223	435,063	477,936	525,261	577,506
11.75	268,286	293,843	322,024	353,108	387,399	425,236	466,989	513,069	563,927
12.00	262,702	287,627	315,105	345,404	378,821	415,684	456,353	501,225	550,738

DISCOUNTED VALUE OF BASE YEAR (1979)INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	352,437	390,771	433,508	481,144	534,229	593,369	659,235	732,567	814,180
8.25	343,834	381,088	422,612	468,888	520,446	577,876	641,825	713,012	792,227
8.50	335,492	371,701	412,051	457,010	507,091	562,866	624,962	694,074	770,969
8.75	327,401	362,598	401,813	445,497	494,149	548,322	608,625	675,731	750,382
9.00	319,554	353,771	391,886	434,336	481,606	534,229	592,797	657,962	730,441
9.25	311,940	345,209	382,260	423,516	469,447	520,571	577,460	640,746	711,126
9.50	304,554	336,904	372,924	413,025	457,660	507,333	562,597	624,065	692,413
9.75	297,386	328,847	363,869	402,851	446,232	494,500	548,192	607,901	674,282
10.00	290,430	321,030	355,086	392,984	435,151	482,059	534,229	592,236	656,714
10.25	283,679	313,445	346,565	383,413	424,405	469,996	520,693	577,052	639,688
10.50	277,125	306,083	338,297	374,129	413,982	458,299	507,570	562,334	623,187
10.75	270,763	298,938	330,274	365,122	403,873	446,955	494,845	548,064	607,192
11.00	264,585	292,002	322,487	356,382	394,065	435,953	482,505	534,229	591,665
11.25	258,586	285,268	314,929	347,901	384,550	425,280	470,537	520,813	576,652
11.50	252,760	278,730	307,593	339,670	375,317	414,925	458,928	507,802	562,075
11.75	247,101	272,381	300,470	331,681	366,357	404,879	447,667	495,183	547,939
12.00	241,604	266,215	293,554	323,925	357,661	395,130	436,742	482,943	534,229

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,675		
1982	2,009	17,349		
1983	26,666	69,844		
1984	81,942	10,959		
1985	37,172	31,539		
1986	21,127			
1987	7,152	2,009		
1988	7,555	8,037		
1989	23,110	30,139		
1990	21,920	42,652		
1991	82,200	43,047		
1992	101,380	89,352		
1993	58,450	108,400		
1994	29,840	74,830		
1995	23,935	22,820		
1996	17,630			

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985				
1986				
1987				
1988				
1989				
1990				
1991				
1992				
1993				
1994				
1995				
1996				

DISCOUNTED COST RATIOS FOR RANGE OF BASE YEAR (1979) COSTS
ESCALATED OVER EXPANSION PERIOD - 1979 TO 1996

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	.990	.987	.983	.979	.976	.972	.968	.964	.960
8.25	.991	.988	.984	.980	.977	.973	.969	.965	.961
8.50	.992	.989	.985	.981	.978	.974	.970	.966	.962
8.75	.993	.989	.986	.982	.978	.975	.971	.967	.963
9.00	.994	.990	.987	.983	.979	.976	.972	.968	.964
9.25	.994	.991	.988	.984	.980	.977	.973	.969	.965
9.50	.995	.992	.989	.985	.981	.978	.974	.970	.966
9.75	.996	.993	.989	.986	.982	.978	.975	.971	.967
10.00	.996	.993	.990	.987	.983	.979	.976	.972	.968
10.25	.997	.994	.991	.988	.984	.980	.977	.973	.969
10.50	.998	.995	.992	.988	.985	.981	.977	.974	.970
10.75	.998	.996	.993	.989	.986	.982	.978	.975	.971
11.00	.999	.996	.993	.990	.987	.983	.979	.976	.972
11.25	1.000	.997	.994	.991	.987	.984	.980	.977	.973
11.50	1.000	.998	.995	.992	.988	.985	.981	.977	.974
11.75	1.001	.998	.995	.992	.989	.986	.982	.978	.975
12.00	1.001	.999	.996	.993	.990	.987	.983	.979	.976

$$\text{COST RATIOS} = \frac{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INDEPENDENT EXPANSION}}{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INTERCONNECTED EXPANSION}}$$

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	-3,562	-5,375	-7,604	-10,311	-13,564	-17,438	-22,016	-27,391	-33,665
8.25	-3,183	-4,899	-7,016	-9,594	-12,698	-16,400	-20,781	-25,932	-31,950
8.50	-2,825	-4,449	-6,459	-8,912	-11,872	-15,409	-19,602	-24,536	-30,308
8.75	-2,488	-4,024	-5,931	-8,265	-11,086	-14,465	-18,475	-23,201	-28,736
9.00	-2,171	-3,622	-5,430	-7,649	-10,338	-13,564	-17,399	-21,925	-27,232
9.25	-1,873	-3,243	-4,956	-7,065	-9,627	-12,705	-16,372	-20,705	-25,792
9.50	-1,594	-2,885	-4,507	-6,510	-8,949	-11,887	-15,392	-19,539	-24,414
9.75	-1,331	-2,548	-4,082	-5,984	-8,306	-11,108	-14,456	-18,426	-23,097
10.00	-1,086	-2,230	-3,681	-5,485	-7,694	-10,365	-13,564	-17,361	-21,836
10.25	-856	-1,932	-3,302	-5,012	-7,112	-9,658	-12,713	-16,345	-20,631
10.50	-641	-1,651	-2,944	-4,564	-6,560	-8,986	-11,902	-15,375	-19,479
10.75	-441	-1,387	-2,607	-4,141	-6,036	-8,346	-11,128	-14,448	-18,377
11.00	-254	-1,140	-2,289	-3,740	-5,539	-7,737	-10,392	-13,564	-17,324
11.25	-80	-909	-1,989	-3,361	-5,068	-7,159	-9,690	-12,720	-16,318
11.50	80	-693	-1,708	-3,003	-4,621	-6,610	-9,022	-11,916	-15,358
11.75	229	-491	-1,443	-2,665	-4,198	-6,088	-8,386	-11,149	-14,440
12.00	367	-302	-1,195	-2,347	-3,798	-5,592	-7,781	-10,417	-13,564

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	367,521	404,713	445,907	491,538	542,088	598,088	660,126	728,848	804,970
8.25	359,139	395,342	435,430	479,824	528,991	583,447	643,759	710,556	784,529
8.50	350,998	386,242	425,258	468,454	516,283	569,243	627,885	692,818	764,711
8.75	343,088	377,404	415,382	457,417	503,949	555,461	612,487	675,615	745,495
9.00	335,403	368,819	405,791	446,703	491,979	542,088	597,548	658,929	726,861
9.25	327,936	360,480	396,476	436,299	480,358	529,110	583,054	642,744	708,789
9.50	320,678	352,377	387,429	426,196	469,077	516,512	568,988	627,041	691,260
9.75	313,624	344,503	378,639	416,384	458,123	504,284	555,338	611,804	674,255
10.00	306,766	336,850	370,099	406,853	447,486	492,412	542,088	597,018	657,757
10.25	300,098	329,412	361,801	397,594	437,154	480,884	529,226	582,668	641,748
10.50	293,615	322,182	353,736	388,598	427,119	469,689	516,738	568,739	626,213
10.75	287,309	315,152	345,898	379,856	417,370	458,817	504,613	555,217	611,134
11.00	281,177	308,316	338,278	371,361	407,898	448,256	492,837	542,088	596,498
11.25	275,211	301,669	330,869	363,104	398,694	437,996	481,401	529,340	582,289
11.50	269,407	295,203	323,666	355,077	389,749	428,028	470,292	516,960	568,494
11.75	263,759	288,914	316,661	347,273	381,055	418,341	459,499	504,936	555,098
12.00	258,263	282,795	309,847	339,686	372,604	408,928	449,014	493,256	542,088

