RAILBELT INTERTIE RECONNAISSANCE STUDY

Benefit/Cost Analysis

Prepared for

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TABLE OF CONTENTS

Section		Page
1	INTRODUCTION	
	1.1 Objective	1-1
	1.2 Background	1-1
	1.3 Study Overview	1-2
	1.4 Summary of Findings	1-4
2	DESCRIPTION AND COSTS OF ALTERNATIVES	
	2.1 New Intertie Between Anchorage and the Kenai Peninsula	2-1
	2.2 Full Upgrade of the Existing Anchorage-Fairbanks Intertie	2-2
	2.3 Limited Upgrade of the Existing Anchorage-Fairbanks Intertie	2-2
	2.4 New Intertie From Palmer Through Glennallen to Delta Junction (Northeast Intertie)	2-3
	2.5 Coal-Fired Power Plants in the Railbelt	2-4
	2.6 Natural Gas Pipeline Linking Fairbanks With the Cook Inlet Area	2-6
	2.7 Electric End-Use Conservation Programs	2-6
3	SYSTEM STABILITY: IMPACT OF NEW KENAI-ANCHORAGE INTERTIE	3-1
4	IMPACT OF PROPOSED INTERTIES ON SYSTEM RELIABILITY	
	4.1 Overview	4-1
	4.2 Analysis of Historical Customer Outages	4-2
	4.3 Potential Changes in Customer Outages	4-9
	4.4 Costs of Customer Outages	4-16
	4.5 Value of Improved System Reliability	4-21
	4.6 Useful Readings	4-23
	4.7 References	4-23
5	ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS OF THE INTERTIE ALTERNATIVES	
	5.1 Overview	5-1
	5.2 Introduction	5-2
	5.3 Base Case Scenarios and Sensitivity Scenarios	5-4
	5.4 Economy Energy Transfers Between Kenai and Anchorage With Existing Line	5-6

TABLE OF CONTENTS (continued)

Section			Page
	5.5	New Kenai-Anchorage Line: Economy Energy Transfer and Transmission Loss Benefits	5-9
	5.6	Economy Energy Transfers Between Anchorage and Fairbanks With Existing Line	5-13
	5.7	Full Upgrade of Anchorage-Fairbanks Line: Economy Energy and Transmission Loss Benefits	5-15
	5.8	Limited Upgrade of Anchorage-Fairbanks Line: Economy Energy and Transmission Loss Benefits	5-19
	5.9	Northeast Intertie: Economy Energy and Transmission Loss Benefits	5-23
	5.10	Impact of Additional Military Load in Fairbanks	5-27
	5.11	References	5-28
6	BENEFITS OF INCREASED CAPACITY SHARING		
	6.1	Overview	6-1
	6.2	Railbelt Capacity Surplus	6-1
	6.3	Railbelt Capacity Shortage Without New/Upgraded Interties	6-2
	6.4	Reduced Railbelt Capacity Shortage Due to New/Upgraded Interties	6-9
	6.5	Benefits of Reduced Railbelt Capacity Shortage Due to New/Upgraded Interties	6-15
	6.6	Other Capacity Sharing Benefits	6-18
	6.7	References	6-20
7	OPERATING RESERVE SHARING		
	7.1	Overview	7-1
	7.2	Anchorage Operating Reserve Requirement	7-2
	7.3	The Cost of Operating Reserves	7-2
	7.4	Kenai-Anchorage Transmission Capacity	7-2
	7.5	Kenai Generating Capability	7-3
	7.6	Savings in Operating Reserve Costs	7-3
8	COAL-FIRED GENERATION		
	8.1	Introduction	8-1
	8.2	Reduced Energy Costs and Transmission Losses	8-2
	8.3	Capacity Benefits	8-5
	8.4	Total Costs and Benefits	8-5
	8.5	Benefits of Cogeneration	8-8
	8.6	References	8-10

TABLE OF CONTENTS (continued)

Section		Page
9	ELECTRIC END-USE CONSERVATION PROGRAMS	
	9.1 Introduction	9-1
	9.2 Energy Savings	9-2
	9.3 Capacity Savings	9-4
	9.4 Evaluation of End-Use Conservation Programs	9-8
	9.5 References	9-8
10	GAS PIPELINE BETWEEN COOK INLET AND FAIRBANKS: BENEFITS WITHIN THE ELECTRIC POWER SECTOR	
	10.1 Introduction	10-1
	10.2 Reduced Transmission Losses	10-1
	10.3 Reduced Electric Energy Costs	10-3
	10.4 Improved Electric System Reliability in Fairbanks	10-5
	10.5 Total Power Sector Benefits	10-5
11	GAS PIPELINE BETWEEN COOK INLET AND FAIRBANKS: BENEFITS OUTSIDE THE ELECTRIC POWER SECTOR	
	11.1 Introduction	11-1
	11.2 Residential	11-1
	11.3 Commercial	11-2
	11.4 Military	11-2
	11.5 UAF/FMUS District Heat	11-2
	11.6 Total Benefits Outside the Power Sector	11-3
12	ENVIRONMENTAL EVALUATION OF ALTERNATIVES	
	12.1 Overview	12-1
	12.2 Comparison of Environmental Impacts	12-3
	12.3 Generic Impacts	12-12
	12.4 Kenai-Anchorage Intertie	12-16
	12.5 Anchorage-Fairbanks Intertie	12-25
	12.6 Natural Gas Pipeline System From Cook Inlet to Fairbanks	12-31
	12.7 Coal-Fired Power Plants	12-36
	12.8 Electric End-User Conservation Programs	12-46
	12.9 References	12-47
13	SUMMARY AND CONCLUSIONS	
	13.1 Overview	13-1
	13.2 New Kenai-Anchorage Intertie	13-4
	13.3 Full Upgrade of Anchorage-Fairbanks Intertie to 225 MW	13-6

TABLE OF CONTENTS (continued)

Section		Page
13.4	Limited Upgrade of the Anchorage-Fairbanks Intertie to 100 MW	13-8
13.5	Northeast Intertie	13-10
13.6	50-MW Coal-Fired Power Plant at Healy	13-12
13.7	Cook Inlet-Fairbanks Gas Pipeline	13-14
13.8	End-Use Conservation Programs: Top Three	13-16
13.9	End-Use Conservation Programs: Top Eight	13-18
13.10	Other Proposals and Comments	13-20
Appendix A	SUMMARY OF UTILITIES DATA ON CUSTOMER OUTAGES	A-1
Appendix B	FUEL PRICE FORECASTS	B-1
Appendix C	DEMAND FORECASTS	C-1
Appendix D	ANALYSIS OF COGENERATION POTENTIAL	D-1
Appendix E	PRODUCTION SIMULATION MODELING	E-1
Appendix F	MODELING ASSUMPTIONS	F-1
Appendix G	SCREENING ANALYSIS OF POWER SUPPLY ALTERNATIVES AND END-USE PROGRAMS	G-1
Appendix H	BENEFITS OF INCREASED HYDRO-THERMAL COORDINATION	H-1
Appendix I	GAS PIPELINE BETWEEN COOK INLET AND FAIRBANKS: BENEFITS OUTSIDE THE ELECTRIC POWER SECTOR	I-1
Appendix J	RESPONSES TO COMMENTS ON DRAFT FINAL REPORT	J-1

LIST OF ILLUSTRATIONS

Figure		Page
1-1	Railbelt Alternatives: Costs and Benefits	1-6
1-2	Railbelt Alternatives: Benefit/Cost Ratios	1-7
4-1	Outage Hours per Customer of Railbelt Utilities	4-5
4-2	Unserved Energy per Customer of Railbelt Utilities	4-5
4-3	Distribution of Railbelt Unserved Energy by Utility	4-6
4-4	Outage Hours of Railbelt Areas	4-7
4-5	Unserved Energy of Railbelt Areas	4-8
4-6	Distribution of Unserved Energy by Area	4-8
4-7	Railbelt Areas Unserved Energy by Outage Duration	4-10
4-8	Railbelt Utilities Unserved Energy by Outage Duration	4-10
5-1	Kenai Load Requirements Versus Kenai Hydro Energy	5-6
9-1	Energy Savings of End-Use Programs	9-4
13-1	Railbelt Alternatives: Net Benefits	13-2
13-2	Railbelt Alternatives: Cost and Benefits	13-2
13-3	Railbelt Alternatives: Benefit/Cost Ratios	13-3
13-4	New Kenai-Anchorage Intertie: Net Benefits	13-5
13-5	New Kenai-Anchorage Intertie: Breakdown of Expected Benefits	13-5
13-6	Anchorage-Fairbanks Full Upgrade: Net Benefits	13-7
13-7	Anchorage-Fairbanks Full Upgrade: Breakdown of Expected Benefits	13-7
13-8	Anchorage-Fairbanks Upgrade to 100 MW: Net Benefits	13-9
13-9	Anchorage-Fairbanks Upgrade to 100 MW: Breakdown of Expected Benefits	13-9
13-10	Northeast Intertie: Net Benefits	13-11
13-11	Northeast Intertie: Breakdown of Expected Benefits	13-11
13-12	50-MW Coal-Fired Power Plant at Healy: Net Benefits	13-13
13-13	50-MW Coal-Fired Power Plant at Healy: Breakdown of Expected Benefits	13-13
13-14	Gas Pipeline: Net Benefits	13-15
13-15	Gas Pipeline: Benefits Within Versus Outside the Electric Power Sector	13-15
13-16	Gas Pipeline: Breakdown of Expected Benefits	13-15
13-17	Top Three End-Use Programs: Net Benefits	13-17
13-18	Top Three End-Use Programs: Breakdown of Expected Benefits	13-17
13-19	Top Eight End-Use Programs: Net Benefits	13-19
13-20	Top Eight End-Use Programs: Breakdown of Expected Benefits	13-19

LIST OF TABLES

Table		Page
1-1	Railbelt Alternatives: Costs and Benefits	1-5
2-1	Capital Cost Estimates	2-4
2-2	Annual Operations and Maintenance Cost Estimates	2-4
3-1	Recommended Solution Without New Intertie	3-4
3-2	Recommended Solution With New Intertie	3-5
4-1	Form of Utility Data on Customer Outages	4-3
4-2	Demand by Utility and Residential-Industrial/Commercial Split	4-4
4-3	Summary of Outage Hours and Unserved Energy for the Railbelt	4-7
4-4	Summary of Unserved Energy Reduction by Intertie	4-17
4-5	Distribution of Customer Classes in the Railbelt	4-20
4-6	Summary of Customer Outage Costs	4-21
4-7	Unserved Energy Saved by the Interties	4-22
4-8	Value of Unserved Energy Saved by the Interties	4-22
4-9	Present Value of Reliability Benefit	4-23
5-1	Kenai-Anchorage Transfers With Existing Line	5-8
5-2	Change in Kenai-Anchorage Transfers Due to the New Line	5-10
5-3	Annual Transfer Benefits Due to the New Kenai-Anchorage Line	5-11
5-4	Present Value of Transfer Benefits Due to New Kenai-Anchorage Line	5-12
5-5	Anchorage-Fairbanks Transfers With Existing Line	5-14
5-6	Change In Anchorage-Fairbanks Transfers Due to the Full Upgrade of the AF Line to 225 MW	5-16
5-7	Annual Transfer Benefits Due to the Full Upgrade of the AF Line to 225 MW	5-17
5-8	Present Value of Transfer Benefits Due to Full Upgrade of AF Line to 225 MW	5-18
5-9	Change in Anchorage-Fairbanks Transfers Due to the Limited Upgrade of the AF Line to 100 MW	5-20
5-10	Annual Transfer Benefits Due to the Limited Upgrade of the AF Line to 100 MW	5-21
5-11	Present Value of Transfer Benefits Due to the Upgrade of the AF Line to 100 MW	5-22
5-12	Change in Anchorage-Fairbanks Transfers Due to the New Northeast Line	5-24
5-13	Annual Transfer Benefits Due to the New Northeast Line	5-25
5-14	Present Value of Transfer Benefits Due to the Northeast Line	5-26
6-1	Kenai Capacity Surplus	6-3
6-2	Fairbanks Capacity Surplus	6-4
6-3	Kenai Capacity Shortage	6-6
6-4	Fairbanks Capacity Shortage	6-7

LIST OF TABLES (continued)

Table		Page
6-5	Anchorage Capacity Shortage	6-8
6-6	Kenai/Anchorage Capacity Shortage	6-10
6-7	Reduced Kenai/Anchorage Capacity Shortage Due to Kenai-Anchorage New Intertie	6-11
6-8	Anchorage/Fairbanks Capacity Shortage	6-13
6-9	Reduced Anchorage/Fairbanks Capacity Shortage Due to Anchorage-Fairbanks Intertie Upgrade	6-14
6-10	Benefits of Reduced Kenai/Anchorage Capacity Shortage	6-16
6-11	Benefits of Reduced Anchorage/Fairbanks Capacity Shortage	6-17
8-1	Change in Anchorage-Fairbanks Transfers Due to New 50-MW Coal Plant at Healy	8-4
8-2	Annual Benefits Due to New 50-MW Coal Plant at Healy	8-6
8-3	50-MW Coal-Fired Power Plant at Healy: Summary of Costs and Benefits	8-7
8-4	Breakeven Capital Cost and Thermal Energy Credit	8-8
9-1	Energy Savings by Program	9-3
9-2	Present Value of Energy Benefits Due to Top Three End-Use Programs	9-5
9-3	Present Value of Energy Benefits Due to Top Eight End-Use Programs	9-6
9-4	Peak Demand Reductions by Program	9-7
9-5	Capacity Benefits	9-9
9-6	Present Value of Net Benefits Due to Top Three Programs	9-10
9-7	Present Value of Net Benefits Due to Top Eight Programs	9-11
10-1	Change in Anchorage-Fairbanks Transfers Due to the Gas Pipeline	10-2
10-2	Annual Benefits of the Gas Pipeline Within the Electric Power Sector	10-4
10-3	Present Value of Gas Pipeline Benefits Within the Electric Power Sector	10-6
11-1	Benefits Outside the Electric Power Sector	11-3
12-1	Definitions of Impact Levels	12-4
12-2	Summary of Environmental Evaluations	12-5
13-1	New Kenai-Anchorage Intertie: Summary of Costs and Benfits	13-4
13-2	Anchorage-Fairbanks Full Upgrade: Summary of Costs and Benefits	13-6
13-3	Anchorage-Fairbanks Upgrade to 100 MW: Summary of Costs and Benefits	13-8
13-4	Anchorage-Fairbanks Northeast Intertie: Summary of Costs and Benefits	13-10

LIST OF TABLES (continued)

Table		Page
13-5	50-MW Coal-Fired Power Plant at Healy: Summary of Costs and Benefits	13-12
13-6	Cook Inlet-Fairbanks Gas Pipeline: Summary of Costs and Benefits	13-14
13-7	Top Three End-Use Programs: Summary of Costs and Benefits	13-16
13-8	Top Eight End-Use Programs: Summary of Costs and Benefits	13-18
13-9	Average Value of Increased Economy Energy Transfer	13-22
13-10	Value of Two-Month Transfer Benefit	13-22
13-11	Impact of Two-Month Outage on Operating Reserve Benefit	13-23

Section 1
INTRODUCTION

1.1 OBJECTIVE

The primary purpose of the Railbelt intertie studies undertaken by the Alaska Power Authority (APA) is to assess the costs and benefits of various intertie proposals that have been suggested for the Railbelt, as well as the costs and benefits of coal-fired power plants, electric end-use conservation programs, and a natural gas pipeline between Anchorage and Fairbanks. The purpose of this report is to present the results of that analysis.

1.2 BACKGROUND

Statutory direction to undertake these studies was provided in the capital budget passed during the special legislative session in July 1987:

> The sum of $2,500,000 is appropriated from the Railbelt energy fund in the general fund to the Alaska Power Authority for preparing studies required under AS 44.83.177-44.83.185 for electric interties between the Kenai Peninsula and Fairbanks.

This language directs the Alaska Power Authority to perform reconnaissance and feasibility studies of Railbelt intertie alternatives. Further action in the 1988 legislative session resulted in a reduction of the appropriation to $2,250,000 and added legislative intent that a proposed natural gas pipeline between Cook Inlet and Fairbanks also be assessed as part of the overall study.

The electric intertie projects that were initially identified for review were

1. A new transmission line between Anchorage and the Kenai Peninsula.

2. Upgrade of the existing intertie between Anchorage and Fairbanks to substantially higher transfer capability.

Two additional intertie projects were later added for consideration as alternatives to the proposed upgrade of the Anchorage-Fairbanks line.

3. A new transmission line from Palmer through Glennallen to Delta Junction, where it would connect with the Golden Valley system in the Fairbanks area. (This project has been referred to as the "Northeast Intertie.")

4. A limited upgrade of the existing Anchorage-Fairbanks intertie from 70 MW to 100 MW transfer capability.

Further, although the statutory direction makes it clear that the intertie projects are intended as the main focus of the study, it was decided that several other Railbelt energy proposals would also be assessed within the study's overall framework, specifically

1. A natural gas pipeline from Cook Inlet to Fairbanks.

2. Coal-fired power plants in the Railbelt.

3. Electric end-use conservation programs (i.e., programs designed to induce higher levels of efficiency among electric energy consumers).

1.3 STUDY OVERVIEW

The assessment of these selected projects and programs is focused on a comparison of their expected economic costs and benefits. APA assigned the primary task of performing these economic assessments to Decision Focus Incorporated (DFI). The costs of each proposal, as well as certain other inputs to the economic analysis such as fuel price and electric demand forecasts, were established in advance of the overall economic assessment through a series of studies undertaken by APA in conjunction with other contractors.

Several categories of possible benefit have been evaluated for the intertie proposals. These primary benefit categories include:

1. *System Stability.* An intertie project may enhance the stability of an electrical system following certain transmission disturbances and, as a result, may either allow greater operating flexibility or the avoidance of other costs that would be necessary to provide

comparable stability conditions.[1] This element of the analysis is presented in Section 3.

2. *Reliability.* Intertie projects can affect system reliability and a value can be attached to estimated improvements. Reliability can be measured by the number, duration, and magnitude of customer outages. Reliability benefits are explored in Section 4.

3. *Economy Energy Transfer.* Savings are realized when an intertie project allows more displacement of higher cost energy in one area with lower cost energy imported from another area. This is presented in Section 5.

4. *Transmission Efficiency.* Improved interties can produce savings to the extent that transmission losses are reduced. This is also presented in Section 5.

5. *Capacity Sharing.* An intertie project may allow two or more areas to share capacity and, as a result, an increment of future investment in plant capacity could be deferred or avoided. This is presented in Section 6.

6. *Operating Reserve Sharing.* Operating reserves are typically maintained to help avoid customer outages. An intertie project could allow two or more areas to share operating reserves and therefore reduce operating costs. This is presented in Section 7.

Coal-fired generation is assessed by comparing total system costs over the long term for scenarios that include a coal plant with scenarios that do not. A 50-MW coal-fired power plant at Healy was selected for evaluation. The impact on project economics of cogenerating steam to supply a coal drying process was also explored. These issues are presented in Section 8.

End-use conservation programs can be similarly assessed. The evaluation was performed with respect to the top three end-use programs identified in an earlier screening analysis (presented in Appendix G), and also with respect to the top eight programs identified in that analysis. The evaluation of these programs is presented in Section 9.

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[1] In the case of the proposed new intertie between Anchorage and the Kenai Peninsula, the new line would allow the avoidance of certain costs that might otherwise be incurred for stability considerations.

The proposed gas pipeline linking Fairbanks with the Cook Inlet area has been assessed by estimating its impacts both within the electric power sector and also within the residential and commercial heating markets. The power sector analysis is presented in Section 10. Impacts outside the power sector were explored by the Institute of Social and Economic Research (ISER). Section 11 of this report presents the results of their analysis.

This report also includes a comparison of the expected environmental consequences of the projects and programs selected for review. These comparative assessments are presented in Section 12, which was prepared by Dames & Moore.

1.4 SUMMARY OF FINDINGS

Table 1-1 and Figure 1-1 show the expected costs and benefits for each of the eight alternatives selected for evaluation. The total costs include both the capital costs and the present value of future operations and maintenance costs. Figure 1-2 shows the expected benefit/cost ratios.

The alternatives for which expected benefits exceed costs include:

1. Limited upgrade of the Anchorage-Fairbanks intertie from 70 MW to 100 MW

2. Construction of a natural gas pipeline linking Fairbanks with the Cook Inlet area

3. Electric end-use conservation programs

The alternatives for which costs exceed the expected benefits include:

1. New intertie between Anchorage and the Kenai Peninsula

2. Full upgrade of the Anchorage-Fairbanks intertie

3. The proposed Northeast intertie linking Anchorage and Fairbanks via Glennallen

4. The proposed 50-MW coal-fired power plant.

These findings are presented briefly below in the order they appear in Figures 1-1 and 1-2.

Table 1-1

RAILBELT ALTERNATIVES: COSTS AND BENEFITS

	Estimated Cost[a] ($1987 million)	Estimated Benefits[b] ($1987 million)	Benefit to Cost Ratio
New Kenai-Anchorage Intertie	103	43 to 49[c]	0.42 to 0.48
Full Upgrade of Anchorage-Fairbanks Intertie	134	96	0.72
Limited Upgrade of Anchorage-Fairbanks Intertie	10	40	3.88
Northeast Intertie	188	159[d]	0.85
50-MW Coal-Fired Power Plant	177 to 257[e]	108[f]	0.42 to 0.61
Gas Pipeline Between Cook Inlet and Fairbanks	284	527[g]	1.86
Top Three End-Use Conservation Programs	16	25 to 28	1.56 to 1.74
Top Eight End-Use Conservation Programs	43	54 to 61	1.23 to 1.39[h]

Notes:

a. Includes both capital and O&M costs

b. Present value of total benefits between 1994 and 2028

c. Benefits would be $8-9 million higher if existing line were shut down for maintenance two months per year for the next 35 years.

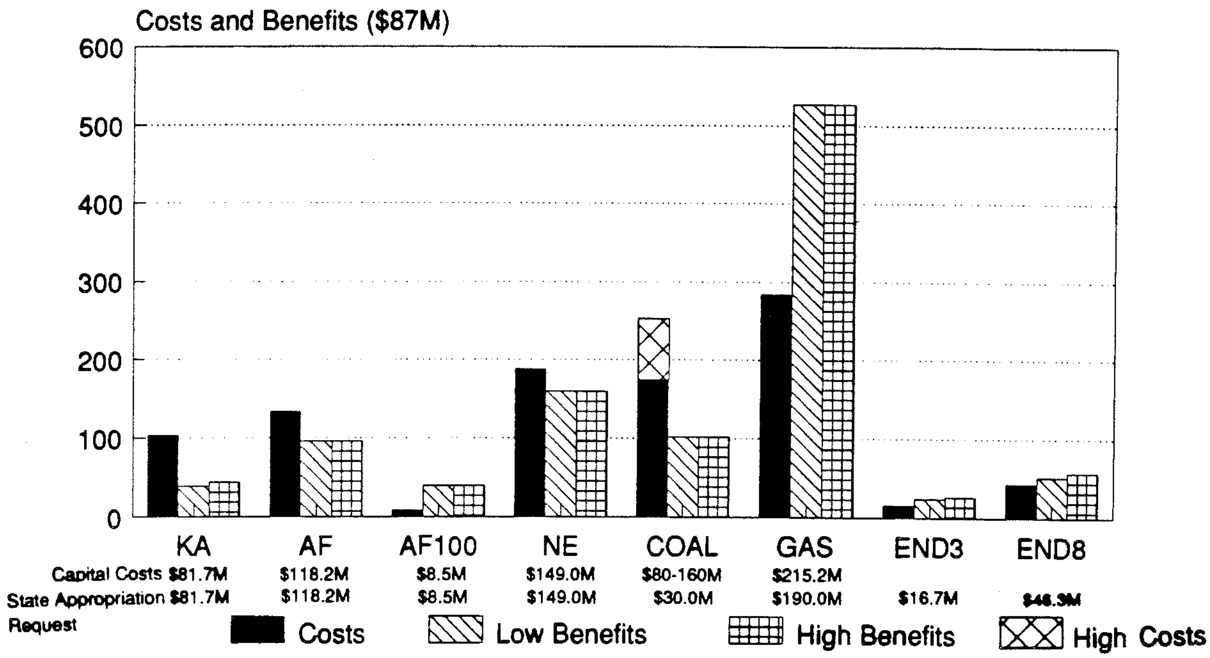
d. Benefits would be $13 million lower if none of the backscatter radar load were supplied by the grid; benefits could be $6 million higher if the Northeast intertie allowed Fairbanks to share in future new capacity in Anchorage.

e. Cost does not include any consideration of possible subsidy by the federal government.

f. Benefits do not include any credit for cogeneration or coal drying.

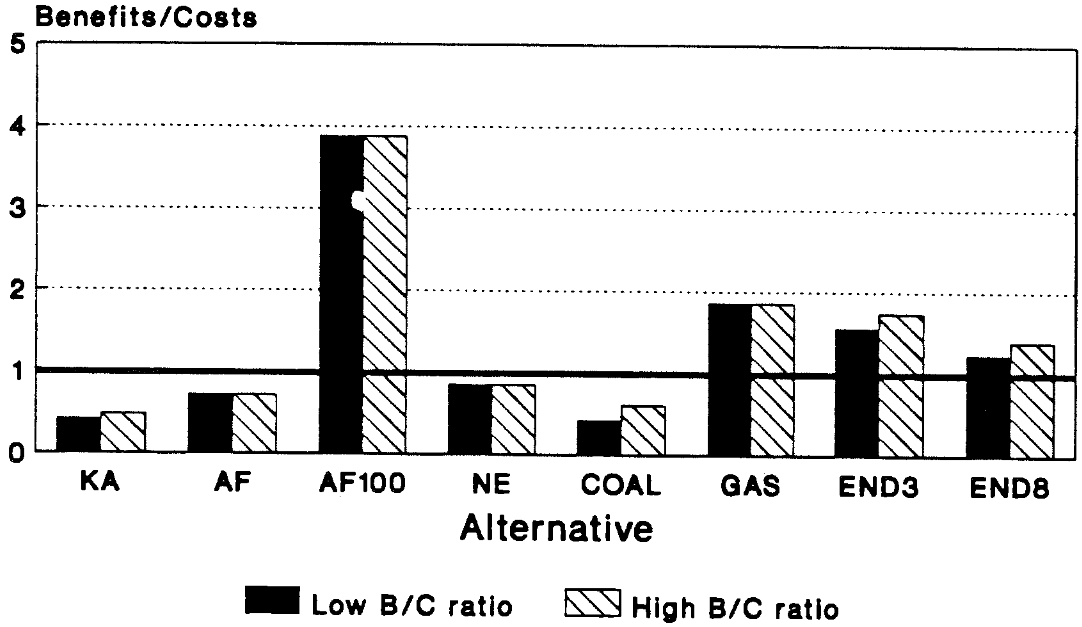
g. Includes all benefits, both within and outside the electric power sector.

h. Incremental Benefit/cost ratio of remaining five programs is 1.05 to 1.19.



Note: Each cost column shows expected total costs, including capital costs and the present value of future O&M costs. Each benefit column shows the present value of future benefits. Additional information is included below each set of columns. First, the estimated capital cost (expressed in 1987 dollars) is identified for each project except the end-use conservation programs. The budgetary cost of these programs consists primarily of rebates rather than capital costs. Both a high and a low capital cost estimate is included for the 50-MW coal-fired power plant alternative. Second, an estimate of "State appropriation request" is shown to indicate the extent of State funding that either is presently sought or apparently would be sought by project advocates. In the case of the end-use programs, these estimates are equal to total estimated budgetary costs of program implementation over a 10-year period. All of the State appropriation requests also are shown in 1987 dollars, except for the coal plant request which is expressed in nominal dollars.

Figure 1-1. Railbelt Alternatives: Costs and Benefits



Based on expected net benefits for nine base case scenarios.

Figure 1-2. Railbelt Alternatives: Benefit/Cost Ratios

1.4.1 New Kenai-Anchorage Intertie

This alternative consists of a new 230-KV transmission line between Anchorage and the Kenai Peninsula with a transfer capacity of 250 MW. The capital cost of the proposed Kenai-Anchorage intertie is $81.7 million for the "Enstar" route and $99.4 million for the "Tesoro" route[2]. This analysis of benefits and costs is based on the lower of these two capital cost estimates. Operations and maintenance cost is estimated at $1.2 million per year. The present value of total costs is estimated at $103.1 million.

The expected value of benefits is estimated between $43.1 million and $49.1 million. This consists of benefits in the following six categories:

1. *Stability*: The new intertie would allow the avoidance of $2.8 million in costs to provide stability with Bradley Lake at peak output.

[2]Unless otherwise noted, these and all other costs and benefits are presented in terms of 1987 dollars.

2. *Reliability*: The value of improved reliability due to the new intertie is estimated between $11.2 million and $17.2 million.

3. *Increased Economy Energy Transfer*: Savings due to increased transfers between the Kenai Peninsula and Anchorage are estimated at $8.9 million[3].

4. *Reduced Transmission Losses*: Because of its higher transfer efficiency, the new intertie would reduce transmission losses. The value of savings due to reduced transmission losses is estimated at $8.6 million.

5. *Increased Capacity Sharing*: The improved transmission link would allow Anchorage to rely on a greater portion of the Kenai Peninsula generation capacity surplus for meeting the Anchorage capacity requirement. This value is estimated at $10.8 million.

6. *Increased Spinning Reserve Sharing*: Improved access to Kenai Peninsula spinning reserves is estimated to produce a value of $0.7 million.

It was recently suggested that, in the future, the existing line may be unavailable for transfers during two months each year due to scheduled maintenance. Though insufficient time was available for careful evaluation of this issue, a brief analysis suggests that the benefits of the new intertie would increase by $8 to $9 million if two month per year transfer interruptions for the existing line were assumed over the next 35 years.

1.4.2 Full Upgrade of Anchorage-Fairbanks Intertie to 225 MW

This alternative consists of new transmission line segments between Healy and Fairbanks and between Willow and the Wasilla area. Transfer capacity between Anchorage and Fairbanks would be increased to 225 MW. The capital cost of the proposed full upgrade of the Anchorage-Fairbanks intertie is $118.2 million. The

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[3]This is far below the estimate presented in the preliminary economic assessment issued by APA in March 1987. The main reason for this is the assumption on natural gas transportation costs. In the 1987 analysis, APA assumed that the cost of transporting natural gas by pipeline from the Kenai Peninsula to Anchorage was essentially variable and could be avoided if transport volumes were reduced. Very large benefits were calculated by assuming that, if the new intertie were built, generation would be moved from Anchorage, where the gas price includes a delivery margin, to the Kenai Peninsula where gas is available at wellhead prices. However, although the electric utility may face lower gas prices on the Kenai Peninsula, there is no real cost savings overall because the cost of gas transportation via pipeline is primarily fixed. Lower gas transport volumes do not result in significant overall cost reductions.

additional operations and maintenance cost is estimated at $0.9 million per year. The present value of total costs is estimated at $133.9 million.

The expected value of benefits is estimated at $95.9 million in the following four categories:

1. *Reliability*: The value of improved reliability is estimated at $1.4 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers between Anchorage and Fairbanks are estimated at $87.1 million.

3. *Reduced Transmission Losses*: Because of its higher transfer efficiency, the upgraded intertie would reduce transmission losses. The value of this reduction is estimated at $6.3 million.

4. *Increased Capacity Sharing*: The upgrade would allow Anchorage to rely on a greater portion of the Fairbanks generation capacity surplus for meeting the Anchorage capacity requirement. This value is estimated at $1.1 million.

1.4.3 Limited Upgrade of Anchorage-Fairbanks Intertie to 100 MW

This alternative consists of electrical equipment to provide a limited increase in the transfer capacity of the existing line. Presently, when the maximum of 70 MW is input at one end (typically in Anchorage), 61.6 MW can be received at the other end (typically in Fairbanks). This alternative would allow an additional 30 MW to be input at one end with the result that an additional 22.6 MW would be received at the other end. Transmission losses for this increment would therefore be 25 percent from the sender's perspective and 33 percent from the receiver's perspective. The estimated capital cost of this limited upgrade is $8.5 million (again, expressed in 1987 dollars). Operations and maintenance cost is estimated at $0.1 million per year. The present value of total costs is $10.3 million.

The expected value of benefits is $39.9 million in the following two categories:

1. *Increased Economy Energy Transfer*: Savings due to increased transfers between Anchorage and Fairbanks, after adjusting for increased transmission losses, are estimated at $38.8 million. Unlike the full upgrade proposal, transmission losses are increased

for this alternative and this increase is accounted for in the estimate of net savings.

2. *Increased Capacity Sharing Benefits*: As with the full upgrade proposal, these benefits are estimated at $1.1 million.

1.4.4 Northeast Intertie

This alternative consists of a new transmission line from Palmer through Glennallen to Delta Junction with a transfer capacity of 150 MW. It would provide an alternate route for transfers between the Anchorage and Fairbanks areas, and would provide the Copper Valley area with access to the Railbelt electric grid. The capital cost of the Northeast intertie is estimated at $149 million (1987 dollars), and the annual operations and maintenance cost is estimated at $2.2 million. The present value of total costs is estimated at $188.1 million.

The expected value of benefits is $159.3 million in the following three categories:

1. *Reliability*: The value of improved reliability, primarily in the Fairbanks area, as a result of the Northeast intertie is estimated at $10.3 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers, again adjusting for increased transmission losses, are estimated at $147.9 million. Although the combination of the two lines between Anchorage and Fairbanks provides more efficient transfer than the single line alone, the increase in transfer levels results in a net increase in total expected transmission losses. The expected savings account for transfers both to Fairbanks and to the Copper Valley area for displacement of Copper Valley's diesel generation.

3. *Increased Capacity Sharing*: As for the other intertie alternatives between Anchorage and Fairbanks, increased capacity sharing benefits are estimated at $1.1 million.

These estimates include the assumption in a number of cases that a portion of the electrical load for the backscatter radar facility will be served by the utility grid. If that assumption is removed from the analysis, expected benefits would decline by approximately $13 million.

1.4.5 50-MW Coal-Fired Power Plant

A 50-MW coal-fired power plant at Healy was selected for evaluation. The possible contribution of cogenerated steam for provision to a coal-drying facility was considered after the power plant economics had been assessed separately. The costs and benefits presented here pertain to a single-purpose power plant with no cogeneration component. Further, the costs expressed are total costs without any consideration of possible subsidy from the federal government or elsewhere.

The power plant economics were reviewed with both a high and a low assumption on capital costs. For the high case, an estimate of approximately $160 million was used as developed for this study by Stone & Webster Engineering Corporation. The low case was based on a total capital cost of $80 million. The fixed O&M expense was assumed to be $5.6 million per year. The fuel cost was assumed at $0.85 per MBtu, reflecting a blend of 50 percent waste coal valued at $0.50 per MBtu and 50 percent standard coal valued at $1.20 per MBtu. The present value of total costs was estimated between $177 million and $257 million.

The expected value of benefits is estimated at $107.7 million in the following three categories:

1. *Reduced Energy Costs*: These are savings in the variable costs of power generation (i.e. fuel and variable O&M costs), and are estimated at $67.3 million.

2. *Reduced Transmission Losses*: Because power delivered to Fairbanks from Healy would displace power delivered from Anchorage, transmission losses would be reduced. Approximately 70 percent of the losses between Anchorage and Fairbanks occur on average between Healy and Fairbanks. The estimate of savings from reduced transmission losses is $4.3 million.

3. *Capacity Benefit*: Construction of a 50-MW coal plant allows the avoidance of 50 MW of alternative capacity, assumed in this analysis to be combustion turbine capacity. The estimated value of this capacity benefit is $36.2 million.

If steam were also produced at the plant for provision to an adjacent facility, it is estimated that the cost of production would be $3.65 per MBtu of additional steam. This cogeneration component would add benefit to the overall plant economics if the value of the steam to the adjacent facility were to exceed $3.65 per MBtu. No estimate of the value of steam to a coal drying facility has been made for this analysis.

1.4.6 Gas Pipeline Between Cook Inlet and Fairbanks

This alternative consists of a natural gas transmission and distribution system linking Fairbanks with the Cook Inlet area. The estimated capital cost is $183 million (1987 dollars) for the main pipeline between Cook Inlet and Fairbanks, plus $32.5 million for the distribution system within Fairbanks. The annual O&M cost is estimated at $3.9 million. The present value of total costs is therefore $284 million.

The present value of benefits is estimated at $527 million in the following four categories:

1. *Reliability*: Electric system reliability would be improved in the Fairbanks area to the extent that local generation is increased and intertie purchases decline. The value of improved reliability is estimated at $5.8 million.

2. *Reduced Energy Costs*: Variable costs of power production in the Fairbanks area are estimated to decrease as a result of natural gas availability. The value of this reduction is estimated at $95.3 million.

3. *Reduced Transmission Losses*: Because intertie purchases would be substantially reduced, transmission losses would decline. The value of reduced transmission losses is estimated at $17.8 million.

4. *Benefits Outside the Electric Power Sector*: Most of the benefits attributed to the gas pipeline alternative are estimated within the residential and commercial heating sectors in the Fairbanks area due primarily to the substitution of natural gas for fuel oil. The value of these benefits is estimated at $408 million.

1.4.7 Electric End-Use Conservation Programs

Proposed electric end-use conservation programs were analyzed in two groups: (1) three programs judged to be most economic on the basis of a preliminary economic screening, and (2) all eight programs judged to be promising on a preliminary basis, including the top three. Both the top three and the top eight programs are described here.

The top three programs include (1) electric-to-gas water heat conversions, (2) efficient fluorescent lamps, and (3) incandescent to fluorescent lamp conversions. The top eight programs include, in addition to the three listed above: (4) efficient electric water heaters, (5) electric-to-gas clothes dryer conversions, (6) efficient refrigerators, (7) electronic ballasts for fluorescent lamps, and (8) electric efficiency in new commercial buildings.

Programs #1 through #7 are structured around dealer/contractor rebates, i.e., rebates to the businesses that sell or install eligible efficiency equipment, thereby reducing the price of efficiency investments faced by consumers. Program #8 would provide rebates to the owners and designers of new or remodeled commercial buildings based on the design efficiency of lighting and ventilation systems.

Each program was assumed to be implemented over a 10-year period. The estimated cost of achieving program-induced efficiencies is $16 million for the top three programs, and $43 million for the top eight programs.

The benefits of these programs are estimated between $25 million and $28 million for the top three programs, and between $53.7 million and $60.7 million for the top eight programs. These benefits are realized in three categories, which are described below:

1. *Reduced Energy Costs*: The net reduction in total energy costs is estimated at $19.2 million for the top three programs and $40.1 million for the top eight programs.

2. *Reduced Transmission Losses*: Transmission losses are reduced by an estimated $0.2 million for the top three programs and $0.5 million for the top eight programs.

3. *Capacity Value*: The conservation programs allow the avoidance of an increment of new electric generating capacity. The value of this avoided capacity is estimated between $5.7 million and $8.7 million for the top three programs and between $13.1 and $20.1 million for the top eight programs.

The sum of budgetary costs required to implement these programs over a 10-year period is estimated at $16.7 million (1987 dollars) for the top three programs, and $46.3 million for the top eight programs.

Section 2

DESCRIPTION AND COSTS OF ALTERNATIVES

2.1 NEW INTERTIE BETWEEN ANCHORAGE AND THE KENAI PENINSULA

The preliminary design and cost estimates for these options were developed by Power Engineers, Incorporated. Two route alternatives were identified:

1. "Enstar" route, which follows an existing natural gas pipeline through the Kenai National Wildlife Refuge, followed by a submarine crossing of Turnagain Arm into Anchorage. The capital cost is estimated at $81.7 million (in 1987 dollars). Annual operations and maintenance cost is estimated at 1.5 percent of capital cost, or $1.2 million per year.

2. "Tesoro" route, which follows an existing oil products pipeline along the west coast of the Kenai Peninsula, followed by a submarine crossing of Turnagain Arm into Anchorage. The capital cost is estimated at $99.4 million (in 1987 dollars). Annual operations and maintenance cost is again estimated at 1.5 percent of capital cost, or $1.5 million per year.

Either line would be constructed at 230 KV and have a transfer capacity of 250 MW. Because the Enstar route crosses land within the Wildlife Refuge that had been proposed (though not yet designated) as "wilderness," it was anticipated that both Congressional and Presidential approval would be required to obtain the necessary right-of-way. Though cost considerations clearly favor the Enstar route, the Tesoro route was developed in case the proposed wilderness designation forced abandonment of the less expensive alternative. However, the Department of Interior has now acted favorably on a request by the State to exclude from wilderness designation a corridor adjacent to the Enstar pipeline for possible future construction of the proposed intertie. If Congress agrees to exclude the intertie corridor from wilderness designation, the two proposed routes would then be roughly equivalent in terms of permitting difficulty.

Preliminary schedules for permitting and construction suggest that completion of the intertie should not be expected prior to 1994, regardless of the route.

2.2 FULL UPGRADE OF THE EXISTING ANCHORAGE-FAIRBANKS INTERTIE

The preliminary design and cost estimate for this proposal was developed by Harza Engineering Company. Presently, the transmission link between the Wasilla area and Fairbanks consists of three segments:

1. Wasilla to Willow—138 KV line owned by Matanuska Electric Association.

2. Willow to Healy—345 KV line owned by the Alaska Power Authority (APA). The line is presently operated at 138 KV, consistent with voltages at either end.

3. Healy to Fairbanks—138 KV line owned by Golden Valley Electric Association (GVEA).

The full upgrade proposal consists primarily of new 345 KV line construction between Willow and the Chugach Electric Association (CEA) transmission system south of Wasilla, and new construction between Healy and Fairbanks. (Existing segments would be supplemented, not replaced, by the new line construction.) This revised link between Anchorage and Fairbanks would initially be operated at 230 KV, raising the transfer capability from the present level of 70 MW to 225 MW.

The capital cost of this upgrade is estimated at $118.2 million in 1987 dollars. The additional operations and maintenance cost of the intertie following this upgrade is estimated at $900,000 per year, again in 1987 dollars.