DISCOUNTED VALUE OF BASE YEAR (1979)INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	371,083	410,087	453,511	501,849	555,652	615,526	682,142	756,239	838,635
8.25	362,322	400,241	442,446	489,418	541,689	599,846	664,540	736,487	816,479
8.50	353,823	390,691	431,717	477,367	528,155	584,652	647,487	717,354	795,019
8.75	345,577	381,428	421,312	465,682	515,036	569,926	630,962	698,816	774,231
9.00	337,575	372,441	411,221	454,352	502,317	555,652	614,947	680,855	754,093
9.25	329,809	363,722	401,432	443,364	489,985	541,815	599,426	663,449	734,581
9.50	322,272	355,261	391,936	432,706	478,026	528,400	584,380	646,580	715,674
9.75	314,955	347,050	382,722	422,367	466,428	515,391	569,794	630,229	697,352
10.00	307,851	339,081	373,780	412,338	455,179	502,777	555,652	614,379	679,593
10.25	300,954	331,344	365,103	402,606	444,266	490,542	541,939	599,013	662,379
10.50	294,256	323,833	356,680	393,162	433,679	478,675	528,640	584,113	645,691
10.75	287,750	316,539	348,504	383,997	423,406	467,163	515,741	569,665	629,511
11.00	281,431	309,457	340,566	375,100	413,437	455,993	503,229	555,652	613,822
11.25	275,291	302,578	332,858	366,464	403,762	445,155	491,090	542,060	598,608
11.50	269,326	295,896	325,373	358,080	394,370	434,637	479,313	528,876	583,851
11.75	263,530	289,405	318,104	349,938	385,253	424,429	467,885	516,084	569,538
12.00	257,897	283,098	311,042	342,032	376,402	414,520	456,794	503,673	555,652

	CAPITAL DISBURSEMENTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS		FUEL COMPONENT OF OPERATING COSTS IN $1000 FOR ALTERNATIVE SYSTEM EXPANSIONS	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	INDEPENDENT ESCALATED $	INTERCONNECTED ESCALATED $
1979				
1980				
1981		4,011		
1982	2,009	14,228		
1983	26,666	46,967		
1984	81,942	10,959		
1985	37,172	31,539	8,468	7,648
1986	27,727	5,480	9,324	8,498
1987	33,552	23,929	10,267	9,029
1988	106,555	90,237		
1989	145,210	135,530		
1990	94,760	115,330		
1991	119,475	112,834		
1992	101,380	89,352	6,851	8,324
1993	58,450	108,400	7,212	8,654
1994	29,840	74,830	7,933	8,016
1995	23,935	22,820	8,654	8,745
1996	17,630		9,015	9,109

	ADDITIONAL DISBURSEMENTS IN $1000 FOR UNDERLYING TRANSMISSION SYSTEM		SUSITNA CONSTRUCTION POWER COSTS IN $1000 FOR ALTERNATIVE MODES OF SUPPLY	
	INDEPENDENT COSTS - $79	INTERCONNECTED COSTS - $79	DIESEL GENERATION COSTS - $79	INTERTIE TAPLINE COSTS - $79
1979				
1980				
1981				
1982				
1983				
1984				
1985			2,835	267
1986			695	483
1987			697	481
1988			696	478
1989			3,055	752
1990			1,324	902
1991			187	734
1992			623	430
1993			623	419
1994			-500	304
1995				
1996				

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DISCOUNTED COST RATIOS FOR RANGE OF BASE YEAR (1979) COSTS
ESCALATED OVER EXPANSION PERIOD - 1979 TO 1996

	ESCALATION RATES								
DISCOUNT RATE	4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	1.050	1.044	1.039	1.033	1.028	1.022	1.017	1.012	1.006
8.25	1.051	1.045	1.040	1.034	1.029	1.024	1.018	1.013	1.008
8.50	1.052	1.047	1.041	1.036	1.030	1.025	1.020	1.014	1.009
8.75	1.054	1.048	1.043	1.037	1.032	1.026	1.021	1.016	1.010
9.00	1.055	1.050	1.044	1.039	1.033	1.028	1.022	1.017	1.012
9.25	1.056	1.051	1.046	1.040	1.035	1.029	1.024	1.018	1.013
9.50	1.058	1.052	1.047	1.041	1.036	1.030	1.025	1.020	1.014
9.75	1.059	1.054	1.048	1.043	1.037	1.032	1.026	1.021	1.016
10.00	1.061	1.055	1.050	1.044	1.039	1.033	1.028	1.022	1.017
10.25	1.062	1.056	1.051	1.046	1.040	1.035	1.029	1.024	1.018
10.50	1.063	1.058	1.052	1.047	1.041	1.036	1.031	1.025	1.020
10.75	1.065	1.059	1.054	1.048	1.043	1.037	1.032	1.027	1.021
11.00	1.066	1.061	1.055	1.050	1.044	1.039	1.033	1.028	1.023
11.25	1.067	1.062	1.056	1.051	1.046	1.040	1.035	1.029	1.024
11.50	1.069	1.063	1.058	1.052	1.047	1.041	1.036	1.031	1.025
11.75	1.070	1.065	1.059	1.054	1.048	1.043	1.037	1.032	1.027
12.00	1.071	1.066	1.060	1.055	1.050	1.044	1.039	1.033	1.028

$$\text{COST RATIOS} = \frac{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INDEPENDENT EXPANSION}}{\text{DISCOUNTED VALUE OF DISBURSEMENTS FOR INTERCONNECTED EXPANSION}}$$

5 APRIL 79

ECON.ANAL.NO 8

ALASKA POWER AUTHORITY
ANCHORAGE - FAIRBANKS INTERTIE
ECONOMIC FEASIBILITY STUDY

DIFFERENTIAL DISCOUNTED VALUE OF BASE YEAR (1979) COSTS
INDEPENDENT SYSTEM COSTS MINUS INTERCONNECTED SYSTEM COSTS
(IN $1000)

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	30,913	30,276	29,194	27,595	25,399	22,515	18,844	14,275	8,685
8.25	31,014	30,476	29,511	28,050	26,015	23,319	19,865	15,546	10,243
8.50	31,094	30,649	29,796	28,467	26,586	24,070	20,824	16,746	11,720
8.75	31,153	30,798	30,051	28,848	27,115	24,771	21,725	17,878	13,117
9.00	31,192	30,922	30,278	29,195	27,604	25,425	22,571	18,945	14,440
9.25	31,212	31,024	30,477	29,509	28,053	26,033	23,363	19,950	15,689
9.50	31,214	31,104	30,650	29,793	28,466	26,597	24,104	20,895	16,870
9.75	31,199	31,164	30,798	30,046	28,844	27,120	24,796	21,783	17,985
10.00	31,169	31,204	30,923	30,271	29,188	27,604	25,442	22,617	19,035
10.25	31,123	31,225	31,025	30,470	29,500	28,049	26,042	23,398	20,025
10.50	31,063	31,229	31,106	30,642	29,781	28,458	26,601	24,130	20,957
10.75	30,990	31,216	31,166	30,791	30,033	28,832	27,118	24,813	21,833
11.00	30,903	31,188	31,208	30,916	30,258	29,174	27,596	25,451	22,655
11.25	30,805	31,144	31,231	31,019	30,455	29,483	28,037	26,045	23,427
11.50	30,695	31,086	31,236	31,100	30,628	29,763	28,443	26,597	24,149
11.75	30,575	31,015	31,226	31,162	30,777	30,014	28,814	27,110	24,824
12.00	30,444	30,932	31,199	31,205	30,902	30,238	29,154	27,583	25,455

DISCOUNTED VALUE OF BASE YEAR (1979) INDEPENDENT SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	654,225	716,927	785,918	861,816	945,299	1,037,112	1,138,066	1,249,052	1,371,043
8.25	639,351	700,481	767,729	841,696	923,041	1,012,486	1,110,819	1,218,906	1,337,690
8.50	624,883	684,486	750,042	822,135	901,405	988,552	1,084,343	1,189,617	1,305,290
8.75	610,808	668,929	732,842	803,116	880,371	965,288	1,058,612	1,161,157	1,273,813
9.00	597,114	653,796	716,114	784,621	859,921	942,674	1,033,604	1,133,501	1,243,229
9.25	583,790	639,073	699,842	766,634	840,035	920,688	1,009,294	1,106,622	1,213,510
9.50	570,824	624,748	684,013	749,139	820,697	899,311	985,661	1,080,495	1,184,627
9.75	558,205	610,809	668,613	732,121	801,890	878,523	962,684	1,055,098	1,156,555
10.00	545,922	597,244	653,628	715,566	783,596	858,306	940,342	1,030,406	1,129,267
10.25	533,965	584,041	639,046	699,457	765,799	838,643	918,615	1,006,398	1,102,740
10.50	522,324	571,189	624,854	683,783	748,485	819,516	897,484	983,052	1,076,948
10.75	510,990	558,678	611,041	668,530	731,639	800,908	876,930	960,348	1,051,869
11.00	499,953	546,498	597,595	653,684	715,245	782,804	856,935	938,266	1,027,480
11.25	489,205	534,637	584,505	639,233	699,291	765,188	837,483	916,785	1,003,761
11.50	478,736	523,088	571,759	625,166	683,763	748,045	818,556	895,889	980,689
11.75	468,539	511,839	559,349	611,471	668,647	731,361	800,139	875,558	958,246
12.00	458,604	500,883	547,263	598,136	653,932	715,121	782,215	855,775	936,412

DISCOUNTED VALUE OF BASE YEAR (1979)INTERCONNECTED SYSTEM COSTS
IN $1000

DISCOUNT RATE	ESCALATION RATES 4%	5%	6%	7%	8%	9%	10%	11%	12%
8.00	623,312	686,652	756,724	834,221	919,901	1,014,597	1,119,222	1,234,777	1,362,358
8.25	608,336	670,005	738,218	813,646	897,026	989,167	1,090,955	1,203,360	1,327,446
8.50	593,789	653,837	720,246	793,668	874,819	964,482	1,063,519	1,172,871	1,293,570
8.75	579,655	638,131	702,791	774,268	853,256	940,517	1,036,887	1,143,279	1,260,696
9.00	565,923	622,873	685,836	755,426	832,317	917,249	1,011,033	1,114,556	1,228,790
9.25	552,579	608,049	669,365	737,125	811,982	894,655	985,931	1,086,672	1,197,820
9.50	539,610	593,644	653,363	719,347	792,231	872,713	961,557	1,059,600	1,167,757
9.75	527,005	579,646	637,814	702,075	773,046	851,403	937,888	1,033,314	1,138,570
10.00	514,753	566,040	622,705	685,294	754,408	830,703	914,900	1,007,789	1,110,232
10.25	502,842	552,816	608,021	668,988	736,299	810,594	892,572	983,000	1,082,714
10.50	491,261	539,961	593,748	653,141	718,704	791,058	870,883	958,922	1,055,991
10.75	480,000	527,462	579,875	637,739	701,605	772,076	849,812	935,535	1,030,036
11.00	469,050	515,310	566,387	622,768	684,988	753,631	829,339	912,814	1,004,825
11.25	458,400	503,493	553,274	608,215	668,836	735,705	809,446	890,740	980,334
11.50	448,041	492,001	540,523	594,066	653,135	718,282	790,113	869,291	956,541
11.75	437,964	480,824	528,123	580,308	637,870	701,346	771,325	848,448	933,422
12.00	428,160	469,952	516,063	566,931	623,030	684,883	753,062	828,192	910,958

APPENDIX F

TRANSMISSION LINE FINANCIAL ANALYSIS

ANCHORAGE-FAIRBANKS INTERCONNECTION

SEMI-ANNUAL DISBURSEMENTS

FOR

TRANSMISSION INTERTIE FACILITIES

(TLFAP)

1979

BASE-LINE

AND

ESCALATED

COSTS

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
SEMI-ANNUAL DISBURSEMENTS FOR TRANSMISSION INTERTIE FACILITIES
UNINFLATED 1979 LEVEL COSTS

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
102.0	1. TRANSMISSION LINE							
104.0	ENGINEERING AND CONSTRUCTION							
105.0	SUPERVISION	452	753	0	392	693	723	3012
106.0	RIGHT OF WAY	0	2209	6628	0	0	0	8837
108.0	FOUNDATIONS	0	0	0	2280	6165	0	8445
110.0	TOWERS	0	0	0	0	9727	11888	21615
112.0	HARDWARE	0	0	0	0	72	405	477
114.0	INSULATORS	0	0	0	0	75	428	503
116.0	CONDUCTOR	0	0	0	0	1614	9147	10761
119.0								
120.0	SUB-TOTAL	452	2962	6628	2672	18346	22591	53650
122.0								
130.0	2. SUBSTATIONS							
132.0	ENGINEERING & CONSTRUCTION							
133.0	SUPERVISION	563	563	563	563	282	282	2816
134.0	LAND	81	0	0	0	0	0	81
136.0	TRANSFORMERS	0	0	341	596	596	170	1703
138.0	CIRCUIT BREAKERS	0	0	391	684	684	195	1953
140.0	STATION EQUIPMENT	0	0	269	471	471	135	1345
141.0	STRUCTURES & ACCESSORIES	0	0	805	1610	1610	0	4026
145.0								
146.0	SUB-TOTAL	644	563	2369	3924	3642	782	11924
149.0								
150.0	3. CONTROL AND COMMUNICATIONS							
152.0	ENGINEERING AND INSTALLATION							
153.0	SUPERVISION	0	0	0	0	71	94	165
154.0	EQUIPMENT	0	0	0	0	1254	1881	3135
156.0								
158.0	SUB-TOTAL	0	0	0	0	1325	1975	3300
160.0								
162.0	TOTAL	1096	3525	8996	6596	23313	25348	68874
164.0								
166.0	TOTAL FOR YEAR	0	4621	0	15592	0	48661	68874

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
SEMI-ANNUAL DISBURSEMENTS FOR TRANSMISSION INTERTIE FACILITIES
COSTS INFLATED FROM 1979 BASELINE

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
172.0	1. TRANSMISSION LINE							
174.0	ENGRG & CONSTR. SUPERV.	452	783	0	440	810	879	3365
176.0	RIGHT OF WAY	0	2298	7169	0	0	0	9466
178.0	FOUNDATIONS	0	0	0	2565	7212	0	9777
180.0	TOWERS	0	0	0	0	11379	14464	25843
182.0	HARDWARE	0	0	0	0	84	493	577
184.0	INSULATORS	0	0	0	0	88	520	608
186.0	CONDUCTOR	0	0	0	0	1888	11129	13017
189.0								
190.0	SUB-TOTAL	452	3081	7169	3005	21462	27485	62653
191.0								
200.0	2. SUBSTATIONS							
202.0	ENGRG & CONST. SUPERV.	563	586	609	634	329	343	3064
204.0	LAND	81	0	0	0	0	0	81
206.0	TRANSFORMERS	0	0	368	670	697	207	1943
208.0	CIRCUIT BREAKERS	0	0	422	769	800	238	2229
210.0	STATION EQUIPMENT	0	0	291	530	551	164	1535
211.0	STRUCTURES & ACCESSORIES	0	0	871	1811	1884	0	4566
215.0								
216.0	SUBTOTAL	644	586	2562	4414	4261	951	13418
217.0								
218.0	3. CONTROL AND COMMUNICATIONS							
219.0	ENGINEERING AND INSTALLATION							
220.0	SUPERVISION	0	0	0	0	83	114	197
222.0	EQUIPMENT	0	0	0	0	1467	2289	3756
224.0								
226.0	SUB-TOTAL	0	0	0	0	1550	2403	3953
228.0								
230.0	TOTAL	1096	3666	9730	7419	27273	30839	80024
232.0								
234.0	SUMMARY OF PRICE ESCALATION							
235.0	AT 8.0% PA	0	141	734	824	3960	5492	11150

ANCHORAGE-FAIRBANKS INTERCONNECTION

FINANCIAL PLAN A

BASE-CASE

(TLFAP)