The main issue with respect to land use involves the new segment from Healy to Fairbanks. The proposed route crosses federal land south of the Tanana River near Fairbanks. Agreement would have to be worked out with the military at Fort Wainwright.

Again, preliminary schedules for permitting and construction suggest that completion of the upgrade should not be expected prior to 1994.

2.3 LIMITED UPGRADE OF THE EXISTING ANCHORAGE-FAIRBANKS INTERTIE

This option was developed by Power Technologies, Incorporated (PTI) at the request of APA and represents an alternative that would provide a small but potentially useful increment of transfer capability over the existing intertie. Presently, Fairbanks can receive an estimated 61.6 MW of power over the intertie when 70 MW is input from Anchorage, assuming the existing 25-MW Healy coal plant is in operation at the time. Most of the losses are incurred on the section of the line between Healy and Fairbanks. The limited upgrade alternative would allow Fairbanks to receive an estimated 84.2 MW over the intertie when 100 MW is input from Anchorage. In other words, an additional 30 MW of power input from Anchorage would allow an additional 22.6 MW to be received in Fairbanks.

The estimated capital cost of this limited upgrade is $8.8 million in 1988 dollars. Its main components consist of one SVS (static var) unit supplementing the three units now in place on the intertie, one additional transformer, and six series capacitors. The additional operations and maintenance cost is estimated at $0.1 million per year.

The present system does not meet the system performance criteria established for the limited upgrade. In order for the present system to meet the same criteria at 70-MW export from Anchorage, the additional SVS unit and one series capacitor would have to be installed. This implies that system performance under the proposed limited upgrade would be improved relative to system performance today.

2.4 NEW INTERTIE FROM PALMER THROUGH GLENNALLEN TO DELTA JUNCTION (NORTHEAST INTERTIE)

The preliminary design and cost estimate for this alternative was developed by Power Engineers, Incorporated. The proposed line would be constructed at 230 KV but operated initially at 138 KV with a transfer capacity of 150 MW. In combination with the existing Anchorage-Fairbanks intertie, the combined transfer capability would therefore be 220 MW, minus whatever intermediate load is served along the Northeast intertie route. For illustration, if the intermediate load served by the intertie in the Glennallen-Valdez area were 10 MW, the combined transfer capability between Anchorage and Fairbanks would be 210 MW.

The capital cost of the Northeast intertie is estimated at $155 million in 1988 dollars. Annual operations and maintenance cost is estimated at 1.5 percent of capital cost, or $2.3 million per year.

Preliminary schedules for permitting and construction suggest that completion of the intertie should not be expected prior to 1994.

2.5 COAL-FIRED POWER PLANTS IN THE RAILBELT

Preliminary design and cost estimates were developed by Stone & Webster Engineering Corporation. Capital cost as well as operations and maintenance cost estimates were developed for coal-fired power plants in three different sizes (50 MW, 100 MW, and 150 MW) and four different Railbelt locations (Healy, Nenana, Beluga, and Matanuska Valley).

Table 2-1 shows a summary of the capital cost estimates and Table 2-2 shows a summary of the operations and maintenance costs.

Table 2-1

CAPITAL COST ESTIMATES
(1988 dollars)

	Healy	Nenana	Beluga	Matanuska
50 MW				
$/kW	3,322	3,378	3,476	3,119
Total ($M)	166.1	168.9	173.8	155.9
100 MW				
$/kW	2,499	2,522	2,610	2,340
Total ($M)	249.9	252.3	261.0	234.0
150 MW				
$/kW	2,143	2,158	2,235	1,952
Total ($M)	321.5	323.7	335.3	292.9

Table 2-2

ANNUAL OPERATIONS AND MAINTENANCE COST ESTIMATES*
(millions of 1988 dollars)

	Healy	Nenana	Beluga	Matanuska
50 MW	7.2	7.2	7.2	7.4
100 MW	10.2	10.2	10.2	10.5
150 MW	13.0	13.0	13.0	13.4

* Excludes first year costs for training and commissioning

The combustion technology selected for development of these estimates is atmospheric fluidized bed, based primarily on its expected cost advantage over conventional pulverized coal plants. The cost advantage results from the avoidance of a flue gas desulfurization system.

Organizations proposing to build coal-fired power plants at Healy and at Nenana have thus far maintained that such plants with capacities of approximately 100 MW could be built at an installed cost of about $1,600 per kilowatt, in contrast to the Stone & Webster estimate of about $2,500 per kilowatt. In other words, the Stone & Webster estimate is on the order of 50 percent higher than the estimates suggested by these prospective sponsors.

Because comparable detail has not been made available for the lower estimates, the causes of this substantial difference are not precisely known. However, it appears that the major issue is the estimate of cost differential between Alaska and the lower 48, especially in the area of labor cost.

The power system analysis focused on a single coal-fired power plant proposal: a 50-MW minemouth plant at Healy. Results are presented for two different capital cost estimates: $1600 per kilowatt as previously estimated by potential project sponsors, and $3322 per kilowatt as estimated by Stone & Webster for the 50-MW size. These estimates are applied only to the cost of constructing a single-purpose power plant, and do not include the additional cost that would be incurred for a cogeneration plant that could provide a significant volume of steam to an adjacent facility as well as 50 MW of power.

Stone & Webster also provided an estimate of the additional cost necessary to build and operate a cogeneration plant that could produce not only 50 MW of power, but also sufficient high quality steam for drying an estimated 650,000 tons per year of coal, although very limited resources were available for this estimation task. Their estimate is that the additional capital cost is $368 per kilowatt, and the additional operations and maintenance cost is $400 thousand per year. These factors were used in attempting to assess the impact on coal plant economics of constructing a cogeneration facility as proposed rather than a single-purpose power plant.

Stone & Webster concluded that coal-fired power plants at any of the four sites, and at any of the three sizes, could meet environmental standards including air quality standards, and should be able to obtain all necessary permits.

2.6 NATURAL GAS PIPELINE LINKING FAIRBANKS WITH THE COOK INLET AREA

Preliminary design and cost estimates for this alternative were also prepared by Stone & Webster Engineering Corporation. The capital cost of a 16-inch diameter natural gas pipeline linking Fairbanks with the Cook Inlet area is estimated at $190 million in 1988 dollars. A 16-inch system could accommodate preliminary projections of residential and commercial consumption in the Fairbanks area over the next 30 years and, if required, its capacity could be expanded with compression to accommodate military consumption as well. (For purposes of comparison, the Stone & Webster capital cost estimate for a 20-inch pipeline—the size initially proposed by Enstar Natural Gas Company—is $235 million in 1988 dollars.)

The probability that North Slope natural gas will be available in Fairbanks for transmission to Anchorage at sustained price levels that undercut Cook Inlet gas during the next 30 years was judged by APA to be too low to form a basis for pipeline planning at this time. Though possible future levels of Anchorage demand for natural gas were, as a result, not considered in sizing the pipeline proposal, the selected 16-inch system would be capable of carrying nearly enough gas to satisfy current levels of residential and commercial demand in Anchorage.

The capital cost of the distribution system in Fairbanks is estimated at $33.8 million in 1988 dollars. The annual operations and maintenance expense for the system additions is estimated at $4.0 million ($2.4 million for the distribution system, $1.6 million for the main transmission pipeline).

The major environmental issue with respect to pipeline construction would be the potential cumulative effect on fisheries resources of the numerous instream crossings proposed. However, proper construction techniques can reduce these impacts below significant levels. With respect to air quality impacts, it is expected that widespread conversion to natural gas would reduce pollutants, especially sulfur dioxide and particulates, though increased production of water from natural gas combustion compared with coal or oil may produce increased ice fog during cold weather conditions.

2.7 ELECTRIC END-USE CONSERVATION PROGRAMS

The Institute of Social and Economic Research (ISER) was given the task of identifying the most promising electric end-use conservation programs that could be devised for the Railbelt and estimating their expected costs and load reduction impacts. Because these programs are generally less well understood than the other alternatives presented in this section, they are described below in greater detail.

Based on preliminary screening criteria, nine programs were identified by ISER for further analysis. Eight of the nine programs are structured around dealer/contractor rebates, i.e., rebates to the businesses that sell or install eligible efficiency equipment, thereby reducing the price of efficiency investments faced by consumers. The ninth program would provide rebates to the owners and designers of new or remodeled commercial buildings based on the design efficiency of lighti ıg and ventilation systems.

All the programs are intended to encourage the installation of efficient equipment either initially (in the case of the ninth program) or at the time of normal replacement of standard equipment. No intensive retrofit programs are proposed, primarily because they are more expensive (useful equipment is prematurely replaced) and the present cost of electrical generation in the Railbelt is relatively low. However, though the proposed programs are more cost-effective than accelerated retrofit-type programs, they need more time for their effects to fully register. Because the stock of appliances and equipment takes 10 to 20 years to turn over, programs that encourage efficiency upgrades at the time of normal replacement must be in place for 10 to 20 years to have the potential for affecting the entire appliance stock.

The nine programs are summarized briefly below, with the residential programs listed first, followed by commercial.

1. *Water Heater Conversions*: $500 rebate for the conversion of a residential electric water heater to natural gas.

2. *Efficient Electric Water Heaters*: $40 rebate for the purchase of an electric water heater with an efficiency over 95 percent.

3. *Gas Dryer Rebates*: $170 rebate for installation of gas piping to a clothes dryer within a residence, $50 rebate for purchase of a gas clothes dryer.

4. *Efficient Refrigerator Rebates*: $50 rebate for purchase of refrigerator at least 28 percent more efficient than required by new federal appliance efficiency standards.

5. *Efficient Freezer Rebates*: $50 rebate for purchase of freezer at least 35 percent more efficient than required by new federal appliance efficiency standards.

6. *Fluorescent Lamp Rebates*: Rebates from $0.30 to $1.80 for purchase of energy efficient fluorescent lamps.

7. *Electronic Ballast Rebates*: $13 rebate paid for each electronic fluorescent ballast. (A ballast is the device used to start and provide proper operating conditions for fluorescent lamps.)

8. *Incandescent to Fluorescent Conversions*: $7 to $12 rebates for purchase of compact fluorescent lamps, adapters, and fixtures suitable for replacing incandescent lamps.

9. *Sliding-Scale New Construction Rebates*: $1 per square foot rebate for every one watt per square foot reduction in lighting or ventilation power consumption below a threshold level. This rebate applies in the commercial sector to new construction or remodel projects, and would be divided (85 percent / 15 percent) between the building owner and the architect/engineer project designer.

The commercial lighting programs (#6, #7, and #8 above) generate nearly 60 percent of the expected savings from all nine programs. Within the residential category, the electric water heater conversion program appears to have the most impact and also the lowest cost per kilowatthour saved.

In estimating program impact, care was taken to avoid double counting efficiency measures already assumed to occur within the electric demand forecast (i.e., "market driven" efficiency), and to base projected response rates of consumers to these incentives not only on the available electric end-use data for the Railbelt but also on the program participation rates reported by others. It is estimated by ISER that if the incentive payments for all nine programs were held in place over a period of 20 years, the savings in the 20th year would be approximately 7 percent of estimated load. Load reduction impact builds over the 20-year period up to this 7 percent peak and then declines over the ensuing 20 years due to the termination of incentives, the retirement and replacement of equipment bought earlier with the incentives, and the return to "normal" purchasing behavior. The amount of electricity saved, as well as program cost, is roughly proportional to the length of the program. If the programs were in place for 5 years instead of 20, program impact would peak in year 5 at roughly 2 percent of estimated load, and then decline from there.

The technology screening analysis described in the Interim Report of the Railbelt Intertie Feasibility Study (January 30, 1989) confirmed that the top three programs consisted of two commercial lighting programs (incandescent to fluorescent conversions and rebates for more efficient fluorescent lamps) and the residential electric-to-gas hot water heat conversion program. The one program that was eliminated from further analysis was the residential rebate program for efficient freezers. For the purpose of further analysis, the programs were therefore combined into two groups: the "top three" programs and the "next five" programs.

In addition, it was assumed for subsequent analysis that the programs would remain in place for 10 years. This judgment was based on the idea that program funding over a 20-year period was unrealistic, but that more than a few years of implementation would be necessary for these types of programs to have a significant impact.

Program costs can be presented either as "resource costs" or "budgetary costs." Resource costs are used in the economic analysis and refer to the total resources expended to achieve the electric energy saving. Using the rebate program for efficient fluorescent lamps as an example, the resource costs include the incremental cost of the more efficient lamp, the additional cost of fuel for providing heat to the building (since the reduced heat output of the efficient lamps requires more output from the heating system), and the administrative costs of the rebate program. Budgetary costs include the administrative cost of the program and the cost of the rebates themselves.

For the top three programs implemented over a ten-year period, the discounted present value of resource costs is approximately $15 million. The sum of budgetary costs is estimated at $16.7 million in 1987 dollars, and $24.3 million in nominal dollars assuming incentive payments increase with inflation at 4.5 percent per year.

For the next five programs, the discounted present value of resource costs is approximately $27 million (again assuming a 10-year implementation period). The sum of budgetary costs is estimated at $29.6 million in 1987 dollars, and $43.9 million in nominal dollars assuming incentive payments increase with inflation at 4.5 percent per year.

Section 3

SYSTEM STABILITY: IMPACT OF NEW KENAI-ANCHORAGE INTERTIE[1]

Electrical system stability is maintained when all generators supplying power to a transmission grid are in synchronous operation. Instability occurs when one or more generators pulls "out of step" with the rest of the system, i.e., when synchronous operation breaks down. In that event, devices installed on transmission lines would trigger protective actions that could produce an extensive power outage. If the protection devices did not function properly, the instability could produce damage to utility and consumer equipment. Systems are therefore designed to minimize the risk of unstable conditions to avoid either extensive power outages or, should protection systems fail, equipment damage.

If not properly accounted for in system design, instability can be produced by certain significant system disturbances. Railbelt utility representatives initially perceived that the risk of instability will increase after the Bradley Lake hydroelectric project is built. It is intended that the transmission system connecting Bradley Lake with the Railbelt grid will consist of two paths between the project and Soldotna: a new direct line between the two points (referred to here as the "new Bradley-Soldotna line") and a connection with the existing Homer Electric line that runs along the west coast of the Kenai Peninsula (referred to here as the "existing Homer line"). The worst case from the standpoint of system stability would be a fault involving all three line conductors near the Bradley Lake project on the new Bradley-Soldotna line while the project is operating at peak capacity. When the new line is tripped, all of Bradley Lake's output would be directed across the existing Homer line.

A study of these possibilities was commissioned by the Technical Coordinating Committee of the Bradley Lake Project Management Committee (PMC). The Bradley Lake PMC consists of representatives of Railbelt utilities that have committed to purchasing power from the project and a representative of APA. The study was performed by Southern Engineers, Incorporated (SEI) and concluded that instability will

[1]This section was prepared by the Alaska Power Authority (APA), and was reviewed and approved by Power Technologies, Incorporated (PTI). The detailed analysis supporting the results of this section is presented in the Phase I and Phase II reports of the Railbelt Stability Study recently concluded by PTI.

arise as a result of certain transmission failures on the Kenai Peninsula following the completion of Bradley Lake, unless corrective measures are implemented. It further concluded that the main component of the preferred solution was to build the proposed new 230 KV intertie between Anchorage and Soldotna. According to the SEI analysis, resolving the stability issue without the new intertie would require a substantial investment in large voltage support devices (SVS), limitation on Bradley Lake output below its actual peak capability, and frequent "unit tripping" at Bradley Lake for faults throughout the Kenai Peninsula area, which would in turn cause numerous customer outages and generally degrade system reliability. Although SEI concluded that unit tripping would also be necessary at times if the proposed new 230 KV line were built, the particular occasions believed to require it would be infrequent.

The SEI study was considered preliminary and incomplete by APA technical staff, though its conclusions are highly relevant to the feasibility assessment of the proposed Kenai-Anchorage intertie as well as potentially significant for the design and operation of the Bradley Lake project. Consequently, APA issued a contract to PTI to perform an independent assessment of the stability issue, including careful development of solutions with and without the proposed new intertie. PTI specializes in the type of analysis required for exploration of stability problems and solutions.

The initial conclusions reached by PTI were as follows:

1. There are in fact significant stability problems when Bradley Lake is generating power above about 60 MW.

2. Important options to provide stability were not considered in the SEI analysis. These include braking resistors, excitation stabilizers, and use of the Bradley Lake deflectors.

Further, PTI found that the output level at Bradley Lake is the most important factor contributing to stability problems in the event of transmission failures, and that the cost of solutions to address these problems increases rapidly as Bradley Lake output is assumed to approach peak project capacity. In other words, the cost increment to provide stability is relatively small between 60-MW output and 90-MW output, but is relatively large between 90-MW output and 120-MW output. This is important for two reasons:

1. Although the peak capacity of Bradley Lake had been assumed at 90 MW throughout the project development stage, refinement of that estimate during detailed project design has resulted in an increase in estimated peak project capacity to 119 MW. Though this does not result in any increase in the amount of energy the project can produce during a year (i.e., kWh), it does mean that

more power can be generated at any given time than was previously estimated.

2. PTI has shown that, without the proposed new Kenai-Anchorage intertie, stability can be maintained in the event of a worst case transmission fault with relatively minor investments as long as Bradley Lake is not operated above 90 MW. Specifically, the addition of braking resistors and stabilizers at the Bradley Lake project site at an estimated cost of $750 thousand would result in satisfactory stability conditions, provided that power was ramped back from 90 MW to 60 MW upon trip of the new Bradley-Soldotna line.

PTI was directed to devote most of its attention to providing stability with Bradley Lake output assumed at 119 MW (hereafter rounded up to 120 MW), and to do so with no "unit tripping" at Bradley Lake, though limited ramp back of power was allowed. As summarized in the Interim Report (January 30, 1989), the preliminary results from PTI indicated that stability could be maintained in the absence of the proposed new intertie with the addition of a braking resistor and stabilizers at the Bradley site, plus three series capacitors at a total estimated cost of $2.5 million. With the proposed new intertie, the Interim Report showed a total estimated cost of $750 thousand for the braking resistor and stabilizers alone. According to these preliminary figures, the proposed intertie would therefore allow the avoidance of $1.75 million to provide comparable stability conditions.

The Interim Report also stated that additional stability aids may ultimately be recommended to further improve electrical conditions or to address other transmission failures or operating conditions. The following major changes were made subsequent to the Interim Report that resulted in the recommendation of additional stability aids:

1. To further improve electrical conditions, the allowable range of voltage and frequency excursions following a transmission failure was further tightened at the request of Railbelt electric utility representatives.

2. The preliminary results assumed that Bradley Lake would be operated at 120-MW peak output only during peak load conditions. Additional investment is required to maintain stability if peak output is assumed during off-peak load conditions. The revised analysis assumed 120-MW Bradley Lake output during low load conditions.

3. The preliminary results assumed that at least one generator each at Cooper Lake and Bernice Lake, also located on the Kenai Peninsula, would be on-line at the time Bradley Lake was producing 120 MW. Additional investment is required to maintain stability if Bradley Lake is operating alone on the Kenai Peninsula, particularly at peak output. The revised analysis assumed that no generation other than Bradley Lake is on-line at the time of the simulated transmission failure.

As a result of these modifications, the revised solutions recommended by PTI are designed to maintain stability following a worst case three-phase fault on the new Bradley-Soldotna line near the Bradley Lake project, when Bradley Lake is operating at 120 MW during low load conditions with 75 MW being exported from the Kenai Peninsula, with no other generation on-line on the Kenai Peninsula, and with voltage and frequency excursions remaining within the tighter constraints requested by Railbelt utility representatives. Tables 3-1 and 3-2 show the components of the recommended solutions with and without the proposed new Kenai-Anchorage intertie. The capital cost estimates associated with these recommendations were developed by APA in consultation with PTI.

Table 3-1

RECOMMENDED SOLUTION WITHOUT NEW INTERTIE

Component	Capital Cost ($1989 Millions)
1 +30/-25 MVAR SVS	3.2
3 Series Capacitors	0.9
SCADA and communications	0.3
1 Circuit Switcher	0.2
Misc. (land, site preparation, etc.)	0.4
Subtotal	5.0
Engineering and Administration (20%)	1.0
Contingency (20%)	1.0
Total	7.0
Added Bradley Lake Costs	
Braking Resistors and Stabilizers	0.75

Table 3-2

RECOMMENDED SOLUTION WITH NEW INTERTIE

Component	Capital Cost ($1989 Millions)
1 +10/-10 MVAR SVS	1.5
2 Series Capacitors	0.6
SCADA and communications	0.3
1 Circuit Switcher	0.4
Misc. (land, site preparation, etc.)	0.4
Subtotal	3.0
Engineering and Administration (20%)	0.6
Contingency (20%)	0.6
Total	4.2
Added Bradley Lake Costs	
Braking Resistors and Stabilizers	0.75

The added Bradley Lake costs of $0.75 million are common to both scenarios. Other capital costs are estimated at $7.0 million without the new intertie and $4.2 million with the new intertie. Therefore, the proposed Kenai-Anchorage intertie is now estimated to allow the avoidance of $2.8 million in capital costs to provide comparable stability conditions. The estimated difference between the two scenarios in operations and maintenance costs for the stability aids is not significant.[2]

Detailed specification studies would be required to proceed with either alternative. Most significant among these are SSR/SSO studies (sub-synchronous oscillation/sub-synchronous resonance) required for final specification of the series capacitors. Though the probability is low, it is possible that these studies would conclude that satisfactory specification could not be achieved and that series capacitors could not be used. Since these contribute to the stability solution with or without the proposed intertie, that conclusion would have comparable impact in either case. PTI has developed an equivalent solution without the intertie that uses two SVS units rather than one SVS and three series capacitors. The "all SVS" solution is estimated to cost an additional $1.6 million.

[2]Memorandum from Afzal Khan to Donald Shira, APA, March 21, 1989. The annual difference in O&M is estimated at $4,500. The present value of this difference over 35 years is $79,000.

Subject to this qualification on the use of series capacitors, PTI maintains a very high level of confidence that the solutions recommended will provide stability under the full range of anticipated conditions.

Section 4

IMPACT OF PROPOSED INTERTIES ON SYSTEM RELIABILITY

4.1 OVERVIEW

This section analyzes the effects that upgraded or new interties would have on Railbelt service reliability. Reliability is an important attribute of electric power systems, because the value of most power used greatly exceeds its cost. The costs to utilities of customer outages may be relatively small when measured in terms of lost revenues. However, the costs incurred by customers can be large, particularly for certain types of industrial and commercial customers. Upgraded or new interties could affect both the frequency and the duration of customer outages. This section considers the effects on reliability of

1. The new Kenai-Anchorage line.
2. The Anchorage-Fairbanks upgrade.
3. The new Anchorage-Fairbanks Northeast intertie.

The assessment of the value of improved system reliability due to new or upgraded transmission lines requires estimates of the intertie impacts on customer outages and the costs of avoided outages. The costs are difficult to calculate and the analysis of potential changes in customer outages in the Railbelt is complicated by the addition of Bradley Lake.

Because an in-depth study was not possible within the time constraints of this study, we used the results of recent research on the costs of customer outages compiled by the Electric Power Research Institute (EPRI) and a detailed study performed by Ontario Hydro that we judged to be the most applicable to the Railbelt. We also analyzed historical outages data in the Railbelt and discussed expectations for potential changes in customer outages with the Railbelt utilities, Alaska Power Authority (APA), and Power Technologies, Incorporated (PTI).

This section examines historical customer outages in the Railbelt, describes the potential changes in customer outages that would result from the proposed new or upgraded transmission lines, summarizes the costs of customer outages, and summarizes the value of improved system reliability.

4.2 ANALYSIS OF HISTORICAL CUSTOMER OUTAGES

4.2.1 Customer Outages

To determine the historical level of customer outages in the study area, we collected information on outages in 1986 and 1987 from the eight utilities[1] that could be affected by one or more of the intertie proposals. Because only outages that could have been eliminated with the implementation of new or upgraded interties were important to this study, transmission- and generation-related outages only were considered.[2] The information we received from the utilities varied in format and detail considerably. Some utilities reported individual outages down to the feeder level, while others simply summarized the total outage hours per customer per year. Table 4-1 summarizes the form of the data received from each utility. Appendix A includes the detailed outages data.

4.2.2 Customer Unserved Energy

Customer unserved energy due to a customer outage is the electric energy that would have been demanded by the customer if the customer was not subject to the outage. The total unserved energy of an outage is the total number of customers affected by the outage multiplied by the average demand per customer and by the duration of the outage. For example, if 2500 customers were without power for one hour and the average demand per customer was 5 kWh/hour, then the total unserved energy would be 2500 customers x 5 kWh/hour x 1 hour = 12500 kWh or 12.5 MWh. For outages where different numbers of customers were affected for different amounts of time, the utilities often recorded multiple outages affecting different numbers of customers for different durations. For example, if an outage affects 5000 customers, but half are restored within half an hour and the other half within an hour, the outage would be recorded as one outage for half an hour for 2500 customers and another outage for one hour for the 2500 other customers.

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[1]Anchorage Municipal Light and Power (AMLP), Chugach Electric Association (CEA), Matanuska Electric Association (MEA), Homer Electric Association (HEA), Seward Electric System (SES), Golden Valley Electric Association (GVEA), Fairbanks Municipal Utility System (FMUS), and Copper Valley Electric Association (CVEA).

[2]Transmission line outages occur when a transmission line goes down and the receiving area is unable to meet the new demand through spinning reserves. Generation-related outages occur when a generating unit goes down, and demand cannot be met because of insufficient spinning reserves or inadequate access to spinning reserves through the transmission system.

Table 4-1

FORM OF UTILITY DATA ON CUSTOMER OUTAGES

Utility	How Outages Were Reported
AMLP	Date, time, duration, cause, location, and number of customers affected for each outage.
CEA	Total unserved energy per customer from REA Form 7 (Chugach detailed outage information was not available at the time of the survey).
MEA	Date, time, duration, cause, location, and number of customers affected for each outage.
HEA	Date, time, duration, cause, location, and number of customers affected for each outage.
SES	Date and average outage time of transmission line outages only.
FMUS	Date, time, duration, cause, location, feeder, and type of feeder demand for each feeder.
GVEA	Outage hours per customer from REA Form 7, along with breakdowns of outages by duration for five years (1983 to 1987).
CVEA	Outage hours per customer from REA Form 7 for six years (1982 to 1987).

Customer demand varies by the time of day and by the time of year. For example, load is typically higher in the winter than in the summer, and load is higher during the workday than during the weekend. Thus the average demand was modified to reflect the time of the outage by dividing the year into two time periods: peak and off-peak. Peak hours were defined as the highest half demand hours of the year, and off-peak hours were defined as the lowest half demand hours of the year. A peak-to-off-peak ratio was then determined for each utility, and a corresponding weight was applied to each outage's average customer demand depending upon whether an outage occurred during the peak or off-peak period. In addition, using the residential demand for each utility [1] and [2], we determined the load splits between residential and industrial/commercial customers. This information was used to determine the unserved energy breakdowns by customer type and proved useful later in evaluating customer outage costs. Table 4-2 shows the average demand per customer, the off-peak-to-peak-load ratios, and the residential and industrial/commercial load fractions for each utility.

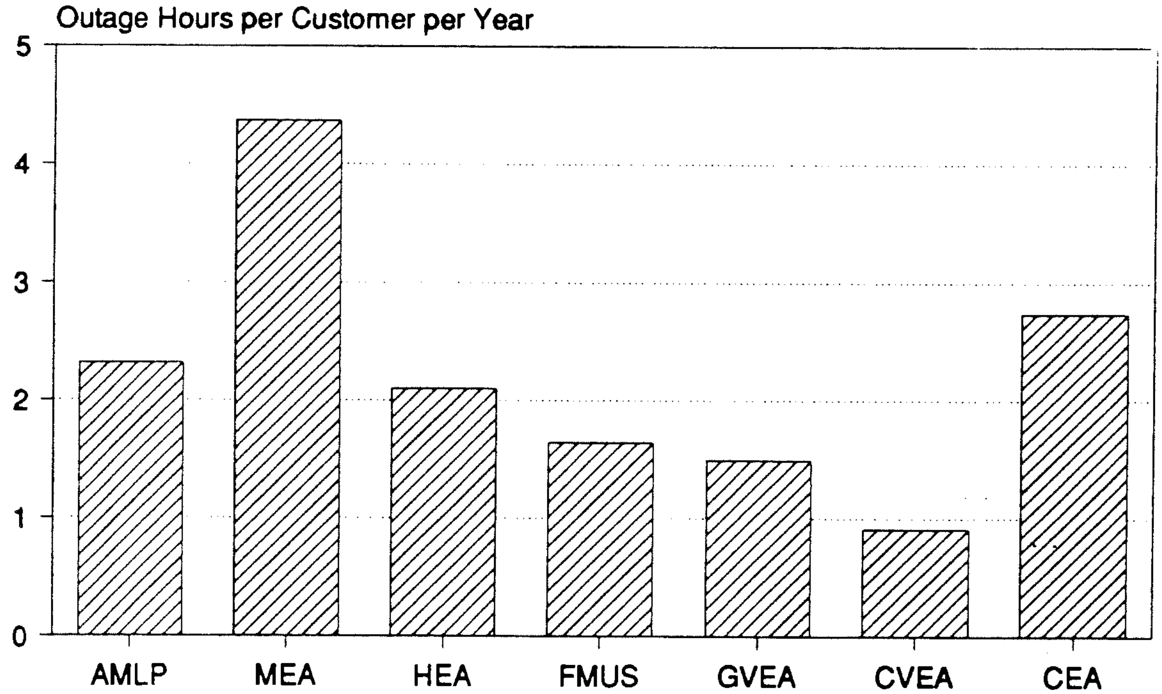
Table 4-2

DEMAND BY UTILITY AND RESIDENTIAL-INDUSTRIAL/COMMERCIAL SPLIT
(1986)

Utility	Total Demand (MWh/yr)	Number of Customer	Average Demand/ Customer (kWh/hr)	Resid'al Demand (MWh/yr)	Demand (Fraction) Resid'al	Demand (Fraction) Ind/Comm	Off-Peak-to-Peak Ratio
AMLP	817217	30311	3.08	178375	0.22	0.78	0.72
CEA	918322	61222	1.71	478040	0.52	0.48	0.74
MEA	418656	27725	1.72	272746	0.65	0.35	0.61
HEA	397024	16914	2.68	139903	0.35	0.65	0.78
SES	33315	1626	2.34	11873	0.36	0.64	0.75
CVEA	43570	2310	2.15	11750	0.27	0.73	0.75
GVEA	451716	26053	1.98	181389	0.40	0.60	0.74
FMUS	145865	6334	2.63	26554	0.18	0.82	0.74
Total	3225685	172495		1300630	0.40	0.60	

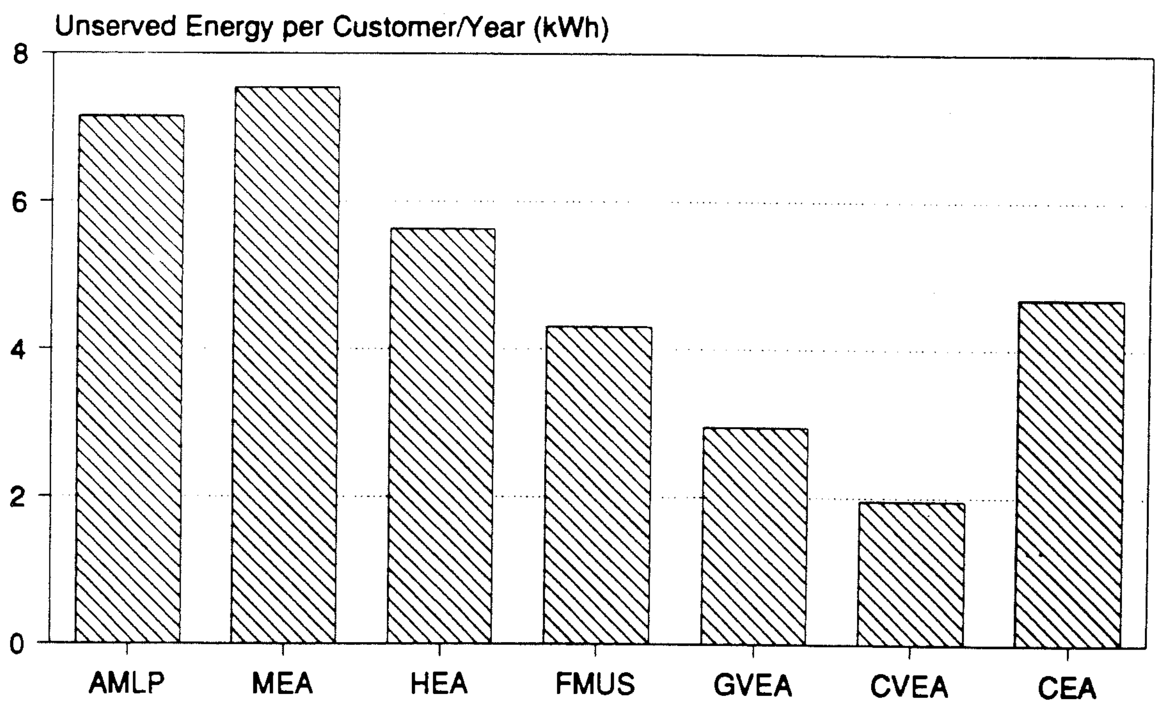
Utility Outages. Evaluating the unserved energy by utility, we found that most of the utilities had outage hours ranging from a little more than four hours per customer per year, to less than one hour per customer per year. SES was somewhat unusual. SES exceeded all other utilities in terms of outage hours (10.3 hours/customer/year) and unserved energy (24.2 kWh/customer/year). Since SES imports all of its power from CEA, mostly via the existing Anchorage-Kenai line (University-Daves Creek), whenever that line or SES's link to it goes down, all the SES customers are without power until either the transmission line is restored or the SES can get its diesel generators on-line, which takes 15 to 45 minutes. Among the other utilities, MEA, which also buys all of its power from CEA, had the next largest outages with 4.4 outage hours per customer per year and 7.5 kWh of unserved energy per customer per year. CEA had the next largest outages with approximately 2.7 outage hours per customer per year although AMLP had more unserved energy (7.1 kWh/customer/year versus 4.7 kWh/customer/year at CEA) due to its much greater fraction of industrial/commercial load.[3] The Copper Valley area (CVEA) and the Fairbanks area have the lowest outage hours (and unserved energy) per customer. Figure 4-1 shows the total outage hours per customer by utility for the survey period, Figure 4-2 shows the corresponding total unserved energy per customer by utility, and Figure 4-3 shows the split of unserved energy by utility.

[3]78% of load at AMLP compared to 48% of load at CEA.



Note: SES outage hours = 10.34

Figure 4-1. Outage Hours per Customer of Railbelt Utilities (1986/87 Average)



Note: SES unserved energy = 24.19 kWh

Figure 4-2. Unserved Energy per Customer of Railbelt Utilities (1986/87 Average)

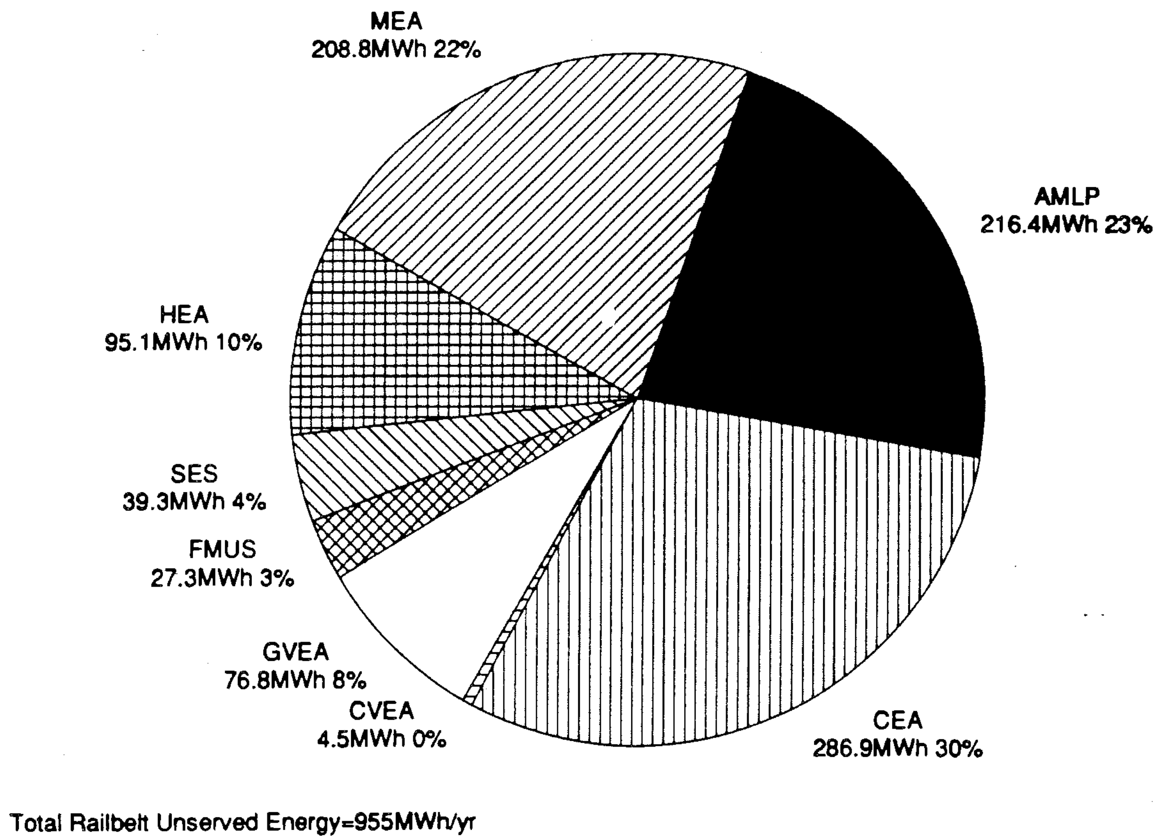


Figure 4-3. Distribution of Railbelt Unserved Energy by Utility (1986/87 Average)

Area Outages. The Railbelt averaged 955 MWh of unserved energy over the survey period (see Table 4-3). This came to approximately 2.6 outage hours per customer per year and about 5.5 kWh of unserved energy per customer per year. Residential customers experienced approximately 44 percent of the unserved energy. Anchorage and Kenai experienced the greatest number of outage hours per customer: 2.91 and 2.71 hours per customer, respectively; corresponding to 6.12 and 6.23 kWh of unserved energy per customer per year. Fairbanks and Copper Valley experienced the lowest outages per customer: 1.53 and 0.91 outage hours per customer, respectively; corresponding to 3.21 and 1.95 kWh of unserved energy per customer. Most of the total unserved energy (69 percent) was in Anchorage; Kenai had 20 percent and Fairbanks had the other 11 percent; Copper Valley had less than 1 percent. Figure 4-4 illustrates customer total outage hours by area, Figure 4-5 shows customer unserved energy by area, and Figure 4-6 shows the unserved energy split by area.