70% REA LOAN AT 5% INTEREST RATE

30% MUNICIPAL BONDS AT 7.5% BONDING RATE

100% COMBINED SOURCES AT 5.7% COMPOSITE RATE

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
~~FUNDING SOURCES AND~~
INTEREST DURING CONSTRUCTION

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
400.0	FUNDING SOURCES							
401.0	APA BONDS	0	0	0	0	0	0	0
402.0	REA LOANS	767	2567	6811	5193	19091	21588	56017
403.0	CFC LOANS	0	0	0	0	0	0	0
404.0	FFB LOANS	0	0	0	0	0	0	0
405.0	AMU BONDS	164	550	1460	1113	4091	4626	12004
406.0	FMU BONDS	164	550	1460	1113	4091	4626	12004
408.0								
409.0	TOTAL	1096	3666	9730	7419	27273	30839	80024
410.0								
411.0	INTEREST DURING CONSTRUCTION							
412.0	APA BONDS	0	0	0	0	0	0	0
413.0	REA LOANS	0	19	83	254	383	861	1600
414.0	CFC LOANS	0	0	0	0	0	0	0
415.0	FFB LOANS	0	0	0	0	0	0	0
416.0	AMU BONDS	0	6	27	83	128	286	529
417.0	FMU BONDS	0	6	27	83	128	286	529
420.0								
421.0	TOTAL	0	32	137	419	639	1432	2659
422.0								

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT TABLE AND
COMPOSITE INTEREST RATE

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
430.0	% DEBT ASSUMED BY EACH UTILITY							
432.0	AML & P	15.00	0.0	0.0	0.0	0.0	0.0	15.00
434.0	CEA	30.00	0.0	0.0	0.0	0.0	0.0	30.00
436.0	MEA	3.00	0.0	0.0	0.0	0.0	0.0	3.00
438.0	HEA	1.00	0.0	0.0	0.0	0.0	0.0	1.00
442.0	FMUS	15.00	0.0	0.0	0.0	0.0	0.0	15.00
444.0	GVEA	36.00	0.0	0.0	0.0	0.0	0.0	36.00
446.0	CVEA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
447.0								
448.0								
449.0								
450.0	DEBT ASSUMED BY EACH UTILITY							
452.0	AML & P	164	550	1460	1113	4091	4626	12004
454.0	CEA	329	1100	2919	2226	8182	9252	24007
456.0	MEA	33	110	292	223	818	925	2401
458.0	HEA	11	37	97	74	273	308	800
462.0	FMUS	164	550	1460	1113	4091	4626	12004
464.0	GVEA	395	1320	3503	2671	9818	11102	28809
466.0	CVEA	0	0	0	0	0	0	0
468.0		------	------	------	------	------	------	------
470.0	TOTAL DEBT	1096	3666	9730	7419	27273	30839	80024
472.0								
474.0								
476.0								
500.0	COMPOSITE INTEREST RATE CALCULATIONS							
501.0	APA BONDS	0	0	0	0	0	0	0
502.0	REA LOANS	2801	0	0	0	0	0	2801
503.0	CFC LOANS	0	0	0	0	0	0	0
504.0	FFB LOANS	0	0	0	0	0	0	0
505.0	AMU BONDS	900	0	0	0	0	0	900
506.0	FMU BONDS	900	0	0	0	0	0	900
508.0								
510.0	COMPOSITE RATE	0.057	0.0	0.0	0.0	0.0	0.0	0.057

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT SERVICE SCHEDULE

LINE NO		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
152.0	APA												
154.0	SINKING FUND	0	0	0	0	0	0	0	0	0	0	0	0
156.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0
158.0													
160.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
161.0													
166.0	REA												
168.0	REPAYMENT	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600
171.0	OUTSTANDING	54416	52816	51216	49615	48015	46414	44814	43213	41613	40012	38412	36811
172.0	INTEREST DUE	2801	2721	2641	2561	2481	2401	2321	2241	2161	2081	2001	1921
174.0													
176.0	DEBT SERVICE	4401	4321	4241	4161	4081	4001	3921	3841	3761	3681	3601	3521
177.0													
182.0	CFC												
184.0	REPAYMENT	0	0	0	0	0	0	0	0	0	0	0	0
187.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
188.0	INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
190.0													
192.0	DEBT SERVICE	0	0	0	0	0	0	0	0	0	0	0	0
193.0													
198.0	FFB												
200.0	REPAYMENT	0	0	0	0	0	0	0	0	0	0	0	0
202.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
204.0													
206.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
207.0													
212.0	AMU												
214.0	SINKING FUND	81	81	81	81	81	81	81	81	81	81	81	81
216.0	INTEREST DUE	940	940	940	940	940	940	940	940	940	940	940	940
218.0													
220.0	S.FUND+INTEREST	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021
221.0													
228.0	FMU												
230.0	SINKING FUND	81	81	81	81	81	81	81	81	81	81	81	81
232.0	INTEREST DUE	940	940	940	940	940	940	940	940	940	940	940	940
234.0													
236.0	S.FUND+INTEREST	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021
250.0	TOTAL REPAYMENTS OR												
251.0	S. FUND PAYMENTS	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763
253.0	TOT INTEREST DUE	4681	4601	4521	4441	4361	4281	4201	4121	4041	3961	3881	3801
255.0													
257.0	TOTAL DEBT SERVI	6444	6364	6284	6204	6124	6044	5964	5884	5804	5724	5644	5564

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT SERVICE SCHEDULE

LINE NO		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
152.0	APA												
154.0	SINKING FUND	0	0	0	0	0	0	0	0	0	0	0	0
156.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0
158.0													
160.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
161.0													
166.0	REA												
168.0	REPAYMENT	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600
171.0	OUTSTANDING	35211	33610	32010	30409	28809	27208	25608	24007	22407	20806	19206	17605
172.0	INTEREST DUE	1841	1761	1681	1600	1520	1440	1360	1280	1200	1120	1040	960
174.0													
176.0	DEBT SERVICE	3441	3361	3281	3201	3121	3041	2961	2881	2801	2721	2641	2561
177.0													
182.0	CFC												
184.0	REPAYMENT	0	0	0	0	0	0	0	0	0	0	0	0
187.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
188.0	INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
190.0													
192.0	DEBT SERVICE	0	0	0	0	0	0	0	0	0	0	0	0
193.0													
198.0	FFB												
200.0	REPAYMENT	0	0	0	0	0	0	0	0	0	0	0	0
202.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
204.0													
206.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
207.0													
212.0	AMU												
214.0	SINKING FUND	81	81	81	81	81	81	81	81	81	81	81	81
216.0	INTEREST DUE	940	940	940	940	940	940	940	940	940	940	940	940
218.0													
220.0	S.FUND+INTEREST	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021
221.0													
228.0	FMU												
230.0	SINKING FUND	81	81	81	81	81	81	81	81	81	81	81	81
232.0	INTEREST DUE	940	940	940	940	940	940	940	940	940	940	940	940
234.0													
236.0	S.FUND+INTEREST	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021
250.0	TOTAL REPAYMENTS OR												
251.0	S. FUND PAYMENTS	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763
253.0	TOT INTEREST DUE	3721	3640	3560	3480	3400	3320	3240	3160	3080	3000	2920	2840
255.0													
257.0	TOTAL DEBT SERVI	5483	5403	5323	5243	5163	5083	5003	4923	4843	4763	4683	4603

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT SERVICE SCHEDULE

LINE NO		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
152.0	APA											
154.0	SINKING FUND	0	0	0	0	0	0	0	0	0	0	0
156.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0
158.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
160.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0
161.0												
166.0	REA											
168.0	REPAYMENT	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600	1600
171.0	OUTSTANDING	16005	14404	12804	11203	9603	8002	6402	4801	3201	1600	0
172.0	INTEREST DUE	880	800	720	640	560	480	400	320	240	160	80
174.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
176.0	DEBT SERVICE	2481	2401	2321	2241	2161	2081	2001	1921	1841	1761	1681
177.0												
182.0	CFC											
184.0	REPAYMENT	0	0	0	0	0	0	0	0	0	0	0
187.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0
188.0	INTEREST	0	0	0	0	0	0	0	0	0	0	0
190.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
192.0	DEBT SERVICE	0	0	0	0	0	0	0	0	0	0	0
193.0												
198.0	FFB											
200.0	REPAYMENT	0	0	0	0	0	0	0	0	0	0	0
202.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0
204.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
206.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0
207.0												
212.0	AMU											
214.0	SINKING FUND	81	81	81	81	81	81	81	81	81	81	81
216.0	INTEREST DUE	940	940	940	940	940	940	940	940	0	0	0
218.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
220.0	S.FUND+INTEREST	1021	1021	1021	1021	1021	1021	1021	1021	81	81	81
221.0												
228.0	FMU											
230.0	SINKING FUND	81	81	81	81	81	81	81	81	81	81	81
232.0	INTEREST DUE	940	940	940	940	940	940	940	940	940	940	940
234.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
236.0	S.FUND+INTEREST	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021	1021
250.0	TOTAL REPAYMENTS OR											
251.0	S. FUND PAYMENTS	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763	1763
253.0	TOT INTEREST DUE	2760	2680	2600	2520	2440	2360	2280	2200	1180	1100	1020
255.0		----------	----------	----------	----------	----------	----------	----------	----------	----------	----------	----------
257.0	TOTAL DEBT SERVI	4523	4443	4363	4283	4203	4123	4043	3963	2943	2863	2783

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT REPAYMENT AND SINKING FUND
ALLOCATION BY UTILITY

LINE NO		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
352.0	AML & P												
354.0	REPAYMENT AMOUNT	264	264	264	264	264	264	264	264	264	264	264	264
358.0	OUTSTANDING	8991	8727	8462	8198	7933	7669	7405	7140	6876	6611	6347	6082
360.0	INTEREST DUE	702	690	678	666	654	642	630	618	606	594	582	570
361.0													
362.0	CEA												
364.0	REPAYMENT AMOUNT	529	529	529	529	529	529	529	529	529	529	529	529
368.0	OUTSTANDING	17982	17454	16925	16396	15867	15338	14809	14280	13751	13222	12693	12165
370.0	INTEREST DUE	1404	1380	1356	1332	1308	1284	1260	1236	1212	1188	1164	1140
371.0													
372.0	MEA												
374.0	REPAYMENT AMOUNT	53	53	53	53	53	53	53	53	53	53	53	53
378.0	OUTSTANDING	1798	1745	1692	1640	1587	1534	1481	1428	1375	1322	1269	1216
380.0	INTEREST DUE	140	138	136	133	131	128	126	124	121	119	116	114
381.0													
382.0	HEA												
384.0	REPAYMENT AMOUNT	18	18	18	18	18	18	18	18	18	18	18	18
388.0	OUTSTANDING	599	582	564	547	529	511	494	476	458	441	423	405
390.0	INTEREST DUE	47	46	45	44	44	43	42	41	40	40	39	38
391.0													
402.0	FMUS												
404.0	REPAYMENT AMOUNT	264	264	264	264	264	264	264	264	264	264	264	264
408.0	OUTSTANDING	8991	8727	8462	8198	7933	7669	7405	7140	6876	6611	6347	6082
410.0	INTEREST DUE	702	690	678	666	654	642	630	618	606	594	582	570
411.0													
412.0	GVEA												
414.0	REPAYMENT AMOUNT	635	635	635	635	635	635	635	635	635	635	635	635
416.0	CUMULATIVE	635	1269	1904	2539	3173	3808	4443	5077	5712	6347	6981	7616
418.0	OUTSTANDING	21579	20944	20310	19675	19040	18406	17771	17136	16502	15867	15232	14598
420.0	INTEREST DUE	1685	1656	1627	1599	1570	1541	1512	1483	1455	1426	1397	1368
421.0													
422.0	CVEA												
424.0	REPAYMENT AMOUNT	0	0	0	0	0	0	0	0	0	0	0	0
426.0	CUMULATIVE	0	0	0	0	0	0	0	0	0	0	0	0
428.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
430.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT REPAYMENT AND SINKING FUND
ALLOCATION BY UTILITY

LINE NO		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
352.0	AML & P												
354.0	REPAYMENT AMOUNT	264	264	264	264	264	264	264	264	264	264	264	264
358.0	OUTSTANDING	5818	5553	5289	5025	4760	4496	4231	3967	3702	3438	3173	2909
360.0	INTEREST DUE	558	546	534	522	510	498	486	474	462	450	438	426
361.0													
362.0	CEA												
364.0	REPAYMENT AMOUNT	529	529	529	529	529	529	529	529	529	529	529	529
368.0	OUTSTANDING	11636	11107	10578	10049	9520	8991	8462	7933	7405	6876	6347	5818
370.0	INTEREST DUE	1116	1092	1068	1044	1020	996	972	948	924	900	876	852
371.0													
372.0	MEA												
374.0	REPAYMENT AMOUNT	53	53	53	53	53	53	53	53	53	53	53	53
378.0	OUTSTANDING	1164	1111	1058	1005	952	899	846	793	740	688	635	582
380.0	INTEREST DUE	112	109	107	104	102	100	97	95	92	90	88	85
381.0													
382.0	HEA												
384.0	REPAYMENT AMOUNT	18	18	18	18	18	18	18	18	18	18	18	18
388.0	OUTSTANDING	388	370	353	335	317	300	282	264	247	229	212	194
390.0	INTEREST DUE	37	36	36	35	34	33	32	32	31	30	29	28
391.0													
402.0	FMUS												
404.0	REPAYMENT AMOUNT	264	264	264	264	264	264	264	264	264	264	264	264
408.0	OUTSTANDING	5818	5553	5289	5025	4760	4496	4231	3967	3702	3438	3173	2909
410.0	INTEREST DUE	558	546	534	522	510	498	486	474	462	450	438	426
411.0													
412.0	GVEA												
414.0	REPAYMENT AMOUNT	635	635	635	635	635	635	635	635	635	635	635	635
416.0	CUMULATIVE	8251	8885	9520	10155	10789	11424	12059	12693	13328	13963	14598	15232
418.0	OUTSTANDING	13963	13328	12693	12059	11424	10789	10155	9520	8885	8251	7616	6981
420.0	INTEREST DUE	1339	1311	1282	1253	1224	1195	1167	1138	1109	1080	1051	1022
421.0													
422.0	CVEA												
424.0	REPAYMENT AMOUNT	0	0	0	0	0	0	0	0	0	0	0	0
426.0	CUMULATIVE	0	0	0	0	0	0	0	0	0	0	0	0
428.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
430.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT REPAYMENT AND SINKING FUND
ALLOCATION BY UTILITY

LINE NO		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
352.0	AML & P											
354.0	REPAYMENT AMOUNT	264	264	264	264	264	264	264	264	264	264	264
358.0	OUTSTANDING	2644	2380	2116	1851	1587	1322	1058	793	529	264	0
360.0	INTEREST DUE	414	402	390	378	366	354	342	330	177	165	153
361.0												
362.0	CEA											
364.0	REPAYMENT AMOUNT	529	529	529	529	529	529	529	529	529	529	529
368.0	OUTSTANDING	5289	4760	4231	3702	3173	2644	2116	1587	1058	529	0
370.0	INTEREST DUE	828	804	780	756	732	708	684	660	354	330	306
371.0												
372.0	MEA											
374.0	REPAYMENT AMOUNT	53	53	53	53	53	53	53	53	53	53	53
378.0	OUTSTANDING	529	476	423	370	317	264	212	159	106	53	0
380.0	INTEREST DUE	83	80	78	76	73	71	68	66	35	33	31
381.0												
382.0	HEA											
384.0	REPAYMENT AMOUNT	18	18	18	18	18	18	18	18	18	18	18
388.0	OUTSTANDING	176	159	141	123	106	88	71	53	35	18	0
390.0	INTEREST DUE	28	27	26	25	24	24	23	22	12	11	10
391.0												
402.0	FMUS											
404.0	REPAYMENT AMOUNT	264	264	264	264	264	264	264	264	264	264	264
408.0	OUTSTANDING	2644	2380	2116	1851	1587	1322	1058	793	529	264	0
410.0	INTEREST DUE	414	402	390	378	366	354	342	330	177	165	153
411.0												
412.0	GVEA											
414.0	REPAYMENT AMOUNT	635	635	635	635	635	635	635	635	635	635	635
416.0	CUMULATIVE	15867	16502	17136	17771	18406	19040	19675	20310	20944	21579	22214
418.0	OUTSTANDING	6347	5712	5077	4443	3808	3173	2539	1904	1269	635	0
420.0	INTEREST DUE	994	965	936	907	878	850	821	792	425	396	367
421.0												
422.0	CVEA											
424.0	REPAYMENT AMOUNT	0	0	0	0	0	0	0	0	0	0	0
426.0	CUMULATIVE	0	0	0	0	0	0	0	0	0	0	0
428.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0
430.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0