Table 4-3

SUMMARY OF OUTAGE HOURS AND UNSERVED ENERGY FOR THE RAILBELT

	1986	1987	Average (1986/87)
Outage Hours per Customer	3.37	1.82	2.59
Unserved Energy (kWh per customer)	7.19	3.89	5.54
Unserved Energy (MWh)	1239.79	670.36	955.07

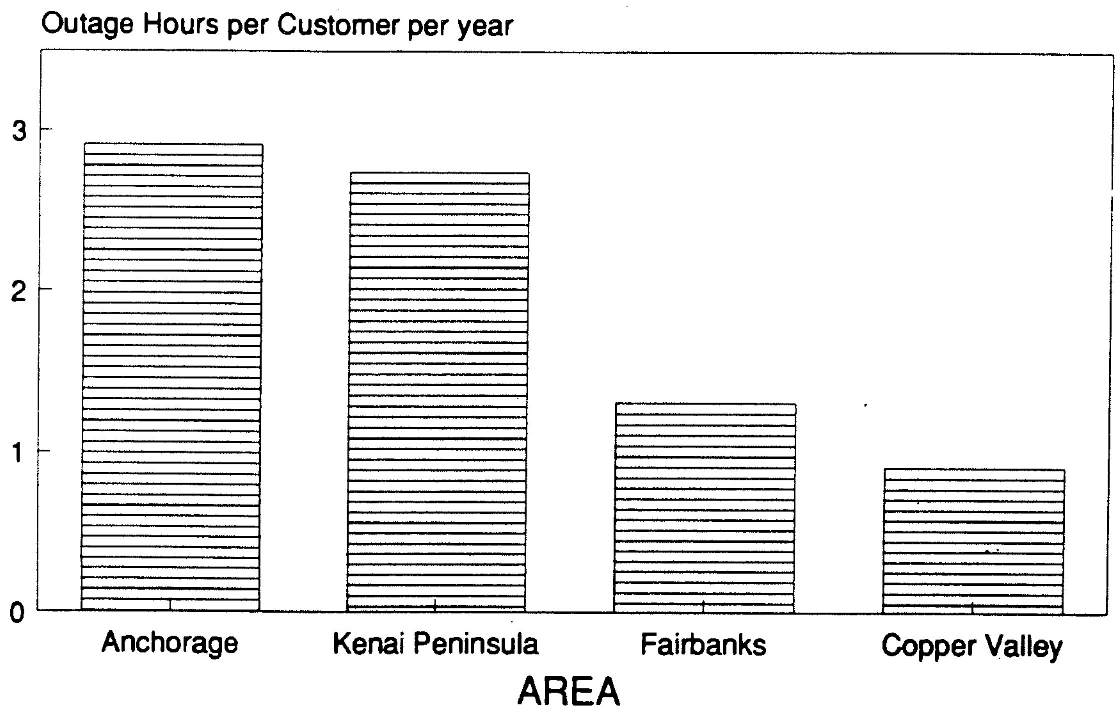


Figure 4-4. Outage Hours of Railbelt Areas (1986/87 Average)

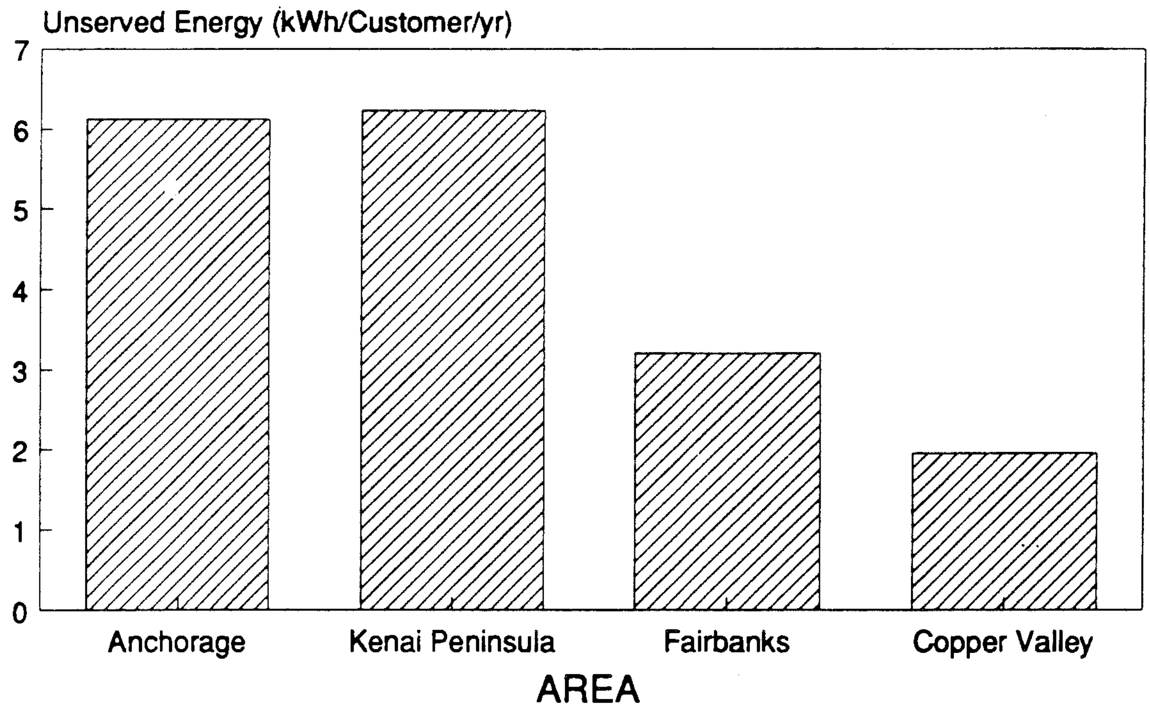
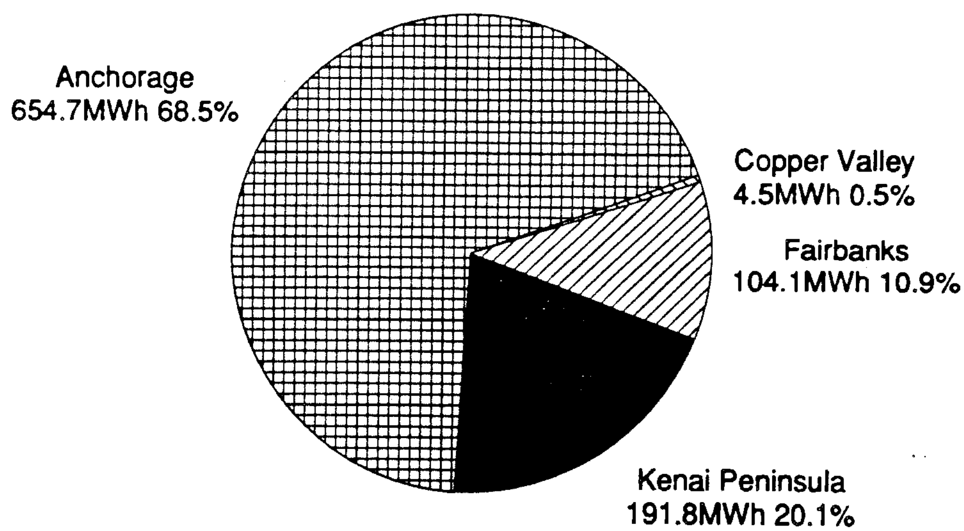


Figure 4-5. Unserved Energy of Railbelt Areas (1986/87 Averages)



Total Unserved Energy = 955 MWh/Yr

Figure 4-6. Distribution of Unserved Energy by Area (1986/87 Average)

Duration of Outages. Most of the unserved energy in Anchorage and Kenai results from outages longer than one hour (81 and 62 percent, respectively); in Fairbanks, most of the unserved energy occurs in outages of less than 20 minutes (around 60 percent); in Copper Valley, all outages have short duration (less than 20 minutes). The breakdown of outage duration is shown by area in Figure 4-7 and by utility in Figure 4-8.

4.2.3 Causes of Outages

At a meeting with representatives from the Railbelt utilities,[4] we presented this data and discussed the major causes of the recorded customer outages. The utilities identified natural causes (wind, birds, storms, avalanches, and small animals), faulty equipment, and other (airplanes and operator error) as the major causes of transmission-related outages; and improper reserves coordination, faulty equipment, and human error as the major causes of generation-related outages.

Most of the outages in Kenai and Anchorage are transmission-line related, primarily due to natural causes. Chugach for example, reported that 9 out of 10 outages were due to transmission line failure. However in Fairbanks, the outages are estimated to be almost equally split between generation and transmission failures.

4.3 POTENTIAL CHANGES IN CUSTOMER OUTAGES

The analysis of potential changes in customer outages due to potential upgrade and/or construction of new interties in the Railbelt is complicated by the addition of Bradley Lake. The integration of Bradley Lake in the system will change the pattern of system operations, particularly in the southern Railbelt, and will often produce a reversal in the direction of power flow between Anchorage and the Kenai Peninsula.

We reviewed the historical outages data with the utilities and discussed realistic expectations for potential changes in customer outages. We also met with PTI (Power Technologies, Incorporated) and discussed system stability and reliability issues.

These discussions also shed light on the potential impacts of Bradley Lake (without any new interties or upgrades) on customer outages in the Kenai Peninsula and in Anchorage. This was important primarily for the analysis of the impacts of the proposed new Kenai-Anchorage intertie.

[4] December 20, 1988, with AMLP, CEA, MEA, HEA, and GVEA represented.

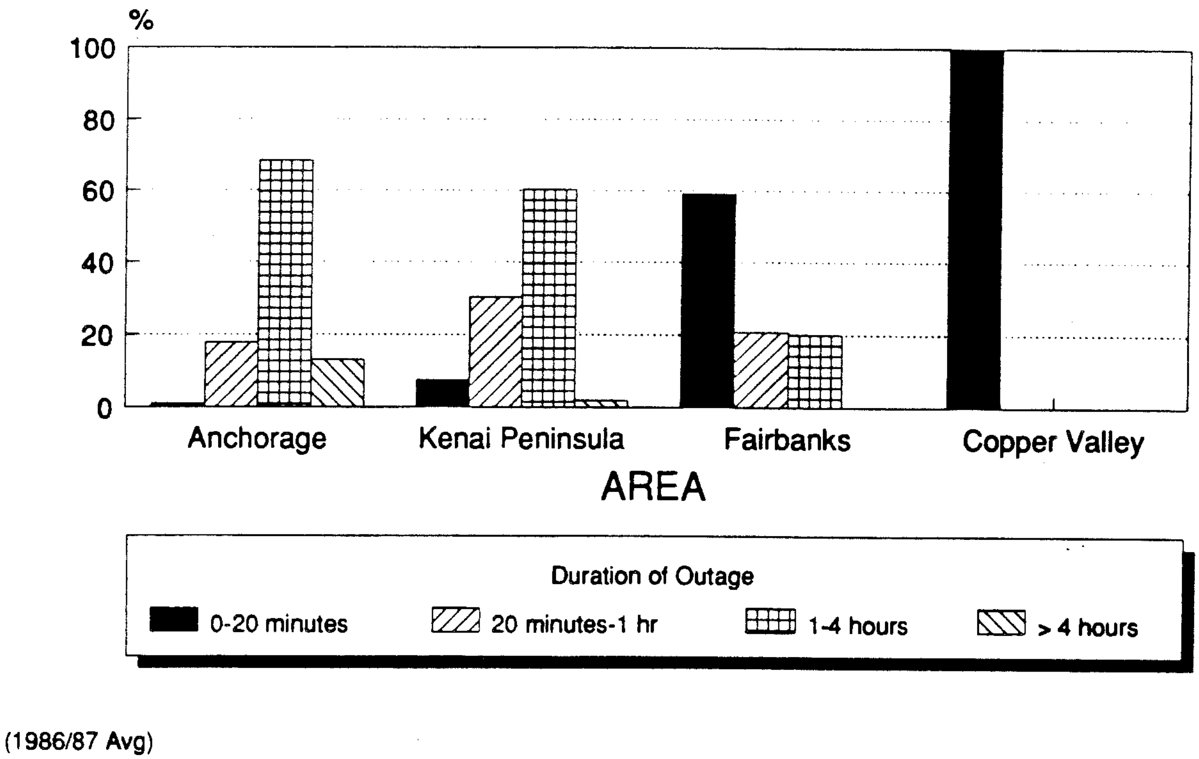


Figure 4-7. Railbelt Areas Unserved Energy by Outage Duration (1986/87 Average)

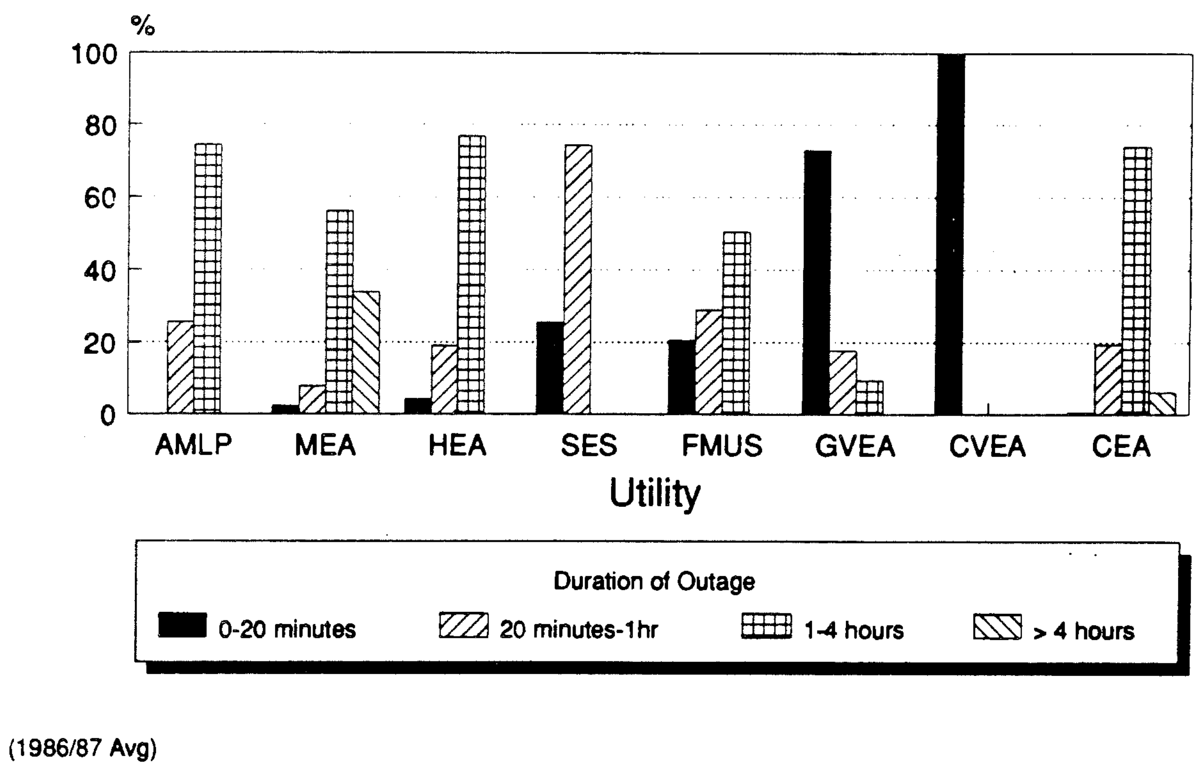


Figure 4-8. Railbelt Utilities Unserved Energy by Outage Duration

Next, we present our analysis of the potential changes in customer outages for each of the three proposed interties separately. We present the impacts of each intertie for each of the three areas, Kenai, Anchorage and Fairbanks.[5]

4.3.1 Kenai-Anchorage New Intertie

The Kenai-Anchorage new intertie would impact customer outages in the Railbelt, primarily in Kenai and Anchorage.[6] These impacts depend on the direction of power flow between the two areas. The results of the production simulation modeling indicate that, after Bradley Lake comes on-line, the Kenai Peninsula will be an exporter of power to the north approximately 40 percent of the time and will be an importer of power from the north approximately 60 percent of the time. These estimates are used in the reliability analysis below.

Kenai Outages. Historically, the customer outages on the Kenai Peninsula have been caused primarily by failures of the existing Kenai-Anchorage transmission line.[7] The major issue discussed below is the extent to which such failures will cause customer outages in the future after Bradley Lake is on-line, with and without the proposed new intertie.

Kenai Export. The addition of Bradley Lake will result in exports from the Kenai Peninsula to the north for significant blocks of time. If the existing line fails when such exports are taking place, the question is whether Kenai Peninsula generation (primarily Bradley Lake) can scale back efficiently enough to keep the disturbance from causing an outage on the Kenai Peninsula.

PTI has modeled the Railbelt generation and transmission system extensively for APA during the course of this intertie analysis, with particular attention to the system response anticipated for major transmission failures. Special focus was placed on the characteristics and response of Bradley Lake and the Kenai Peninsula system. According to PTI, there should be relatively few customer outages on the Kenai Peninsula when the existing Kenai-Anchorage line fails, if power is being exported from

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[5] The analysis of the Northeast intertie includes four areas where we add the Valdez-Glennallen area.

[6] In this outages analysis, we assumed that either of the routes proposed for the new Kenai-Anchorage intertie (i.e., Tesoro or Enstar) would have the same impacts on system reliability.

[7] Note again that all reference to customer outages in this analysis refers exclusively to generation and transmission related outages; i.e., only those outages that might be affected by transmission improvements. No outages related to the distribution system are included. Further, the discussion in this section excludes consideration of all outages in Seward.

the Kenai Peninsula. The estimate offered by PTI is that, under Kenai export conditions, we may expect that 20 percent of the failures of the existing Kenai-Anchorage line will produce customer outages on the Kenai Peninsula (assuming no new intertie). For the other 80 percent of those line failures, Kenai Peninsula generation will adjust to the disturbance such that Kenai Peninsula outages are avoided. Given this estimate, the new intertie would be expected to eliminate the remaining outages occurring for 20 percent of the existing line failures.

Representatives of Railbelt utilities have expressed a lack of confidence in this estimate. They have maintained that less effectiveness should be credited to Bradley Lake for this type of disturbance and more should be credited to the new intertie.[8] Because the issue depends on judgmental estimates, we assume that the response of Bradley Lake and other Kenai generation will result in avoidance of potential outages on the Kenai Peninsula for 60 percent of these events. The new intertie is therefore credited with avoiding the remaining 40 percent. For the "high" case, we assume that the response of Bradley Lake and other Kenai generation will result in avoidance of 20 percent of these potential outages. The new intertie in this case is therefore credited with avoiding the remaining 80 percent.

Kenai Import. If the existing line fails while power is being imported from the north to the Kenai Peninsula, an outage would be expected to occur on the Kenai Peninsula unless spinning reserves were available to supply the Kenai load immediately upon loss of power supply from the north. As discussed in Section 7, Bradley Lake could be considered to supply spinning reserve, but is not fast enough to prevent an outage from occurring if power were suddenly cut off from the Kenai Peninsula upon trip of the transmission line from Anchorage. We therefore assume for this analysis that all failures of the existing Kenai-Anchorage line (under Kenai import conditions) would produce an outage on the Kenai Peninsula in the absence of the proposed new line. However, we further assume that the "spinning reserve" benefit of Bradley Lake will be effective in reducing the duration of these outages by half relative to their length in preceding years.[9]

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[8]CEA suggested that "the analysis should assume a base case of 40 percent [rather than 80 percent]." Letter from Gerald M. Mackey to Salim J. Jabbour, March 20, 1989.

[9]Most of the Railbelt generating units can pick up additional load immediately up to each unit's individual capacity. In other words, if a 60-MW gas-fired combustion turbine is operating at 40 MW, it can increase its output to 60 MW immediately if called for. It therefore is providing 20 MW of spinning reserve. The "spinning reserve" available at Bradley Lake is much slower. Although power output can be reduced from the project very quickly, it can be increased only at a maximum rate of about 1.2 MW per second (0.6 MW per second per unit) according to Stone & Webster. However, even at 0.6 MW per second output could be increased by up to 36 MW in one minute. In addition, it is expected that Bradley Lake could be brought on-line from a cold start in less than five minutes, again according to Stone & Webster. This is faster than could be accomplished with a combustion turbine.

Other Transmission Related Outages. Most of the transmission related outages on the Kenai Peninsula have been caused by failure of the existing line between University substation in Anchorage and Daves Creek on the Kenai Peninsula. A small proportion of transmission-related outages are traceable to other locations. The proposed new line may reduce or eliminate the incidence of outages due to these other events. On the other hand, the new line would itself create additional exposure to transmission-related disturbances. We assume here that the impacts described above dominate the reliability issue, and the net result of these other impacts is of much less consequence.

Anchorage Outages. The proposed new Kenai-Anchorage line would improve Anchorage reliability if failure of the existing line would otherwise cause Anchorage outages. The issue is whether and to what extent failures of the existing Kenai-Anchorage line would be expected to cause outages in Anchorage in the future. As with the Kenai analysis, this expectation depends on the direction of power flow between Anchorage and the Kenai Peninsula.

Anchorage Export. When Anchorage is exporting power to the Kenai Peninsula, as it does currently, failures of the existing transmission line should not cause an outage in Anchorage. Anchorage area generation is expected to scale back quickly when the Kenai Peninsula load is cut off.

Anchorage Import. When Anchorage imports power from the Kenai Peninsula, the extent of outages due to failure of the existing transmission line will depend on three main factors: (1) the number of times that the existing line fails during Anchorage import conditions, (2) the amount of power being transferred from the Kenai Peninsula to Anchorage at the time of the line failure, and (3) the amount of spinning reserves accessible to the Anchorage area at the time of the line failure. We address the three factors separately.

1. Information from Chugach Electric indicates that a number of corrective measures have recently been implemented to reduce the number of failures on the existing Kenai-Anchorage line. After adjusting the history of failures on that line during the past five years to remove those that should no longer occur due to these improvements, the average number of failures that would have resulted in outages is three per year over that time period [3]. Because we estimate that Anchorage will be importing from the Kenai Peninsula approximately 40 percent of the time based on the production simulation results, the average number of line failures that would be expected under Anchorage import conditions is 1.2 per year.

2. The physical characteristics of the current transmission link between Anchorage and the Kenai Peninsula limit imports into Anchorage to approximately 60 MW.[10] We assume for this analysis that the line will be fully loaded at 60 MW at the time of the line failure.

3. Anchorage utilities presently carry spinning reserves in excess of 60 MW, though some of this may be carried on the Kenai Peninsula. In the post-Bradley Lake period, we assume that some spinning reserve is accessible in the Anchorage area but not enough to pick up the entire supply requirement upon loss of the line.

For the "low" case, we assume one outage per year of one hour duration limited to 30 MW due to the availability of some spinning reserve in Anchorage. For the "high" case, we assume two outages per year of one hour duration, again limited to 30 MW each due to available spinning reserve.[11]

Fairbanks Outages. The Kenai-Anchorage new intertie would impact customer outages in Fairbanks only indirectly. In this analysis, we assumed that the benefits of the Kenai-Anchorage new intertie would be limited to the Kenai-Anchorage area; i.e., there would be no impacts on customer outages in Fairbanks.

4.3.2 Anchorage-Fairbanks Intertie Upgrade

The Anchorage-Fairbanks intertie upgrade would have minor impacts on customer outages in the Railbelt.

Kenai Outages. Based on our conversations with the utilities, we assumed that the Anchorage-Fairbanks intertie upgrade would have no impact on customer outages in Kenai.

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[10]Transfer limits will depend on the extent of reconductoring performed by Chugach and on the stability aids added to the system. Our analysis has assumed a 75-MW limit at the sending node on the Kenai Peninsula and roughly a 60-MW limit at the receiving node in Anchorage.

[11]These outage magnitudes can be expressed as 30 MWh of unserved energy in the low case, and 60 MWh of unserved energy in the high case.

Anchorage Outages. The Anchorage-Fairbanks intertie upgrade would have little impact on customer outages in Anchorage. However, according to our conversation with MEA, around 10 percent of MEA's unserved energy could be avoided.

Fairbanks Outages. According to our conversations with GVEA, the Anchorage-Fairbanks upgrade would have no impacts on customer outages in Fairbanks.

4.3.3 Anchorage-Fairbanks Northeast Intertie

The Anchorage-Fairbanks Northeast intertie would impact customer outages in the Railbelt, primarily in Fairbanks and the Valdez-Glennallen areas.

Kenai Outages. Based on our conversations with the utilities, we assumed that the Anchorage-Fairbanks Northeast intertie would have no impact on customer outages in Kenai.

Anchorage Outages. The Anchorage-Fairbanks northeast intertie would have little impact on customer outages in Anchorage. However, according to our conversation with MEA, the Northeast intertie would help reduce the duration of customer outages around 50 percent of the time. It is therefore estimated that around 25 percent of MEA's unserved energy could be avoided.

Fairbanks Outages. According to estimates provided by GVEA, the Anchorage-Fairbanks Northeast intertie would have no impacts on generation-related outages in Fairbanks, but it would have saved eight out of the ten (80 percent) and nine out of the fifteen (60 percent) transmission-related outages in 1986 and 1987, respectively, because it provides a redundant path for imports from Anchorage.[12] We assumed that the Anchorage-Fairbanks Northeast intertie would save 70 percent of the transmission-related customer outages in Fairbanks. Since around half of the outages in Fairbanks are generation-related, we estimated that the Anchorage-Fairbanks intertie would save 35 percent of the customer outages in Fairbanks.

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[12] The existing line has 70 MW of capacity. The NE intertie would have 150 MW of capacity. Outages on the existing line would be fully backed up. Outages on the NE line would be backed up only when transfers are at 70 MW or below.

Copper Valley Outages. Because of the small fraction of unserved energy in this area (less than one-half percent of the Railbelt unserved energy, refer to Figure 4-3) and because the Anchorage-Fairbanks Northeast intertie would link this electrically isolated area to the Railbelt system, we assumed that all of the Copper Valley outages would be avoided.

4.3.4 Summary

Table 4-4 summarizes the potential impacts of the proposed interties on Railbelt customers unserved energy.

4.4 COSTS OF CUSTOMER OUTAGES

The costs to customers of unexpected outages has been studied in great depth using numerous different methods [4]. Customers suffer damages from outages through lost production, equipment damage, increased labor costs, lost leisure time, and in several other ways. If service reliability is poor enough, they may be prompted to buy emergency backup sources like batteries or generators, or in drastic cases, to leave the utility's service area.

4.4.1 Basic Elements of Outage Costs

There are two ways to determine customer outage costs: one can try to measure the actual losses that a customer sustained during an outage, or one can measure how much a customer would be willing to pay to avoid an outage. Since people do not always act rationally, the two are not always the same. We use studies from Sanghvi [5] and Ontario Hydro [6] that utilize the two different methods. Because outages at different times, of different lengths, to different people, incur different costs, it is most accurate to model costs as a function of the most important attributes. According to the literature [6,7], the two most important attributes are duration and type of customer affected.

The **duration**, or how long an outage lasts, is important because as duration increases, total costs increase. The longer the outage, the more expensive it is. Typically, customers prefer a single long outage to several short outages totalling the same amount of time. As a result, outage costs per unit of energy go down with time.[13]

[13] In some cases this does not hold, for example, a grocery's freezer may maintain food for four hours, but beyond this, it starts to spoil.

Table 4-4

SUMMARY OF UNSERVED ENERGY REDUCTION BY INTERTIE

Area	New Kenai-Anchorage Low	New Kenai-Anchorage High
Kenai	46% of all unserved energy saved[a] (except SES outages)	62% of all unserved energy saved[b] (except SES outages)
Anchorage	30 MWh of[c] unserved energy saved	60 MWh of un-served energy saved[d]
Fairbanks	0	0
Copper Valley	0	0

Area	Upgraded Anchorage-Fairbanks	Northeast Intertie (Anchorage-Fairbanks)
Kenai	0	0
Anchorage	10% of MEA's unserved energy	25% of MEA's unserved energy
Fairbanks	0	35% of all unserved energy saved
Copper Valley	0	100% of all unserved energy saved

[a] Based on 40% of unserved energy saved when Kenai exports (40% of the time) and 50% of unserved energy saved when Kenai imports (60% of the time).

[b] Based on 80% of unserved energy saved when Kenai exports (40% of the time) and 50% of unserved energy saved when Kenai imports (60% of the time).

[c] Based on one 1-hour/30 MW outage saved.

[d] Based on two 1-hour/30 MW outages saved.

Outage costs also vary significantly by **customer type**. Expensive machinery may be damaged by an outage for large industrial customers, or a retailer may see his/her shop emptied when the lights go out, but residential customers might only have to defer recreational or household activities. Usually studies group the customers into three groups: residential, commercial, and industrial. However, the Ontario Hydro study has shown that there are significant differences within the industrial and commercial customer classes and so those two groups are further subdivided. In the next subsection, we outline costs by each of these customer types and delve in more detail into the differences between these groups.

4.4.2 Customer Outage Costs

Because an in-depth study was not possible within the time constraint of this study, we have applied the results of past studies in this analysis. We focused on the Ontario Hydro work because it is most applicable to the Railbelt, and we used other studies [5,6] as needed.

Residential Customers. During an outage, a household's preferred consumption pattern is disrupted. Some activities must be postponed until the power resumes, while others may be foregone altogether. More significantly, residential heating systems may be interrupted during cold weather. It is clear that the residential customers get at least as much value from the electricity they purchase as they pay for it, otherwise they would not purchase it. However, measuring the consumer surplus above and beyond the purchase price is difficult. Some studies have estimated the cost of unserved energy as the value of lost leisure, since it is what the household member could have earned had they chosen to go to work. Other studies have utilized the concept of consumer surplus and created a consumer demand function to compute it. After doing an exhaustive survey of the available studies, Sanghvi has estimated that the costs to customers of inconvenience and lost leisure and their willingness to pay to avoid such interruptions is in the range of $0.07 to $2.00 per kWh (1987 dollars). Because of the impact of outages on residential heating systems in Alaska, we selected the upper boundary for use in this analysis, i.e., $2.00 per kWh.

Industrial Customers. During an outage, industrial customers suffer damages resulting from lost opportunity costs that are more easily measured and greater than the costs sustained by residential customers. Because industrial customers incur process restart costs, studies (Ontario Hydro and Sanghvi) have shown that they suffer very high initial outage costs. For longer outages, idle resource costs tend to dominate, although some of the lost production may be made up by working longer hours or by utilizing excess capacity. Industrial customers also suffer damages to equipment and products (e.g., gears grinding to a halt) and from employee hazards associated with loss of power to machinery and insufficient lighting in the workplace. Because small industrial customers typically have less emergency backup, they have slightly higher outage costs than large industrial customers. In the Railbelt, there are only a few large industrial customers (petroleum refineries); the remaining industrial load seems to consist of small industrial customers. We used costs from the Ontario Hydro study that range from $69.00 per kWh (1980 dollars) for a one-minute outage to $1.34 per kWh (1980 dollars) for an outage ten hours long.[14]

Commercial Customers. Commercial customers are the hardest to classify because the range of activities they cover is very broad. Therefore, commercial customers display a broad range of outage costs. For this reason, the Ontario Hydro study divided up commercial customers into three subgroups:

1. *Office Buildings*

2. *Retail Trade and Service*, i.e., establishments providing services to the general public and to other businesses, including major chain and independent retailers.

3. *Institutions*, i.e., schools, medical facilities, municipal services, and so on.[15]

Office buildings can face substantial problems from short-term power outages, and as a result they experience the greatest short-term outage costs.[16] In addition, the cumulative lost labor costs are substantial in office buildings. Outage costs in this group range from $8.57 to $195.00 per kWh (1980 dollars).

Retail trade and service customers have fairly low short-term outage costs; longer outages tend to prevent them from doing business. Because few retailers maintain standby generation, they have the greatest outage costs beyond four hours as

[14]Although the average cost of unserved energy (in $/kWh) decreases as outage length increases, the total cost of the outage (in dollars) increases as outage length increases.

[15]To obtain Railbelt distributions on commercial customers, we mapped these three customer types into the following ISER building types and used the ISER Load Forecast Report for distributions: (1) *Office Buildings*—ISER building types: large and small office buildings; (2) *Retail Trade and Service*—ISER building types: restaurant, large and small retail, grocery, lodging, car service, and warehouse; (3) *Institutions*—ISER building types: medical, school, college, assembly.

[16]Power outages in office buildings lead to problems such as disruption of computer systems, difficult evacuation without elevators, air conditioning and ventilation systems stopping, which interrupts work in many offices where the windows cannot be opened.

they start to sustain product spoilage. Outage costs for this group range from $3.18 to $23.40 per kWh (1980 dollars).

Institutions have the smallest overall outage costs. The only part of this group with high possible outage costs are medical facilities that generally have standby generation. Costs for this group range from $0.35 to $2.20 per kWh.

The distribution for each of the classes in the Railbelt region is listed in Table 4-5. The costs at various durations for each of the customer types is shown in Table 4-6.

Table 4-5

DISTRIBUTION OF CUSTOMER CLASSES IN THE RAILBELT

Customer	Total Energy (GWh)	Percent
Residential	1245	41.7
Large Industrial	179	5.0
Small Industrial	77	2.6
Commercial/Retail	773	25.9
Commercial/Office Bldgs	344	11.5
Commercial/Institutions	368	12.3
Total (Excluding Distribution Losses) =	2984	100.0

(Source: [7])

Knowing the total unserved energy, customer type distribution, and duration for each outage, we can compute outage costs by multiplying the total unserved energy by the cost per unit of energy to obtain a total customer cost. Because the outage costs will vary by customer type and duration of outage, we modify the costs accordingly. The equation to compute customer outage costs is as follows:

$$\text{Customer Outage Cost (\$)} = \text{Unserved Energy (MWh)} \times \text{Cost of Unserved Energy (Customer Type, Duration) (\$/MWh)}$$

where cost of unserved energy (customer type, duration) is taken from Table 4-6.

Table 4-6

SUMMARY OF CUSTOMER OUTAGE COSTS

	Outage Cost ($/kWh, 1980 $)					Average Comm/Ind Outage Cost, $/MWh		Total Outage Cost
Outage	Lg Ind	Sm Ind	Com/Bldg	Com/Retl	Com/Inst	1980 $	1987 $	1987 $/MW
1 sec	61.80	69.00	195.00	23.40	1.80	58781	80001	0
1 min	61.80	69.00	195.00	23.40	1.80	58781	80001	1333
5 min	15.97	18.68	47.77	8.57	0.92	15923	21671	1805
10 min	10.24	12.38	29.35	6.71	0.80	10563	14376	2395
15 min	8.33	10.28	23.21	6.09	0.77	8772	11939	2985
20 min	7.38	9.24	20.16	5.79	0.75	7887	10735	3575
1 hour	3.97	6.31	14.33	7.32	1.01	6987	9509	9509
2 hours	3.12	5.34	13.02	8.33	1.06	7056	9604	19208
4 hours	2.26	4.37	11.71	9.33	1.11	7120	9691	38763
8 hours	1.66	4.03	10.14	12.28	2.2	8273	11259	90071
10 hours	1.34	3.1	8.57	15.23	2.2	9198	12518	125179
Fraction of Load	0.103	0.044	0.198	0.444	0.211	1		

Outage cost for residential customers: $2/kWh or $2000/MWh (1987$)

4.5 VALUE OF IMPROVED SYSTEM RELIABILITY

This subsection uses the potential changes in customer outages (Section 4.3) and the cost of customer outages (Section 4.4) to determine the value of improved system reliability. The value of improved system reliability is the lesser of reduced customer outage costs achieved through the interties and the cost of increased spinning reserves to achieve a similar reduction of customer outage costs. For example, if it is cheaper to attain the same level of reliability through increased spinning reserves, then the costs of increased spinning reserves is the true value of increased system reliability.

Uncertainty surrounds the estimates of spinning reserve that would normally be available in the system. Further uncertainty exists regarding the additional spinning reserve that would be needed to achieve a specified improvement in overall system reliability. However, by applying the analysis presented in Section 7, we can estimate that the cost of providing one additional megawatt of spinning reserve throughout the year is on the order of $80,000.[17]

The results presented below are based on estimates of reduced customer outage costs. At a cost of $80,000 per MW of additional spinning reserve, it is unlikely that

[17] 1,000 kW x 8760 hours x 0.005 MBtu/kWh x $1.80 = $78,840.

the spinning reserve approach would produce a lower estimate of the value of improved reliability.

We applied the potential improvements in system reliability (Table 4-4) and determined unserved energy savings. Tables 4-7 and 4-8 summarize the results for each area and each intertie.

Table 4-9 shows the present value of reliability benefit for each intertie proposal assuming the identified annual benefits were maintained throughout a 35-year economic life.

Table 4-7

UNSERVED ENERGY SAVED BY THE INTERTIES
(MWh/year)

Area	New K-A Low	New K-A High	Upgraded A-F	A-F Northeast
Kenai	70.2	94.6	0.0	0.0
Anchorage	30.0	60.0	20.9	52.2
Fairbanks	0.0	0.0	0.0	36.4
Copper Valley	0.0	0.0	0.0	4.5
Total	100.2	154.6	20.9	93.1

Table 4-8

VALUE OF UNSERVED ENERGY SAVED BY THE INTERTIES
(M$/year)

Area	New K-A Low	New K-A High	Upgraded A-F	A-F Northeast
Kenai	0.454	0.612	0.000	0.000
Anchorage	0.187	0.373	0.078	0.195
Fairbanks	0.000	0.000	0.000	0.333
Copper Valley	0.000	0.000	0.000	0.059
Total	0.641	0.985	0.078	0.587

Table 4-9

PRESENT VALUE OF RELIABILITY BENEFIT
(4.5% real discount rate)

		$1987 Millions
Kenai-Anchorage New Intertie	Low	11.2
	High	17.2
Anchorage-Fairbanks Intertie Upgrade		1.4
Anchorage-Fairbanks Northeast Intertie		10.3

4.6 USEFUL READINGS

W.B. Shew, "How to Assess the Value of Electricity Reliability," *The Value of Service Reliability to Consumers*, EPRI, EA-4494, May 1986.

E. Masbak, "Shortage Costs: Results of Empirical Studies," *The Value of Service Reliability to Consumers*, EPRI, EA-4494, May 1986.

A.P. Sanghvi, "Optimal Electricity Supply Reliability Using Customer Shortage Costs," *The Value of Service Reliability to Consumers*, EPRI, EA-4494, May 1986.

4.7 REFERENCES

[1] *Alaska Electric Power Statistics, 1960-1986*, Alaska Power Authority, November 1987.

[2] *Summary Supplement on Railbelt Utilities*, Alaska Power Authority, November 1987.

[3] Memo from David Burlingame to Tom Lovas, Chugach Electric Association, October 14, 1988.

[4] F.J. Alessio, P. Lewin, and S. G. Parsons, "The Layman's Guide to the Value of Electric Power Reliability," *The Value of Service Reliability to Consumers*, EPRI, EA-4494, May 1986.

[5] A. P. Sanghvi, "Economic Costs of Electricity Supply Interruptions: U.S. and Foreign Experience," *The Value of Service Reliability to Consumers*, EPRI, EA-4494, May 1986.

[6] L.V. Skof, "Ontario Hydro Surveys on Power System Reliability: Summary of

Customer Viewpoints," presented at EPRI Seminar on the Value of Service Reliability to Customers, St. Louis, October 1983.

[7] *Forecast of Electricity Demand in the Alaska Railbelt Region: 1988-2010*, Institute of Social and Economic Research, University of Alaska, Anchorage, November 1988, Draft.

Section 5

ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS OF THE INTERTIE ALTERNATIVES

5.1 OVERVIEW

This section describes the benefits that the intertie options[1] provide in terms of increased economy energy savings and decreased transmission losses. We cover these benefits together in this section because they are closely related. The economy energy and transmission loss savings were simultaneously analyzed using the Over/Under production simulation model.[2] A number of adjustments were subsequently made to the Over/Under results as follows:

1. For all Anchorage-Fairbanks options (the full upgrade, the limited upgrade, and the Northeast intertie), an adjustment was made to account for the North Pole operating constraint (refer to Section 5.2).

2. For the new Kenai-Anchorage line, an adjustment was made to account for the increased transfer levels that (a) would be appropriate considering the part-load performance of thermal units, and (b) are not recognized in the Over/Under simulation.

3. For the Northeast intertie, an adjustment was made primarily to account more carefully for the changes in diesel operation and maintenance costs that would be expected in the Copper Valley area.

The results of this analysis show that the greatest benefits to be gained within these benefit categories occur between Anchorage and Fairbanks because of the larger

[1]The intertie options analyzed in this study are: full Anchorage-Fairbanks upgrade to 225 MW, limited Anchorage-Fairbanks upgrade to 100 MW, the Northeast intertie, and the new Kenai-Anchorage line.

[2]The Over/Under model is a long-term capacity expansion/production simulation model that was developed by Decision Focus Incorporated for the Electric Power Research Institute.

disparities in marginal power production costs in those two areas, and because the optimal power flow across the line exceeds its present capacity during periods of heavy demand. The optimal power flow is projected to exceed the capacity of the existing line more often in the future. Both the Anchorage-Fairbanks upgrade to 225 MW and the Northeast intertie provide significant economy energy and transmission loss benefits. The Anchorage-Fairbanks limited upgrade to 100 MW also alleviates the capacity constraint of the existing line, but to a lesser degree. The new Kenai-Anchorage line produces lower benefits within these categories. The capacity of the existing Kenai-Anchorage line is often sufficient to accommodate cost-effective transfer levels, so the incremental value of increased transfer capacity is less.

5.2 INTRODUCTION

5.2.1 Increased Economy Energy Benefits

Economy energy benefits are realized when an intertie allows energy transferred from a lower-cost area to displace energy that would otherwise be produced in a higher-cost area. Increases in transmission capacity can provide opportunity for additional economy energy savings. For example, if an existing line allows 200 GWh per year of cost-effective transfers between the two areas and a new line expands this opportunity to 300 GWh per year, then the new line allows the transfer of an additional 100 GWh per year of economy energy and therefore provides opportunity for additional savings.

5.2.2 Reduced Transmission Loss Benefits

Reduced transmission loss benefits occur because of more efficient interties. For example, if 40 GWh per year of losses are incurred over an existing line, and 10 GWh per year are incurred with a new line, then the new line provides transmission loss savings equal in value to the cost of producing 30 GWh per year.[3]

5.2.3 North Pole Operating Constraint

The "North Pole operating constraint" occurs because the poor part-load performance of the North Pole oil-fired combustion turbines in Fairbanks mandates that, for economic reasons, the units are always operated above a certain minimum load level. When the demand in Fairbanks for energy over the intertie exceeds the intertie capa-

[3]However, if substantially more energy flows over the line because it is more efficient or has greater capacity, it is possible that total transmission losses would actually increase. An increase in total losses would reduce the benefit of increased economy energy transfers.

city, one of the North Pole units must be started. Because the minimum economic level of operation of these units is relatively high, intertie purchases must be reduced substantially whenever a North Pole unit is started, even if demand exceeds intertie capacity only slightly. The Anchorage-Fairbanks intertie options would reduce or eliminate this North Pole constraint by allowing a higher level of energy imports into Fairbanks from Anchorage. As a result, there would be fewer occasions for which a North Pole unit would be started up.

The benefit calculations for each of the Anchorage-Fairbanks intertie alternatives (including the full upgrade, the limited upgrade, and the Northeast intertie) are based on the assumption that the North Pole units are normally operated only when intertie capacity added to existing and economic coal-fired capacity is insufficient to meet Fairbanks load. If North Pole units were operated for significant periods to provide improved reliability or improved electrical conditions in the area, even when intertie capacity is sufficient, then the benefits of the intertie alternatives would be lower than we have estimated.

5.2.4 Benefits of Increased Hydro-Thermal Coordination

The Kenai-Anchorage transfers estimated by the Over/Under model were adjusted to account for part-load performance characteristics of thermal power plants based on improved hydro-thermal coordination. Significant benefits can be achieved by scheduling the energy production of a hydro resource so as to minimize the part-load operation of thermal units elsewhere in the system. Thermal units are much more efficient at full load than at part load. The idea is to schedule the hydro energy in a way that minimizes part-load operation of thermal units and maximizes their full-load operation. The Over/Under simulation is not sufficiently detailed to capture this possibility, so an adjustment was calculated to estimate the additional transfers between Kenai and Anchorage that would achieve the optimal coordination of hydro units on the Kenai and thermal units in Anchorage. Benefits of the new intertie are increased to the extent that existing line characteristics limit these additional transfers.

5.2.5 Modeling Approach

In performing this analysis, we constructed a representation of the Railbelt generation and transmission system in the Over/Under model and simulated system operation under various fuel price and load conditions. Each of the intertie alternatives was subjected to the same set of inputs over the 35-year period from 1994 to 2028. The initial year was set at 1994 because most of the alternatives probably could not be brought on-line before then. Electricity demand and fuel prices are assumed constant between 2010 and 2028 due to the heightened uncertainty associated with distant time frames. Total system costs under each set of assumptions were computed in 1987 dollars for each year and discounted back to 1994. Significant modeling assumptions are presented in Appendix F. The methodology used for multi-area production simulation and the calculation of adjustments associated with the North Pole operating constraint are described in Appendix E. The adjustment of Kenai-Anchorage transfers based on improved hydro-thermal coordination is described in Appendix H.