ANCHORAGE-FAIRBANKS INTERCONNECTION

FINANCIAL COMPARISON

OF

LOAN PACKAGES

(COMPARE)

10/15/5% CFC LOANS AT 8.75% INTEREST RATE

10/5/5% FFB LOANS AT 9.375% INTEREST RATE

PRESENT VALUE COMPARISON OF CFC/FFB PROPORTIONATE LOAN PACKAGES

Basecase: 10% CFC Funds @ 8.75%/10% FFB Funds @ 9.375%

Constr. Period (Years 1–3) → 35 Year Amortization Period (from Year 4)

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	0	73	156	453	929	909	889	869	849	829	809	789	769
FFB	0	76	164	484	979	957	936	915	893	872	850	829	807
TOTAL	0	149	320	936	1908	1866	1825	1783	1742	1700	1659	1618	1576
DISCOUNTED VALUE	0	139	279	764	1455	1331	1216	1111	1014	925	843	768	700
PRESENT VALUE	16672	0	0	0	0	0	0	0	0	0	0	0	0

Year	13	14	15	16	17	18	19	20	21	22	23	24	25
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	749	729	709	689	669	649	629	609	589	569	549	529	509
FFB	786	764	743	722	700	679	657	636	614	593	572	550	529
TOTAL	1535	1493	1452	1410	1369	1327	1286	1245	1203	1162	1120	1079	1037
DISCOUNTED VALUE	637	579	526	478	433	393	356	322	291	262	236	213	191
PRESENT VALUE	0	0	0	0	0	0	0	0	0	0	0	0	0

Year	26	27	28	29	30	31	32	33	34	35	36	37	38
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	489	469	449	429	409	389	369	349	329	309	289	269	249
FFB	507	486	464	443	422	400	379	357	336	314	293	271	250
TOTAL	996	955	913	872	830	789	747	706	664	623	582	540	499
DISCOUNTED VALUE	172	154	137	123	109	97	86	76	67	58	51	44	38
PRESENT VALUE	0	0	0	0	0	0	0	0	0	0	0	0	0

PRESENT VALUE COMPARISON OF CFC/FFB PROPORTIONATE LOAN PACKAGES

Sub-Case 1: 15% CFC Funds @ 8.75%/5% FFB Funds @ 9.375%

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	0	110	233	679	1393	1363	1333	1303	1273	1243	1213	1183	1153
FFB	0	38	82	242	489	479	468	457	447	436	425	414	404
TOTAL	0	147	315	921	1883	1842	1801	1760	1720	1679	1638	1598	1557
DISCOUNTED VALUE	0	138	276	752	1436	1313	1200	1096	1001	913	833	759	691
PRESENT VALUE	16470	0	0	0	0	0	0	0	0	0	0	0	0

Year	13	14	15	16	17	18	19	20	21	22	23	24	25
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	1123	1093	1063	1033	1003	973	943	913	883	853	823	793	763
FFB	393	382	372	361	350	339	329	318	307	297	286	275	264
TOTAL	1516	1475	1435	1394	1353	1312	1272	1231	1190	1150	1109	1068	1027
DISCOUNTED VALUE	629	572	520	472	428	388	352	318	287	259	234	211	189
PRESENT VALUE	0	0	0	0	0	0	0	0	0	0	0	0	0

Year	26	27	28	29	30	31	32	33	34	35	36	37	38
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	733	703	673	643	613	583	553	523	493	463	433	403	373
FFB	254	243	232	221	211	200	189	179	168	157	146	136	125
TOTAL	987	946	905	865	824	783	742	702	661	620	579	539	498
DISCOUNTED VALUE	170	152	136	122	108	96	85	75	66	58	51	44	38
PRESENT VALUE	0	0	0	0	0	0	0	0	0	0	0	0	0

PRESENT VALUE COMPARISON OF CFC/FFB PROPORTIONATE LOAN PACKAGES

Sub-Case 2: 5% CFC Funds @ 8.75%/15% FFB Funds @ 9.375%

Year	0	1	2	3	4	5	6	7	8	9	10	11	12
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	0	37	78	226	464	454	444	434	424	414	404	394	384
FFB	0	113	246	726	1468	1436	1404	1372	1340	1307	1275	1243	1211
TOTAL	0	150	324	952	1933	1890	1848	1806	1764	1722	1680	1638	1595
DISCOUNTED VALUE	0	140	283	777	1474	1348	1232	1125	1027	937	854	778	708
PRESENT VALUE	16873	0	0	0	0	0	0	0	0	0	0	0	0

Year	13	14	15	16	17	18	19	20	21	22	23	24	25
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	374	364	354	344	334	324	314	304	294	284	274	264	254
FFB	1179	1147	1115	1082	1050	1018	986	954	922	890	857	825	793
TOTAL	1553	1511	1469	1427	1385	1342	1300	1258	1216	1174	1132	1090	1047
DISCOUNTED VALUE	645	586	532	483	438	397	360	325	294	265	239	215	193
PRESENT VALUE	0	0	0	0	0	0	0	0	0	0	0	0	0

Year	26	27	28	29	30	31	32	33	34	35	36	37	38
DEBT SERVICE AND FEES FOR ALL LOANS													
CFC	244	234	224	214	204	194	184	174	164	154	144	134	124
FFB	761	729	697	664	632	600	568	536	504	472	439	407	375
TOTAL	1005	963	921	879	837	794	752	710	668	626	584	542	499
DISCOUNTED VALUE	173	155	139	124	110	98	86	76	67	59	51	44	38
PRESENT VALUE	0	0	0	0	0	0	0	0	0	0	0	0	0

ANCHORAGE-FAIRBANKS INTERCONNECTION

FINANCIAL PLAN B

CHANGE-CASE 1

(TLFAP)

50% REA LOAN AT 5% INTEREST RATE

15% CFC LOAN AT 8.75% INTEREST RATE

5% FFB LOAN AT 9.375% INTEREST RATE

30% MUNICIPAL BONDS AT 7.25% BONDING RATE

100% COMBINED SOURCES AT 6.5% COMPOSITE RATE

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
FUNDING SOURCES AND
INTEREST DURING CONSTRUCTION

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
400.0	FUNDING SOURCES							
401.0	APA BONDS	0	0	0	0	0	0	0
402.0	REA LOANS	548	1833	4865	3710	13636	15420	40012
403.0	CFC LOANS	164	550	1460	1113	4091	4626	12004
404.0	FFB LOANS	55	183	487	371	1364	1542	4001
405.0	AMU BONDS	164	550	1460	1113	4091	4626	12004
406.0	FMU BONDS	164	550	1460	1113	4091	4626	12004
408.0								
409.0	TOTAL	1096	3666	9730	7419	27273	30839	80024
410.0								
411.0	INTEREST DURING CONSTRUCTION							
412.0	APA BONDS	0	0	0	0	0	0	0
413.0	REA LOANS	0	14	60	181	274	615	1143
414.0	CFC LOANS	0	7	31	95	144	323	600
415.0	FFB LOANS	0	3	11	34	51	115	214
416.0	AMU BONDS	0	6	26	80	123	276	511
417.0	FMU BONDS	0	6	26	80	123	276	511
420.0								
421.0	TOTAL	0	35	154	470	715	1605	2980
422.0								

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT TABLE AND
COMPOSITE INTEREST RATE