The four intertie options examined in this section are as follows:

1. The new Kenai-Anchorage line with capacity of 250 MW (labelled "KA line").

2. The full Anchorage-Fairbanks upgrade to 225 MW capacity (labelled "AF line").

3. The limited Anchorage-Fairbanks upgrade to 100 MW capacity (labelled "AF100 line").

4. The Northeast intertie, which would raise total Anchorage-Fairbanks transfer capacity to 220 MW (labelled "NE line").

5.3 BASE CASE SCENARIOS AND SENSITIVITY SCENARIOS

5.3.1 Base Case Scenarios

A set of base case scenarios were developed for the combination of three fuel price and three load forecast assumptions. The fuel price forecasts are discussed in Appendix B, and the load forecasts are discussed in Appendix C. Joint probabilities for each of the nine fuel price and load forecast combinations were established based on fuel price probabilities adopted by the Alaska Power Authority (APA) Board of Directors and load forecast probabilities adopted by APA and the Institute of Social and Economic Research (ISER) [1]. The joint probabilities are as follows:

Fuel Price	Load Forecast	Joint Probability
Low	Low	0.30
Low	Middle	0.23
Low	High	0.06
Middle	Low	0.03
Middle	Middle	0.08
Middle	High	0.19
High	Low	0.00
High	Middle	0.02
High	High	0.08

These were used to calculate probability-weighted outcomes, which are referred to as "expected values" throughout the analysis.

5.3.2 Sensitivity Scenarios

The following sensitivity cases were evaluated:

1. *A load forecast provided by the Railbelt utilities.* This sensitivity was evaluated with all three of the fuel price projections. The utility forecast is presented in Appendix C, and is generally high compared with the load forecasts used in the base case scenarios.

2. *No additional military or University of Alaska Fairbanks (UAF) load served by Fairbanks utilities.* This adjustment reduced Fairbanks utility loads by six to seven percent relative to the base case in which these load increments were included (see Appendix C for further discussion).

3. *The Alaska Department of Revenue (ADOR) middle fuel price forecast.* As discussed in Appendix B, these prices are lower than our base case low. This sensitivity was evaluated only in combination with the high load scenario.

4. *Wet and dry hydro cases.* This sensitivity tested the effects of large changes in hydro energy on the total system operation. A wet case was defined as 20 percent more available energy each year for the entire analysis horizon while a dry case was defined as 20 percent less energy. These cases were run with the high load scenario.

5. *High gas price escalation between 2011 and 2028.* This sensitivity tested the effects of possible natural gas resource depletion leading to much higher gas prices in the post-2010 period. In this case, gas prices escalate rapidly after 2010 while coal prices remain flat and oil prices growth is extrapolated based on the trend from 1990 to 2010. Again, this was run in combination with the high load scenario.

5.4 ECONOMY ENERGY TRANSFERS BETWEEN KENAI AND ANCHORAGE WITH EXISTING LINE

Gas-fired generating units on the Kenai Peninsula are rarely dispatched in the production simulation. Both the Anchorage and Kenai areas have some gas priced at wellhead and some priced at wellhead plus delivery. However, Anchorage has combined-cycle and combustion turbine plants that are more efficient than Kenai's combustion turbine generation. The simulation results indicate that little or no economy energy benefit can be gained by regular operation of Kenai gas-fired generation for transfer to the north.

Kenai will have substantial hydro resources after completion of the Bradley Lake project. The available hydro energy over the course of an average year will, however, be less than the anticipated energy requirements of the Kenai Peninsula for all load forecasts (see Figure 5-1). Because there is virtually no variable cost to dispatching available hydro energy, all that potential is used in the production simulation with or without the new line. Because the Kenai gas-fired generation remains more costly than available gas-fired energy in Anchorage, Kenai is a net importer of energy from Anchorage even after Bradley Lake comes on-line. Part of the net annual transfer across the Kenai-Anchorage line is due to this import of energy on the Kenai Peninsula.

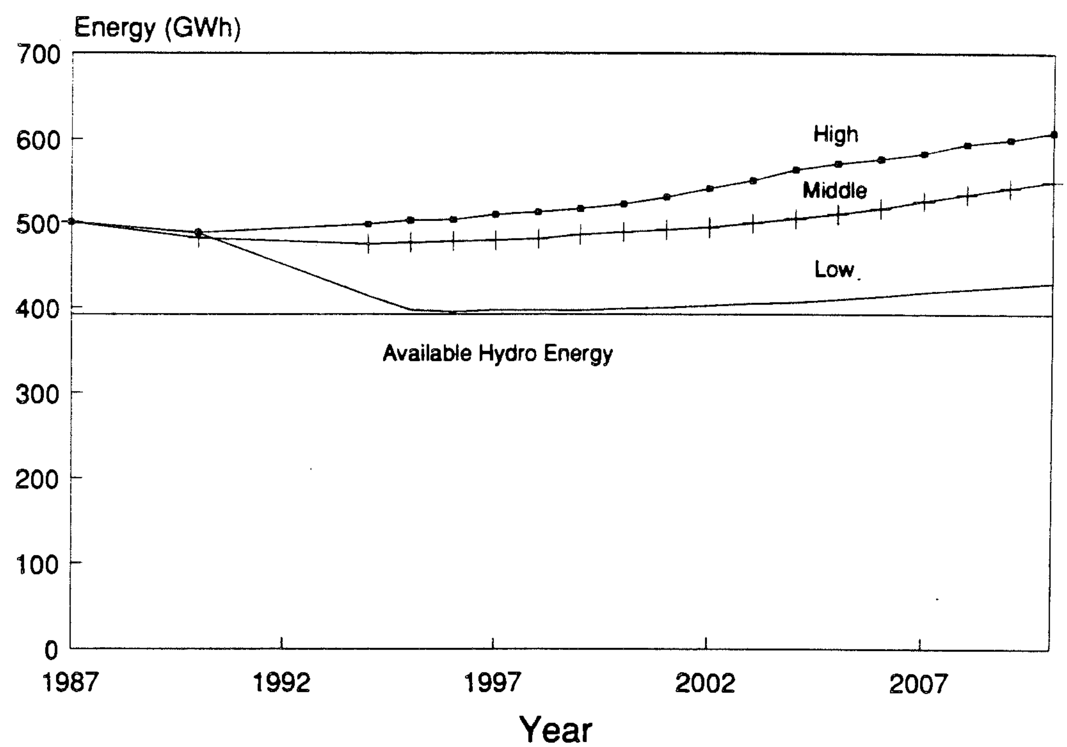

Figure 5-1. Kenai Load Requirements versus Kenai Hydro Energy

The main component of anticipated transfers is based on the expected optimal pattern of dispatch from Bradley Lake. Bradley Lake has sufficient storage capability to allow hydro energy production during the winter in excess of Kenai requirements. Further, the hydro resources on the Kenai will have peak generating capacity in excess of Kenai peak demand, which will allow cost-effective transfers from the Kenai Peninsula during certain blocks of time that must then be "paid back" by importing energy from Anchorage during other blocks of time.

The production simulation performed in the Over/Under model captures some of the transfer anticipated due to the pattern of Bradley Lake operation. However, because it is a long-term model that necessarily involves certain simplifications, it does not capture transfers that appear cost-effective as a means of limiting the part-load operation of thermal units in the Anchorage area. The methodology used to estimate these additional transfer levels and transfer benefits is described in Appendix H.

Anticipated transfers between the two areas without the new intertie are shown in Table 5-1. Including the cost-effective transfers estimated to limit part-load operation of thermal units in Anchorage, transfer levels from Kenai to Anchorage in 1994 are about 132 GWh per year[4] in the expected case, declining slightly by 2010. Transfers from Anchorage to Kenai in 1994 are about 224 GWh per year in the expected case, growing noticeably by 2010 due to anticipated load growth on the Kenai Peninsula. Transmission losses associated with these transfer levels are also shown.

[4]The existing Kenai-Anchorage line has a transfer limit of 657 GWh per year (based on 75 MW x 8760 hours per year).

Table 5-1

KENAI-ANCHORAGE TRANSFERS WITH EXISTING LINE

Assumptions			Joint	Economy Energy Transfer (GWh/yr) South ----> North			North ----> South			Transmission Loss (GWh/yr)		
Scenario	Fuel	Load	Probab.	1994	2002	2010	1994	2002	2010	1994	2002	20_0
Base	Low	Low	0.30	146.8	147.2	140.1	182.5	177.8	197.1	26.9	26.4	28.1
		Middle	0.23	132.9	118.0	117.2	234.9	258.4	302.4	30.3	30.8	35.6
		High	0.06	120.2	118.2	117.6	253.3	294.7	365.6	30.9	34.2	40.3
	Middle	Low	0.03	144.5	147.2	140.1	183.5	177.8	197.1	27.6	26.4	28.1
		Middle	0.08	131.1	118.0	117.1	235.9	258.4	302.4	31.0	30.8	35.6
		High	0.19	117.6	118.2	117.4	255.3	294.7	365.6	30.5	34.2	41.3
	High	Low	0.00	144.5	146.9	140.1	183.5	177.8	197.1	27.6	26.4	28.1
		Middle	0.02	131.1	117.5	117.2	235.9	258.4	302.4	31.0	31.7	35.6
		High	0.08	117.6	118.3	117.4	255.3	295.7	365.6	30.5	34.1	41.3
Base Case Expected Values				132.3	127.8	124.9	224.2	243.7	288.4	29.3	30.5	34.9
Utility	Low		0.60	122.1	121.2	119.1	263.0	278.3	299.3	31.1	33.0	34.5
Load	Middle		0.30	117.9	121.2	118.4	265.0	278.3	299.3	31.4	33.0	35.5
Forecast	High		0.10	117.9	120.2	118.7	265.0	279.3	299.3	31.4	32.8	35.5
Utility Load Forecast Exp. Values				120.4	121.1	118.9	263.8	278.4	299.3	31.4	33.0	34.9
DOR Fuel	Middle	High		120.2	118.2	117.6	178.7	294.7	351.0	24.2	34.2	39.0
NoMiltry	Low	High		119.6	117.9	117.5	253.3	294.7	365.6	30.8	34.2	40.3
DryHydro	Low	High		118.3	116.9	117.1	330.8	357.3	443.6	37.6	39.9	48.6
WetHydro	Low	High		165.8	148.4	130.8	209.0	247.2	294.4	31.0	32.7	35.1
GasEscal	Low	High		120.2	116.6	117.0	254.1	361.0	369.8	31.0	40.0	40.6

Note: Years for GasEscal sensitivity are: 1994, 2010, and 2028.

5.5 NEW KENAI-ANCHORAGE LINE: ECONOMY ENERGY TRANSFER AND TRANSMISSION LOSS BENEFITS

5.5.1 Increased Kenai-Anchorage Transfers

The change in transfer levels due to the new Kenai-Anchorage line is shown in Table 5-2. Including the transfers for limiting part-load operation of thermal units, transfer levels in 1994 from Kenai to Anchorage increase by about 52 GWh per year in the expected case. Transfers from Anchorage to Kenai in 1994 increase by about 37 GWh per year in the expected case. The change in transmission losses is also shown. For the expected case in 1994, losses would be reduced by approximately 21 GWh per year.

5.5.2 Benefits of Increased Kenai-Anchorage Transfers

The annual savings associated with these increased transfers and reduced transmission losses are shown in Table 5-3. Including the increased hydro-thermal coordination benefits described in Appendix H, the expected annual savings vary between $0.8 and $1.1 million per year between 1994 and 2010. The present value of these savings, discounted back to 1994 at a real rate of 4.5 percent, is shown in Table 5-4. The expected value of these two benefit categories combined is $17.6 million. This estimate does not vary appreciably for the selected set of sensitivity cases.

Table 5-2

CHANGE IN KENAI-ANCHORAGE TRANSFERS DUE TO THE NEW LINE

Assumptions				Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
				South ----> North			North ----> South					
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	56.8	61.0	54.0	46.2	46.5	42.4	-18.8	-18.3	-18.9
		Middle	0.23	50.7	51.1	45.0	36.9	28.7	25.7	-21.7	-22.2	-25.4
		High	0.06	45.4	56.0	44.9	30.0	27.1	21.2	-22.4	-24.8	-29.8
	Middle	Low	0.03	59.0	61.0	54.0	45.2	46.5	42.4	-18.5	-18.3	-18.9
		Middle	0.08	53.5	51.1	45.1	35.9	28.7	25.7	-21.4	-22.2	-25.4
		High	0.19	49.1	56.0	45.2	29.0	27.1	21.2	-22.0	-24.8	-29.8
	High	Low	0.00	59.0	61.3	54.0	45.2	46.5	42.4	-18.5	-18.3	-18.9
		Middle	0.02	53.5	51.6	45.0	35.9	28.7	25.7	-21.4	-22.2	-25.4
		High	0.08	49.1	57.0	45.0	29.0	26.1	21.2	-22.0	-24.7	-29.8
Base Case Expected Values				52.3	56.1	48.0	37.3	34.0	29.8	-20.8	-21.8	-24.7
Utility Load Forecast	Low		0.60	45.3	66.2	44.8	29.3	28.3	25.9	-23.2	-23.7	-25.3
	Middle		0.30	50.5	66.2	45.5	28.3	28.3	25.9	-22.7	-23.7	-25.2
	High		0.10	50.5	68.2	44.8	28.3	27.3	25.9	-22.7	-23.5	-25.2
Utility Load Forecast Exp. Values				47.4	66.4	45.0	28.9	28.2	25.9	-23.0	-23.7	-25.3
DOR Fuel	Middle	High		45.4	56.0	44.9	104.6	27.1	35.8	-15.8	-24.8	-28.5
NoMiltry	Low	High		45.5	54.4	45.0	30.0	27.1	21.2	-22.4	-24.8	-29.8
DryHydro	Low	High		45.6	50.4	45.0	24.5	43.6	20.7	-27.7	-29.1	-36.6
WetHydro	Low	High		45.7	59.4	44.9	33.1	30.5	27.0	-22.4	-23.5	-25.7
GasEscal	Low	High		45.4	44.9	45.0	29.9	22.5	20.9	-22.5	-29.6	-30.1

Note: Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 5-3

ANNUAL TRANSFER BENEFITS DUE TO THE NEW KENAI-ANCHORAGE LINE

Assumptions			Joint	Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	0.5	0.5	0.5	0.3	0.3	0.3	0.8	0.8	0.8
		Middle	0.23	0.4	0.4	0.5	0.4	0.4	0.5	0.8	0.8	0.9
		High	0.06	0.4	0.4	0.4	0.4	0.5	0.6	0.7	0.8	1.0
	Middle	Low	0.03	0.6	0.6	0.7	0.4	0.4	0.5	0.9	1.0	1.1
		Middle	0.08	0.5	0.5	0.7	0.4	0.5	0.7	0.9	1.0	1.3
		High	0.19	0.4	0.5	0.7	0.5	0.6	0.8	0.9	1.1	1.5
	High	Low	0.00	0.7	0.8	0.9	0.4	0.5	0.6	1.1	1.3	1.4
		Middle	0.02	0.6	0.6	0.9	0.5	0.7	0.9	1.1	1.3	1.7
		High	0.08	0.5	0.6	0.9	0.5	0.8	1.1	1.1	1.4	1.9
Base Case Expected Values				0.5	0.5	0.6	0.4	0.5	0.6	0.8	0.9	1.1
Utility	Low		0.60	0.4	0.4	0.4	0.4	0.4	0.5	0.8	0.8	0.9
Load	Middle		0.30	0.5	0.5	0.6	0.5	0.6	0.7	0.9	1.1	1.3
Forecast	High		0.10	0.5	0.6	0.8	0.6	0.7	0.9	1.1	1.3	1.7
Utility Load Forecast Exp. Values				0.4	0.4	0.5	0.5	0.5	0.6	0.8	1.0	1.1
DOR Fuel	Middle	High		0.5	0.4	0.4	0.3	0.4	0.5	0.7	0.8	0.9
NoMiltry	Low	High		0.4	0.4	0.4	0.4	0.5	0.6	0.7	0.8	1.0
DryHydro	Low	High		0.4	0.4	0.5	0.5	0.6	0.7	0.8	1.0	1.2
WetHydro	Low	High		0.4	0.4	0.5	0.3	0.4	0.5	0.7	0.8	0.9
GasEscal	Low	High		0.4	0.4	0.4	0.4	0.6	1.3	0.7	1.0	1.6

Notes:

1. All values are in 1987 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer
   + Reduced Transmission Loss
4. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 5-4

PRESENT VALUE OF TRANSFER BENEFITS DUE TO NEW KENAI-ANCHORAGE LINE

Scenario	Assumptions Fuel	Assumptions Load	Joint Probab.	Increased Economy Energy Transfer	Reduced Trans. Losses	Net Transfer Benefits
Base	Low	Low	0.30	8.2	5.2	13.4
		Middle	0.23	7.3	7.5	14.8
		High	0.06	7.1	8.8	15.9
	Middle	Low	0.03	11.2	7.1	18.3
		Middle	0.08	10.1	10.1	20.1
		High	0.19	10.0	12.0	22.0
	High	Low	0.00	14.0	8.9	22.9
		Middle	0.02	12.4	12.5	24.9
		High	0.08	12.7	14.9	27.6
Base Case Expected Values				8.9	8.6	17.6
Utility Load Forecast	Low		0.60	6.9	8.1	14.9
	Middle		0.30	9.7	10.9	20.5
	High		0.10	12.1	13.5	25.7
Utility Load Forecast Exp. Values				8.2	9.5	17.7
DOR Fuel	Middle	High		7.1	7.6	14.8
NoMiltry	Low	High		7.1	8.7	15.8
DryHydro	Low	High		7.6	11.1	18.8
WetHydro	Low	High		7.5	7.3	14.8
GasEscal	Low	High		7.3	10.7	18.0

Note: All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)

5.6 ECONOMY ENERGY TRANSFERS BETWEEN ANCHORAGE AND FAIRBANKS WITH EXISTING LINE

The system simulation indicates that nearly all transfers between Anchorage and Fairbanks flow from the south to the north. The only exceptions to this are in the later years of the gas price escalation sensitivity.[5] The cost differential between oil and gas reflected in the fuel price forecasts is the motivation for transfers between the two areas.

Fairbanks relies first upon its existing coal-fired capacity. In the absence of an intertie, Fairbanks would next rely upon existing oil-fired capacity. The availability of gas-fired capacity in Anchorage combined with the price advantage of Cook Inlet gas with respect to oil creates an opportunity for economy energy transfer savings. For example, the North Pole oil-fired combustion turbines in Fairbanks have a full-load heat rate of approximately 10,900 Btu/kWh. The gas-fired combustion turbines #3 and #5 at Beluga are somewhat less efficient at full load, with a heat rate of 12,691 Btu/kWh. Based on the fuel oil and natural gas price forecasts adopted for 1994 in the low case and ignoring variable O&M costs (which are similar for these units), a variable generation cost of $30.19 per MWh is computed for the North Pole units compared with $16.28 per MWh for the Beluga units. Even after adding 15 percent transmission losses, the Beluga units would be 57 percent less expensive. In 1990, the estimated price differential between Fairbanks #4 fuel oil and Cook Inlet wellhead (Chugach) gas is $1.23, $1.76, and $2.04 per MBtu for the low, middle and high fuel forecasts respectively, i.e. it is higher for the higher price scenarios. In addition, as time goes on, the differential within each forecast also increases to $1.89, $2.72, and $3.58 per MBtu for the three fuel forecast scenarios in 2010.

Table 5-5 shows the estimated transfer levels from Anchorage to Fairbanks over the existing line in the absence of any upgrade. These results are based on the transfers indicated by the Over/Under production simulation, net of adjustments calculated due to the North Pole constraint.[6] In the expected case in 1994, transfers from Anchorage to Fairbanks are estimated at 389 GWh per year,[7] remaining roughly constant between 1994 and 2010. Transmission losses associated with these transfers are estimated at 37 to 42 GWh per year, averaging around 10 percent. Somewhat higher transfers are estimated in the utility load forecast sensitivity scenarios. No significant differences in transfers are observed in the other sensitivity scenarios.

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[5]As described in Appendix F, the capacity expansion plan developed for these simulations did not include any increase in coal-fired capacity. For the assessment of a new 50-MW coal-fired power plant at Healy described in Section 8 (where a coal plant was included in the expansion plan), the simulation showed some limited transfers from north to south.

[6]Again, the North Pole constraint reduces the level of transfers that would otherwise be expected, because intertie purchases must be reduced substantially whenever a North Pole unit is started up.

[7]The existing Anchorage-Fairbanks line has a transfer limit of 613.2 GWh per year (based on 70 MW x 8760 hours per year).

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Table 5-5

ANCHORAGE-FAIRBANKS TRANSFERS WITH EXISTING LINE

Assumptions				Economy Energy Transfer (GWh/yr)						Transmission Loss (GWh/yr)		
			Joint	South ----> North			North ----> South					
Scenario	Fuel	Load	Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	338.8	324.8	373.4	0.0	0.0	0.0	30.7	30.3	38.2
		Middle	0.23	346.7	346.6	391.8	0.0	0.0	0.0	31.3	33.4	40.6
		High	0.06	340.3	387.1	453.9	0.0	0.0	0.0	31.9	39.9	49.9
	Middle	Low	0.03	444.0	472.7	462.8	0.0	0.0	0.0	43.8	48.0	48.3
		Middle	0.08	436.1	466.2	429.0	0.0	0.0	0.0	42.6	47.7	44.7
		High	0.19	471.7	428.8	418.4	0.0	0.0	0.0	47.9	44.7	45.1
	High	Low	0.00	444.0	450.2	453.2	0.0	0.0	0.0	43.8	44.2	46.8
		Middle	0.02	436.0	396.2	411.0	0.0	0.0	0.0	42.6	35.8	41.9
		High	0.08	471.7	355.9	381.1	0.0	0.0	0.0	47.9	32.3	38.9
Base Case Expected Values				389.5	373.3	399.8	0.0	0.0	0.0	37.1	36.6	41.8
Utility Load Forecast	Low		0.60	397.4	454.4	519.6	0.0	0.0	0.0	41.4	49.9	58.8
	Middle		0.30	440.8	423.9	472.6	0.0	0.0	0.0	46.6	46.1	52.9
	High		0.10	440.8	368.9	450.4	0.0	0.0	0.0	46.6	36.7	49.1
Utility Load Forecast Exp. Values				414.8	436.7	498.6	0.0	0.0	0.0	43.5	47.5	56.1
DOR Fuel	Middle	High		447.5	450.9	468.2	0.0	0.0	0.0	50.4	50.8	52.3
NoMiltry	Low	High		344.1	370.3	421.6	0.0	0.0	0.0	30.9	37.3	45.4
DryHydro	Low	High		340.2	386.9	453.5	0.0	0.0	0.0	31.9	39.8	49.8
WetHydro	Low	High		340.3	387.3	454.3	0.0	0.0	0.0	31.9	39.9	49.9
GasEscal	Low	High		341.7	424.4	0.0	0.0	0.0	406.6	32.2	46.3	44.6

Note: Years for GasEscal sensitivity are: 1994, 2010, and 2028.

5.7 FULL UPGRADE OF ANCHORAGE-FAIRBANKS LINE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS

5.7.1 Increased Anchorage-Fairbanks Transfers

The change in transfer levels due to the full upgrade of the Anchorage-Fairbanks intertie is shown in Table 5-6. Transfers from Anchorage to Fairbanks are estimated to increase by 227 GWh per year in 1994 for the expected case and by 337 GWh per year in 2010. Despite the increase in transfer levels, total transmission losses are reduced because the line is far more efficient after the proposed full upgrade. Higher increases in transfers are estimated for the utility load forecast sensitivity scenarios (335 GWh per year in 1994 and 381 GWh per year in 2010). No significant differences are observed in the other sensitivity cases relative to the base case scenarios that incorporate the same low fuel prices.

5.7.2 Benefits of Increased Anchorage-Fairbanks Transfers

The annual savings associated with the increased Anchorage-Fairbanks transfers and reduced transmission losses are shown in Table 5-7. The expected annual savings rise from $2.3 million in 1994 to $6.8 million in 2010. Higher savings are estimated in the utility load forecast sensitivity scenarios ($3.9 million in 1994 and $8.2 million in 2010).

The present value of these savings discounted to 1994 at 4.5 percent is shown in Table 5-8. The expected value of these two benefit categories combined is $93.4 million, about 93 percent of which is attributable to economy energy savings. Nearly half of the total benefits can be traced to the removal of the North Pole constraint. In other words, the analysis indicates that inability to provide economical small increments of power in Fairbanks when needed at times of full intertie loading is very costly. Removing this constraint by increasing intertie capacity has a present value of approximately $45 million.

When the utility load forecast is assumed, the estimated benefit in these categories is approximately $32 million higher. This is primarily due to the fact that the amount of additional transfer depends heavily on the demand for energy in Fairbanks, and that the Fairbanks component of the utility load forecast is significantly higher than forecasts used in the base case combinations. Benefits calculated for the other sensitivity cases are not appreciably different from the base case expected values.

Table 5-6

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO THE FULL UPGRADE OF THE AF LINE TO 225 MW

Assumptions				Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
				South ----> North			North ----> South					
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	355.8	282.3	409.1	0.0	0.0	0.0	-5.0	-10.7	-6.8
		Middle	0.23	338.9	244.7	376.6	0.0	0.0	0.0	-6.2	-13.8	-9.8
		High	0.06	387.5	249.3	362.9	0.0	0.0	0.0	-3.7	-17.1	-15.4
	Middle	Low	0.03	37.1	41.9	106.6	0.0	0.0	0.0	-28.7	-31.5	-29.3
		Middle	0.08	36.3	63.4	186.1	0.0	0.0	0.0	-27.8	-30.6	-22.9
		High	0.19	41.7	178.4	311.5	0.0	0.0	0.0	-31.5	-23.5	-16.1
	High	Low	0.00	37.1	64.4	108.9	0.0	0.0	0.0	-28.7	-27.7	-28.0
		Middle	0.02	36.4	133.4	169.3	0.0	0.0	0.0	-27.8	-18.6	-22.1
		High	0.08	41.7	251.2	264.7	0.0	0.0	0.0	-31.5	-11.1	-15.1
Base Case Expected Values				227.5	221.5	336.8	0.0	0.0	0.0	-15.3	-16.7	-12.7
Utility	Low		0.60	439.0	288.8	400.2	0.0	0.0	0.0	-19.5	-10.9	-25.7
Load	Middle		0.30	179.6	305.7	379.5	0.0	0.0	0.0	-24.7	-17.1	-15.8
Forecast	High		0.10	179.7	360.7	273.0	0.0	0.0	0.0	-10.3	-16.2	-12.0
Utility Load Forecast Exp. Values				335.3	301.1	381.3	0.0	0.0	0.0	-20.2	-13.3	-21.4
DOR Fuel	Middle	High		280.2	371.3	478.2	0.0	0.0	0.0	-22.1	-15.9	-7.2
NoMiltry	Low	High		339.3	224.0	351.7	0.0	0.0	0.0	-5.9	-17.4	-14.1
DryHydro	Low	High		387.8	244.3	336.7	0.0	0.0	0.0	-3.4	-16.9	-17.2
WetHydro	Low	High		387.1	254.2	387.7	0.0	0.0	0.0	-4.0	-16.9	-13.7
GasEscal	Low	High		388.2	372.3	0.0	0.0	0.0	271.9	-3.8	-11.1	-10.5

Note: Years for GasEscal sensitivity are : 1994, 2010, and 2028.

Table 5-7

ANNUAL TRANSFER BENEFITS DUE TO THE FULL UPGRADE OF THE AF LINE TO 225 MW

Assumptions				Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	3.0	3.9	5.9	0.2	0.3	0.1	3.2	4.2	5.9
		Middle	0.23	2.7	3.7	6.0	0.2	0.4	0.1	2.9	4.1	6.1
		High	0.06	3.3	4.2	6.4	0.2	0.4	0.3	3.5	4.6	6.7
	Middle	Low	0.03	1.2	1.4	3.9	0.7	0.7	0.6	1.8	2.2	4.6
		Middle	0.08	1.2	2.0	5.8	0.7	0.8	0.5	1.8	2.8	6.3
		High	0.19	1.3	4.4	8.6	0.7	0.7	0.3	2.0	5.1	8.9
	High	Low	0.00	1.3	1.7	4.9	0.7	0.8	0.7	2.1	2.5	5.6
		Middle	0.02	1.2	2.4	7.1	0.7	0.6	0.5	2.0	3.0	7.6
		High	0.08	1.4	5.3	10.5	0.8	0.4	0.3	2.2	5.7	10.8
Base Case Expected Values				2.3	3.8	6.8	0.4	0.5	0.2	2.7	4.3	7.0
Utility	Low		0.60	4.0	5.0	7.0	0.2	0.5	0.3	4.2	5.4	7.3
Load	Middle		0.30	3.7	6.7	9.5	0.6	0.5	0.3	4.3	7.2	9.8
Forecast	High		0.10	4.1	7.9	11.5	0.7	0.2	0.6	4.8	8.2	12.1
Utility Load Forecast Exp. Values				3.9	5.8	8.2	0.4	0.4	0.3	4.3	6.2	8.5
DOR Fuel	Middle	High		3.0	4.6	6.4	0.4	0.2	0.0	3.5	4.8	6.4
NoMiltry	Low	High		2.7	3.7	6.1	0.2	0.4	0.3	2.9	4.2	6.4
DryHydro	Low	High		3.3	4.2	6.3	0.2	0.4	0.3	3.5	4.6	6.6
WetHydro	Low	High		3.3	4.2	6.6	0.2	0.4	0.2	3.5	4.7	6.8
GasEscal	Low	High		3.3	6.4	2.3	0.2	0.3	0.5	3.5	6.7	2.8

Notes:

1. All values are in 1987 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer
   \+ Reduced Transmission Loss
4. Years for GasEscal sensitivity are : 1994, 2010, and 2028.

Table 5-8

PRESENT VALUE OF TRANSFER BENEFITS DUE TO FULL UPGRADE OF AF LINE TO 225 MW

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Increased Economy Energy Transfer	Reduced Trans. Losses	Net Transfer Benefits
Base	Low	Low	0.30	83.2	2.7	85.9
		Middle	0.23	83.8	3.4	87.2
		High	0.06	92.9	5.2	98.1
	Middle	Low	0.03	46.1	12.7	58.9
		Middle	0.08	62.2	11.7	73.9
		High	0.19	99.7	10.3	110.1
	High	Low	0.00	55.0	14.7	69.7
		Middle	0.02	74.8	12.8	87.6
		High	0.08	119.7	10.8	130.5
Base Case Expected Values				87.1	6.3	93.4
Utility	Low		0.60	104.0	5.8	109.8
Load	Middle		0.30	134.1	8.8	142.9
Forecast	High		0.10	158.7	11.0	169.6
Utility Load Forecast Exp. Values				118.5	7.2	125.7
DOR Fuel	Middle	High		93.6	3.8	97.4
NoMiltry	Low	High		86.3	4.8	91.1
DryHydro	Low	High		91.3	5.6	96.9
WetHydro	Low	High		94.4	4.6	99.0
GasEscal	Low	High		83.3	4.5	87.8

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

5.8 LIMITED UPGRADE OF ANCHORAGE-FAIRBANKS LINE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS.

As described in Section 2, the limited upgrade option consists of the addition of electrical equipment, primarily series capacitors and SVS, to allow a higher level of transfer over the existing line. Presently, the line is limited to 70-MW input at the Anchorage end. Assuming the existing Healy coal plant is operating, which is usually the case, approximately 62 MW can be received in Fairbanks. The limited upgrade would allow 100 MW to be input at the Anchorage end with approximately 84 MW received on the Fairbanks end.

5.8.1 Increased Anchorage-Fairbanks Transfers

Transfers without the limited upgrade are described in Section 5.6 and presented in Table 5-5. The change in transfer levels due to the limited upgrade of the Anchorage-Fairbanks intertie is shown in Table 5-9. In the expected case, transfers from Anchorage to Fairbanks are projected to increase in 1994 by about 94 GWh per year and by 142 GWh per year in 2010. Overall, the sensitivity cases do not show major differences relative to base case scenarios that incorporate the same low fuel prices.

5.8.2 Benefits of Increased Anchorage-Fairbanks Transfers

As shown in Table 5-10, the value of the increased Anchorage-Fairbanks transfers ranges from nearly $1.2 million per year in 1994 to $3.3 million per year in 2010. "Reduced transmission losses" are negative because, although the limited upgrade permits higher transfer levels, it also results in higher losses. The cost of these higher losses are netted out against the value of the increased transfers.

The present value of these savings discounted to 1994 at 4.5 percent is shown in Table 5-11. The expected value of these two benefit categories combined is $38.8 million. Nearly 85 percent of these benefits can be traced to the removal of the North Pole constraint.

Total benefits in these categories are somewhat lower in all the sensitivities. The load forecast is again the main reason for this, though its impact for the limited upgrade is different from its impact in the full upgrade. All of the sensitivities reflect a relatively high load forecast. The main reason that benefits of the limited upgrade are reduced for the higher load forecasts is that there are fewer opportunities to avoid starting up one of the North Pole units.

Table 5-9

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO THE LIMITED UPGRADE OF THE AF LINE TO 100 MW

Assumptions				Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
				South ----> North			North ----> South					
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	132.1	171.1	145.5	0.0	0.0	0.0	17.8	23.3	21.8
		Middle	0.23	117.2	167.5	137.0	0.0	0.0	0.0	16.0	23.6	24.4
		High	0.06	158.5	136.1	110.0	0.0	0.0	0.0	21.7	24.0	30.1
	Middle	Low	0.03	38.2	40.7	94.9	0.0	0.0	0.0	6.5	7.5	15.4
		Middle	0.08	38.1	62.0	120.7	0.0	0.0	0.0	6.5	10.6	18.9
		High	0.19	41.9	140.1	176.9	0.0	0.0	0.0	7.7	23.6	31.0
	High	Low	0.00	37.7	19.3	68.8	0.0	0.0	0.0	6.4	2.6	8.9
		Middle	0.02	37.3	38.3	98.4	0.0	0.0	0.0	6.3	5.0	13.4
		High	0.08	40.5	98.6	140.7	0.0	0.0	0.0	7.4	13.3	22.0
Base Case Expected Values				93.6	141.1	142.4	0.0	0.0	0.0	13.4	20.8	24.1
Utility Load Forecast	Low		0.60	120.1	111.6	124.2	0.0	0.0	0.0	22.8	30.5	36.1
	Middle		0.30	150.5	216.2	111.9	0.0	0.0	0.0	26.5	40.6	26.4
	High		0.10	146.0	140.6	97.4	0.0	0.0	0.0	25.3	22.0	22.8
Utility Load Forecast Exp. Values				131.8	145.9	117.8	0.0	0.0	0.0	24.2	32.7	31.8
DOR Fuel	Middle	High		160.6	142.7	140.6	0.0	0.0	0.0	22.1	25.7	37.6
NoMiltry	Low	High		118.1	159.2	115.0	0.0	0.0	0.0	16.1	24.2	26.4
DryHydro	Low	High		158.5	136.0	108.3	0.0	0.0	0.0	21.7	24.0	29.6
WetHydro	Low	High		158.5	136.2	110.3	0.0	0.0	0.0	21.7	24.1	30.1
GasEscal	Low	High		159.3	203.4	0.0	0.0	0.0	0.0	21.9	40.8	0.0

Note: Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 5-10

ANNUAL TRANSFER BENEFITS DUE TO THE LIMITED UPGRADE OF THE AF LINE TO 100 MW

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Increased Economy Energy Transfer (M$/Yr) 1994	2002	2010	Reduced Transmission Loss (M$/Yr) 1994	2002	2010	Net Transfer Benefits (M$/Yr) 1994	2002	2010
Base	Low	Low	0.30	1.61	2.78	2.97	-0.25	-0.42	-0.45	1.36	2.36	2.52
		Middle	0.23	1.42	2.68	2.49	-0.22	-0.43	-0.52	1.20	2.25	1.97
		High	0.06	1.91	1.93	1.27	-0.30	-0.47	-0.62	1.61	1.46	0.65
	Middle	Low	0.03	0.57	0.66	2.61	-0.13	-0.19	-0.45	0.44	0.47	2.16
		Middle	0.08	0.56	1.12	3.35	-0.13	-0.27	-0.56	0.43	0.85	2.79
		High	0.19	0.60	2.66	4.59	-0.16	-0.61	-0.90	0.44	2.05	3.69
	High	Low	0.00	0.61	0.61	3.20	-0.15	-0.09	-0.39	0.46	0.52	2.81
		Middle	0.02	0.60	1.17	4.20	-0.15	-0.16	-0.57	0.45	1.01	3.63
		High	0.08	0.63	2.96	5.67	-0.18	-0.43	-0.91	0.45	2.53	4.76
Base Case Expected Values				1.18	2.47	3.32	-0.21	-0.44	-0.61	0.97	2.03	2.71
Utility Load Forecast	Low		0.60	1.33	1.04	1.28	-0.38	-0.66	-0.77	2.58	0.38	0.51
	Middle		0.30	2.26	3.73	2.35	-0.55	-1.07	-0.76	1.71	2.66	1.59
	High		0.10	2.49	3.96	2.96	-0.61	-0.71	-0.87	1.88	3.25	2.09
Utility Load Forecast Exp. Values				1.72	2.14	1.77	-0.45	-0.79	-0.78	2.25	1.35	0.99
DOR Fuel	Middle	High		1.87	1.85	1.13	-0.30	-0.44	-0.60	1.57	1.41	0.53
NoMiltry	Low	High		1.42	2.44	1.65	-0.21	-0.45	-0.55	1.21	1.99	1.10
DryHydro	Low	High		1.91	1.91	1.19	-0.30	-0.48	-0.63	1.61	1.43	0.56
WetHydro	Low	High		1.91	1.94	1.27	-0.30	-0.47	-0.62	1.61	1.47	0.65
GasEscal	Low	High		1.92	2.98	0.00	-0.30	-0.81	0.00	1.62	2.17	0.00

Notes:

1. All values are in 1987 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer + Reduced Transmission Loss
4. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 5-11

PRESENT VALUE OF TRANSFER BENEFITS DUE TO THE UPGRADE OF THE AF LINE TO 100 MW

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Increased Economy Energy Transfer	Reduced Trans. Losses	Net Transfer Benefits
Base	Low	Low	0.30	44.2	-3.6	40.6
		Middle	0.23	40.6	-5.5	35.1
		High	0.06	33.4	-11.5	22.0
	Middle	Low	0.03	25.6	-2.8	22.8
		Middle	0.08	32.8	-3.7	29.1
		High	0.19	53.1	-8.0	45.1
	High	Low	0.00	29.3	-1.0	28.4
		Middle	0.02	39.0	-2.4	36.7
		High	0.08	63.1	-6.2	56.9
Base Case Expected Values				44.3	-5.5	38.8
Utility	Low		0.60	41.0	-17.0	24.1
Load	Middle		0.30	53.9	-15.8	38.1
Forecast	High		0.10	62.0	-15.6	46.3
Utility Load Forecast Exp. Values				47.0	-16.5	30.5
DOR Fuel	Middle	High		32.2	-11.8	20.5
NoMiltry	Low	High		36.2	-8.4	27.7
DryHydro	Low	High		32.8	-11.6	21.3
WetHydro	Low	High		33.5	-11.5	22.1
GasEscal	Low	High		26.1	-9.1	17.1

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

5.9 NORTHEAST INTERTIE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS

5.9.1 Increased Anchorage-Copper Valley/Fairbanks Transfers

Transfers without the new intertie are described in Section 5.6 and presented in Table 5-5. Table 5-12 shows the increase in transfers from Anchorage to Copper Valley and Fairbanks as a result of the Northeast intertie. In the base case, the expected increase in transfers varies from 247 GWh per year in 1994 to 350 GWh per year in 2010. Larger increases were calculated for the utility load forecast scenarios.

5.9.2 Benefits of Increased Anchorage-Copper Valley/Fairbanks Transfers

To evaluate the benefits of the Northeast intertie, the costs of operation in the isolated Copper Valley area must be included. Of these additional costs, those associated with operating Copper Valley's diesel generators are most important. The load forecast for the Copper Valley service area is also important. Because most of the energy available from the Solomon Gulch hydro project is presently consumed, most of the energy generation required to meet higher demands is projected to come from diesel generation as long as Copper Valley remains isolated. What most distinguishes the benefits of the Northeast intertie from the benefits of the full Anchorage-Fairbanks upgrade is the value gained by displacing expensive diesel generation in the Copper Valley area with gas-fired generation from the Anchorage area. Another contributing factor is the availability of surplus energy during the summer at Solomon Gulch that must presently be spilled due to insufficient local demand and insufficient reservoir storage capacity. An additional 12 GWh per year was assumed to be available from Solomon Gulch if the Northeast intertie were built, since a connection with the Railbelt would allow the summer surplus energy to be used.

The annual savings associated with the increased transfers from Anchorage to Copper Valley and Fairbanks (net of transmission losses) is shown in Table 5-13. The expected annual savings rise from $5.7 million in 1994 to $9.6 million in 2010. Table 5-14 shows the present value of these savings discounted to 1994 at 4.5 percent. The expected value of these benefit categories is $147.9 million. Similar benefits were calculated for the sensitivity scenarios. Most of the difference between the annual and total benefits of the full Anchorage-Fairbanks upgrade (Tables 5-7 and 5-8), and the annual and total benefits of the Northeast intertie (Tables 5-13 and 5-14), is due to the displacement of diesel generation in Copper Valley by gas-fired generation in Anchorage.