LINE NO		1981-1	1981-2	1982-1	1982-2	1983-1	1983-2	TOTAL
430.0	% DEBT ASSUMED BY EACH UTILITY							
432.0	AML & P	15.00	0.0	0.0	0.0	0.0	0.0	15.00
434.0	CEA	30.00	0.0	0.0	0.0	0.0	0.0	30.00
436.0	MEA	3.00	0.0	0.0	0.0	0.0	0.0	3.00
438.0	HEA	1.00	0.0	0.0	0.0	0.0	0.0	1.00
442.0	FMUS	15.00	0.0	0.0	0.0	0.0	0.0	15.00
444.0	GVEA	36.00	0.0	0.0	0.0	0.0	0.0	36.00
446.0	CVEA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
447.0								
448.0								
449.0								
450.0	DEBT ASSUMED BY EACH UTILITY							
452.0	AML & P	164	550	1460	1113	4091	4626	12004
454.0	CEA	329	1100	2919	2226	8182	9252	24007
456.0	MEA	33	110	292	223	818	925	2401
458.0	HEA	11	37	97	74	273	308	800
462.0	FMUS	164	550	1460	1113	4091	4626	12004
464.0	GVEA	395	1320	3503	2671	9818	11102	28809
466.0	CVEA	0	0	0	0	0	0	0
468.0								
470.0	TOTAL DEBT	1096	3666	9730	7419	27273	30839	80024
472.0								
474.0								
476.0								
500.0	COMPOSITE INTEREST RATE CALCULATIONS							
501.0	APA BONDS	0	0	0	0	0	0	0
502.0	REA LOANS	2001	0	0	0	0	0	2001
503.0	CFC LOANS	1050	0	0	0	0	0	1050
504.0	FFB LOANS	375	0	0	0	0	0	375
505.0	AMU BONDS	870	0	0	0	0	0	870
506.0	FMU BONDS	870	0	0	0	0	0	870
508.0								
510.0	COMPOSITE RATE	0.065	0.0	0.0	0.0	0.0	0.0	0.065

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT SERVICE SCHEDULE

LINE NO		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
152.0	APA												
154.0	SINKING FUND	0	0	0	0	0	0	0	0	0	0	0	0
156.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0
158.0													
160.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
161.0													
166.0	REA												
168.0	REPAYMENT	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143
171.0	OUTSTANDING	38869	37726	36583	35439	34296	33153	32010	30866	29723	28580	27437	26294
172.0	INTEREST DUE	2001	1943	1886	1829	1772	1715	1658	1600	1543	1486	1429	1372
174.0													
176.0	DEBT SERVICE	3144	3087	3029	2972	2915	2858	2801	2744	2687	2629	2572	2515
177.0													
182.0	CFC												
184.0	REPAYMENT	343	343	343	343	343	343	343	343	343	343	343	343
187.0	OUTSTANDING	11661	11318	10975	10632	10289	9946	9603	9260	8917	8574	8231	7888
188.0	INTEREST	1050	1020	990	960	930	900	870	840	810	780	750	720
190.0													
192.0	DEBT SERVICE	1393	1363	1333	1303	1273	1243	1213	1183	1153	1123	1093	1063
193.0													
198.0	FFB												
200.0	REPAYMENT	114	114	114	114	114	114	114	114	114	114	114	114
202.0	OUTSTANDING	3887	3773	3658	3544	3430	3315	3201	3087	2972	2858	2744	2629
204.0													
206.0	S.FUND+INTEREST	4001	3887	3773	3658	3544	3430	3315	3201	3087	2972	2858	2744
207.0													
212.0	AMU												
214.0	SINKING FUND	86	86	86	86	86	86	86	86	86	86	86	86
216.0	INTEREST DUE	907	907	907	907	907	907	907	907	907	907	907	907
218.0													
220.0	S.FUND+INTEREST	993	993	993	993	993	993	993	993	993	993	993	993
221.0													
228.0	FMU												
230.0	SINKING FUND	86	86	86	86	86	86	86	86	86	86	86	86
232.0	INTEREST DUE	907	907	907	907	907	907	907	907	907	907	907	907
234.0													
236.0	S.FUND+INTEREST	993	993	993	993	993	993	993	993	993	993	993	993
250.0	TOTAL REPAYMENTS OR												
251.0	S. FUND PAYMENTS	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772
253.0	TOT INTEREST DUE	8752	8551	8349	8148	7947	7745	7544	7342	7141	6939	6738	6536
255.0													
257.0	TOTAL DEBT SERVI	10524	10323	10121	9920	9718	9517	9315	9114	8912	8711	8509	8308

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT SERVICE SCHEDULE

LINE NO		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
152.0	APA												
154.0	SINKING FUND	0	0	0	0	0	0	0	0	0	0	0	0
156.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0
158.0													
160.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0	0
161.0													
166.0	REA												
168.0	REPAYMENT	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143
171.0	OUTSTANDING	25150	24007	22864	21721	20578	19434	18291	17148	16005	14862	13718	12575
172.0	INTEREST DUE	1315	1258	1200	1143	1086	1029	972	915	857	800	743	686
174.0													
176.0	DEBT SERVICE	2458	2401	2344	2286	2229	2172	2115	2058	2001	1943	1886	1829
177.0													
182.0	CFC												
184.0	REPAYMENT	343	343	343	343	343	343	343	343	343	343	343	343
187.0	OUTSTANDING	7545	7202	6859	6516	6173	5830	5487	5144	4801	4458	4116	3773
188.0	INTEREST	690	660	630	600	570	540	510	480	450	420	390	360
190.0													
192.0	DEBT SERVICE	1033	1003	973	943	913	883	853	823	793	763	733	703
193.0													
198.0	FFB												
200.0	REPAYMENT	114	114	114	114	114	114	114	114	114	114	114	114
202.0	OUTSTANDING	2515	2401	2286	2172	2058	1943	1829	1715	1600	1486	1372	1258
204.0													
206.0	S.FUND+INTEREST	2629	2515	2401	2286	2172	2058	1943	1829	1715	1600	1486	1372
207.0													
212.0	AMU												
214.0	SINKING FUND	86	86	86	86	86	86	86	86	86	86	86	86
216.0	INTEREST DUE	907	907	907	907	907	907	907	907	907	907	907	907
218.0													
220.0	S.FUND+INTEREST	993	993	993	993	993	993	993	993	993	993	993	993
221.0													
228.0	FMU												
230.0	SINKING FUND	86	86	86	86	86	86	86	86	86	86	86	86
232.0	INTEREST DUE	907	907	907	907	907	907	907	907	907	907	907	907
234.0													
236.0	S.FUND+INTEREST	993	993	993	993	993	993	993	993	993	993	993	993
250.0	TOTAL REPAYMENTS OR												
251.0	S. FUND PAYMENTS	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772
253.0	TOT INTEREST DUE	6335	6133	5932	5730	5529	5327	5126	4924	4723	4521	4320	4118
255.0													
257.0	TOTAL DEBT SERVI	8107	7905	7704	7502	7301	7099	6898	6696	6495	6293	6092	5890

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT SERVICE SCHEDULE

LINE NO		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
152.0	APA											
154.0	SINKING FUND	0	0	0	0	0	0	0	0	0	0	0
156.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0
158.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
160.0	S.FUND+INTEREST	0	0	0	0	0	0	0	0	0	0	0
161.0												
166.0	REA											
168.0	REPAYMENT	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143	1143
171.0	OUTSTANDING	11432	10289	9146	8002	6859	5716	4573	3430	2286	1143	0
172.0	INTEREST DUE	629	572	514	457	400	343	286	229	171	114	57
174.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
176.0	DEBT SERVICE	1772	1715	1658	1600	1543	1486	1429	1372	1315	1258	1200
177.0												
182.0	CFC											
184.0	REPAYMENT	343	343	343	343	343	343	343	343	343	343	343
187.0	OUTSTANDING	3430	3087	2744	2401	2058	1715	1372	1029	686	343	0
188.0	INTEREST	330	300	270	240	210	180	150	120	90	60	30
190.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
192.0	DEBT SERVICE	673	643	613	583	553	523	493	463	433	403	373
193.0												
198.0	FFB											
200.0	REPAYMENT	114	114	114	114	114	114	114	114	114	114	114
202.0	OUTSTANDING	1143	1029	915	800	686	572	457	343	229	114	0
204.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
206.0	S.FUND+INTEREST	1258	1143	1029	915	800	686	572	457	343	229	114
207.0												
212.0	AMU											
214.0	SINKING FUND	86	86	86	86	86	86	86	86	86	86	86
216.0	INTEREST DUE	907	907	907	907	907	907	907	907	0	0	0
218.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
220.0	S.FUND+INTEREST	993	993	993	993	993	993	993	993	86	86	86
221.0												
228.0	FMU											
230.0	SINKING FUND	86	86	86	86	86	86	86	86	86	86	86
232.0	INTEREST DUE	907	907	907	907	907	907	907	907	907	907	907
234.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
236.0	S.FUND+INTEREST	993	993	993	993	993	993	993	993	993	993	993
250.0	TOTAL REPAYMENTS OR											
251.0	S. FUND PAYMENTS	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772	1772
253.0	TOT INTEREST DUE	3917	3715	3514	3312	3111	2909	2708	2506	1397	1196	994
255.0		-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
257.0	TOTAL DEBT SERVI	5689	5487	5286	5084	4883	4681	4480	4278	3169	2968	2766