The amount of diesel generation subject to displacement depends on the load forecast for the Copper Valley area. An important component of the load forecast is

Table 5-12

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO THE NEW NORTHEAST LINE

	Assumptions			Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
			Joint	South ----> North			North ----> South					
Scenario	Fuel	Load	Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	382.7	214.3	424.2	0.0	0.0	0.0	22.0	9.1	20.1
		Middle	0.23	365.7	208.2	398.6	0.0	0.0	0.0	20.7	7.2	17.1
		High	0.06	414.2	245.3	378.5	0.0	0.0	0.0	23.2	6.3	11.8
	Middle	Low	0.03	44.6	48.6	118.3	0.0	0.0	0.0	-8.1	-10.0	-5.9
		Middle	0.08	44.1	70.4	194.8	0.0	0.0	0.0	-7.5	-8.5	0.9
		High	0.19	48.3	186.8	327.3	0.0	0.0	0.0	-10.0	0.2	10.2
	High	Low	0.00	44.6	71.0	127.9	0.0	0.0	0.0	-8.1	-6.1	-4.4
		Middle	0.02	44.2	140.4	161.5	0.0	0.0	0.0	-7.5	3.4	-0.1
		High	0.08	48.5	258.8	248.7	0.0	0.0	0.0	-9.9	12.6	8.1
Base Case Expected Values				246.5	195.2	350.1	0.0	0.0	0.0	9.3	5.0	13.3
Utility Load Forecast	Low		0.60	465.7	293.1	293.3	0.0	0.0	0.0	21.9	4.9	10.9
	Middle		0.30	187.7	321.1	389.8	0.0	0.0	0.0	-0.7	9.2	11.9
	High		0.10	188.0	340.1	1694.9	0.0	0.0	0.0	-0.7	16.0	6.0
Utility Load Forecast Exp. Values				354.5	306.2	462.4	0.0	0.0	0.0	12.8	7.3	10.7
DOR Fuel	Middle	High		307.0	398.1	496.1	0.0	0.0	0.0	5.1	11.1	18.2
NoMiltry	Low	High		366.0	212.7	356.5	0.0	0.0	0.0	21.0	5.3	11.4
DryHydro	Low	High		414.3	245.6	354.2	0.0	0.0	0.0	23.2	6.3	10.1
WetHydro	Low	High		414.2	245.2	396.7	0.0	0.0	0.0	23.2	6.3	13.1
GasEscal	Low	High		415.0	374.9	0.0	0.0	0.0	272.2	23.1	15.2	13.4

Note: Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 5-13

ANNUAL TRANSFER BENEFITS DUE TO THE NEW NORTHEAST LINE

Assumptions				Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	7.1	8.1	8.9	-0.3	-0.1	-0.4	6.8	8.0	8.5
		Middle	0.23	5.2	6.3	8.6	-0.3	-0.1	-0.4	4.9	6.2	8.2
		High	0.06	7.0	7.4	9.5	-0.3	-0.1	-0.3	6.7	7.3	9.2
	Middle	Low	0.03	5.5	6.0	7.6	0.2	0.2	0.1	5.7	6.3	7.7
		Middle	0.08	3.8	4.7	9.0	0.2	0.2	-0.1	3.9	4.9	8.9
		High	0.19	5.3	7.8	12.3	0.2	0.0	-0.4	5.5	7.8	11.8
	High	Low	0.00	5.7	6.7	9.0	0.2	0.2	0.0	5.9	6.9	9.1
		Middle	0.02	4.0	5.5	10.9	0.2	-0.1	-0.2	4.2	5.4	10.7
		High	0.08	5.7	9.2	15.0	0.3	-0.4	-0.5	6.0	8.8	14.5
Base Case Expected Values				5.8	7.3	10.0	-0.1	-0.1	-0.4	5.7	7.2	9.6
Utility Load Forecast	Low		0.60	7.6	7.4	9.6	-0.3	-0.1	-0.3	7.3	7.3	9.3
	Middle		0.30	5.5	9.5	12.8	0.1	-0.2	-0.5	5.6	9.2	12.3
	High		0.10	4.9	11.0	15.4	0.1	-0.5	-0.4	5.0	10.4	15.0
Utility Load Forecast Exp. Values				6.7	8.4	11.1	-0.1	-0.2	-0.4	6.5	8.2	10.8
DOR Fuel	Middle	High		6.5	7.5	9.1	-0.0	-0.2	-0.4	6.5	7.3	8.7
NoMiltry	Low	High		6.4	6.8	9.0	-0.3	-0.0	-0.2	6.1	6.8	8.8
DryHydro	Low	High		8.2	8.5	10.6	-0.3	-0.1	-0.3	7.9	8.4	10.3
WetHydro	Low	High		7.3	7.7	9.9	-0.3	-0.1	-0.3	7.0	7.7	9.6
GasEscal	Low	High		8.9	13.3	15.5	-0.3	-0.3	-0.7	8.6	13.2	14.8

Notes:

1. All values are in 1987 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer + Reduced Transmission Loss
4. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 5-14

PRESENT VALUE OF TRANSFER BENEFITS DUE TO THE NORTHEAST LINE

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Increased Economy Energy Transfer	Reduced Trans. Losses	Net Transfer Benefits
Base	Low	Low	0.30	152.0	-6.0	146.0
		Middle	0.23	134.4	-5.6	128.8
		High	0.06	154.1	-4.4	149.7
	Middle	Low	0.03	121.5	3.2	124.7
		Middle	0.08	119.5	1.6	121.0
		High	0.19	169.7	-1.3	168.4
	High	Low	0.00	138.5	2.9	141.4
		Middle	0.02	140.2	0.9	141.1
		High	0.08	200.2	-2.5	197.7
Base Case Expected Values				151.5	-3.6	147.9
Utility Load Forecast	Low		0.60	158.0	-3.9	154.1
	Middle		0.30	195.9	-3.9	191.9
	High		0.10	217.8	-4.2	213.6
Utility Load Forecast Exp. Values				175.3	-3.9	171.4
DOR Fuel	Middle	High		151.3	-4.0	147.3
NoMiltry	Low	High		147.5	-4.3	143.2
DryHydro	Low	High		174.0	-4.0	170.0
WetHydro	Low	High		161.0	-4.8	156.2
GasEscal	Low	High		219.7	-5.2	214.5

Notes: 1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

the load associated with the backscatter radar site. For the base scenarios, it was assumed in the low load case that the radar site will be supplied entirely by on-site generation; i.e., none of the radar load is supplied from the utility grid. In the mid load case, an average of 2.7 MW or 23.2 GWh per year was assumed to be supplied from the grid. In the high load case, the grid supplies an average of 3.7 MW or 32 GWh per year. There is much uncertainty surrounding these estimates, and the Air Force has not yet decided on a power supply plan. If the radar site load were entirely excluded from the Northeast intertie analysis, based on the assumption that no power will be supplied to the site from the utility grid, then the expected value of Northeast intertie benefits would decline by approximately $13 million.

A preliminary estimate of benefits previously discussed with utility representatives was different from the estimate reported here. Two adjustments were made that account for the difference:

1. It was previously assumed that the efficiency of diesel generators operated by Copper Valley will not change over the analysis period. However, because existing units are presently scheduled for retirement in the year 2000, new diesel generators were assumed from that time forward with improved efficiencies, specifically full-load heat rates of 10,000 Btu/kWh [2].

2. A "high" set of cases was previously reported that was based on an estimate of variable O&M costs of $83 per MWh. This figure actually represents personnel costs. It is variable in the sense that most of it could be saved if the Northeast intertie were built and, as a result, the Copper Valley diesel generation were maintained only as reserve. However, the previous analysis assumed that this cost was also variable in an upward direction; i.e., if the output of the diesel generators doubled, this cost would also double. A recent conversation with CVEA[8] indicated that personnel costs would not change with increased diesel generation. The costs associated with increased diesel generation were therefore reduced relative to the values previously estimated.

5.10 IMPACT OF ADDITIONAL MILITARY LOAD IN FAIRBANKS

As discussed in Appendix C, an increment of additional military load, and to a minor extent additional University of Alaska load, was added to the Fairbanks demand forecast for all base case scenarios. Sensitivity cases were run in which the military increment was removed from the high load, low fuel price case. The reduction in benefits recorded for this sensitivity test was $7.0 million for the full AF upgrade and $6.5 million for the Northeast intertie. With the limited AF100 upgrade, the reduction of load removed some of the constraints imposed by operating the North Pole plants and benefits actually increased $5.8 million.

[8]Phone conversation between Salim J. Jabbour and Lowell Highbargain on March 28, 1989.

5.11 REFERENCES

[1] Letter from Steve Colt (ISER) to Mike Gordon (DFI), February 1, 1989.

[2] RMR Associates, *Reference Guide to Small Cogeneration Systems for Utilities*, final report prepared for Electric Power Research Institute, EM-4371, February 1986.

Section 6
BENEFITS OF INCREASED CAPACITY SHARING

6.1 OVERVIEW

A new/upgraded intertie could allow two or more areas to share and/or increase sharing generation capacity. As a result, an increment of future investment in generation capacity could be deferred or avoided. This section describes the benefits of increased capacity sharing due to the new Kenai-Anchorage line, the full upgrade of the Anchorage-Fairbanks line to 225 MW, and the new Anchorage-Fairbanks Northeast intertie.

We start by presenting the Railbelt capacity surplus (expected mainly in Kenai and Fairbanks) and the Railbelt capacity shortage without new/upgraded interties (expected mainly in Anchorage). We then present the reduced Railbelt capacity shortage due to new/upgraded interties. The benefits of reduced Railbelt capacity shortage (i.e., benefits of capacity sharing) due to the new Kenai-Anchorage line vary between $5.35 and $15.23 million; the benefits of the new/upgraded Anchorage-Fairbanks line vary between $0.00 and $1.68 million.

6.2 RAILBELT CAPACITY SURPLUS

Capacity surplus is local generation capacity in excess of required generation capacity. Local generation capacity is here defined as existing local capacity minus local capacity retirements.[1] Required generation capacity is the sum of peak load and capacity reserve margin. Capacity reserve margin is a fraction of peak load. The following equations summarize the calculation of the capacity surplus.

Capacity Surplus	=	Local Capacity - Required Capacity
Required Capacity	=	Peak Load + Capacity Reserve Margin
Capacity Reserve Margin	=	Fraction x Peak Load

[1]For this analysis, capacity retirements are assumed to occur as planned according to retirement schedules. If life extension or repowering of generating units were assumed instead, existing capacity surpluses would persist over a longer time period, and the benefits of capacity sharing via interties would be deferred and, as a result, reduced.

According to the Alaska Intertie Agreement [1], the capacity reserve margin should be equal to thirty (30) percent of the annual peak load. Kenai is expected to have a capacity surplus of over 100 MW when Bradley Lake comes on line (expected in the fall of 1991); the Kenai surplus is expected to continue for at least 25 years.[2] Table 6-1 summarizes the Kenai capacity surplus for all four load forecasts.[3]

The existing capacity in Fairbanks is also larger than the capacity requirements in Fairbanks. Fairbanks is expected to have a capacity surplus for the next ten to fifteen years depending on load growth. The current capacity surplus in Fairbanks is around 100 MW. Table 6-2 summarizes the Fairbanks capacity surplus for all four load forecasts.

Anchorage has a current capacity surplus of around 300 MW. However, because of planned capacity retirements and projected load growth, the Anchorage capacity surplus is expected to disappear as early as 1995. Capacity surplus in Kenai and Fairbanks is therefore expected to persist longer than capacity surplus in Anchorage. As a result, there will be no benefit from sharing the Anchorage capacity surplus with Kenai and Fairbanks, both of which will have their own local surplus longer than Anchorage will. However, there will be benefit realized from sharing the Kenai and Fairbanks surplus with Anchorage after a capacity shortage develops in Anchorage.

6.3 RAILBELT CAPACITY SHORTAGE WITHOUT NEW/UPGRADED INTERTIES

Capacity shortage is required generation capacity in excess of available capacity. For Kenai and Fairbanks, available capacity equals local capacity. For Anchorage, available capacity equals local capacity plus other capacity accessible through transmission lines. In other words, Anchorage can draw on surplus in Kenai and Fairbanks to alleviate an Anchorage shortage. However, neither Kenai nor Fairbanks can draw on surplus in Anchorage, for there is none when Kenai and Fairbanks experience shortages.

[2]The capacity surplus decreases over time as the load grows and as generation capacity is retired.

[3]Load growth for 2011 through 2028 was based on the growth rate of the last five years of the load forecast, i.e. 2005 through 2010. This assumption had no impact on the capacity sharing benefits calculated in this section because 2009 was the last year for which there was a capacity sharing benefit (Refer to Sections 6.4 and 6.5).

Table 6-1

KENAI CAPACITY SURPLUS*

Year	Load Growth Low	Middle	High	Utility
1994	113	99	95	82
1995	114	96	91	78
1996	114	96	90	78
1997	114	95	89	77
1998	114	95	88	77
1999	114	94	88	76
2000	113	93	86	76
2001	113	93	85	75
2002	112	92	82	75
2003	112	91	80	74
2004	111	90	78	73
2005	106	84	71	68
2006	105	82	70	67
2007	86	62	51	49
2008	85	61	48	48
2009	84	59	47	47
2010	43	18	5	7
2011	41	15	3	5
2012	40	14	2	3
2013	38	13	0	2
2014	37	11	0	1
2015	36	10	0	0
2016	35	9	0	0
2017	33	8	0	0
2018	32	6	0	0
2019	31	5	0	0
2020	29	4	0	0
2021	28	2	0	0
2022	27	1	0	0
2023	25	0	0	0
2024	24	0	0	0
2025	23	0	0	0
2026	22	0	0	0
2027	20	0	0	0
2028	19	0	0	0

*Based on a 30 percent planning reserve margin.

Table 6-2

FAIRBANKS CAPACITY SURPLUS*

	Load Growth			
Year	Low	Middle	High	Utility
1994	90	92	83	58
1995	88	89	78	53
1996	81	81	70	43
1997	77	77	64	37
1998	76	76	62	34
1999	76	74	60	31
2000	68	66	49	20
2001	49	46	31	0
2002	4	2	0	0
2003	3	0	0	0
2004	2	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0

*Based on a 30 percent planning reserve margin.

6.3.1 Kenai Capacity Shortage

Kenai is expected to have a capacity surplus for the next 25 years. Kenai would have capacity shortages after 2014 only under the high and utility load growth forecasts. Table 6-3 illustrates the expected local capacity in Kenai between 1994 and 2028 and the corresponding capacity shortage for all four load forecasts.

6.3.2 Fairbanks Capacity Shortage

Fairbanks is expected to have a capacity surplus for the next 10 to 15 years. Depending on the load forecast, Fairbanks is expected to start having a capacity shortage between 2001 and 2005. Table 6-4 illustrates the expected local capacity in Fairbanks between 1994 and 2028 and the corresponding capacity shortage for all four load forecasts.

6.3.3 Anchorage Capacity Shortage

While the existing capacity surplus in Anchorage may disappear as early as 1995, capacity shortages in Anchorage may not occur until 1996 or 1997. The reason for this time lag between capacity surplus and capacity shortage in Anchorage is the existing transmission lines that make surplus capacity in Kenai and Fairbanks accessible in Anchorage. A capacity shortage exists in Anchorage only if the Anchorage capacity requirements exceed the sum of the Anchorage local capacity and the capacity surplus in Kenai and Fairbanks accessible in Anchorage. The Kenai capacity surplus that is accessible in Anchorage is the minimum of the Kenai capacity surplus and the capacity of the Kenai-Anchorage line (currently 60 MW, based on Anchorage delivery). The Fairbanks capacity surplus that is accessible in Anchorage is the minimum of the Fairbanks capacity surplus and the capacity of the Anchorage-Fairbanks line (currently 62 MW, based on Anchorage delivery). Table 6-5 illustrates the expected local capacity in Anchorage between 1994 and 2028 and the corresponding capacity shortage for all four load forecasts.

Table 6-3

KENAI CAPACITY SHORTAGE

		Load Growth : Low			Load Growth : Middle			Load Growth : High			Load Growth : Utility		
Year	Local Capacity (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	198	65	85	0	76	99	0	80	103	0	89	116	0
1995	195	62	81	0	76	99	0	80	104	0	90	117	0
1996	195	62	81	0	76	99	0	80	105	0	90	117	0
1997	195	62	81	0	77	100	0	82	106	0	90	118	0
1998	195	63	81	0	77	100	0	82	107	0	91	118	0
1999	195	63	81	0	78	101	0	83	107	0	91	119	0
2000	195	63	82	0	78	102	0	84	109	0	92	119	0
2001	195	63	82	0	79	102	0	85	110	0	92	120	0
2002	195	64	83	0	79	103	0	87	113	0	93	120	0
2003	195	64	83	0	80	104	0	88	115	0	93	121	0
2004	195	64	84	0	81	105	0	90	117	0	94	122	0
2005	190	65	84	0	82	106	0	91	119	0	94	122	0
2006	190	66	85	0	83	108	0	92	120	0	94	123	0
2007	172	66	86	0	84	110	0	93	121	0	95	123	0
2008	172	67	87	0	85	111	0	95	124	0	95	124	0
2009	172	68	88	0	87	113	0	96	125	0	96	125	0
2010	132	68	89	0	88	114	0	97	127	0	96	125	0
2011	131	69	90	0	89	116	0	98	128	0	97	126	0
2012	131	70	91	0	90	117	0	99	129	0	98	128	0
2013	131	71	93	0	91	118	0	100	131	0	99	129	0
2014	131	72	94	0	92	120	0	101	132	1	100	130	0
2015	131	73	95	0	93	121	0	102	133	2	101	132	1
2016	131	74	96	0	94	122	0	103	134	3	102	133	2
2017	131	75	98	0	95	123	0	104	136	5	103	134	3
2018	131	76	99	0	96	125	0	105	137	6	104	136	5
2019	131	77	100	0	97	126	0	106	138	7	105	137	6
2020	131	78	102	0	98	127	0	107	140	9	106	138	7
2021	131	79	103	0	99	129	0	108	141	10	107	139	8
2022	131	80	104	0	100	130	0	109	142	11	108	141	10
2023	131	81	106	0	101	131	0	110	144	13	109	142	11
2024	131	82	107	0	102	133	2	111	145	14	110	143	12
2025	131	83	108	0	103	134	3	112	146	15	111	145	14
2026	131	84	109	0	104	135	4	113	147	16	112	146	15
2027	131	85	111	0	105	136	5	114	149	18	113	147	16
2028	131	86	112	0	106	138	7	115	150	19	114	149	18

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Kenai = Kenai Capacity Requirement - Kenai Local Capacity

Table 6-4

FAIRBANKS CAPACITY SHORTAGE

		Load Growth : Low			Load Growth : Middle			Load Growth : High			Load Growth : Utility		
Year	Local Capacity (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	245	119	155	0	118	153	0	125	162	0	144	187	0
1995	243	119	155	0	119	154	0	127	165	0	146	190	0
1996	236	119	155	0	119	155	0	128	166	0	149	193	0
1997	233	120	156	0	120	156	0	130	169	0	151	196	0
1998	233	121	157	0	121	157	0	132	171	0	153	199	0
1999	233	121	157	0	122	159	0	133	173	0	156	202	0
2000	226	121	158	0	123	160	0	136	177	0	158	206	0
2001	208	122	159	0	125	162	0	136	177	0	161	209	1
2002	165	124	161	0	126	163	0	141	183	18	163	212	47
2003	165	125	162	0	127	165	0	143	185	20	166	216	51
2004	165	126	163	0	129	167	2	146	190	25	168	219	54
2005	145	127	165	20	131	170	25	152	197	52	171	222	77
2006	61	128	167	106	133	173	112	157	205	144	174	226	165
2007	0	130	169	169	136	177	177	157	204	204	177	230	230
2008	0	132	172	172	139	180	180	158	206	206	179	233	233
2009	0	133	173	173	141	183	183	160	208	208	182	237	237
2010	0	135	176	176	143	187	187	163	212	212	185	241	241
2011	0	136	177	177	145	189	189	166	216	216	188	244	244
2012	0	137	179	179	147	192	192	169	220	220	191	248	248
2013	0	138	180	180	149	194	194	172	224	224	194	252	252
2014	0	139	181	181	151	197	197	175	228	228	197	256	256
2015	0	140	183	183	153	200	200	178	232	232	200	260	260
2016	0	141	184	184	155	202	202	181	236	236	203	264	264
2017	0	142	185	185	157	205	205	184	240	240	206	268	268
2018	0	143	186	186	159	207	207	187	244	244	209	272	272
2019	0	144	188	188	161	210	210	190	248	248	212	276	276
2020	0	145	189	189	163	213	213	193	251	251	215	280	280
2021	0	146	190	190	165	215	215	196	255	255	218	283	283
2022	0	147	192	192	167	218	218	199	259	259	221	287	287
2023	0	148	193	193	169	220	220	202	263	263	224	291	291
2024	0	149	194	194	171	223	223	205	267	267	227	295	295
2025	0	150	196	196	173	226	226	208	271	271	230	299	299
2026	0	151	197	197	175	228	228	211	275	275	233	303	303
2027	0	152	198	198	177	231	231	214	279	279	236	307	307
2028	0	153	199	199	179	233	233	217	283	283	239	311	311

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Fairbanks = Fairbanks Capacity Requirement - Fairbanks Local Capacity

Table 6-5

ANCHORAGE CAPACITY SHORTAGE

Year	Local Capacity (MW)	Load Growth : Low Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : Middle Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : High Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : Utility Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	658	383	498	0	386	502	0	404	525	0	395	513	0
1995	524	382	497	0	390	507	0	407	529	0	403	523	0
1996	404	381	495	0	392	510	0	411	534	8	411	534	27
1997	372	381	495	1	393	510	16	417	543	49	419	545	76
1998	353	380	494	19	396	515	40	423	550	76	428	556	110
1999	142	380	494	230	401	522	258	430	559	297	437	568	335
2000	142	380	494	230	405	527	263	438	569	318	446	579	357
2001	142	382	497	246	411	534	286	447	581	348	455	591	389
2002	142	385	501	295	416	540	336	455	592	390	464	603	401
2003	142	389	506	301	422	549	347	465	604	402	474	616	414
2004	142	393	511	307	430	559	357	475	618	416	483	628	426
2005	142	397	515	313	438	570	368	483	628	426	493	641	439
2006	142	401	522	320	448	583	381	494	642	440	503	654	452
2007	142	406	528	326	460	598	396	504	655	463	514	668	477
2008	142	411	534	332	471	612	410	513	666	476	524	681	491
2009	55	416	541	426	482	627	513	520	676	574	535	695	593
2010	30	422	549	475	494	642	594	532	691	656	546	710	673
2011	30	427	555	484	504	655	609	542	704	671	556	723	688
2012	30	432	562	492	514	668	624	552	717	685	566	736	702
2013	30	437	568	500	524	681	638	562	730	700	576	749	717
2014	30	442	575	508	534	694	652	572	743	713	586	762	731
2015	30	447	581	515	544	707	667	582	756	726	596	775	745
2016	30	452	588	523	554	720	681	592	769	739	606	788	758
2017	30	457	594	531	564	733	695	602	782	752	616	801	771
2018	30	462	601	539	574	746	710	612	795	765	626	814	784
2019	30	467	607	547	584	759	724	622	808	778	636	827	797
2020	30	472	614	554	594	772	738	632	821	791	646	840	810
2021	30	477	620	562	604	785	752	642	834	804	656	853	823
2022	30	482	627	570	614	798	767	652	847	817	666	866	836
2023	30	487	633	578	624	811	781	662	860	830	676	879	849
2024	30	492	640	586	634	824	794	672	873	843	686	892	862
2025	30	497	646	593	644	837	807	682	886	856	696	905	875
2026	30	502	653	601	654	850	820	692	899	869	706	918	888
2027	30	507	659	609	664	863	833	702	912	882	716	931	901
2028	30	512	666	617	674	876	846	712	925	895	726	944	914

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Anchorage = Anchorage Capacity Requirement
- Anchorage Local Capacity
- Surplus in Kenai and Fairbanks Accessible via Transmission Lines.

6.4 REDUCED RAILBELT CAPACITY SHORTAGE DUE TO NEW/UPGRADED INTERTIES

6.4.1 Kenai-Anchorage New Intertie

The new Kenai-Anchorage intertie would allow Anchorage to use the capacity surplus in Kenai without the 60 MW transfer limit that exists today.[4] For capacity planning purposes, Kenai and Anchorage could then be considered a single area; the load, capacity, and required capacity of the Kenai/Anchorage combined area would then be equal to the sum of the loads, capacities, and required capacities in the two areas. The Kenai-Anchorage area could also rely on capacity surplus in Fairbanks to the extent that this surplus is less than the transfer capacity of the existing Anchorage-Fairbanks line (62 MW, based on Anchorage delivery). The new Kenai-Anchorage line would therefore allow Anchorage to fully use the capacity surplus in Kenai and correspondingly reduce capacity shortages in Anchorage. Table 6-6 illustrates the capacity shortages in the Kenai/Anchorage combined area for all four load forecasts.

The capacity shortage in the Kenai/Anchorage combined area (case with new intertie) is less than or equal to the sum of the capacity shortages in the two areas (case without new intertie). For example, there is a 40 MW capacity shortage in Anchorage for the middle load growth forecast in 1998[5] and a 5 MW capacity shortage in the Anchorage/Kenai combined area. Therefore, the new Kenai-Anchorage intertie would reduce the capacity shortage in 1998 by 35 MW (40 MW - 5 MW) for the middle load forecast. This reduced capacity shortage is due to the fact that the new intertie would allow Anchorage to fully use the 95 MW surplus in Kenai in 1998 (refer to Table 6-1); only 60 MW would be used without the new intertie. Table 6-7 illustrates the reduced Kenai/Anchorage capacity shortages due to the Kenai-Anchorage new intertie.

According to Table 6-7, the Kenai/Anchorage capacity shortages are reduced between 1996 and 2009; no capacity shortage reductions are identified after 2009. Therefore, these reduced shortages represent *deferred capacity additions* rather than *avoided capacity additions*. Avoided capacity additions could be accomplished if the new Kenai-Anchorage intertie would reduce the capacity reserve margin of the Kenai/Anchorage area.

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[4]The transfer limit for the new intertie would be 250 MW adjusted for transmission losses.

[5]There is no capacity shortage in Kenai in 1998.

Table 6-6

KENAI/ANCHORAGE CAPACITY SHORTAGE

Year	Kenai/ Anchorage Capacity (MW)	Load Growth : Low Load (MW)	Low Capacity Requir't (MW)	Low Capacity Shortage (MW)	Load Growth : Middle Load (MW)	Middle Capacity Requir't (MW)	Middle Capacity Shortage (MW)	Load Growth : High Load (MW)	High Capacity Requir't (MW)	High Capacity Shortage (MW)	Load Growth : Utility Load (MW)	Utility Capacity Requir't (MW)	Utility Capacity Shortage (MW)
1994	856	448	582	0	462	601	0	484	629	0	484	629	0
1995	719	445	578	0	466	606	0	487	633	0	492	640	0
1996	599	443	576	0	468	609	0	491	639	0	501	651	9
1997	567	443	576	0	469	610	0	499	648	19	510	663	59
1998	548	442	575	0	473	615	5	505	657	47	519	674	93
1999	337	443	575	176	479	623	224	513	666	270	528	686	319
2000	337	443	576	177	484	629	230	521	678	292	537	699	341
2001	337	445	579	193	489	636	253	532	691	323	547	711	374
2002	337	449	584	242	495	643	304	542	705	368	557	724	387
2003	337	453	589	249	502	653	316	553	719	382	567	737	400
2004	337	457	594	256	511	664	327	566	735	398	577	750	413
2005	332	461	600	268	520	676	344	575	747	415	587	763	431
2006	332	467	607	275	531	691	359	586	762	430	598	777	445
2007	314	472	614	300	544	707	393	597	777	463	609	791	477
2008	314	478	621	307	556	723	409	608	790	476	620	805	491
2009	227	484	629	402	569	740	513	616	801	574	631	820	593
2010	162	490	637	475	582	756	594	629	818	656	642	835	673
2011	161	496	645	484	593	770	609	640	832	671	653	849	688
2012	161	502	653	492	604	785	624	651	846	685	664	863	702
2013	161	508	661	500	615	799	638	662	861	700	675	878	717
2014	161	514	669	508	626	813	652	673	875	714	686	892	731
2015	161	520	676	515	637	828	667	684	889	728	697	906	745
2016	161	526	684	523	648	842	681	695	904	743	708	921	760
2017	161	532	692	531	659	856	695	706	918	757	719	935	774
2018	161	538	700	539	670	871	710	717	932	771	730	949	788
2019	161	544	708	547	681	885	724	728	947	786	741	963	802
2020	161	550	715	554	692	899	738	739	961	800	752	978	817
2021	161	556	723	562	703	913	752	750	975	814	763	992	831
2022	161	562	731	570	714	928	767	761	989	828	774	1006	845
2023	161	568	739	578	725	942	781	772	1004	843	785	1021	860
2024	161	574	747	586	736	956	795	783	1018	857	796	1035	874
2025	161	580	754	593	747	971	810	794	1032	871	807	1049	888
2026	161	586	762	601	758	985	824	805	1047	886	818	1064	903
2027	161	592	770	609	769	999	838	816	1061	900	829	1078	917
2028	161	598	778	617	780	1014	853	827	1075	914	840	1092	931

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Kenai/Anchorage Area = Kenai/Anchorage Capacity Requirement
- Kenai/Anchorage Capacity
- Surplus in Fairbanks Accessible via Existing Anchorage/Fairbanks Line.

Table 6-7

REDUCED KENAI/ANCHORAGE CAPACITY SHORTAGE DUE TO KENAI-ANCHORAGE NEW INTERTIE

	Load Growth			
Year	Low	Middle	High	Utility
1994	0	0	0	0
1995	0	0	0	0
1996	0	0	8	18
1997	1	16	29	17
1998	19	35	28	17
1999	54	34	28	16
2000	53	33	26	16
2001	53	33	25	15
2002	52	32	22	15
2003	52	31	20	14
2004	51	30	18	13
2005	46	24	11	8
2006	45	22	10	7
2007	26	2	0	0
2008	25	1	0	0
2009	24	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0

6.4.2 Anchorage-Fairbanks Intertie Upgrade

The Anchorage-Fairbanks intertie upgrade would allow Anchorage to use the capacity surplus in Fairbanks without the 62 MW transfer limit that exists today.[6] For capacity planning purposes, Anchorage and Fairbanks could then be considered a single area; the load, capacity, and required capacity of the Anchorage/Fairbanks combined area would then be equal to the sum of the loads, capacities, and required capacities in the two areas. The Anchorage/Fairbanks area could also rely on capacity surplus in Kenai to the extent that this surplus is less than the transfer capacity of the existing Kenai-Anchorage line (60 MW, based on Anchorage delivery). The Anchorage-Fairbanks intertie upgrade would therefore allow Anchorage to fully use the capacity surplus in Fairbanks and correspondingly reduce capacity shortages in Anchorage. Table 6-8 illustrates the capacity shortages in the Anchorage/Fairbanks combined area for all four load forecasts.

The capacity shortage in the Anchorage/Fairbanks combined area (case with intertie upgrade) is less than or equal to the sum of the capacity shortages in the two areas (case without new intertie). For example, there is a 40 MW capacity shortage in Anchorage for the middle load growth forecast in 1998[7] and a 26 MW capacity shortage in the Anchorage/Fairbanks combined area. Therefore, the Anchorage-Fairbanks intertie upgrade would reduce the capacity shortage in 1998 by 14 MW (40 MW - 26 MW) for the middle load forecast. This reduced capacity shortage is due to the fact that the intertie upgrade would allow Anchorage to fully use the 76 MW surplus in Fairbanks in 1998 (refer to Table 6-2); only 62 MW would be used without the new intertie. Table 6-9 illustrates the reduced Anchorage/Fairbanks capacity shortages due to the Anchorage-Fairbanks intertie upgrade.

According to Table 6-9, the Anchorage/Fairbanks capacity shortages are reduced between 1996 and 2000; no capacity shortage reductions are identified after 2000. Therefore, these reduced shortages represent *deferred capacity additions* rather than *avoided capacity additions*. Avoided capacity additions could be accomplished if the Anchorage-Fairbanks intertie upgrade would reduce the capacity reserve margin of the Anchorage/Fairbanks area.

6.4.3 Anchorage-Fairbanks Northeast Intertie

The Anchorage-Fairbanks Northeast intertie would allow Anchorage and Fairbanks to reduce their capacity requirements by the same amount calculated for the Anchorage-Fairbanks intertie upgrade.

[6] The transfer limit of the upgraded intertie would be 225 MW adjusted for transmission losses.

[7] There is no capacity shortage in Fairbanks in 1998.

Table 6-8

ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE

Year	Anchorage/ Fairbanks Capacity (MW)	Load Growth : Low			Load Growth : Middle			Load Growth : High			Load Growth : Utility		
		Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	903	502	653	0	504	655	0	529	688	0	539	700	0
1995	767	502	652	0	509	661	0	533	694	0	549	714	0
1996	640	500	650	0	511	665	0	539	700	0	559	727	27
1997	605	501	651	0	513	666	1	547	711	46	570	741	76
1998	586	500	650	4	517	672	26	555	722	76	581	756	110
1999	375	501	651	216	523	680	245	563	732	297	592	770	335
2000	368	502	652	224	529	687	259	574	746	318	604	785	357
2001	350	505	656	246	535	696	286	583	758	348	615	800	390
2002	307	509	662	295	541	703	336	596	775	408	627	815	448
2003	307	514	668	301	549	714	347	607	789	422	639	831	464
2004	307	518	674	307	558	726	359	621	808	441	652	847	480
2005	287	524	681	334	569	740	393	635	825	478	664	864	517
2006	203	530	689	426	581	756	493	651	846	583	677	880	617
2007	142	536	697	495	596	774	572	661	859	666	690	897	707
2008	142	543	706	504	610	793	591	671	872	682	703	914	724
2009	55	550	714	599	624	811	696	680	884	782	717	932	830
2010	30	558	725	652	637	828	781	695	904	868	731	950	913
2011	30	564	733	662	649	844	799	708	921	887	744	967	933
2012	30	570	740	671	661	860	815	721	937	906	757	984	951
2013	30	576	748	680	673	875	832	734	954	924	770	1001	969
2014	30	582	756	689	685	891	849	747	971	941	783	1018	987
2015	30	588	764	698	697	906	866	760	988	958	796	1035	1005
2016	30	594	772	707	709	922	883	773	1005	975	809	1052	1022
2017	30	600	779	716	721	938	900	786	1022	992	822	1068	1038
2018	30	606	787	725	733	953	917	799	1039	1009	835	1085	1055
2019	30	612	795	734	745	969	934	812	1056	1026	848	1102	1072
2020	30	618	803	744	757	984	951	825	1073	1043	861	1119	1089
2021	30	624	811	753	769	1000	968	838	1090	1060	874	1136	1106
2022	30	630	818	762	781	1016	984	851	1106	1076	887	1153	1123
2023	30	636	826	771	793	1031	1001	864	1123	1093	900	1170	1140
2024	30	642	834	780	805	1047	1017	877	1140	1110	913	1187	1157
2025	30	648	842	789	817	1062	1032	890	1157	1127	926	1204	1174
2026	30	654	850	798	829	1078	1048	903	1174	1144	939	1221	1191
2027	30	660	857	807	841	1094	1064	916	1191	1161	952	1237	1207
2028	30	666	865	816	853	1109	1079	929	1208	1178	965	1254	1224

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Anchorage/Fairbanks Area = Anchorage/Fairbanks Capacity Requirement
- Anchorage/Fairbanks Capacity
- Surplus in Kenai Accessible via Existing Kenai/Anchorage Transmission Line.

Table 6-9

REDUCED ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE DUE TO ANCHORAGE-FAIRBANKS INTERTIE UPGRADE

	Load Growth			
Year	Low	Middle	High	Utility
1994	0	0	0	0
1995	0	0	0	0
1996	0	0	8	0
1997	1	15	2	0
1998	14	14	0	0
1999	14	12	0	0
2000	6	4	0	0
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0

6.5 BENEFITS OF REDUCED RAILBELT CAPACITY SHORTAGE DUE TO NEW/UPGRADED INTERTIES

When capacity is needed, the Railbelt utilities would acquire additional capacity by a) repowering existing power plants, b) extending the life of existing power plants, or c) adding new power plants. The expected reduced capacity shortage due to the new/upgraded interties would allow the Railbelt to reduce the addition of capacity and therefore to save capital costs. Cost savings are largest when the Railbelt can avoid adding a new plant; avoiding repowering or life extension of an existing power plant also leads to cost savings. Since reduced capacity shortages are only temporary (refer to Sections 6.4.1 and 6.4.2), the resulting savings are cost deferrals rather than cost avoidances (refer to Sections 6.4.1 and 6.4.2). Therefore, we assign savings for reduced capacity shortages during any given year based on the reduced capacity shortage in that year (refer to Tables 6-7 and 6-9) and the annual value of saved capacity. The annual value of saved capacity in any given year is calculated at $47 per kilowatt per year.[8]

6.5.1 Kenai-Anchorage New Intertie

Using the calculated reduced Kenai/Anchorage capacity shortages (Table 6-7) and the $39 per kilowatt per year value of saved capacity, we calculate the capital cost savings due to capacity sharing attributed to the Kenai-Anchorage new line. Table 6-10 summarizes the results. The discounted value of all benefits between 1994 and 2028 is largest for the lowest load forecast and lowest for the highest load forecast; with higher loads, there is less surplus capacity available for sharing. At a discount rate of 4.5 percent per year, the benefits of capacity sharing due to the Kenai-Anchorage new intertie vary between $5.35 and $15.23 million.

6.5.2 Anchorage-Fairbanks Intertie Upgrade

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Table 6-9) and the $47 per kilowatt per year value of saved capacity, we calculate the capital cost savings due to capacity sharing attributed to the Anchorage-Fairbanks intertie upgrade. Table 6-11 summarizes the results. At a discount rate of 4.5 percent per year, the benefits of capacity sharing due to the Anchorage-Fairbanks intertie upgrade vary between $0.00 and $1.68 million; there are no capacity sharing benefits for the utility load forecast (because of higher load forecast for Fairbanks).

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[8]Based on the levelized capital cost of a combustion turbine of $450 per kilowatt and a fixed O&M of $12 per kilowatt per year. Levelization is for 20 years at 4.5 percent per year.

Table 6-10

BENEFITS OF REDUCED KENAI/ANCHORAGE CAPACITY SHORTAGE

	Load Growth			
Year	Low	Medium	High	Utility
1990	0.00	0.00	0.00	0.00
1991	0.00	0.00	0.00	0.00
1992	0.00	0.00	0.00	0.00
1993	0.00	0.00	0.00	0.00
1994	0.00	0.00	0.00	0.00
1995	0.00	0.00	0.00	0.00
1996	0.00	0.00	0.38	0.84
1997	0.03	0.77	1.36	0.82
1998	0.88	1.64	1.34	0.79
1999	2.52	1.59	1.29	0.76
2000	2.50	1.56	1.24	0.74
2001	2.48	1.53	1.16	0.71
2002	2.46	1.50	1.05	0.68
2003	2.43	1.45	0.96	0.65
2004	2.41	1.40	0.83	0.63
2005	2.14	1.11	0.52	0.37
2006	2.10	1.05	0.47	0.34
2007	1.21	0.12	0.00	0.00
2008	1.17	0.04	0.00	0.00
2009	1.14	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00
NPV 3.5%	16.71	10.32	8.23	5.73
NPV 4.5%	15.23	9.54	7.68	5.35
NPV 5.5%	13.90	8.83	7.17	5.01

Table 6-11

BENEFITS OF REDUCED ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE

	Load Growth			
Year	Low	Medium	High	Utility
1990	0.00	0.00	0.00	0.00
1991	0.00	0.00	0.00	0.00
1992	0.00	0.00	0.00	0.00
1993	0.00	0.00	0.00	0.00
1994	0.00	0.00	0.00	0.00
1995	0.00	0.00	0.00	0.00
1996	0.00	0.00	0.36	0.00
1997	0.03	0.71	0.10	0.00
1998	0.67	0.64	0.00	0.00
1999	0.66	0.58	0.00	0.00
2000	0.29	0.17	0.00	0.00
2001	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00
2008	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00
2010	0.00	0.00	0.00	0.00
2011	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00
NPV 3.5%	1.36	1.76	0.41	0.00
NPV 4.5%	1.28	1.68	0.40	0.00
NPV 5.5%	1.22	1.60	0.39	0.00

6.5.3 Anchorage-Fairbanks Northeast Intertie

Because the Anchorage-Fairbanks Northeast intertie and the Anchorage-Fairbanks intertie upgrade would lead to the same capacity shortage reductions, these calculations produce the same capacity sharing benefits.

6.6 OTHER CAPACITY SHARING BENEFITS

There are two other ways in which additional capacity sharing benefits could be realized as a result of new additions:

1. New capacity is added in "lumpy" increments, not in smooth, gradual fractions as represented in the preceding analysis. This has two implications.

    a. A "lumpy" capacity addition in a future year can create a new capacity surplus in a given local area that is available for sharing outside the area for a limited time.

    b. The capacity costs that are deferred for a given area due to capacity sharing would tend to be higher than represented in the above analysis, again because capacity is added in larger increments rather than in a fractional manner.

2. Improved transmission may allow two areas to be served by one larger capacity addition in one location rather than two smaller capacity additions in each of the two areas. The capacity sharing benefit would depend on the economies of scale realized from construction of one larger plant rather than two smaller plants.

6.6.1 Future Surpluses Due to "Lumpy" Additions

Future capacity additions in a local area may create a future capacity surplus in that area that was not accounted for in the preceding analysis. However, the issue is the extent to which the new intertie proposals would increase capacity sharing above the levels that are currently attainable with the existing system. Presently, 60 MW can be shared between Kenai and Anchorage, and 62 MW can be shared between Fairbanks and Anchorage. We assume here that future capacity surplus created by capacity additions will not exceed the capacity sharing limitations of the existing transmission system.

6.6.2 "Lumpy" versus Fractional Capacity Costs

The valuation method used in Section 6.5 assumes that the value of deferred capacity equals an average unit cost of capacity multiplied by the estimated fraction of capacity addition that can be deferred. If the increase in capacity sharing due to a transmission improvement results in a reduced capacity shortage of, for example, 12 MW, the value of that increase is expressed as the average annual cost of 12 MW of capacity, even though the local response to this shortage may otherwise have been to add a 50-MW plant. This tends to understate the value of increased capacity sharing due to the transmission improvements. Compensating for this, however, is the fact that the cost of life extension and repowering of existing facilities is assumed to be equal to the cost of new capacity in this analysis. Further, using planned capacity retirements, as noted in Section 6.2, produces the earliest capacity shortages and, as a result, tends to maximize the opportunity and extent of capacity sharing increases.

6.6.3 Economies of Scale in Capacity Additions

It has been suggested by Golden Valley Electric Association (GVEA)[9] that since the Northeast intertie would add a second connection between Anchorage and Fairbanks, Fairbanks could locate some of its new generating capacity in Anchorage. This would, however, be limited by: (1) the smallest transfer capability of each of the two lines[10] (62 MW in this case, based on the existing Anchorage-Fairbanks line), and (2) the Fairbanks capacity shortage. According to the GVEA and Fairbanks Municipal Utility System (FMUS) retirement plans, capacity shortage would not occur in Fairbanks until 2002 at the earliest (refer to Table 6-4). Therefore, only after 2002 would Fairbanks be expected to locate new capacity in Anchorage and share that capacity with Anchorage.

Assuming that Anchorage and Fairbanks would share a 100-MW unit in Anchorage in 2005 rather than adding two smaller units in each area,[11] the capacity sharing savings would depend on the economies of scale of the power plant technology at that time.

Assuming that the one 100-MW unit would be $100 per kW cheaper than two 50-MW units, the realized savings would amount to $10 million for a 1994 present value of around $6 million (in 1987 dollars).

[9]Meeting at the Alaska Power Authority, Anchorage, March 14, 1989.

[10]In case of a fault on the line with the larger transfer capability (Northeast intertie), Fairbanks access to generating capacity in Anchorage would be limited to the transfer capability of the existing line.

[11]In the capacity expansion plan used in this study, a 50-MW unit would be added in Fairbanks in 2005.

6.7 REFERENCES

[1] Alaska Intertie Agreement, December 1985.

Section 7

OPERATING RESERVE SHARING

7.1 OVERVIEW

Operating reserves[1] respond to changes in customer demand and failures in the electric generation and transmission system. Operating reserves improve reliability, but they are often expensive. The hydroelectric capacity on the Kenai Peninsula may provide a less expensive source for some operating reserves that otherwise would be provided by thermal generating units in the Anchorage area.

The operating reserve savings depend on the following three factors:

1. The cost of providing operating reserves from thermal plants in Anchorage.

2. The transmission capacity between Anchorage and Kenai.

3. The generating capability in Kenai.

All three factors are discussed in more detail in the following subsections. The addition of a new Kenai-Anchorage intertie would increase operating reserve savings by about $45,000 (1987 dollars) per year.

Appendix H discusses the transfer of energy back and forth between Anchorage and Kenai to reshape thermal demands to their most efficient production profile. The reshaping of demands served by thermal power plants differs significantly from sharing operating reserves. Reshaping involves moving significant amounts of energy between Kenai and Anchorage and changing the timing of thermal generation in Anchorage. Sharing operating reserves on the other hand, does not involve any transfer of energy between areas, nor the changed timing of any generation. It does involve shifting energy production among Anchorage power plants.

[1]Throughout this report, the term "operating reserves" refers only to "spinning reserves." However, according to the Alaska Intertie Agreement, operating reserves include both spinning and non-spinning reserves. Non-spinning operating reserves were not considered in this analysis because they are projected to exceed requirements in all scenarios.

7.2 ANCHORAGE OPERATING RESERVE REQUIREMENT

The interconnection agreements and operating practices among the Railbelt utilities currently result in the provision of approximately 65 MW of operating reserve accessible in the Anchorage area. Limited amounts of this operating reserve can be provided from outside the Anchorage area. Based on the information available, we estimate it is feasible to transfer up to 30 MW of operating reserve from Kenai to Anchorage. These 30 MW result from examining the generating units typically providing operating reserves and the practice of distributing these reserves such that they are not all lost with a single event.

7.3 THE COST OF OPERATING RESERVES

In order to respond quickly to changing requirements, power plants providing operating reserves are operated at part load such that they can quickly increase or decrease their power output. This is expensive for thermal generating plants in general and gas turbines in particular. Most of the operating reserve provided in the Anchorage area comes from gas turbines. Appendix H provides more specific information about gas turbine part-load operating costs.

The cost of providing operating reserve with Anchorage area gas turbines is about 5000 Btu/kWh. For example, when the 66-MW Beluga #5 CT operates at a loading of 33 MW, its total operating cost (also called heat rate) is 15,012 Btu/kWh. At a loading of 33 MW, Beluga #5 provides 33 MW of spinning reserves (66 MW of rated capacity minus 33 MW of loaded capacity). When Beluga #5 is operated to provide spinning reserves,[2] the cost of providing spinning reserves is the difference between the total operating cost of Beluga #5 (i.e., 15,012 Btu/kWh) and the system marginal cost. The system marginal cost is typically 9,000 to 11,000 Btu/kWh (refer to Appendix H, Table H-2). Therefore, the cost of spinning reserves is estimated at 5000 Btu/kWh.

7.4 KENAI-ANCHORAGE TRANSMISSION CAPACITY

The new intertie will be capable of transferring 250 MW from Kenai to Anchorage; therefore, with the new intertie, transmission will not be a constraint on the transfer of 30 MW of operating reserve. The existing line can transfer 60 MW from Kenai to Anchorage. Based on the analysis described in Appendix H, it is expected that 30 MW of this will be utilized to provide transfers to reshape Anchorage demand for more efficient thermal generation. This will leave 30 MW of capacity available for the transfer of operating reserve. Because this increment of capacity has very high losses (approximately 20 percent), it will be seldom utilized for economy

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[2]Operating Beluga #5 could have been avoided if it were not for the spinning reserves requirement.

transactions. Transferring operating reserve is ideal because it does not incur losses. Since both lines can transfer 30 MW of operating reserve, the main difference between transfer capacity in the area of operating reserve is the reliability/availability of the existing Kenai-Anchorage line. (Please see Appendix J, response to MEA item M-6 for a further discussion of the 30 MW of operating reserve.)

7.5 KENAI GENERATING CAPABILITY

With the addition of Bradley Lake, hydroelectric capacity in Kenai will increase to 133 MW delivered to Soldotna. This hydroelectric capability is energy-limited such that its overall capacity factor is on the order of 35 percent. This means that on average, more than 80 MW of unused hydroelectric capacity exists because of limited energy. This is an ideal operating reserve application. The ability of Kenai hydroelectric plants (particularly Bradley Lake) to respond quickly enough to provide useful operating reserve remains uncertain. Our analysis assumes that of Anchorage's overall needs, Kenai can provide 30 MW of sufficient capability to replace an equivalent amount of operating reserve from thermal generating plants in the Anchorage area. We have assumed no added hydro operating cost resulting from the provision of this operating reserve from Kenai hydroelectric facilities.

7.6 SAVINGS IN OPERATING RESERVE COSTS

The savings in operating reserve costs is the product of: (1) the cost of the thermal operating reserve in Anchorage, (2) the amount of operating reserve displaced, and (3) the amount of time it is displaced. At 5000 Btu/kWh and 30 MW of operating reserve transferred, 150 MBtu of fuel are saved each hour. Our analysis estimates operating reserve could be transferred about 4000 hours a year.[3] This gives an annual savings of 600,000 MBtu per year. Most of these savings (which amount to $1.2 million annually when gas costs $2 per MBtu) result with or without the new Kenai-Anchorage intertie. The new line could provide increased benefits with higher availability and higher capacity to transfer power and operating reserves. Based on our analysis of the detailed simulation results of the Kenai and Anchorage area power dispatch, we conclude that the higher availability of the new intertie is the only significant source of difference in benefits.

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[3]The 4000 hours annual estimate reflects our assessment that operating reserve would only be transferred during "on-peak" hours. This assessment would be affected by factors such as the output level at Bradley Lake on-peak and the relative costs of spinning reserve at various levels of system demand. A more detailed evaluation of economic dispatch and unit commitment could change this assessment. The number of hours affects the analysis only to the extent that intertie availability differs in the two scenarios.

The existing Kenai-Anchorage intertie is assumed to be out of service two weeks per year. This outage would reduce the operating reserve sharing about 150 hours a year and give the new intertie a $45,000 increase in annual benefits with gas at $2 per MBtu.

Section 8
COAL-FIRED GENERATION

8.1 INTRODUCTION

This section presents our analysis of the feasibility of coal-fired power generation in the Railbelt. A 50-MW minemouth plant at Healy was selected for evaluation. The Healy location was selected because the capital costs of a Healy plant were estimated by Stone & Webster [1] to be slighty less than comparable costs at Nenana and Beluga sites. Although capital costs of a coal-fired power plant in the Matanuska Valley were estimated to be lower yet, the Matanuska site is not presently under active consideration for coal-fired power production. Further, the cost of coal at the Healy site would be substantially less than at the Nenana site due to avoided transportation costs, and construction of a plant at Beluga is contingent on future development of a large mine for export, a prospect that remains speculative at this time.

The 50-MW size was selected because the current excess capacity in the Railbelt, combined with forecasts of modest load growth in the foreseeable future, limit the prospects for larger sizes, even though power production costs would be lower on a unit basis if a larger plant were constructed. The 50-MW size selected is also close to the size most recently put forward by prospective project sponsors, specifically representatives of the Usibelli Coal Mine.

The plant is assumed to be an atmoshperic circulating fluidized bed design, operating on a mixture of waste coal (50 percent) and standard coal (50 percent). This was suggested by Usibelli representatives to be a reasonable fuel blend assumption. In the analysis presented in this section, the plant is evaluated initially as a single-purpose coal-fired power plant (i.e., with no cogeneration component). Following that analysis, we present a preliminary estimate of the additional cost of providing high-quality steam from the power plant to a proposed coal drying facility. Based on the power-plant analysis and the estimated cost of cogenerated steam, we estimate what the value or price of that steam would have to be for the power-plant economics to reach the breakeven point.

The benefit categories reviewed for a coal-fired power plant at Healy fall into the following three main categories:

1. *Reduced Energy Costs.* This refers to the reduced variable costs of power production, consisting of fuel costs and variable O&M costs.[1] The estimate of these savings was based on the simulation results from the Over/Under model, adjusted for the impact of the North Pole unit operating constraint[2] described in Section 5.

2. *Reduced Transmission Losses.* If an additional 50 MW were generated at Healy for transmission to Fairbanks, there would be a comparable reduction of gas-fired energy from Anchorage transmitted to Fairbanks over the intertie. Transmission losses associated with the avoided transfers from Anchorage would be saved. However, there would be transmission losses associated with the transfers from the new plant at Healy to Fairbanks. The reduced transmission cost is the net result of these estimated increases and decreases in losses.

3. *Capacity Benefits.* Construction of the coal-fired power plant results in the avoidance of 50 MW of new capacity that would otherwise be added during the study period. We assume that the coal plant would come on-line in 1995. If all existing generators were retired according to the present retirement schedules, 50 MW of new capacity would be added in 1997. The coal plant is given credit for avoidance of this increment of capacity beginning in 1997.

8.2 REDUCED ENERGY COSTS AND TRANSMISSION LOSSES

The following additional assumptions were used for the production system modeling:

[1]The capital costs and fixed O&M costs are netted out in the final analysis.

[2]In the scenarios without the coal plant, the estimated system costs are increased to account for expanded power production from the North Pole units and the consequent reduction of transfers over the intertie. A similar adjustment is made in the scenarios with the coal plant, and the net result is used to adjust the energy cost savings.

Characteristic	Value	Source
Heat Rate	11,337 Btu/kWh	Stone & Webster [1]
Forced Outage Rate	0.08	EPRI TAG [1]
Planned Outage Rate	0.13	EPRI TAG [1]
Variable O&M	$3.83/MWh	Stone & Webster [1]
Fuel Cost[3]	$0.85/Mbtu	Usibelli Coal Mine

We assume in this analysis that the coal plant is added in the absence of any intertie upgrade. As a result, the 70 MW of gas-fired energy that Anchorage could otherwise send to Fairbanks is essentially reduced to 20 MW. Because the variable costs of generating power from the coal plant are low compared with the expected variable costs of gas-fired energy from Anchorage, the coal-fired energy is used first. If intertie capacity were assumed to increase at the time the coal plant comes on-line, the coal-fired generation would still back out 50 MW of gas-fired generation from the Anchorage area.

At full loading of the intertie, approximately 70 percent of the transmission losses incurred between Anchorage and Fairbanks are actually incurred between Healy and Fairbanks.[4] As a result, approximately 70 percent of the transmission losses that would have been incurred as a result of energy imports from Anchorage to Fairbanks would still be incurred if that energy were delivered from Healy instead. The remaining 30 percent represents a savings from reduced transmission losses that would be realized as a result of the proposed Healy coal plant.

Table 8-1 shows the decrease in economy energy transfers from Anchorage to Fairbanks estimated as a result of the coal plant. There is no impact in 1994 because the plant is assumed to come on-line in 1995. Note that the decrease in transfers from Anchorage to Fairbanks declines in nearly all cases by over 300 GWh per year, the approximate amount of coal-fired generation from a 50-MW plant operating at a high capacity factor.[5] The only exception is the high gas price escalation case, for which transfers from south to north had declined to zero by the year 2028 in the case without the coal plant.

[3]As described in Appendix B, waste coal was valued at $0.50 per MBtu and standard coal at $1.20 per MBtu based on discussion with the Usibelli Coal Mine. Assuming a 50/50 mixture, the blended value is estimated at $0.85 per MBtu.

[4]Losses are lower between Anchorage and Healy primarily because the portion of the intertie built by the State between Willow and Healy was constructed for 345 KV operation, while the segment from Healy to Fairbanks was constructed for 138 KV operation.

[5]A 50-MW plant operating at 80 percent capacity factor would produce 350.4 GWh per year.

Table 8-1

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO NEW 50-MW COAL PLANT AT HEALY

Assumptions				Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
				South ----> North			North ----> South					
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	0.0	-295.0	-285.9	0.0	0.0	0.0	0.0	-7.9	-8.9
		Middle	0.23	0.0	-319.2	-293.4	0.0	0.0	0.0	0.0	-8.8	-9.5
		High	0.06	0.0	-325.2	-304.6	0.0	0.0	0.0	0.0	-10.1	-11.5
	Middle	Low	0.03	0.0	-371.4	-361.7	0.0	8.4	1.7	0.0	-11.9	-12.1
		Middle	0.08	0.0	-359.5	-331.1	0.0	7.4	0.0	0.0	-11.7	-11.0
		High	0.19	0.0	-332.0	-338.1	0.0	1.3	0.0	0.0	-11.0	-11.2
	High	Low	0.00	0.0	-349.3	-353.1	0.0	9.2	1.7	0.0	-10.8	-11.7
		Middle	0.02	0.0	-290.4	-318.6	0.0	7.4	0.2	0.0	-8.2	-10.3
		High	0.08	0.0	-261.0	-306.3	0.0	1.3	0.1	0.0	-7.3	-9.5
Base Case Expected Values				0.0	-314.2	-306.9	0.0	1.3	0.1	0.0	-9.2	-10.0
Utility Load Forecast	Low		0.60	0.0	-319.1	-347.7	0.0	0.0	0.0	0.0	-11.8	-13.9
	Middle		0.30	0.0	-343.6	-328.8	0.0	0.0	0.0	0.0	-11.5	-12.5
	High		0.10	0.0	-290.0	-310.9	0.0	0.0	0.0	0.0	-8.7	-11.5
Utility Load Forecast Exp. Values				0.0	-323.5	-338.4	0.0	0.0	0.0	0.0	-11.4	-13.2
DOR Fuel	Middle	High		0.0	-350.6	-330.0	0.0	0.0	0.0	0.0	-12.6	-12.4
NoMiltry	Low	High		0.0	-332.7	-289.9	0.0	0.0	0.0	0.0	-9.8	-10.4
DryHydro	Low	High		0.0	-325.0	-317.4	0.0	0.0	0.0	0.0	-10.1	-11.7
WetHydro	Low	High		0.0	-325.3	-317.7	0.0	0.0	0.0	0.0	-10.1	-11.7
GasEscal	Low	High		0.0	-325.6	0.0	0.0	0.0	143.0	0.0	-11.2	7.6

1. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 8-2 shows the annual energy cost and transmission loss savings associated with the increase in coal-fired generation and reduction of transfers from Anchorage. The expected value is between $4 and $5 million per year. Note again that these energy cost savings are based solely on the reduced variable cost of power production from coal plants versus gas plants.

8.3 CAPACITY BENEFITS

The capital investment cost of a gas-fired combustion turbine is estimated at $450 per kilowatt for a 50-MW unit. At a real interest rate of 4.5 percent, this is converted to an annual cost of approximately $35 per kilowatt. As noted in Section 8.1, the earliest year for which we estimate the need for additional capacity is 1997. As a result, the coal-fired power plant is credited with avoiding the capital investment costs associated with a 50-MW combustion turbine in 1997.

The fixed O&M costs associated with the combustion turbine are also avoided. This adds approximately $12 per kilowatt per year to the capacity credit. The present value of the total capacity benefit is estimated at $36.2 million.

8.4 TOTAL COSTS AND BENEFITS

Table 8-3 shows the aggregate results of the economic analysis for both a low and a high case. The difference between these two cases is the assumed capital cost of the plant. The high case is based on the capital cost estimate developed by Stone & Webster for a 50-MW plant at Healy fueled entirely by standard coal. Their estimate of $3194 per kilowatt in 1987 dollars,[6] would be slightly higher if 50 MW were to be generated from a blend of waste coal and standard coal.[7] The capital cost estimate for the low case is $1600 per kilowatt. This is a figure that has been suggested by potential coal plant sponsors over the past two years, and is used here to demonstrate the impact if the lower cost could be achieved.

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[6]The Stone & Webster estimate for a 150-MW plant is $2143 per kilowatt. The substantial difference in unit cost is attributable to economies of scale.

[7]The Stone & Webster estimate is $3322 per kilowatt in 1988 dollars. We reduced it by four percent to convert to 1987 dollars.

Table 8-2

ANNUAL BENEFITS DUE TO NEW 50-MW COAL PLANT AT HEALY

Scenario	Fuel	Load	Joint Probab.	Reduced Energy Costs (M$/Yr) 1994	2002	2010	Reduced Transmission Loss (M$/Yr) 1994	2002	2010	Net Transfer Benefits (M$/Yr) 1994	2002	2010
Base	Low	Low	0.30	0.0	3.1	2.5	0.0	0.2	0.1	0.0	3.2	2.7
		Middle	0.23	0.0	2.8	2.7	0.0	0.2	0.2	0.0	3.0	2.9
		High	0.06	0.0	3.1	3.8	0.0	0.2	0.2	0.0	3.3	4.1
	Middle	Low	0.03	0.0	4.4	5.1	0.0	0.3	0.3	0.0	4.6	5.4
		Middle	0.08	0.0	5.0	6.2	0.0	0.3	0.3	0.0	5.3	6.5
		High	0.19	0.0	5.9	6.3	0.0	0.3	0.3	0.0	6.2	6.6
	High	Low	0.00	0.0	6.4	8.1	0.0	0.3	0.3	0.0	6.7	8.5
		Middle	0.02	0.0	7.4	9.5	0.0	0.3	0.3	0.0	7.7	9.8
		High	0.08	0.0	8.7	9.4	0.0	0.2	0.3	0.0	8.9	9.7
Base Case Expected Values				0.0	4.3	4.4	0.0	0.2	0.2	0.0	4.5	4.7
Utility Load Forecast	Low		0.60	0.0	3.6	3.5	0.0	0.3	0.3	0.0	3.9	3.8
	Middle		0.30	0.0	5.4	7.1	0.0	0.3	0.3	0.0	5.7	7.4
	High		0.10	0.0	8.0	10.5	0.0	0.3	0.4	0.0	8.3	10.9
Utility Load Forecast Exp. Values				0.0	4.6	5.3	0.0	0.3	0.3	0.0	4.9	5.6
DOR Fuel	Middle	High		0.0	1.6	2.5	0.0	0.2	0.2	0.0	1.8	2.7
NoMiltry	Low	High		0.0	2.6	3.7	0.0	0.2	0.2	0.0	2.9	4.0
DryHydro	Low	High		0.0	3.1	4.0	0.0	0.2	0.2	0.0	3.4	4.2
WetHydro	Low	High		0.0	3.0	3.6	0.0	0.2	0.2	0.0	3.3	3.8
GasEscal	Low	High		0.0	2.7	14.3	0.0	0.3	-0.4	0.0	2.9	13.9

1. All values are in 1987 million dollars.

2. Positive reduced transmission losses are savings.

3. Net Transfer Benefits = Reduced Energy Costs
   + Reduced Transmission Loss

4. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

Table 8-3

50-MW COAL-FIRED POWER PLANT AT HEALY: SUMMARY OF COSTS AND BENEFITS

	Prob	Reduced Energy Costs	Reduced Trans. Losses	Capacity Benefits	Total Benefits	Total Costs Low	Total Costs High	Net Benefits Low	Net Benefits High
LL	0.30	43.9	3.1	36.15	83.15	177.40	257.10	-173.95	-94.25
LM	0.23	46.4	3.3	36.15	85.85	177.40	257.10	-171.25	-91.55
LH	0.06	53.9	4.4	36.15	94.45	177.40	257.10	-162.65	-82.95
ML	0.03	75.4	5.1	36.15	116.65	177.40	257.10	-140.45	-60.75
MM	0.08	86.3	5.3	36.15	127.65	177.40	257.10	-129.45	-49.75
MH	0.19	90.5	5.7	36.15	132.35	177.40	257.10	-124.75	-45.05
HL	0.00	115.0	6.1	36.15	157.25	177.40	257.10	-99.85	-20.15
HM	0.02	129.1	6.0	36.15	171.15	177.40	257.10	-85.95	-6.25
HH	0.08	134.8	6.1	36.15	177.05	177.40	257.10	-80.05	-0.35
Exp Val		67.3	4.3	36.15	107.68	177.40	257.10	-149.42	-69.72
UL	0.60	52.7	5.3	36.15	94.15	177.40	257.10	-162.95	-83.25
UM	0.30	96.3	6.6	36.15	138.95	177.40	257.10	-118.15	-38.45
UH	0.10	142.3	7.5	36.15	185.85	177.40	257.10	-71.25	8.45
Exp Val		74.7	5.9	36.15	116.76	177.40	257.10	-140.34	-60.64
DOR		30.9	4.2	36.15	71.15	177.40	257.10	-185.95	-106.25
NM		53.1	4.0	36.15	93.15	177.40	257.10	-163.95	-84.25
DH		54.8	4.5	36.15	95.45	177.40	257.10	-161.65	-81.95
WH		51.1	4.4	36.15	91.65	177.40	257.10	-165.45	-85.75
GE		87.6	3.7	36.15	127.45	177.40	257.10	-129.65	-49.95

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total costs include:

Cost	Low	High
Capital ($/KW)	1600.00	3194.00
Fixed O&M ($M/yr)	5.58	5.58

3. Capacity benefits are based on $47/kW-yr (including Fixed O&M).
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

The only case for which the coal plant is estimated to deliver a small net benefit is the case that combines the low capital cost, the high gas price forecast, and the utility load forecast. Negative net benefits are estimated for all other cases (i.e., the costs are estimated to exceed the benefits). Referring to the expected values, costs are estimated to exceed benefits by $69.7 million for the low capital cost case and $149.4 million for the high capital cost case.

The most significant insight from the sensitivity cases is the impact of gas prices on the outcome. When gas prices corresponding to the Alaska Department of Revenue (ADOR) oil price outlook are assumed, the coal plant economics decline further relative to the expected value. On the other hand, an assumption of high gas prices corresponding to the high oil price outlook produces a significant improvement in the coal plant economics.

Table 8-4 shows the breakeven capital cost calculated for each scenario. For example, in the expected case the breakeven capital cost is estimated at $206 per kilowatt. This means that the present value of costs would equal the present value of benefits estimated for the 50-MW coal-fired power plant in the expected case if the capital cost of the facility were reduced to $206 per kilowatt.

Table 8-4

BREAKEVEN CAPITAL COST AND THERMAL ENERGY CREDIT

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Bkeven Capital Cost $/KW	Breakeven Steam Credit ($/MBtu): Low	Breakeven Steam Credit ($/MBtu): High
Base	Low	Low	0.30	-284.6	9.2	16.9
		Middle	0.23	-230.6	8.9	16.6
		High	0.06	- 58.6	8.1	15.8
	Middle	Low	0.03	385.4	5.9	13.6
		Middle	0.08	607.4	4.8	12.6
		High	0.19	699.4	4.4	12.1
	High	Low	0.00	1197.4	2.0	9.7
		Middle	0.02	1477.4	0.6	8.4
		High	0.08	1593.4	0.1	7.8
Base Case Expected Values				206.2	6.8	14.5
Utility	Low		0.60	- 64.6	8.1	15.8
Load	Middle		0.30	833.4	3.8	11.5
Forecast	High		0.10	1771.4	-0.8	6.9
Utility Load Forecast Exp. Values				388.4	5.9	13.6
DOR Fuel	Middle	High		-522.6	10.3	18.0
NoMiltry	Low	High		- 58.6	8.1	15.8
DryHydro	Low	High		- 38.6	8.0	15.7
WetHydro	Low	High		-114.6	8.3	16.0
GasEscal	Low	High		601.4	4.9	12.6

8.5 BENEFITS OF COGENERATION

As noted in Section 8.1, the coal-fired power plant at Healy has been proposed as a cogeneration facility that would deliver heat to a coal drying facility. It is estimated that the coal drying process would reduce the moisture content of the coal from roughly 25 to 30 percent to under 5 percent. According to Stone & Webster, coal drying in the amount and on the scale proposed has not yet been commercially established. There are a number of possible coal drying processes that are under investigation, including some that rely on high grade steam and others that rely on lower grade steam or hot gas for the drying process. A process for drying Healy coal has not yet been selected.

For this analysis, we assumed that the process would require high grade steam. Stone & Webster estimated the additional cost of producing sufficient high grade steam from the proposed cogeneration facility to dry an estimated 650,000 tons per year of coal [2]. The estimate is based on the concept that the plant will produce 50 MW of power for sale to the Railbelt electric grid, plus sufficient steam for the drying process. The cost increment to provide the additional steam consists of the added capital cost, fuel cost, and O&M cost to provide the additional energy from the plant above the electric power requirements. These are summarized below:

Capital Cost Increment	$18.4 million or $368 per kilowatt
Annual O&M Cost Increment	$0.4 million
Additional Coal Usage	42,000 tons per year

These factors were based on the assumption that 100 percent standard coal would be consumed in the cogeneration plant. Because we assume a 50/50 blend of waste coal and standard coal, these estimates may be low.

The coal usage estimate was based on an assumed plant capacity factor of 75 percent.[8] At full load, the plant would produce 84.5 MBtu of additional steam per hour, or approximately 555,000 MBtu of additional steam per year to dry the estimated 650,000 tons per year of coal. This is about 0.85 MBtu of steam per ton of "wet" coal.

The annual capital cost associated with the additional steam is estimated at about $1.1 million, assuming amortization over 35 years at 4.5 percent real interest. The annual fuel cost is estimated at about $0.6 million, assuming $0.85 per MBtu. Including annual O&M costs, the total cost reaches a little over $2 million per year. The cost of producing the additional 555,000 MBtu of high grade steam is therefore estimated at about $3.65 per MBtu.

If the operator of a coal drying facility were willing to pay $3.65 per MBtu for steam, then the economics of the coal-fired power plant would be unaffected. The net result of increased cost and increased revenue from cogeneration would be zero. If the operator of the coal drying facility were willing to pay more than $3.65 per MBtu, then

[8]A 75 percent capacity factor means that on an annual basis, the plant would operate at 75 percent of full capacity due to planned outages, forced outages, and occasional part loading.

the economics of the coal-fired power plant would improve as a result of the cogeneration component.

To determine how much the coal dryer would be willing to pay for steam, it would be necessary to estimate the capital and operating costs of the coal drying facility, and also to estimate the value added to the coal from the drying process. However, we have not been able to acquire enough information about coal drying processes and economics to allow us to make these estimates.

Instead, we have calculated how much more than $3.65 per MBtu a coal dryer would have to be willing to pay for the cogeneration plant to break even. As shown in Table 8-4, the required premium above $3.65 per MBtu in the expected case is $6.76 per MBtu given the low plant capital cost, and $14.46 per MBtu given the high plant capital cost. In other words, given the low plant capital cost, a coal dryer would have to be willing to pay $10.41 per MBtu of steam for the economic cost/benefit of the 50-MW cogeneration plant to reach breakeven in the expected case.

8.6 REFERENCES

[1] *Estimated Costs and Environmental Impacts of Coal-Fired Power Plants in the Alaska Railbelt Region*, Stone & Webster Engineering Corporation Report to Alaska Power Authority, November 1988.

[2] Letter from S.M. Rosendahl (Stone & Webster) to Richard Emerman, March 16, 1989.

Section 9

ELECTRIC END-USE CONSERVATION PROGRAMS

9.1 INTRODUCTION

A previous report prepared by the Institute of Social and Economic Research (ISER) identified nine end-use conservation programs for evaluation within this analysis [1]. As described in Section 2, these programs would provide financial incentives to induce consumers to acquire more efficient electrical equipment and appliances than they otherwise would. Because the programs are not designed to induce early replacement of functional equipment, their impacts are projected to increase gradually over a period of years up to a peak level of energy reduction, either when the financial inducements are ended, or when the potential impact of the program has been reached. After the program is ended, the load reduction effects continue until the more efficient equipment is retired. The two categories of benefit that we evaluated for these programs are:

1. *Reduced Energy Requirements.* This value was estimated through production simulation using the Over/Under model.

2. *Reduced Capacity Requirements.* By reducing peak demand, the requirement for plant capacity is reduced. This was estimated outside the Over/Under model.

The nine proposed programs were divided into two groups on the basis of a technology screening analysis (Appendix G). The first group consists of three programs that were judged most economic in the screening analysis, and which together account for nearly half of the total energy savings and about one third of the total program costs. These are the electric-to-gas water heat conversion program, the fluorescent lamp rebate program, and the incandescent to fluorescent lamp conversion program. The second group consists of the next five programs that appeared economically viable in most instances in the screening analysis, including efficient electric water heaters, electric-to-gas clothes dryer conversions, electronic ballasts for fluorescent lights, efficient refrigerators, and sliding scale rebates for efficient new construction of commercial buildings. We evaluated the first group separately and then evaluated the two groups combined. The only program that was not evaluated was the efficient freezer program, which was estimated in the screening analysis to have negative net benefits.

All programs were assumed to be implemented over a 10-year period.[1] The programs were modeled with varying regional impacts. For example, the electric-to-gas water heater conversion program had no impact in Fairbanks, but had 87 percent of its total impact in Anchorage.

For each group of programs, we used the total resource costs that would be incurred to achieve the estimated energy savings, rather than the budgetary costs of running the programs. This is discussed in Section 2.7.

9.2 ENERGY SAVINGS

Table 9-1 shows the energy savings realized by each program for each year of the analysis as input to the simulation model. Figure 9-1 displays these impacts for each of the two groups. For some programs, such as the fluorescent lamp rebate, the energy savings are projected to disappear shortly after the end of the program due to the short life of the appliance. For other programs, such as the electric-to-gas water heat conversion program, energy savings are projected to continue past the analysis horizon. The effects of the fluorescent lamp rebate program do not last long after program termination, but the program saves significant energy for a relatively low cost. Savings from the water heater conversion program cost more, but its impacts last significantly longer.

9.2.1 Top Three Programs

The model simulation identifies the benefits of reduced energy costs and reduced transmission losses for the top three programs. Table 9-2 shows the present value of these benefits; estimated for the expected case to be approximately $19.2 million in reduced energy costs and about $0.2 million in reduced transmission losses. A review of all the cases suggests limited variation, except that higher fuel prices are associated with higher benefits. Benefits increase slightly with higher load forecasts, because generation from less efficient units is displaced at the margin as the loads increase.

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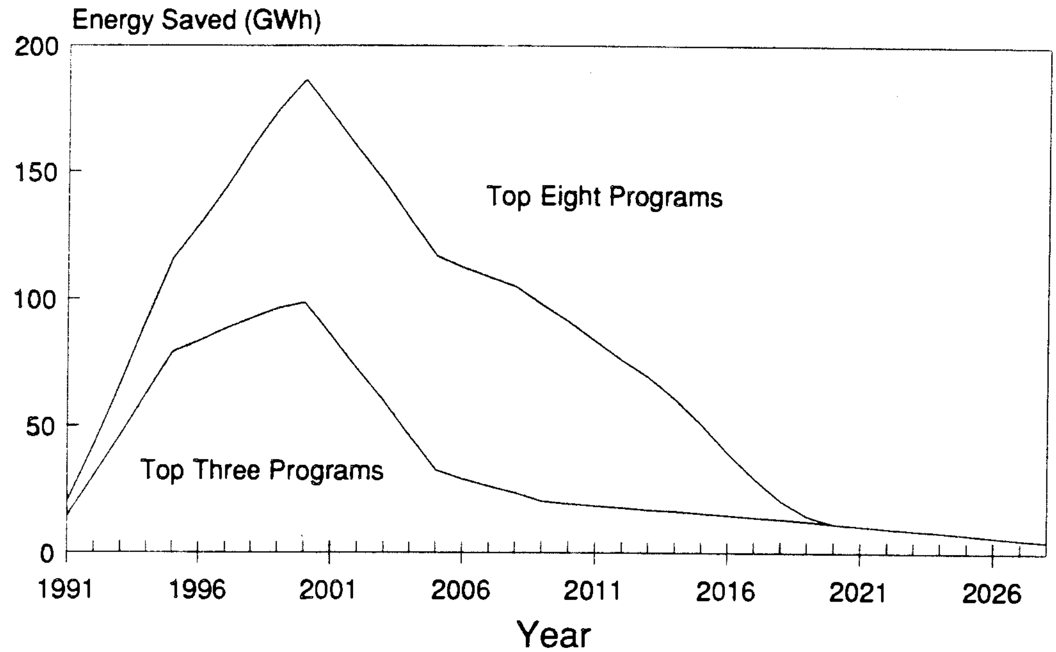
[1]The production simulation began in 1994, but the estimates of program impact provided by ISER were based on implementation beginning in 1991. We assumed for purposes of the simulation that the estimated annual impacts would be the same if program implementation were shifted forward three years to 1994.

Table 9-1

ENERGY SAVINGS BY PROGRAM
(GWh)

Actual Year	Model Year	Water Heater Conv	Incand Conv	Fluor Lamp Rebate	Eff Elect WaterHtr	Sliding Scale Rebate	Gas Dryer Rebate	Elec Ballasts	Eff Refrig	Total Top 3 Programs	Total Top 8 Programs
1991	1	3.40	2.80	8.40	0.56	1.10	0.43	2.90	0.68	14.60	20.27
1992	2	6.60	6.70	17.00	1.19	2.40	1.08	6.30	1.32	30.30	42.59
1993	3	9.90	11.00	25.40	1.91	3.70	1.96	10.90	1.91	46.30	66.68
1994	4	11.90	14.50	36.40	2.75	6.00	2.92	14.80	2.38	62.80	91.65
1995	5	14.60	17.10	47.30	3.61	8.30	4.02	17.90	2.79	79.00	115.62
1996	6	17.30	19.10	46.90	4.56	10.30	5.59	22.00	3.38	83.30	129.13
1997	7	20.00	21.70	46.50	5.56	12.10	7.22	26.70	3.96	88.20	143.74
1998	8	22.30	23.70	46.30	6.63	14.00	9.06	33.10	4.60	92.30	159.69
1999	9	24.70	25.60	45.90	7.74	16.10	11.07	38.00	5.30	96.20	174.41
2000	10	28.00	25.30	45.20	8.79	18.10	13.30	41.60	6.04	98.50	186.33
2001	11	27.00	21.40	37.20	8.23	18.10	13.30	41.60	6.04	85.60	172.87
2002	12	26.00	17.10	29.10	7.60	18.10	13.30	41.60	6.04	72.20	158.84
2003	13	25.10	13.60	20.90	6.88	18.10	13.30	41.60	6.04	59.60	145.52
2004	14	24.40	11.00	10.30	6.03	18.10	13.30	41.60	6.04	45.70	130.77
2005	15	23.60	9.00	0.00	5.18	18.10	13.30	41.60	6.04	32.60	116.82
2006	16	22.70	6.40	0.00	4.22	18.10	13.30	41.60	6.04	29.10	112.36
2007	17	21.90	4.40	0.00	3.22	18.10	13.30	41.60	6.04	26.30	108.56
2008	18	21.20	2.50	0.00	2.15	18.10	13.30	41.60	6.04	23.70	104.89
2009	19	20.40	0.00	0.00	1.05	18.10	13.30	38.70	6.04	20.40	97.59
2010	20	19.30	0.00	0.00	0.00	18.10	12.87	35.30	5.36	19.30	90.93
2011	21	18.60	0.00	0.00	0.00	17.00	12.22	30.70	4.72	18.60	83.24
2012	22	17.80	0.00	0.00	0.00	15.70	11.34	26.80	4.13	17.80	75.77
2013	23	17.00	0.00	0.00	0.00	14.40	10.38	23.70	3.66	17.00	69.14
2014	24	16.50	0.00	0.00	0.00	12.10	9.28	19.60	3.25	16.50	60.73
2015	25	15.70	0.00	0.00	0.00	9.80	7.70	14.90	2.66	15.70	50.76
2016	26	14.90	0.00	0.00	0.00	7.80	6.08	8.50	2.08	14.90	39.36
2017	27	14.10	0.00	0.00	0.00	6.00	4.24	3.60	1.44	14.10	29.38
2018	28	13.40	0.00	0.00	0.00	4.20	2.23	0.00	0.74	13.40	20.57
2019	29	12.60	0.00	0.00	0.00	2.00	0.00	0.00	0.00	12.60	14.60
2020	30	11.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.50	11.50
2021	31	10.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.70	10.70
2022	32	9.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.80	9.80
2023	33	9.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	9.00
2024	34	8.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.30	8.30
2025	35	7.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.40	7.40
2026		6.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.40	6.40
2027		5.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.50	5.50
2028		4.7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.70	4.70
Total Savings		584.30	232.40	412.00	84.20	354.90	249.22	728.70	110.85	1228.70	2756.57



Source: ISER Analysis of End-use
Efficiency Programs, Nov 1988

Figure 9-1. Energy Savings of End-Use Programs

9.2.2 Top Eight Programs Combined

The value of reduced energy cost and transmission losses for all eight programs combined is shown in Table 9-3. The expected values are approximately $40 million and $0.5 million, respectively, with the same pattern of variation noted above. Of most significance, higher fuel prices are correlated with higher benefits.

9.3 CAPACITY SAVINGS

The analysis by ISER provided estimates not only of energy savings but also of reduction in peak demand for each program in each year. Peak demand reductions used for the calculation of capacity benefits are shown in Table 9-4. For the top three programs, the maximum reduction in peak demand would be about 22.6 MW in the tenth and final year of the program. By year 15, peak demand reduction would fall to 6.7 MW. For all eight programs combined, maximum reduction in peak demand would be 41.1 MW in the tenth and final year of the program. By year 15, peak demand reduction would have fallen to about 24.8 MW.

Table 9-2

PRESENT VALUE OF ENERGY BENEFITS DUE TO TOP THREE END-USE PROGRAMS

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Reduced Energy Costs	Reduced Trans. Losses	Net Energy Benefits
Base	Low	Low	0.30	16.19	0.12	16.31
		Middle	0.23	16.62	0.19	16.81
		High	0.06	17.46	0.19	17.65
	Middle	Low	0.03	20.55	0.27	20.82
		Middle	0.08	21.33	0.26	21.59
		High	0.19	22.48	0.26	22.74
	High	Low	0.00	24.85	0.21	25.06
		Middle	0.02	25.85	0.08	25.93
		High	0.08	27.05	0.17	27.22
Base Case Expected Values				19.17	0.19	19.36
Utility Load Forecast	Low		0.60	17.86	0.17	18.03
	Middle		0.30	23.05	0.23	23.28
	High		0.10	27.85	0.18	28.03
Utility Load Forecast Exp. Values				20.42	0.19	20.61
DOR Fuel	Middle	High		14.99	0.05	15.04
NoMiltry	Low	High		17.26	0.22	17.48
DryHydro	Low	High		17.66	0.20	17.86
WetHydro	Low	High		17.36	0.20	17.56
GasEscal	Low	High		20.04	0.13	20.17

Note: All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)

Table 9-3

PRESENT VALUE OF ENERGY BENEFITS DUE TO TOP EIGHT END-USE PROGRAMS

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Reduced Energy Costs	Reduced Trans. Losses	Net Energy Benefits
Base	Low	Low	0.30	33.43	0.27	33.70
		Middle	0.23	34.58	0.46	35.04
		High	0.06	36.65	0.56	37.21
	Middle	Low	0.03	42.71	0.70	43.41
		Middle	0.08	44.59	0.59	45.18
		High	0.19	47.51	0.74	48.25
	High	Low	0.00	52.09	0.68	52.77
		Middle	0.02	54.36	0.37	54.73
		High	0.08	57.82	0.45	58.27
Base Case Expected Values				40.12	0.48	40.60
Utility	Low		0.60	37.63	0.38	38.01
Load	Middle		0.30	52.02	0.53	52.55
Forecast	High		0.10	59.76	0.50	60.26
Utility Load Forecast Exp. Values				44.16	0.44	44.60
DOR Fuel	Middle	High		30.65	0.15	30.80
NoMiltry	Low	High		35.95	0.62	36.57
DryHydro	Low	High		37.05	0.52	37.57
WetHydro	Low	High		36.25	0.56	36.81
GasEscal	Low	High		40.52	0.10	40.62

Note: All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/year).