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT REPAYMENT AND SINKING FUND
ALLOCATION BY UTILITY

LINE NO		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
352.0	AML & P												
354.0	REPAYMENT AMOUNT	266	266	266	266	266	266	266	266	266	266	266	266
358.0	OUTSTANDING	8510	8260	8010	7759	7509	7259	7009	6758	6508	6258	6008	5757
360.0	INTEREST DUE	1313	1283	1252	1222	1192	1162	1132	1101	1071	1041	1011	980
361.0													
362.0	CEA												
364.0	REPAYMENT AMOUNT	532	532	532	532	532	532	532	532	532	532	532	532
368.0	OUTSTANDING	17020	16520	16019	15519	15018	14518	14017	13517	13016	12516	12015	11515
370.0	INTEREST DUE	2626	2565	2505	2444	2384	2324	2263	2203	2142	2082	2021	1961
371.0													
372.0	MEA												
374.0	REPAYMENT AMOUNT	53	53	53	53	53	53	53	53	53	53	53	53
378.0	OUTSTANDING	1702	1652	1602	1552	1502	1452	1402	1352	1302	1252	1202	1151
380.0	INTEREST DUE	263	257	250	244	238	232	226	220	214	208	202	196
381.0													
382.0	HEA												
384.0	REPAYMENT AMOUNT	18	18	18	18	18	18	18	18	18	18	18	18
388.0	OUTSTANDING	567	551	534	517	501	484	467	451	434	417	401	384
390.0	INTEREST DUE	88	86	83	81	79	77	75	73	71	69	67	65
391.0													
402.0	FMUS												
404.0	REPAYMENT AMOUNT	266	266	266	266	266	266	266	266	266	266	266	266
408.0	OUTSTANDING	8510	8260	8010	7759	7509	7259	7009	6758	6508	6258	6008	5757
410.0	INTEREST DUE	1313	1283	1252	1222	1192	1162	1132	1101	1071	1041	1011	980
411.0													
412.0	GVEA												
414.0	REPAYMENT AMOUNT	638	638	638	638	638	638	638	638	638	638	638	638
416.0	CUMULATIVE	638	1276	1914	2552	3189	3827	4465	5103	5741	6379	7017	7655
418.0	OUTSTANDING	20424	19823	19223	18622	18022	17421	16820	16220	15619	15019	14418	13817
420.0	INTEREST DUE	3151	3078	3006	2933	2861	2788	2716	2643	2571	2498	2426	2353
421.0													
422.0	CVEA												
424.0	REPAYMENT AMOUNT	0	0	0	0	0	0	0	0	0	0	0	0
426.0	CUMULATIVE	0	0	0	0	0	0	0	0	0	0	0	0
428.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
430.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT REPAYMENT AND SINKING FUND
ALLOCATION BY UTILITY

LINE NO		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
352.0	AML & P												
354.0	REPAYMENT AMOUNT	266	266	266	266	266	266	266	266	266	266	266	266
358.0	OUTSTANDING	5507	5257	5007	4756	4506	4256	4006	3755	3505	3255	3005	2754
360.0	INTEREST DUE	950	920	890	860	829	799	769	739	708	678	648	618
361.0													
362.0	CEA												
364.0	REPAYMENT AMOUNT	532	532	532	532	532	532	532	532	532	532	532	532
368.0	OUTSTANDING	11014	10514	10013	9513	9012	8512	8011	7511	7010	6510	6009	5509
370.0	INTEREST DUE	1900	1840	1779	1719	1659	1598	1538	1477	1417	1356	1296	1235
371.0													
372.0	MEA												
374.0	REPAYMENT AMOUNT	53	53	53	53	53	53	53	53	53	53	53	53
378.0	OUTSTANDING	1101	1051	1001	951	901	851	801	751	701	651	601	551
380.0	INTEREST DUE	190	184	178	172	166	160	154	148	142	136	130	124
381.0													
382.0	HEA												
384.0	REPAYMENT AMOUNT	18	18	18	18	18	18	18	18	18	18	18	18
388.0	OUTSTANDING	367	350	334	317	300	284	267	250	234	217	200	184
390.0	INTEREST DUE	63	61	59	57	55	53	51	49	47	45	43	41
391.0													
402.0	FMUS												
404.0	REPAYMENT AMOUNT	266	266	266	266	266	266	266	266	266	266	266	266
408.0	OUTSTANDING	5507	5257	5007	4756	4506	4256	4006	3755	3505	3255	3005	2754
410.0	INTEREST DUE	950	920	890	860	829	799	769	739	708	678	648	618
411.0													
412.0	GVEA												
414.0	REPAYMENT AMOUNT	638	638	638	638	638	638	638	638	638	638	638	638
416.0	CUMULATIVE	8293	8930	9568	10206	10844	11482	12120	12758	13396	14034	14671	15309
418.0	OUTSTANDING	13217	12616	12016	11415	10815	10214	9613	9013	8412	7812	7211	6610
420.0	INTEREST DUE	2280	2208	2135	2063	1990	1918	1845	1773	1700	1628	1555	1483
421.0													
422.0	CVEA												
424.0	REPAYMENT AMOUNT	0	0	0	0	0	0	0	0	0	0	0	0
426.0	CUMULATIVE	0	0	0	0	0	0	0	0	0	0	0	0
428.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0	0
430.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0	0

24 APRIL 79

ANCHORAGE - FAIRBANKS INTERCONNECTION
DEBT REPAYMENT AND SINKING FUND
ALLOCATION BY UTILITY

LINE NO		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
352.0	AML & P											
354.0	REPAYMENT AMOUNT	266	266	266	266	266	266	266	266	266	266	266
358.0	OUTSTANDING	2504	2254	2004	1753	1503	1253	1003	752	502	252	2
360.0	INTEREST DUE	588	557	527	497	467	436	406	376	210	179	149
361.0												
362.0	CEA											
364.0	REPAYMENT AMOUNT	532	532	532	532	532	532	532	532	532	532	532
368.0	OUTSTANDING	5008	4508	4007	3507	3006	2506	2005	1505	1004	504	3
370.0	INTEREST DUE	1175	1115	1054	994	933	873	812	752	419	359	298
371.0												
372.0	MEA											
374.0	REPAYMENT AMOUNT	53	53	53	53	53	53	53	53	53	53	53
378.0	OUTSTANDING	501	451	401	351	301	251	201	150	100	50	0
380.0	INTEREST DUE	118	111	105	99	93	87	81	75	42	36	30
381.0												
382.0	HEA											
384.0	REPAYMENT AMOUNT	18	18	18	18	18	18	18	18	18	18	18
388.0	OUTSTANDING	167	150	134	117	100	84	67	50	33	17	0
390.0	INTEREST DUE	39	37	35	33	31	29	27	25	14	12	10
391.0												
402.0	FMUS											
404.0	REPAYMENT AMOUNT	266	266	266	266	266	266	266	266	266	266	266
408.0	OUTSTANDING	2504	2254	2004	1753	1503	1253	1003	752	502	252	2
410.0	INTEREST DUE	588	557	527	497	467	436	406	376	210	179	149
411.0												
412.0	GVEA											
414.0	REPAYMENT AMOUNT	638	638	638	638	638	638	638	638	638	638	638
416.0	CUMULATIVE	15947	16585	17223	17861	18499	19137	19775	20412	21050	21688	22326
418.0	OUTSTANDING	6010	5409	4809	4208	3607	3007	2406	1806	1205	604	4
420.0	INTEREST DUE	1410	1337	1265	1192	1120	1047	975	902	503	431	358
421.0												
422.0	CVEA											
424.0	REPAYMENT AMOUNT	0	0	0	0	0	0	0	0	0	0	0
426.0	CUMULATIVE	0	0	0	0	0	0	0	0	0	0	0
428.0	OUTSTANDING	0	0	0	0	0	0	0	0	0	0	0
430.0	INTEREST DUE	0	0	0	0	0	0	0	0	0	0	0