For the capacity saving calculations, it was assumed that the programs would be implemented in 1991. However, there is no indication of new capacity requirements until 1997. Consequently, no capacity value was credited to the conservation programs for the first six years of implementation. After then, the reduction in peak demand resulting from the programs was multiplied by 1.3 because the demand reduction was credited with a capacity addition saving that includes a 30 percent reserve margin associated with that addition.[2] The resulting estimate of avoided capacity addition was then valued at $47 per kW per year in the high case.[3] However, since it can be

[2]As discussed in Section 6, the Alaska Intertie Agreement sets out a requirement for a 30 percent capacity reserve margin.

[3]Based on the levelized capital cost of a combustion turbine of $450 per kW and a fixed O&M of $12 per kW per year. Levelization is for 20 years at 4.5 percent per year.

Table 9-4
PEAK DEMAND REDUCTIONS BY PROGRAM
(MW)

Year	Water Heater Conv	Incand Conv	Fluor Lamp Rebate	Eff Elect WaterHtr	Sliding Scale Rebate	Gas Dryer Rebate	Elec Ballasts	Eff Refrig	Total Top 3 Programs	Total Top 8 Programs
1991	0.61	0.78	1.96	0.08	0.26	0.08	0.68	0.09	3.34	4.53
1992	1.18	1.87	3.96	0.16	0.57	0.21	1.47	0.17	7.00	9.58
1993	1.77	3.06	5.92	0.26	0.88	0.38	2.54	0.25	10.75	15.05
1994	2.12	4.04	8.48	0.37	1.43	0.56	3.45	0.31	14.64	20.76
1995	2.60	4.76	11.02	0.48	1.97	0.78	4.17	0.36	18.38	26.15
1996	3.09	5.32	10.93	0.61	2.45	1.08	5.13	0.44	19.33	29.04
1997	3.57	6.04	10.83	0.75	2.88	1.40	6.22	0.51	20.44	32.20
1998	3.98	6.60	10.79	0.89	3.33	1.75	7.71	0.60	21.36	35.64
1999	4.41	7.13	10.69	1.04	3.83	2.14	8.85	0.69	22.23	38.78
2000	4.99	7.04	10.53	1.18	4.30	2.57	9.69	0.78	22.57	41.10
2001	4.82	5.96	8.67	1.11	4.30	2.57	9.69	0.78	19.44	37.90
2002	4.64	4.76	6.78	1.02	4.30	2.57	9.69	0.78	16.18	34.55
2003	4.48	3.79	4.87	0.92	4.30	2.57	9.69	0.78	13.13	31.41
2004	4.35	3.06	2.40	0.81	4.30	2.57	9.69	0.78	9.81	27.98
2005	4.21	2.51	0.00	0.70	4.30	2.57	9.69	0.78	6.72	24.76
2006	4.05	1.78	0.00	0.57	4.30	2.57	9.69	0.78	5.83	23.75
2007	3.91	1.23	0.00	0.43	4.30	2.57	9.69	0.78	5.13	22.92
2008	3.78	0.70	0.00	0.29	4.30	2.57	9.69	0.78	4.48	22.12
2009	3.64	0.00	0.00	0.14	4.30	2.57	9.02	0.78	3.64	20.46
2010	3.44	0.00	0.00	0.00	4.30	2.49	8.22	0.70	3.44	19.16
2011	3.32	0.00	0.00	0.00	4.04	2.36	7.15	0.61	3.32	17.49
2012	3.17	0.00	0.00	0.00	3.73	2.19	6.24	0.54	3.17	15.88
2013	3.03	0.00	0.00	0.00	3.42	2.01	5.52	0.47	3.03	14.46
2014	2.94	0.00	0.00	0.00	2.88	1.80	4.57	0.42	2.94	12.60
2015	2.80	0.00	0.00	0.00	2.33	1.49	3.47	0.35	2.80	10.44
2016	2.66	0.00	0.00	0.00	1.86	1.18	1.98	0.27	2.66	7.94
2017	2.51	0.00	0.00	0.00	1.43	0.82	0.84	0.19	2.51	5.79
2018	2.39	0.00	0.00	0.00	1.00	0.43	0.00	0.10	2.39	3.92
2019	2.25	0.00	0.00	0.00	0.48	0.00	0.00	0.00	2.25	2.72
2020	2.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.05	2.05
2021	1.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.91	1.91
2022	1.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.75	1.75
2023	1.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.61	1.61
2024	1.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.48	1.48
2025	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.32	1.32
2026	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.14	1.14
2027	0.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.98	0.98
2028	0.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84	0.84

argued that the conservation programs do not provide the same capacity value as power supply technologies because they cannot be turned on and off at will, we also used a low capacity value of $30.70 per kW. Table 9-5 shows the resulting estimates of capacity value by year, as well as the present value of the capacity benefit. For the top three programs, the present value of capacity benefit using a 4.5 percent discount rate is estimated between $5.7 million and $8.7 million. For all eight programs, the equivalent total capacity benefit is between $13.1 million and $20.1 million.

9.4 EVALUATION OF END-USE CONSERVATION PROGRAMS

Table 9-6 shows the net benefits of the top three programs, and Table 9-7 shows the net benefits of all eight programs combined.

9.5 REFERENCES

[1] *Analysis of Electrical End-Use Efficiency Programs for the Alaskan Railbelt,* Institute of Social and Economic Research, University of Alaska, Anchorage, November 1988, Draft.

Table 9-5
CAPACITY BENEFITS

Year	Capacity Value ($/kW/Yr) Low	Capacity Value ($/kW/Yr) High	Program Peak Savings (MW) End3	Program Peak Savings (MW) End8	Low Capacity Savings ($M/Yr) End3	Low Capacity Savings ($M/Yr) End8	High Capacity Savings ($M/Yr) End3	High Capacity Savings ($M/Yr) End8
1991	0.00	0.00	3.34	4.53	0.00	0.00	0.00	0.00
1992	0.00	0.00	7.00	9.58	0.00	0.00	0.00	0.00
1993	0.00	0.00	10.75	15.05	0.00	0.00	0.00	0.00
1994	0.00	0.00	14.64	20.76	0.00	0.00	0.00	0.00
1995	0.00	0.00	18.38	26.15	0.00	0.00	0.00	0.00
1996	0.00	0.00	19.33	29.04	0.00	0.00	0.00	0.00
1997	39.95	61.10	20.44	32.20	0.82	1.29	1.25	1.97
1998	39.95	61.10	21.36	35.64	0.85	1.42	1.31	2.18
1999	39.95	61.10	22.23	38.78	0.89	1.55	1.36	2.37
2000	39.95	61.10	22.57	41.10	0.90	1.64	1.38	2.51
2001	39.95	61.10	19.44	37.90	0.78	1.51	1.19	2.32
2002	39.95	61.10	16.18	34.55	0.65	1.38	0.99	2.11
2003	39.95	61.10	13.13	31.41	0.52	1.25	0.80	1.92
2004	39.95	61.10	9.81	27.98	0.39	1.12	0.60	1.71
2005	39.95	61.10	6.72	24.76	0.27	0.99	0.41	1.51
2006	39.95	61.10	5.83	23.75	0.23	0.95	0.36	1.45
2007	39.95	61.10	5.13	22.92	0.20	0.92	0.31	1.40
2008	39.95	61.10	4.48	22.12	0.18	0.88	0.27	1.35
2009	39.95	61.10	3.64	20.46	0.15	0.82	0.22	1.25
2010	39.95	61.10	3.44	19.16	0.14	0.77	0.21	1.17
2011	39.95	61.10	3.32	17.49	0.13	0.70	0.20	1.07
2012	39.95	61.10	3.17	15.88	0.13	0.63	0.19	0.97
2013	39.95	61.10	3.03	14.46	0.12	0.58	0.19	0.88
2014	39.95	61.10	2.94	12.60	0.12	0.50	0.18	0.77
2015	39.95	61.10	2.80	10.44	0.11	0.42	0.17	0.64
2016	39.95	61.10	2.66	7.94	0.11	0.32	0.16	0.49
2017	39.95	61.10	2.51	5.79	0.10	0.23	0.15	0.35
2018	39.95	61.10	2.39	3.92	0.10	0.16	0.15	0.24
2019	39.95	61.10	2.25	2.72	0.09	0.11	0.14	0.17
2020	39.95	61.10	2.05	2.05	0.08	0.08	0.13	0.13
2021	39.95	61.10	1.91	1.91	0.08	0.08	0.12	0.12
2022	39.95	61.10	1.75	1.75	0.07	0.07	0.11	0.11
2023	39.95	61.10	1.61	1.61	0.06	0.06	0.10	0.10
2024	39.95	61.10	1.48	1.48	0.06	0.06	0.09	0.09
2025	39.95	61.10	1.32	1.32	0.05	0.05	0.08	0.08
2026	39.95	61.10	1.14	1.14	0.05	0.05	0.07	0.07
2027	39.95	61.10	0.98	0.98	0.04	0.04	0.06	0.06
2028	39.95	61.10	0.84	0.84	0.03	0.03	0.05	0.05
NPV@ 3.5%					6.16	14.41	9.42	22.03
NPV@ 4.5%					5.68	13.12	8.68	20.06
NPV@ 5.5%					5.25	11.99	8.03	18.34

Table 9-6
PRESENT VALUE OF NET BENEFITS DUE TO TOP THREE PROGRAMS

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Reduced Energy Costs	Reduced Trans. Losses	Capacity Value: Low	Capacity Value: High	Total Benefits: Low	Total Benefits: High	Total Costs	Net Benefits: Low	Net Benefits: High
Base	Low	Low	0.30	16.19	0.12	5.68	8.60	21.99	24.99	15.42	6.57	9.57
		Middle	0.23	16.62	0.19	5.68	8.60	22.49	25.49	15.42	7.07	10.07
		High	0.06	17.46	0.19	5.68	8.60	23.33	26.33	15.42	7.91	10.91
	Middle	Low	0.03	20.55	0.27	5.68	8.60	26.50	29.50	16.78	9.72	12.72
		Middle	0.08	21.33	0.26	5.68	8.60	27.27	30.27	16.78	10.49	13.49
		High	0.19	22.48	0.26	5.68	8.60	28.42	31.42	16.78	11.64	14.64
	High	Low	0.00	24.85	0.21	5.68	8.60	30.74	33.74	18.01	12.73	15.73
		Middle	0.02	25.85	0.08	5.68	8.60	31.61	34.61	18.01	13.60	16.60
		High	0.08	27.05	0.17	5.68	8.60	32.90	35.90	18.01	14.89	17.89
Base Case Expected Values				19.17	0.19	5.68	8.60	25.04	28.04	16.09	8.95	11.95
Utility Load Forecast	Low		0.60	17.86	0.17	5.68	8.60	23.71	26.71	15.42	8.29	11.29
	Middle		0.30	23.05	0.23	5.68	8.60	28.96	31.96	16.78	12.18	15.18
	High		0.10	27.85	0.18	5.68	8.60	33.71	36.71	18.01	15.70	18.70
Utility Load Forecast Exp. Values				20.42	0.19	5.68	8.60	26.28	29.29	16.09	10.20	13.20
DOR Fuel	Middle	High		14.99	0.05	5.68	8.60	20.72	23.72	14.68	6.04	9.04
NoMiltry	Low	High		17.26	0.22	5.68	8.60	23.16	26.16	15.42	7.74	10.74
DryHydro	Low	High		17.66	0.20	5.68	8.60	23.54	26.54	15.42	8.12	11.12
WetHydro	Low	High		17.36	0.20	5.68	8.60	23.24	26.24	15.42	7.82	10.82
GasEscal	Low	High		20.04	0.13	5.68	8.60	25.85	28.85	15.42	10.43	13.43

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)
2. Total benefits include:

Benefit	
Reliability benefits	0.00
Stability benefits	0.00

3. Capacity value is 50.7$/KW-yr (High) and 33.2$/KW-yr (Low)
4. Total costs include capital costs and O&M costs.
5. Net Benefits = Total Benefits - Total Costs.

Table 9-7

PRESENT VALUE OF NET BENEFITS DUE TO TOP EIGHT PROGRAMS

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Reduced Energy Costs	Reduced Trans. Losses	Capacity Value: Low	Capacity Value: High	Total Benefits: Low	Total Benefits: High	Total Costs	Net Benefits: Low	Net Benefits: High
Base	Low	Low	0.30	33.43	0.27	13.12	20.06	46.82	53.76	42.25	4.57	11.51
		Middle	0.23	34.58	0.46	13.12	20.06	48.16	55.10	42.25	5.91	12.85
		High	0.06	36.65	0.56	13.12	20.06	50.33	57.27	42.25	8.08	15.02
	Middle	Low	0.03	42.71	0.70	13.12	20.06	56.53	63.47	44.81	11.72	18.66
		Middle	0.08	44.59	0.59	13.12	20.06	58.30	65.24	44.81	13.49	20.43
		High	0.19	47.51	0.74	13.12	20.06	61.37	68.31	44.81	16.56	23.50
	High	Low	0.00	52.09	0.68	13.12	20.06	65.89	72.83	47.20	18.69	25.63
		Middle	0.02	54.36	0.37	13.12	20.06	67.85	74.79	47.20	20.65	27.59
		High	0.08	57.82	0.45	13.12	20.06	71.39	78.33	47.20	24.19	31.13
Base Case Expected Values				40.12	0.48	13.12	20.06	53.71	60.65	43.51	10.20	17.14
Utility	Low		0.60	37.63	0.38	13.12	20.06	51.13	58.07	42.25	8.88	15.82
Load	Middle		0.30	52.02	0.53	13.12	20.06	65.67	72.61	44.81	20.86	27.80
Forecast	High		0.10	59.76	0.50	13.12	20.06	73.38	80.32	47.20	26.18	33.12
Utility Load Forecast Exp. Values				44.16	0.44	13.12	20.06	57.72	64.66	43.51	14.20	21.14
DOR Fuel	Middle	High		30.65	0.15	13.12	20.06	43.92	50.86	40.86	3.06	10.00
NoMiltry	Low	High		35.95	0.62	13.12	20.06	49.69	56.63	42.25	7.44	14.38
DryHydro	Low	High		37.05	0.52	13.12	20.06	50.69	57.63	42.25	8.44	15.38
WetHydro	Low	High		36.25	0.56	13.12	20.06	49.93	56.87	42.25	7.68	14.62
GasEscal	Low	High		40.52	0.10	13.12	20.06	53.74	60.68	42.25	11.49	18.43

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)
2. Total benefits include:

Benefit	
Reliability benefits	0.00
Stability benefits	0.00

3. Capacity value is 50.7$/KW-yr (High) and 33.2$/KW-yr (Low)
4. Total costs include capital costs and O&M costs.
5. Net Benefits = Total Benefits - Total Costs.

Section 10

GAS PIPELINE BETWEEN COOK INLET AND FAIRBANKS: BENEFITS WITHIN THE ELECTRIC POWER SECTOR

10.1 INTRODUCTION

The economic benefits of the proposed Cook Inlet-Fairbanks gas pipeline within the electric power sector fall into three categories:

1. *Reduced transmission losses* between Anchorage and Fairbanks.

2. *Reduced cost of generating electric energy* for consumption in Fairbanks, and to a limited extent for consumption in Anchorage as well.

3. *Improved electric system reliability* in the Fairbanks area.

It is assumed in the simulation modeling that the North Pole combustion turbines and the Chena #5 steam turbine are converted to gas-fired operation. The capital costs of these conversions were estimated by Stone & Webster for Enstar Natural Gas Company, and are included in the overall cost/benefit comparison presented in Section 13. Stone & Webster also estimated savings in O&M costs for the units that would result from conversion to gas, and these too have been included in the overall assessment. Finally, unit efficiencies were reduced by three percent to account for the higher moisture content of the gas.

10.2 REDUCED TRANSMISSION LOSSES

Table 10-1 shows the decline in electricity transfers from Anchorage to Fairbanks projected as a result of the gas pipeline. Virtually all of the transfers that would otherwise occur are eliminated when the fuel price forecast is assumed to be low. For higher fuel price forecasts, there is less reduction of transfers during the later years, though the reduction is still substantial. The reason for this is that the Anchorage area has combined-cycle capacity that is more efficient than the Fairbanks

Table 10-1

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO THE GAS PIPELINE

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Change in Economy Energy Transfer (GWh/yr): South ----> North 1994	South ----> North 2002	South ----> North 2010	North ----> South 1994	North ----> South 2002	North ----> South 2010	Change in Transmission Loss (GWh/yr) 1994	2002	2010
Base	Low	Low	0.30	-332.5	-323.1	-218.7	0.2	0.3	2.3	-30.2	-30.1	-26.7
		Middle	0.23	-340.8	-344.7	-370.5	0.3	1.4	19.3	-30.9	-33.1	-37.6
		High	0.06	-332.3	-383.7	-417.1	0.5	2.2	28.1	-31.3	-39.4	-45.1
	Middle	Low	0.03	-442.2	-167.4	-128.6	0.3	0.3	1.9	-43.6	-25.7	-23.8
		Middle	0.08	-434.5	-203.5	-121.4	0.5	1.4	15.4	-42.4	-28.4	-21.1
		High	0.19	-469.5	-257.0	-141.1	0.9	2.2	18.8	-47.6	-32.0	-23.5
	High	Low	0.00	-442.2	-144.9	-119.0	0.3	0.3	1.9	-43.6	-21.9	-22.3
		Middle	0.02	-434.5	-133.5	-103.3	0.5	1.4	15.4	-42.4	-16.5	-18.3
		High	0.08	-469.5	-184.1	-103.7	0.9	2.2	18.8	-47.6	-19.6	-17.3
Base Case Expected Values				-384.9	-290.3	-229.9	0.5	1.3	13.7	-36.7	-30.4	-28.3
Utility	Low		0.60	-369.0	-444.1	-441.6	0.3	1.8	24.6	-39.3	-49.0	-51.3
Load	Middle		0.30	-435.2	-273.9	-224.1	0.6	1.8	14.0	-46.1	-35.0	-33.7
Forecast	High		0.10	-435.1	-218.9	-201.9	0.6	1.8	14.0	-46.1	-25.5	-29.9
Utility Load Forecast Exp. Values				-395.5	-370.5	-352.4	0.4	1.8	20.4	-42.0	-42.5	-43.9
DOR Fuel	Middle	High		-438.9	-436.0	-431.3	0.4	0.9	27.4	-49.6	-49.6	-47.6
NoMiltry	Low	High		-338.4	-368.1	-400.4	0.6	2.6	30.2	-30.5	-36.9	-41.7
DryHydro	Low	High		-332.3	-383.5	-425.3	0.8	3.6	36.1	-31.3	-39.3	-45.1
WetHydro	Low	High		-332.3	-383.8	-415.1	0.3	1.7	24.8	-31.3	-39.5	-45.3
GasEscal	Low	High		-335.4	-173.0	259.9	0.5	27.2	-402.9	-31.7	-23.7	-16.9

1. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

combustion turbines, though that combined-cycle capacity is not always available to supply power to the north. As the price of gas increases, the higher efficiency of the combined-cycle units more than compensates for the transmission losses, and transfers from Anchorage to Fairbanks resume to the extent that the Anchorage combined-cycle capacity is available.

Clearly, transfers over the existing electric intertie would be substantially reduced. The expected reduction in transmission losses is approximately 45 GWh per year. Table 10-2 shows the benefit of these reduced losses. In the expected case, the benefits range between $0.5 million and $0.8 million per year.

10.3 REDUCED ELECTRIC ENERGY COSTS

The cost of generating electric energy would be reduced when oil and, to some extent, coal is displaced by pipeline gas in Fairbanks generating plants. This is because the variable cost of supplying Cook Inlet gas to Fairbanks would then be less than the cost of alternative fuels. The wellhead price of Cook Inlet gas is used in the calculation of reduced electric energy costs. The capital and operating cost of the pipeline system needed for gas delivery to Fairbanks is accounted for in the overall cost/benefit comparison.

There is a significant amount of oil-fired generation in the case without the pipeline due in large part to the "North Pole constraint" previously discussed. Because the North Pole units are uneconomic to operate at low loading levels, they are operated at relatively high levels whenever they are started. Further, they are started whenever the Fairbanks load exceeds the capacity of on-line coal-fired power plants and the capacity of the intertie. This oil-fired generation that occurs despite the presence of the electric intertie is assumed to be displaced by gas-fired generation when the gas pipeline is in place.

Reduced energy costs are also realized to some extent by substituting gas-fired generation from Fairbanks combustion turbines, some of which have relatively high efficiency, for gas-fired generation from some Anchorage combustion turbines of lower efficiency. A significant portion of the economy energy transfers from Anchorage are generated from available combustion turbine capacity that may have lower efficiency than the Fairbanks units.

Reduced energy costs (Table 10-2) are sensitive to the load forecast, due in large part to the assumption that additional loads in the Fairbanks area would, in the absence of the gas pipeline, be served by oil-fired generation as well as by increased intertie transfers. No additional coal-fired generation is added in the simulation. The

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Table 10-2

ANNUAL BENEFITS OF THE GAS PIPELINE WITHIN THE ELECTRIC POWER SECTOR

	Assumptions			Reduced Energy Costs (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	2.9	4.0	6.3	0.6	0.7	0.4	3.5	4.6	6.7
		Middle	0.23	2.7	4.1	6.8	0.6	0.7	0.6	3.3	4.8	7.4
		High	0.06	3.3	4.8	8.4	0.7	0.9	0.9	4.0	5.7	9.2
	Middle	Low	0.03	0.9	2.0	4.9	1.0	0.7	0.5	1.9	2.6	5.5
		Middle	0.08	0.9	2.7	7.2	0.9	0.8	0.5	1.9	3.4	7.7
		High	0.19	1.1	5.2	11.2	1.1	0.9	0.6	2.1	6.1	11.8
	High	Low	0.00	0.8	2.2	6.0	1.1	0.7	0.6	1.9	2.9	6.6
		Middle	0.02	0.8	3.2	8.7	1.1	0.5	0.4	1.8	3.7	9.2
		High	0.08	1.0	6.2	13.5	1.2	0.6	0.5	2.2	6.8	13.9
Base Case Expected Values				2.1	4.3	8.1	0.8	0.7	0.5	2.9	5.0	8.7
Utility	Low		0.60	4.0	5.7	9.5	0.8	1.1	1.0	4.8	6.7	10.6
Load	Middle		0.30	3.5	7.7	12.7	1.1	1.0	0.9	4.5	8.6	13.6
Forecast	High		0.10	3.6	8.8	15.1	1.2	0.8	1.0	4.8	9.6	16.1
Utility Load Forecast Exp. Values				3.8	6.6	11.0	0.9	1.0	1.0	4.7	7.6	12.0
DOR Fuel	Middle	High		3.2	5.8	8.4	0.9	0.8	0.7	4.1	6.6	9.1
NoMiltry	Low	High		2.7	4.4	7.9	0.6	0.8	0.8	3.4	5.2	8.8
DryHydro	Low	High		3.3	5.0	8.6	0.7	0.9	0.9	4.0	5.8	9.5
WetHydro	Low	High		3.3	4.8	8.2	0.7	0.9	0.8	3.9	5.6	9.0
GasEscal	Low	High		3.8	8.5	-11.8	0.7	0.6	0.3	4.5	9.1	-11.4

1. All values are in 1987 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Reduced Energy Costs + Reduced Transmission Loss
4. Years for GasEscal sensitivity are: 1994, 2010, and 2028.

higher the level of oil-fired generation in the non-pipeline case, the higher the level of energy cost savings realized as a result of the pipeline.

10.4 IMPROVED ELECTRIC SYSTEM RELIABILITY IN FAIRBANKS

We did not perform a separate analysis to estimate the impact of the gas pipeline on Fairbanks electric system reliability. However, since the gas pipeline would lead to reduced electricity imports to Fairbanks over the intertie with a corresponding increase in local generation, an improvement in reliability should be expected. For purposes of this analysis, we assumed that the reliability value of the gas pipeline within the power sector would be comparable to the reliability value estimated for the Northeast intertie in the Fairbanks area. As presented in Section 4, this value was estimated at $0.33 million per year. The present value of that reliability benefit at a 4.5 percent discount rate is approximately $5.8 million.

10.5 TOTAL POWER SECTOR BENEFITS

Table 10-3 shows the summary of power sector benefits projected for the Cook Inlet-Fairbanks gas pipeline, totaling $118.9 million for the expected case. As noted above, the higher the load forecast, the higher the level of projected benefits.

Table 10-3

PRESENT VALUE OF GAS PIPELINE BENEFITS WITHIN THE ELECTRIC POWER SECTOR

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Reduced Energy Costs	Reduced Trans. Losses	Total Power Sector Benefits
Base	Low	Low	0.30	80.9	15.0	101.8
		Middle	0.23	93.6	17.7	117.1
		High	0.06	105.0	20.4	131.1
	Middle	Low	0.03	53.1	14.9	73.8
		Middle	0.08	72.2	16.6	94.6
		High	0.19	116.7	21.0	143.5
	High	Low	0.00	62.6	15.8	84.2
		Middle	0.02	85.6	17.1	108.5
		High	0.08	137.9	21.6	165.3
Base Case Expected Values				95.3	17.8	118.9
Utility Load Forecast	Low		0.60	123.0	21.8	150.6
	Middle		0.30	155.2	24.6	185.6
	High		0.10	180.6	27.0	213.4
Utility Load Forecast Exp. Values				138.4	23.2	167.4
DOR Fuel	Middle	High		110.0	19.3	135.1
NoMiltry	Low	High		97.4	19.4	122.6
DryHydro	Low	High		107.4	20.6	133.8
WetHydro	Low	High		103.1	20.0	128.9
GasEscal	Low	High		90.3	16.2	112.3

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.
3. Total Power Sector Benefits include $5.8M in reliability benefits.

Section 11

GAS PIPELINE BETWEEN COOK INLET AND FAIRBANKS: BENEFITS OUTSIDE THE ELECTRIC POWER SECTOR

11.1 INTRODUCTION

The benefits of Cook Inlet gas availability for electric power generation by Fairbanks utilities was discussed in Section 10. Other benefits of bringing Cook Inlet gas to the Fairbanks area were estimated separately by the Institute of Social and Economic Research (ISER) and are briefly summarized in this section. The ISER analysis of these issues is presented in its entirety in Appendix I. Net benefits could accrue from using natural gas for space heating, water heating, cooking, and clothes drying in both residential and commercial buildings. Additional benefits could be realized in some scenarios by converting to natural gas the coal-fired facilities at the University of Alaska (UAF), the Fairbanks Municipal Utility (FMUS) district heating system, and the Fort Wainwright, Eielson, and Clear military facilities.

Estimates of benefit outside the electric power sector are grouped into four categories:

1. Residential
2. Commercial
3. Military
4. UAF/FMUS District Heat

11.2 RESIDENTIAL

ISER estimated that about 47 percent of the households in the Fairbanks North Star Borough would have access to natural gas after a three-year construction period for the distribution system. Subsequent expansion of the distribution system was estimated to increase the coverage to 58 percent. Among those households with oil heating systems and access to natural gas, ISER estimated that 40 percent would convert from oil to gas each year (i.e., in the second year, 40 percent of the remaining households would convert, and so on). ISER further estimated that, ultimately, 91 percent of the households with access to gas would use gas for space heating and 76 percent would use gas for hot water heating.

Based on the fuel price forecasts presented in Appendix B, and on these and other conversion rate and saturation rate assumptions, the expected value of benefits in the residential sector estimated by ISER is $225 million. Costs of conversion that would be borne by residential households have been accounted for within this estimate of benefit.

11.3 COMMERCIAL

Compared to residential households, a much higher proportion of commercial floorspace is located within the assumed gas distribution territory. ISER assumed that 95 percent of the commercial space not served by the FMUS district heating system would have access to natural gas by the third year of construction of the distribution system. Because of economies of scale, the incentives for conversion from oil to gas would be stronger in the commercial sector than in the residential sector. The expected value of benefit in the commercial sector was estimated by ISER at $96 million. Again, conversion costs have been accounted for within the estimate.

11.4 MILITARY

Conversion of the military power and heat facilities from coal to natural gas is assumed to occur only in the low fuel price scenarios. With higher gas prices, ISER estimated that there would be insufficient incentive for the military to convert. Further, although investigation did not reveal any legal or regulatory prohibition to conversion of military facilities from coal to gas, ISER assumed that the decision would take time. Conversion was therefore assumed in 1999, although gas was assumed to be available in 1994.

The expected value of benefit to the military was estimated by ISER at $68 million. The volume of gas used by the military would be relatively high if conversion occurred, which in turn would help reduce average distribution costs to other gas consumers.

11.5 UAF/FMUS DISTRICT HEAT

Like the military, the FMUS district heating system was assumed to convert from coal to gas only in the low fuel price scenario. The economic incentive for UAF was estimated to be somewhat stronger, and conversion was therefore assumed for both the low and middle fuel price forecasts. The expected value of benefit from these conversions was estimated at $19 million.

11.6 TOTAL BENEFITS OUTSIDE THE POWER SECTOR

The value of benefits outside the electric power sector are presented in Table 11-1 for each of the nine base case scenarios. The expected value of these benefits is $408 million.

Table 11-1

BENEFITS OUTSIDE THE ELECTRIC POWER SECTOR

Scenario	Assumptions: Fuel	Assumptions: Load	Joint Probab.	Residtl	Commercl	Military	UAF/FMUS	Total
Base	Low	Low	0.30	192	83	113	25	413
		Middle	0.23	203	85	113	25	426
		High	0.06	226	96	113	27	462
	Middle	Low	0.03	224	98	0	11	333
		Middle	0.08	237	101	0	11	349
		High	0.19	263	113	0	12	388
	High	Low	0.00	257	115	0	0	372
		Middle	0.02	272	116	0	0	388
		High	0.08	300	132	0	0	432
Base Case Expected Values				225	96	68	19	408

Section 12[1]

ENVIRONMENTAL EVALUATION OF ALTERNATIVES

12.1 OVERVIEW

As a part of the Railbelt Intertie feasibility study, the environmental impacts were evaluated for each of the alternatives. The four intertie alternative plans considered were within two main categories: (1) improvement of the intertie between the Kenai Peninsula and Anchorage, and (2) improvement of the intertie between Anchorage and Fairbanks. The specific intertie alternatives evaluated consist of the following:

- Improvement of the transmission system between the Kenai Peninsula and Anchorage with a new intertie following the "Enstar route".
- Improvement of the transmission system between the Kenai Peninsula and Anchorage with a new intertie following the "Tesoro route".
- Improvement of the transmission system between Anchorage and Fairbanks by upgrading the existing intertie, including the construction of new intertie segments north of Healy and south of Willow.
- Improvement of the transmission system between Anchorage and Fairbanks with a new intertie following the "Northeast Intertie Route" from Sutton through Glennallen to Delta Junction, where the line would tie into the existing Golden Valley transmission line to Fairbanks.

In addition, we evaluated and compared the potential environmental impacts of three other alternative plans being assessed as a part of the overall feasibility study.

- A natural gas pipeline from Cook Inlet to Fairbanks.
- Coal-fired power plants in the Railbelt region.
- Electric end-use conservation programs.

[1]This section was prepared by Dames & Moore.

12.1.1 Approach to Impact Assessments

Information Sources. The impact comparisons were conducted using information from the types of sources listed below. Specific references to published information are presented in the discussions of potential environmental impacts for each alternative plan (Sections 12.4 through 12.8). Our work on this project did not include data collection or field reconnaissance.

- Reports on intertie alternative plans that were prepared by Alaska Power Authority (APA) contractors.
- Other reports addressing environmental issues in the areas being evaluated.
- Dames & Moore file data.
- Dames & Moore's previous experience in and understanding of the locations being evaluated.
- Dames & Moore's experience in evaluating impacts associated with the types of facilities and structures included in the alternative plans.

Impact Evaluations. Our evaluations focused on impacts for the following environmental indicators:

- Air quality
- Water quality
- Fish and wildlife
- Land use and ownership status
- Terrestrial (vegetation and wetlands)
- Recreational resources
- Visual

The impact evaluations were developed on a relatively broad scale since site-specific and route-specific environmental investigations were not conducted. However, there was sufficient information available to develop an overall understanding of the likely level of impacts for each of the environmental indicators considered, and to develop a comparison matrix for these indicators. To more definitively assess the potential impacts of an alternative, further study would be required. If one or more of the alternatives is to be implemented, detailed studies will be required in response to state and federal permitting requirements. Except for the end-use conservation programs, some alternatives may require an Environmental Impact Statement (EIS) or a Supplemental EIS.

As a means of comparing the level of impact among alternatives and among environmental indicators, we established four categories of impact magnitude: negligible, low, moderate, and high impacts. Table 12-1 presents definitions of these levels of impacts for each of the environmental indicators assessed.

Many of the issues of concern are common to at least several alternatives. To minimize redundancy in this report, we addressed "generic impacts", i.e., impacts common to more than one alternative, separately. These generic impacts are presented in Section 12.3.

12.1.2 Chapter Organization

The remainder of this chapter addresses the environmental impacts of the alternative plans. Section 12.2 presents a summary of these impacts, including a comparison matrix showing the level of impact for each environmental indicator for each alternative. Section 12.3 describes the impacts common to several alternatives (Generic Impacts), and Sections 12.4 through 12.8 briefly describe the relevant design details of the alternatives and address the impacts associated with the alternatives.

12.2 COMPARISON OF ENVIRONMENTAL IMPACTS

12.2.1 Background

This comparison of the environmental impacts of the alternatives consists of the following:

- A comparison of the environmental impacts of the two transmission system improvement alternatives between the Kenai Peninsula and Anchorage.

- A comparison of the environmental impacts of the two transmission system improvement alternatives between Anchorage and Fairbanks.

- A comparison of the environmental impacts of the two energy supply alternatives and the end use conservation programs.

Table 12-2 presents a summary of the environmental evaluations for all alternatives considered. As discussed in Sections 12.3 through 12.8, we have assumed that construction and operation would be in compliance with the regulatory

Table 12-1

DEFINITIONS OF IMPACT LEVELS

Environmental Indicator	Level of Impact			
	High Impact	**Moderate Impact**	**Low Impact**	**Negligible Impact**
Air Quality	Emissions would be in violation of federal standards for ambient air quality and existing air quality could be adversely affected.	Pollutant concentrations could approach the maximum levels permitted by federal standards for ambient air quality and protection of existing air quality.	Pollutant concentrations would not approach the maximum levels permitted by federal standards for ambient air quality and protection of existing air quality.	No measurable change in air chemistry.
Water Quality	Water quality is degraded to the point where some constituents exceed regulatory limits.	Water quality is degraded to the point where some constituents occasionally exceed regulatory limits.	Water quality changes but all constituents are at or below the regulatory limits.	No measurable change in the water quality of receiving waters.
Fish and Wildlife	A population or species in the area declines in abundance and/or distribution beyond which natural recruitment would not return it to its former level within several generations.	A portion of a population in the area changes in abundance and/or distribution over more than one generation, but is unlikely to affect the regional population.	A specific group of individuals of a population in a localized area and over a short time period (one generation) is affected.	No measurable change.
Land Use and Ownership	Activities and developments lead to displacement of existing or proposed land uses for which no reasonable alternative location is possible, or high incompatibility with existing or proposed land uses; or they conflict with most land use plans.	Activities and developments alter or preclude a preferred use of an area, or conflict with many land use plans.	Activities and developments result in minor conflict with some infringement on a present or anticipated use.	Activities and developments generally conform with land uses and with land use plans.
Terrestrial (Vegetation and Wetlands)	A population or species in the area declines in abundance and/or distribution beyond which long-term natural recruitment would not return it to its former level.	A portion of a population in the area changes in abundance and/or distribution for a short time period, and recovery to near current levels is likely.	A specific group of individuals of a population in a localized area and over a short time period is affected.	No measurable change.
Recreational Resources	Much reduced recreation and tourism and economic expenditure over the whole area.	Some reduced recreation and tourism and economic expenditures in portions of the area.	Slight and localized reduction in recreation and tourism and economic expenditures.	No measurable change in recreation and tourism and economic expenditures.
Visual	Visual quality is degraded to the extent that it affects essentially all observers usin the area. Reduced property values.	Visual quality degraded to an extent which affects most viewers using the area. Reduced property values.	Minor degradation in visual quality. Most viewers would accept the change. No reduction in property values.	No reduction in visual quality. No reduction in property values.

Table 12-2

SUMMARY OF ENVIRONMENTAL EVALUATIONS

ALTERNATIVE/PLAN	IMPACT LEVEL BY ENVIRONMENTAL INDICATOR: Air Quality	Water Quality	Fish and Wildlife Impact	Land Use Impact and Ownership Status	Terrestrial Impact	Recreational Resources Value	Visual Impact
Kenai-Anchorage Intertie							
Enstar Route	N	L	L	L-M	L	L	L
Tesoro Route	N	L	L	L-M	L	L-M	L-M
Anchorage-Fairbanks Intertie							
Anchorage-Fairbanks	N	L	L	L	L	L	L-M
Northeast Route	N	L	L-M	L-M	L	L	L-M
Cook Inlet-Fairbanks Gas Pipeline	N-L	L-M	M	N-L	L	M	L
Coal-Fired Power Generation							
Beluga	L	L-M	L	M	L	L	L
Matanuska Valley	L	L-M	L-M	L-M	L	L	M
Healy	L	L-M	L	L	L	L	L-M
Nenana	L	L-M	L	L-M	L	L	M
End Use Conservation Programs	N	N	N	N	N	N	N

(a) Impact levels are defined in Table 1-1.

N = Negligible
L = Low
M = Moderate
H = High

requirements of all state and federal agencies, and that construction would include standard mitigative measures that have proven to be successful in Alaska.

12.2.2 Kenai-Anchorage Intertie

Two alternative routes to link the Kenai Peninsula with the Anchorage area via a 230-kV transmission line were evaluated. The two routes, termed the "Enstar route " and the "Tesoro route", would start at a planned new substation in Soldotna and pass east and west, respectively, of the wilderness core of the Kenai National Wildlife Refuge. Both cross Turnagain Arm via submerged conduits and proceed in overhead and buried lines to the vicinity of existing substations.

The evaluation concluded that the transmission line could be constructed along either route with minimal environmental impact. The comparison of alternatives indicates in general that the Tesoro route would have a higher level of potential impacts on recreational and visual resources.

Impacts to water quality and fish are rated as low for both routes. Impacts to wildlife would result primarily from disturbance during construction. Although these impacts would generally be low along both routes, for the Enstar route potential conflicts with large mammals, waterfowl, and swans, as well as the need to trench across salt marshes on both sides of Turnagain Arm could result in localized moderate levels of impact. Overall, impacts to fish and wildlife on both routes are rated low.

Impacts to terrestrial resources (vegetation and wetlands) would also be low for both routes. This evaluation includes the assumption that wetland protection measures and procedures to avoid spruce bark beetle infestations are implemented.

Both of the routes are expected to have a low-to-moderate impact on land use. Land use and ownership along the two routes is varied, but is generally compatible with the route proposed. The major exception is in the northern end of the Enstar route within the Kenai National Wildlife Refuge. This portion of the refuge is designated for miminal management, and the identified transmission line routing is not a permitted use. Thus, a congressionally approved change to the management plan could be required. However, the Department of the Interior (DOI) has agreed to recommend exclusion of a corridor adjacent to the Enstar route from the wilderness designation. This exclusion would allow the proposed use, although the DOI request has not yet received Congressional approval.

A portion of the identified Tesoro route would traverse a state recreation area. However, it is likely that appropriate compensation can be made through land exchanges. North of Turnagain Arm, the Tesoro route options would have low-to-moderate impacts depending on the degree of intrusion on the coastal trail south of Point Woronzof.

Construction activities for both routes have the potential for localized short-term impacts on recreation. North of Turnagain Arm, the transmission lines along the Tesoro route may affect recreational use in the vicinity of the coastal trail. Overall, the impact on recreation would be low for the Enstar route and low to moderate for the Tesoro route.

The Tesoro route is judged to have a low-to-moderate impact on visual resources because of the location of overhead lines along the coast of Cook Inlet south of Point Possession and along the coastal trail in some areas south of Point Woronzof (under one option), as well as the need for a pumping station at Point Possession. The Enstar route would be less visible and is judged to have a low impact on visual resources.

12.2.3 Anchorage-Fairbanks Intertie

The environmental impacts of two alternatives for improving the electrical power grid between Anchorage and Fairbanks were evaluated. The first, termed the "Anchorage-to-Fairbanks route" (AFB), would involve connecting new transmission facilities to each end of an existing 345 kV transmission line located between Willow and Healy. To accomplish this requires building a 100-to-110 mile line segment from Healy to Fairbanks and a 35.5 mile segment from Willow to Lorraine Lake on the west side of Knik Arm. The second route, termed the "Northeast Intertie," extends from Sutton eastward to Glennallen, then northward to Delta Junction where it joins the existing Golden Valley distribution system to Fairbanks.

The evaluation concluded that the transmission line could be constructed along either corridor without significant environmental impacts. In general, the Northeast Intertie route would have a higher level of potential impacts on natural resources due primarily to the greater length of the line and the sensitivity of the habitat areas potentially affected by the line along this route. This route would also have a greater impact with regard to land use issues.

Impacts to water quality and fish resources are rated as low on both route alternatives. Impacts occurring along either route are expected to be minor and temporary in affected surface waters.

Impacts to wildlife would result primarily from disturbance during construction. The proposed AFB improvements would include new transmission lines through the Tanana Flats, an area of significant trumpeter swan, waterfowl, and raptor nesting, and important moose winter range. The Nenana River Valley is used by caribou on their annual migrations. Along the Northeast Intertie route, the Matanuska Valley provides critical moose wintering habitat. Caribou migrate through the area from Isabel Pass to Sourdough and concentrate during the winter in the flats from Sheep Mountain to Glennallen and vicinity. These flats are also important waterfowl and raptor nesting areas and provide critical nesting and rearing habitat for 20 to 25 percent of the world's trumpeter swan population. One route option along this alignment would cross 3 miles of a proposed state critical habitat area. Overall, the impact on fish and wildlife would be low for the AFB route, and low to moderate for the Northeast Intertie.

Impacts to terrestrial resources (vegetation and wetlands) would be low for both routes. This evaluation includes the assumption that wetland protection measures and procedures to minimize surface disturbance and potential affects to surface water quality are implemented.

Land use and ownership along the two potential alignments is varied, but is generally compatible with the routings proposed. The Northeast Intertie route options traverse approximately 15 miles of Fort Greely Military Reservation just south of Delta Junction and an easement would need to be obtained from the U.S. Army. A similar easement would also be needed for the AFB route crossing of a portion of Fort Wainwright as the lines enter Fairbanks. Agreements would need to be negotiated with the U.S. Army regarding placement of the transmission lines to ensure the lines do not conflict with normal Army operations. Along the AFB route, use conflicts with airstrips and airports and residential and native land holdings requiring right-of-way access are the primary issues. All airports and airstrips would be avoided in the proposed route for the Northeast Intertie. This route would, however, pass through areas used by pilots in light aircraft as navigation corridors, especially in poor weather conditions. Land use concerns are of low magnitude for the AFB route and of low-to-moderate magnitude for the Northeast Intertie.

The AFB route segment from Willow to Lorraine Lake would avoid crossing two state recreation areas. Along the Northeast Intertie all proposed route alignments would avoid seven state and two federally designated recreation areas. Access roads along both routes would probably open certain areas to recreational uses which are not open at this time because of limited access. Both routes are judged to have low impacts to recreational users.

The AFB route passes through areas of high visual values from Healy north along the Parks Highway and Alaska Railroad. In some areas north of Healy, travelers using the highway or the railroad may observe the transmission lines and towers in their views of the Alaska Range. This route is likely to have low-to-moderate impacts to these resources depending on final routing decisions. Moderate to high visual values are present on the Northeast route along the Glenn and Richardson Highways in the Matanuska and Copper River Valleys and in the Paxson to Isabel Pass area at the summit of the Alaska Range. Much of this route is likely to have low impacts to visual resources because of the forest cover and terrain features help to shield the line from view. However, there would be areas where the transmission lines and towers would alter views and the overall impact of the Northeast route would also be low to moderate.

12.2.4 Energy Sources and Conservation Alternatives

The environmental impacts of two energy source alternatives along with an end-use electricity conservation program were evaluated. The two alternative sources of energy considered were (1) a natural gas pipeline between Cook Inlet and Fairbanks, and (2) coal-fired power plants, with four sites identified: Beluga, Matanuska Valley, Healy, and Nenana. Of these three alternatives, the end-use conservation program would be the most environmentally acceptable. With this alternative, there would be minor, short-term impacts in portions of communities where new gas lines would be installed. There would also be localized increases in gas combustion. The overall impact of these programs on the environmental indicators would be negligible.

The level of impacts associated with a coal plant are similar to those of the gas line. For each alternative, air quality and terrestrial impacts would be low, and impacts on water quality would be low to moderate. Impacts on fish and wildlife would be greater for the gas line. Recreational resources would be moderately affected by the gas line, with a coal plant resulting in a low level of impact on recreation. For the gas line, visual resource and land use impacts would be low, but for a coal plant these impacts would range from low to moderate.

The environmental impacts of each of the three energy-related alternatives are summarized in the following sections.

Natural Gas Pipeline from Cook Inlet to Fairbanks. A 16-inch diameter natural gas pipeline would be constructed linking Fairbanks with the Cook Inlet area. The pipeline route would extend due north from the existing Beluga gas line at Knik for approximately 7.5 miles to the George Parks Highway, then to Fairbanks along the corridor formed by the Alaska Railroad and the highway. The route would deviate for 8 miles around Denali National Park and would extend cross-country for 46 miles from an area south of Nenana across the Tanana Flats to Fairbanks. The pipeline would be buried except for two above-ground stream crossings at Little Coal Creek and Hurricane Gulch.

Minor and localized air quality changes would occur during construction due to the use of heavy construction equipment. Impacts would be low level and temporary.

A minimum of 144 streams would be crossed along the route, and all but two would require trenching and burial of pipe to below flood scour depths. The potential impact on water quality during construction would be locally moderate but short term assuming that standard, proven mitigation measures for construction activities are followed. Water quality would be essentially unaffected by normal operation of the pipeline.

The overall impact to fish and wildlife would be moderate during construction and negligible during operation. Forty of the streams are used by anadromous fish, and other streams are important for resident species such as grayling, trout, and smaller fish. By mitigating the effects of construction through careful timing and construction techniques to protect fish streams, the potential impact would be no more than moderate during construction. The construction activities should also be carefully timed to avoid calving, lambing, and nesting areas, and places where eagles and bears gather to feed on salmon. During operation, the primary effect on fish and wildlife would result from the occasional use of vehicles for inspection and maintenance of the line. These would be minor, short-term impacts and considered negligible.

The pipeline is expected to have a negligible-to-low impact on land use. Most of the route would be within the existing rights-of-way for the Parks Highway and the Alaska Railroad and would change unimproved land to pipeline right-of-way. The pipeline route would pass through seven small communities which would experience local disruption of traffic during construction.

The overall impact on terrestrial vegetation, including wetlands, would be low. Approximately 3,100 acres of right-of-way vegetation would be disturbed by construction and related facilities plus an unknown area for access roads and mining of about 400,000 cubic yards of non-frost susceptible gravel and riprap. The impact on wetlands during construction can be lessened by winter construction from ice or snow roads and mitigated through the establishment of new wetlands or the enhancement of existing wetlands.

The impacts to recreational resources would be moderate. New access development in previously undeveloped areas on the north and south end of the project would provide new recreational opportunities for some users while reducing wilderness recreational values for others. During construction, the presence of a large pipeline workforce and the year-round construction schedule would result in increased competition among recreational users. Pipeline construction timing and sequencing could be planned to avoid periods of primary hunting, trapping, and fishing activity and to avoid affecting access trails used to reach more remote areas. In areas of high recreational use, revegetation plans may require special planting to reduce visual and aesthetic impacts of right-of-way clearing and construction.

The pipeline would be underground, and except for valve stations and permanent facilities, most vegetation would be allowed to become reestablished. Thus, the visual impact caused by construction would decrease over time. The overall visual impact of the pipeline would be low.

Coal-Fired Power Plants. Based on the results of preliminary dispersion modeling, it is expected that emissions from each of the power plant options would be below the applicable ambient air quality standards and below the allowable limits of air quality degradation. Water quality impacts are expected to be of low-to-moderate magnitude, assuming that plant-related facilities are constructed and operated in compliance with federal and state requirements for solid waste landfills and point source discharges. This assessment further assumes that plant areas where contaminants may be present are constructed to contain runoff and treat runoff prior to discharge.

Plant makeup water would be obtained through Ranney wells installed near major rivers, thus protecting fish resources from direct losses and major fluctuations in stream flow. In general, there will be low impacts on terrestrial vegetation, wetlands, and wildlife, although in the Matanuska Valley area there may be a potential for a moderate level of impact on wildlife due to use of the area by moose.

Land ownership would generally not be an issue of concern, although portions of water pipeline routes and transmission line tie-ins would traverse privately held land. The site identified for a plant in the Nenana area is currently designated for residential use; power plants at the other sites would be in general compliance with the existing land use regulations. There would be a low-to-moderate impact on existing land use in the vicinity of the plants, except at Healy where the plant would be somewhat more compatible with nearby uses and a low impact is expected. At each of the sites, the presence of a 372-foot stack represents a safety risk to pilots of small planes during poor weather since most of the planes are not equipped for instrument flying.

Recreational opportunities may increase slightly due to the increased access provided by new roads associated with the plants, transmission line tie-ins, and water pipelines. The overall impact on recreational resources is expected to be low.

The visual impact would range from low to moderate, dependent on location. At Beluga, the impact would be low since the plant would generally not be observable, whereas at Matanuska and Nenana the impact would be moderate due to the change in visual character and the potential visibility of the plant. A plant in the Healy area would be more compatible with the relatively intense level of human activity and development, with the impact ranging from low to moderate in magnitude, depending on the location of observers.

Electric End-Use Conservation Programs. The Electric End-Use Conservation Programs are intended to reduce electrical consumption through increasing the efficiencies of electrical appliances and/or fixtures or conversion to gas-fueled appliances. The 9 programs, 5 of which are for residential users and 4 for commercial users, are all based on a cash rebate, and none provide for an intensive retrofit program. Appliances would be replaced by more energy efficient appliances as they wear out. To affect the entire appliance stock, the program would have to be in effect for 10 to 20 years.

Because of the long time period over which the reduction in electrical demand would take place, it is unlikely there would be any measurable environmental changes to any of the environmental indicators. Due to the conversion to gas-fueled appliances, there may be a slight increase in natural gas usage. This usage is not expected to have a measurable impact on air quality and the overall impact of the usage increase would have a negligible impact on the environmental indicators.

12.3 GENERIC IMPACTS

Many of the environmental issues of concern are common to at least several alternatives. To minimize redundancy in this report, we have addressed "generic impacts", i.e., impacts common to more than one alternative, in this section. Each discussion of a generic impact consists of a brief description of the activity, facility, or structure involved; the environmental changes that could occur; the level of mitigation that we have assumed would be included; and the overall magnitude of the impact anticipated.

12.3.1 Construction Impacts

Access Roads. Access roads would be required for many of the alternatives, including roads accessing a power plant, pipelines, or construction material areas, particularly gravel extraction sites associated with pipeline construction. Transmission line access would be via existing roadways, spurs from existing roadways, or other methods such as helicopter transport. New access roads would not be constructed along the transmission line corridor.

Where access roads are constructed, the types of impacts would be similar regardless of the location. Road construction would require clearing and stripping of vegetation, topsoil removal, installation of drainage structures, and placement of a road bed. Widening or upgrading existing roads may involve many of the same processes.

Removal of vegetation within the road corridor and for varying distances on either side of the road would result in the loss of wildlife habitat. Typically, the quality of habitat destroyed would be similar to that in surrounding unaffected areas and quantities would be small in relation to adjacent undisturbed areas. However, it is assumed that care would be taken in all specific roadway alignments to minimize disturbance of important areas such as wetlands, riparian zones, and potential raptor nesting sites. Areas where herbaceous and shrubby vegetation is left after tree removal adjacent to roads can actually improve conditions for some wildlife by providing a greater diversity of habitats (the "edge effect").

The potential for adverse impacts on wetland functions is low since the area affected would be relatively small and project development would require extensive mitigation that would offset most of the impacts. We have assumed that to obtain agency approval of a permit application to fill or remove wetlands, APA would be required to comply with a "no net loss" policy of wetland protection. Thus, use of wetland areas for project-related facilities would require mitigation measures such as establishing new wetlands or enhancing the value of existing wetland areas to match the value of lost wetlands.

Spruce occur along portions of the routes on the Kenai Peninsula. In these areas the danger of infestation with the spruce bark beetle during clearing is a major concern. Adult beetles disperse in the spring and lay their eggs in newly downed timber. The larvae incubate, feeding on the woody/bark interface for about 2 years. In some areas of the Kenai Peninsula, slash left from clearing has been infested with beetles that, upon hatching in large numbers, have infested live spruce. However, cleared trees would be removed from the area as soon as possible or burned, and the anticipated impact with implementation of this mitigation is expected to be low.

Equipment operation and worker activities during construction of new roads would create noise and visual disturbance effects that would extend beyond the area of direct disturbance. Vehicle exhaust and dust would also affect the surrounding area. These effects would be of limited extent and duration at any one location during the construction period.

Traffic on most roads in any of the alternatives considered would be infrequent during construction, and vehicle-animal conflicts are not expected to be a general problem.

Vegetation removal and earth movement for construction would increase the potential for soil erosion during periods of rainfall. This, along with the need for some construction within surface waters, could introduce sediments into surface waters downstream of the work areas. However, many standard mitigation procedures have proven to be effective in minimizing erosion during construction, and we have assumed that appropriate erosion control techniques would be included in project design. Potential mitigation measures include slope control, use of natural and artificial materials to cover areas of raw earth, creation of sediment traps in drainageways upstream of perennial surface waters, and revegetation of cuts and fills and other disturbed areas.

Visual impacts would occur in areas where views are altered by the presence of crews and equipment and the construction laydown areas. These changes will generally be noticeable only near populated areas or along transportation routes near the corridors.

Overall, the impact of access road construction on the environmental indicators assessed is expected to be low.

Transmission Lines. Many of the impacts associated with construction of aerial transmission lines would be similar to those of access road construction. However, where construction follows existing rights-of-way, the earth moving activities would be minimal and focused on areas of pole installation. This may require the removal of overstory vegetation to eliminate conflict with transmission line routing. Removal of overstory vegetation without the need for stripping of ground cover and topsoil would cause minimal disturbance and, in most cases, have little potential for adverse water quality impacts.

Buried transmission line segments would have a greater construction impact as trenching may intercept ground water or collect surface runoff. Dewatering of trenches, if required, produces a waste stream with a very high suspended sediment load that must be contained for settling prior to release to surface waters. Backfilled trenches should be graded to control runoff and gullying and revegetated as soon as possible.

Submarine portions of transmission lines would require trenching and cable laying across the Turnagain Arm estuary. This dynamic glacial estuary is characterized by very high ambient suspended sediment levels and is generally thought to support only limited biomass and productivity of benthic organisms. Exceptions are on upper tideflats and saltmarshes where emergent plants and attached algal growth is substantial. Except in these areas, trenching and backfill of the submarine segments is not expected to cause significant loss of marine life. Work activity in the open water of the Arm may cause some alteration in the behavior patterns and movements of beluga whales that frequent the area from late spring through fall.

The burial of transmission lines and the installation of submarine transmission lines is expected to have a low impact on the environmental indicators evaluated.

Pipelines. Pipeline construction impacts would be similar in most cases to those of buried transmission lines, requiring removal of vegetation, trenching, backfilling, and revegetation. Problems of trench dewatering can be considerable in some areas. Pipelines have the added problem of burial through streams.

Pipeline stream crossing must be reviewed and approved by the Alaska Department of Fish & Game (ADF&G), and we have assumed that all stream crossing permits would include stipulations requiring mitigation procedures designed to minimize sediment release. Several construction methods have been used which result in no more than moderate stream disturbance. We have also assumed that permit stipulations would require that stream crossings avoid critical stream reaches (e.g., spawning areas) and critical times of the year.

With these mitigation measures included, pipeline installation is expected to have a moderate impact.

12.3.2 Operation

Access Roads. Vehicle use of most access roads constructed for the various alternatives would generally be low. For water and gas pipeline routes, use would be primarily for periodic inspections and maintenance. However, since there are few secondary roads in most areas of Alaska, these roads may also be used by residents and some tourists for access to remote areas currently not accessible except by plane. Access to these areas could allow recreational activities such as hunting, fishing, trapping, hiking, boating, skiing, dog mushing, and snowmobiling. Each of these activities would increase disturbance of wildlife and would decrease the "wilderness" character of areas used while concurrently providing a positive economic effect on some communities due to increased spending on recreation.

Growth of vegetation along roadsides would provide valuable wildlife habitat in some areas, and the edge effect, coupled with low human use rates, would encourage animal use of these routes. Winter use for travel by large animals is likely. In some areas, vehicle-wildlife collisions, particularly those involving moose, may be a concern occasionally.

The aesthetic impact of access roads would potentially be greatest in areas where no such roads currently exist. However, these features would be visible primarily from the air or from a limited number of view points along existing roadways. In most cases, the number of individuals observing the access roads would be low.

In general, the effect of operation of the access roads would have a low impact on each of the environmental indicators.

Transmission Lines. Operation of overland transmission lines has a limited potential for environmental impacts. Voltages in the system are not expected to have significant effects on plants and animals in the area. Sheppard (1988) summarized the scientific literature available concerning health effects of power transmission lines for Seattle City Light. This was an update to the Environmental Impact Statement for City Light's Highline 230 kV transmission project. Sheppard reviewed several recent studies largely stemming from the New York State Power Lines Project. In summary, he found "there are still neither definitive research data nor firm conclusions upon which to determine risk or establish health and safety standards." However, Sheppard indicated that a conservative approach would be prudent. He recommended that transmission line locations be selected to minimize chronic exposure to magnetic fields based on the available data giving credence to the possibility of a causal relationship between exposure of magnetic fields and cancer. Further studies would be needed to determine the locations of residences adjacent to portions of the rights-of-way. It is estimated there will be minimal risk due to the relatively low voltages and the distance between lines and homes.

Bird collisions with aerial transmission lines have been documented in some areas under some conditions. Species most vulnerable to mortalities are larger forms such as swans, geese, waterfowl and raptors. The areas of greatest concern would be where transmission lines occur in major flyways or bird concentration areas where visibility may often be reduced by fog. Except in major nesting or staging areas, the number of collisions would likely be small, and there would not be a measurable impact on bird populations.

Visual impacts of above-ground transmission lines are greater than those of buried lines or roads because of the increased distances over which lines and poles are visible and the additional (vertical) dimension of disturbance. However, along many portions of the alternative corridors there are natural screens, such as forested areas or hills, that would block views of the transmission lines. Pumping stations required for buried portions of the transmission system entail new structures in some areas where there are currently no buildings. These may be visible for extended distances, especially from the air.

Buried transmission lines are not expected to have operational impacts beyond those described above for the associated access roads.

Submerged transmission lines under Turnagain Arm would have no impacts during normal operations. Should a line be ruptured by seabed erosion (either from currents or ice scour), a small quantity of the cooling oil present in the conduit would be lost to the environment.

Pipelines. Impacts of buried pipelines would be negligible under normal operating conditions. Although the possibility of a pipeline rupture is remote, a rupture of the gas pipeline could have a severe but localized short-term impact on terrestrial ecosystem components due to gas releases and/or fire. A pipeline rupture under a stream could result in the release of natural gas through the water column, a condition that could have toxic impacts on aquatic biota downstream if significant concentrations of hydrocarbons are entrained or dissolve in the water.

12.4 KENAI-ANCHORAGE INTERTIE

12.4.1 Background

Four routing alternatives were initially examined for construction of a new intertie between the Kenai Peninsula and Anchorage (Alaska Power Authority Railbelt Utilities 1987). Based on evaluations of cost, service reliability, and general environmental considerations, two of these were selected as possible alternatives. These routes both originate at a planned new Soldotna Substation, skirt the wilderness core of the Kenai National Wildlife Refuge (KNWR), and make a submarine crossing of the Turnagain Arm of Cook Inlet to reach the Anchorage area.

Over most of each route, the system route consists of transmission lines suspended either on single wooden, tubular X-frame, or wooden H-frame poles. The submarine portion and some other sections of the line would be buried. Each route alternative requires a right-of-way width of approximately 115 feet.

12.4.2 Enstar Route Description

The Enstar route starts at the proposed Soldotna Substation and angles generally northeast for about 6.5 miles along the outskirts of Soldotna and Sterling to the southern boundary of the KNWR. It then turns east, paralleling the refuge boundary in an existing right-of-way for about 8 miles before heading southeast to intersect the Enstar gas line right-of-way. This portion of the route is seldom far from human developments, although 3.25 miles of new right-of-way would traverse wetlands. There are two crossings of Soldotna Creek, a small Kenai River tributary, and one of Moose River, an important anadromous fish stream with a major recreational fishery at its mouth. This area of the Moose River is also a spring and fall concentration area for trumpeter swans and other waterfowl.

The route then turns generally northeast paralleling the adjacent Enstar pipeline right-of-way, entering the KNWR, and roughly following the 400-foot elevation along the toe of the mountains to the east. The existing pipeline and access road pass through a corridor between two designated wilderness sections of the refuge. The transmission line route would extend along the northwest side of the existing gas line right-of-way, except where it passes three landing strips and extends to the southeastern shore of Chickaloon Bay.

Terrain is generally flat along this portion of the route. The route crosses several tributaries of Moose River and the Chickaloon River, as well as Big Indian Creek, Little Indian Creek, and Burnt Island Creek, three independent drainages entering Chickaloon Bay. Most of these streams support rainbow trout and Dolly Varden char; most also have two to five species of salmon. In addition, the Chickaloon River has a run of coho salmon and hooligan.

Dominant vegetation type is closed spruce-hardwood forest comprised of a complex mosaic of spruce-poplar-birch forest, high brush, and wet tundra (low brush bog and muskeg) communities. The area includes habitat for a diversity of wildlife, the most important of which is moose. Also important are brown bear, black bear, wolf, and beaver. Some caribou occur in the Kenai-Soldotna area and along the foot of the mountains in the KNWR. Portions of this area are managed to improve moose habitat.

A variety of waterfowl, including trumpeter swans, nest on the many small ponds in the center of the refuge; however, swan use of the few small ponds (Alfonasi Lake and Trapper Joe Lakes) within 0.5 mile of the route alignment has not been documented. Chickaloon Flats is an important fall staging area for geese.

A terminal/pumping station building would be constructed 4 miles south of Chickaloon Bay (near the crossing of Big Indian Creek). From this station to the other side of Turnagain Arm, the line would be buried in four, self-contained oil-filled conductor cables. Burial of the line would minimize conflicts with waterfowl and reduce aesthetic impacts across Chickaloon Flats. Portions of this segment of the route cross high-value salt marsh and riparian willow/alder thickets.

The submarine portion of the line would be an 8.5-mile continuation of the buried section south of Chickaloon Bay. Two options have been considered for landfall on the north side of Turnagain Arm: one would be near the southeast end of Potter Marsh, the other would come ashore about 2 miles to the northwest, opposite the widest part of the marsh. Potter Marsh is a unique wildlife habitat which supports nesting by a number of species of waterfowl as well as Arctic terns and perhaps raptors. It is heavily used for recreational viewing of its many bird species and a boardwalk access has been provided for viewing of waterfowl and spawning salmon. The upper tideflats along Turnagain Arm are fringed with salt marsh that is biologically very productive in the spring and summer. Waterfowl and shorebird use may be significant during spring and fall migrations.

Under the first option, there are two sub-options for by-passing the marsh. The first would entail a continuation of the buried line on the seaward side of the Alaska Railroad. This would eliminate potential impacts on the Potter Section House State Historic Site, Potter Point State Game Refuge, and the Rabbit Creek Rifle Range but would require trenching for about 3 miles in salt marsh vegetation west of the railroad grade. The second sub-option would have only a 0.25-mile buried section to the terminal/pumping station site. From there an overhead line would follow the Old Seward Highway around the east side of Potter Marsh to the northern end. This would pass through or adjacent to Little Rabbit Creek Bluff Park. Some tree removal would probably be required along this alignment.

Under the second landfall option, only about 1 mile of trenching would be required to pass the north of Potter marsh where the terminal/pumping station could be placed next to the railroad.

From north of Potter Marsh, there are two options to tie in to the Anchorage area grid system. Both would traverse areas of considerable existing development and require only minimal disruption of remaining natural habitats. The shortest route would be a new right-of-way along Old Seward Highway continuing to the Ptarmigan section line. It follows this line due east for about 1 mile and then turns due north for 2 miles along Elmore and Bragaw Streets to a new Huffman substation.

The longer route from north of Potter Marsh follows Old Seward Highway north to O'Malley Road. It would turn west and north along the Minnesota Street By-pass to an existing right-of-way continuing into the International Substation. This route would cross Campbell Creek, an important stream for coho, pink, and chinook salmon, and would pass near Strawberry Lake and Blueberry Lake.

Total length of the Enstar Route is 67.3 miles from the Soldotna Substation to north of Potter Marsh, with an additional 3 to 9 miles to reach one of the substations.

12.4.3 Tesoro Route Description

The second alternative route to connect the new Soldotna Substation to the Anchorage grid replaces an existing 115-kV transmission line that extends northwest for 24.2 miles to the Bernice Lake Substation. This segment passes through developed land along Kenai Spur road for about the first third of the distance, extends north-northwest through a corner of the KNWR, and then turns east through mostly private lands to Bernice Lake. From there it turns northeast within the North Kenai Road right-of-way for 11.5 miles to the Captain Cook State Recreation Area and crosses the Swanson River, an important salmon fishing and canoeing stream. North of the Recreation Area, the route is a new right-of-way adjacent to an existing pipeline right-of-way for nearly 25 miles to Point Possession.

From Bernice Lake north the terrain is generally flat at an elevation of about 100 feet. In addition to the Swanson River, several smaller streams are crossed. Most of these streams are expected to support rainbow trout and Dolly Varden char; larger streams also have one or more species of salmon.

The dominant vegetation type is a closed spruce-hardwood forest comprised of a complex mosaic of spruce-poplar-birch forest, high brush, and wet tundra (bog and muskeg) communities. The area includes important habitat for a diversity of wildlife, the most important of which is moose. Also important are brown bear, black bear, caribou, and beaver. A variety of waterfowl, including trumpeter swans, nest on the many small ponds within the nearby refuge; however, swan use of the few small ponds within 0.5 mile of the route alignment (most are south of the Recreation Area) has not been documented.

A terminal/pumping station building would be constructed at Point Possession. From this station to the other side of the Arm, the line would be buried in four, self-contained oil filled conductor cables. Because of the steepness of the bluff at this location there is little salt marsh or riparian willow/alder thickets to be crossed in entering or leaving the arm.

The submarine portion of the line would be a 13.5-mile long crossing at the mouth of Turnagain Arm. Landfall on the north side of the Arm would be at Point Campbell, southwest of the west end of the runways at Anchorage International Airport. The second terminal/pumping station would be 0.75 mile north of the shoreline.

Two options have been considered for the route from Point Campbell to the International Substation. Both would be in or near Kincaid Park for a short distance. The first route would extend along the south side of the airport with a 1-mile underground section at the south end of the north/south runway. It would then zig-zag east around some residential areas to the Minnesota Street extension, then turn north to the substation.

The second option would extend northeast from Point Campbell around the west end of the east/west airport runways in a 2.2-mile underground section. It would turn east and north to the Point Woronzof Substation. An existing buried 138-kV cable would also be upgraded for the 6-mile distance between the Point Woronzof and International substations.

Both of these options pass through wooded areas. The southern route encounters some residential areas east of the north/south runway, while the western route is largely in publicly owned land with little development. The primary large mammal usage of the area is as winter range for moose, although this use may be declining with increasing urbanization in the area. The upper tideflats along Turnagain Arm are fringed with salt marsh that is biologically very productive in the spring and summer. Waterfowl and shorebird use may be significant during spring and fall migrations.

Overall, the Tesoro Route is about 83.4 miles long, with 70 percent of this in forested areas.

12.4.4 Comparison of Impacts

Air Quality. Impacts of construction and operation of the Kenai-Anchorage Intertie on air quality would be confined to locally generated equipment exhaust and fugitive dust (see Generic Impact discussions in Section 12.3). The Tesoro Route with the western option to Point Woronzof would remove all construction at the northern end of the route from proximity to residential areas; however, the Tesoro route would have greater proximity to residential areas in the Soldotna to North Kenai area. Thus, there would be no significant differences between the impacts of either primary route alternative (the Enstar Route or the Tesoro Route) or between the impacts of the options or sub-options described. Air quality impacts would be negligible in magnitude for both routes.

Water Quality. Since there would not be access roads installed along either corridor, neither route alternative would substantially affect water quantity. The Enstar route has a larger number of significant stream crossings in areas not served by existing public highways (i.e., about 13) than does the Tesoro Route (about 4). Although these areas may require short access spurs from existing access roads, development and use of access areas would result in a low level of impact on water quality. There are two streams along the Enstar route in the Chickaloon Flats area that would require trenching. The extent of use of the lower reaches of these streams by important anadromous fish species is unknown; however, some use by salmon is reported in both Burnt Island and Little Indian creeks.

The effects on water quality of the crossing of Turnagain Arm by the buried submarine conduit on either route would be low and would not differ between routes. The effects of crossing the mudflats on either side of Turnagain Arm would also differ little between alternatives although the distance traversed would be greater for the Enstar route. Silt resulting from trenching would be temporarily suspended, but would not result in a significant increase in turbidity due to the normally high level of suspended solids in the waters of Upper Cook Inlet. Similarly, trenching to bury the line along the Arm side of the railroad tracks would not significantly affect water quality. Both alternatives on the north side of the Arm are rated as having a low impact potential on water quality.

In summary, overall effects on water quality are rated as low for both the Enstar and Tesoro routes.

Fish and Wildlife. The potential effects of each route alternative on fish resources on the Kenai Peninsula would be proportional to the potential effects on water quality since effects on fish result primarily from water quality degradation. One exception would be in Big and Little Indian creeks, where trenching across streams could interfere with spawning habitat, if present. Impacts to fish on the Kenai Peninsula leg are thus considered generally low for the Enstar route, with a potential for a localized moderate impact, and low for the Tesoro route.

Primary wildlife concerns along the Enstar route are waterfowl and swan use along the Moose River, Chickaloon Flats and other smaller streams and lakes, as well as use by moose, and perhaps caribou (primarily in the segments within the KNWR). Potential impacts to eagle nesting areas would likely be mitigated by routing adjustments. During construction, impacts to wildlife on the Kenai Peninsula would be slightly greater for the Enstar route than the Tesoro Route because of disturbances on Chickaloon Flats and because the route lies across likely migration corridors between the mountains to the east and the flats to the west. Animals such as moose, and possibly caribou, that move from high hillsides in the summer to lowland winter range may frequently cross the route, although this would not constitute a significant impact after the initial period of construction activities. The area of the Enstar route within the KNWR would remain a high use and high success area for moose hunting since management practices and public access to the area would not be altered. Impacts to wildlife on the Kenai Peninsula leg are considered low for both routes.

On the Anchorage side of Turnagain Arm, neither of the alternatives or their optional routings would have a significant impact on fish, assuming that trenching across Rabbit Creek would not occur during periods of anadromous fish usage.

Potential wildlife concerns on the north side of the Arm focus on the Potter Marsh area where the nearby overhead line would have some potential for bird collisions. However, the routing along the Old Seward Highway is not likely to be in a heavily used flight path because of the high terrain immediately to the north and existing vegetation between the marsh and the line. Other impacts on wildlife would be relatively minor.

Overall, the impacts are classified as low for both routes.

Land Use Impacts and Ownership Status. Both the Enstar and Tesoro routes pass through a variety of land ownerships including some private, borough, state, and Native lands. A major portion of the Enstar route (about 38 miles) lies within the KNWR, paralleling the existing Enstar gas pipeline right-of-way. This route has been identified in the Final Comprehensive Conservation Plan (U. S. Fish and Wildlife Service 1985) as a utility corridor. However, the northern portion of the route (north of Mystery Creek), is designated as a "minimal management" area where overhead transmission lines are not allowed outside the existing 50-foot right-of-way. Since the line would require a 115-ft corridor for overhead lines for about 18 miles in this area, a change in the management plan and preparation of an environmental impact statement could be required. However, the DOI has agreed to exclude a new corridor, located adjacent to the Enstar route, from the wilderness designation. The DOI request must be approved by Congress for the proposed exclusion to be permitted. The major non-utility related use of the lands along this route is for hunting which would not be unduly affected by establishment of the transmission line. The impact of the Enstar route on land use on the Kenai Peninsula would be low to moderate.

The Tesoro route, except for passage through the Captain Cook State Recreation Area (CCSRA), is on existing rights-of-way or borough land designated for utility corridors along the inlet. Within the CCSRA, securing a right-of-way would require allocation of funds for replacement with lands of equal value which would require National Park Service approval under the Federal Land and Water Conservation Act. The Swanson River within the CCSRA receives considerable fishing and canoeing use during the summer months. Passage of overhead lines in the vicinity of the existing bridge crossing would not adversely affect those activities, much of which occurs upstream. The impact of the Tesoro route on land use on the Kenai Peninsula is considered low to moderate.

North of Turnagain Arm, the Enstar route options would avoid direct passage through sensitive public land use areas including the Potter Section House State Historic Site, Potter Point State Game Refuge, and the Rabbit Creek Rifle Range. The majority of the route under both options (to the Huffman or International substation) would parallel existing rights-of-way. The impact of the Enstar route on land use in the Anchorage area would be low. However, impacts may increase above this level in localized residential areas, with the level of impact dependent on the final alignment and the proximity of residences.

North of Turnagain Arm, the Tesoro route options would avoid extensive routing through sensitive land use areas. The majority of the route under both options (to the Point Woronzof or International substation) would parallel existing rights-of-way. However, both options would infringe to some degree on Kincaid Park. The route around the west end of the airport to Point Woronzof would be buried in the park and opposite the east-west runway but would be in the woods on timber H-poles along the coastal trail extension south of Point Woronzof. This option would thus have a greater land use sensitivity than would the option passing south of the airport. Both options would pass through residential areas en route to the International substation. The impact of the Tesoro route on land use in the Anchorage area is judged to be generally low for the option south of the airport and low to moderate for the option passing west of the airport. This impact level may be reduced to low if conflicts with Kincaid Park and the coastal trail can be eliminated. However, as with the Enstar route, impacts may increase above these levels in localized residential areas.

Overall, the impact of each route on land use is expected to be low to moderate.

Terrestrial Impacts (Vegetation and Wetlands). Many of the terrestrial impacts of the route alternatives have been addressed in the above sections. Substantial clearing of overstory vegetation would be required for either route. However, since understory and shrub vegetation would be unaffected over most of the rights-of-way, the impact would be negligible. Potentially serious infestations by spruce bark beetles that could begin in trees cleared along the right-of-way would be mitigated by removal or burning of cut timber from the area.

Wetlands disturbance would be kept to a minimum by route selection, minimizing access, careful tower placement, and mitigation developed in concert with state and federal agencies. The saltmarsh areas to be crossed by the Enstar route are wider than for the Tesoro route, especially for the option passing along the south side of the railroad in the Potter Marsh area. However, except for minor disturbances during construction, impacts are expected to be negligible. With the mitigation measures that are included in both alternatives, the impacts to terrestrial resources would be, at most, low.

Recreation Resources. The primary recreational uses of areas along the alternative routes on the Kenai Peninsula are hunting, fishing, hiking, canoeing, skiing, and snowmobiling. Although there could be interference with some of these activities during construction, this disruption would be short term and restricted in geographic area at any one time. Construction in the KNWR would be timed to minimize conflict with moose seasons and access would be allowed for hunters along the present right-of-way. Initial plans would allow continued recreational use of the right-of-way; however, if increased recreational activity adversely affects the available resources, some areas might require grating.

North of Turnagain Arm, the primary recreational activities are nature observation (at Potter Marsh), and skiing, walking, or running on the coastal trail along Knik Arm. Construction activities on either option of the Enstar alternative could temporarily interfere with the enjoyment of natural features and wildlife in the vicinity of Potter Marsh. Construction along the Tesoro route option around the west end of the airport would temporarily diminish enjoyment of recreation along the coastal trail. Following construction, transmission line facilities might be visible from place to place along the coastal trail, especially in winter, and could reduce the enjoyment of recreational activities.

Overall, the Enstar route would have a low level of impact on recreational resources. The Tesoro route would have a low-to-moderate impact because of the potential disturbance to recreation along the coastal trail, especially during construction.

Visual Impacts. The Soldotna substation would be located in an area of considerable commercial and residential development adjacent to the Sterling Highway and would be visually compatible with these surroundings. Most of the first 18 miles of the Enstar route would be near (e.g., within 1 to 2 miles) existing residential areas and would be in existing rights-of-way. However, some new right-of-way would be required and overhead lines in these areas would be visible from residential properties. From the KNWR boundary to the north side of Turnagain Arm, the Enstar route would not be visible from residences or from public roadways. Increased right-of-way width and the transmission lines would be visible to some air travelers. The pumping station constructed against the hills on the south edge of Chickaloon Flats would be relatively inconspicuous to air travellers in and out of Anchorage.

Most of the first 40 miles of the Tesoro route would be near existing residential or commercial development and/or within existing rights-of-way. Within the Captain Cook State Recreation Area, the line is expected to be visible along the road and from the bridge. This is an area of considerable natural beauty. From the Recreation Area north to Point Possession, the line follows the coastline and would be visible to Kenai-Anchorage air traffic. The terminal/station building also would be visible to air travelers leaving or approaching Anchorage International Airport from the south and to air traffic between Anchorage and Kenai.

North of Turnagain Arm on the Enstar route, the transmission lines north of Potter Marsh might be visible in some areas to those enjoying the natural setting and wildlife of the marsh. The pumping station might also be visible from the roadway south of the marsh. The option that includes buried cables on the Arm side of the railroad would have no adverse aesthetic impacts. The pumping station under this option would be removed from the marsh viewing area. North of Potter Marsh, both options of the Enstar route would parallel existing roads and/or be within existing rights-of-way through mostly residential areas with existing power lines. New installations at the Huffman or International substations could intrude on the viewsheds of some area residences.

North of the Arm, portions of the Tesoro route option passing west around the airport might be visible to users of the coastal trail extension. From the Earthquake Park area to the International Substation, upgrading of the buried cable could disrupt neighborhood aesthetics during the construction period. The route south of the airport would have less impact on Kincaid Park and the coastal trail. However, overhead lines would pass through some neighborhoods in the DeLong Lake area.

Overall, the Enstar route would have a low level of impact or visual resources. The Tesoro Route would have a low-to-moderate impact unless screening can be provided to minimize the impact on the aesthetic values of the coastal trail.

12.5 ANCHORAGE-FAIRBANKS INTERTIE

12.5.1 Background

Two main alternatives were evaluated for improvement of the intertie between Anchorage and Fairbanks: (1) a new transmission line corridor, the Anchorage to Fairbanks (AFB) route, that extends the existing route between Douglas and Healy with two new segments, one of which generally follows the Parks Highway, and (2) a new transmission line corridor, the Northeast Intertie, from Sutton to Delta Junction. Detailed information on these routes is presented in the intertie route analysis reports of Harza (1987) and Hart Crowser and Power Engineering (1989). A summary of relevant information on the alternative routes is presented in Section 12.5.2 and 12.5.3.

12.5.2 Anchorage to Fairbanks Route Description

Line Description. The system over most of the route would consist of transmission lines suspended on X-frame, tubular type, guyed-steel structures. The total height of these structures would be 100 feet. In special cases single poles would be used, and three-pole guyed structures would be used for angle and dead-end applications. Free-standing H-frame steel structures with the same configuration as the X-frame would be used for line sections where guy wire installation is objectionable (Harza 1987).

Route Description. This route would consist of three segments, with two segments requiring new construction. The third segment, representing the bulk of the total route length along this corridor, is the existing Douglas to Healy Intertie. The Douglas to Healy Intertie will not require changes or new construction. The route south from Willow (Douglas Substation) to Lorraine Lake would be a new line, as would the final section from Healy to Fairbanks. There are two route options for the Healy to Fairbanks line. Both roughly parallel the Parks Highway north from Healy to the vicinity of Nenana where they turn in a northeasterly direction toward Fairbanks. Here the lines separate with the southern option staying more in the Tanana River Valley while the northern option climbs into the foothills north of the Parks Highway, looping around the northern part of the city then extending south to the Fort Wainwright Substation, passing through a portion of Fort Wainwright southeast of downtown Fairbanks. The northern option would have a total length of 118.5 miles, with 55.5 miles of new corridor. The southern option would have a total length of about 100 miles, with about 95 to 97 miles of new corridor. For the 35.5-mile Willow to Lorraine Lake segment, 23 miles would be new corridor. Thus, the total length of new construction for the identified intertie improvement would range from 135.5 to 154 miles.

12.5.3 Northeast Intertie Route Description

Line Description. Along most of the route, the system would consist of transmission lines suspended on weathered steel X-frame towers. The total height of each tower would be 100 feet. Single poles would be used along highway rights-of-way or for double circuit use.

Route Description. Generally, this route would extend along the Glenn Highway from Sutton through Glennallen, then from Glennallen to Delta Junction along the Richardson Highway. Two route options along this corridor were initially considered. Of these, only a variant of the "northwestern" option has survived preliminary environmental screening. This option runs north of the Glenn Highway from Sutton to Sheep Mountain where it extends up the Caribou Creek Valley north of Sheep and Gunsight Mountains. It returns to the north side of the highway east of Gunsight Mountain and then roughly parallels the highway to Glennallen. From Glennallen this option proceeds north along the eastern side of the TAPS line to just south of Sourdough. At this point, the suggested route crosses the Gakona River and the Richardson Highway. The route remains on the east of the highway the rest of the way, except for a 2.5 mile section at Rainbow Ridge.

An alternate route has been proposed between Sutton and Glennallen by a local resident group. This would place the line further north of the Glenn Highway to reduce impact on area residents. The proposed alternate would be shorter than the "northwestern" option described above but would also traverse more difficult conditions and terrain. More information on this alternate is included in the Northeast Intertie Design and Cost Estimate Study produced by Hart Crowser and Power Engineers, Inc.

The total length of the Northeast Intertie would be approximately 260 miles, with the actual distance dependent on the option selected.

12.5.4 Comparison of Impacts

Air Quality. Impacts of construction and operation on air quality would be limited to locally generated equipment exhaust and fugitive dust (see Section 12.3, Generic Impacts). The major difference between the two alternatives is the length of the routes, with the Northeast Intertie being almost two times longer than the route additions required to close the AFB loop. Impacts to air quality will be largely temporary and localized during construction, although more area would be affected along the Northeast route because of its greater length. Impacts would be negligible for both routes.

Water Quality. Neither primary route alternative would substantially affect water quantity. Impacts on water quality would be primarily associated with construction of short access spurs from existing roadways to the corridor.

Impacts to water quality are expected to be low for both routes.

Fish and Wildlife. The effects on fish resources would be proportional to the effects on water quality since impacts on fish result primarily from degradation of water quality. Thus, impacts to fish are expected to be low for both routes.

Impacts to wildlife for each route would be similar in many respects. Moose habitat would be affected in the Tanana, Susitna, and Matanuska River Valleys. Both routes traverse caribou migration routes and winter range, and both cross wetlands used for waterfowl, Trumpeter swan, and raptor nesting areas. Both routes also intersect habitats used by black and brown bears. The level of impacts would be related to the length of line traversing habitat areas or migration routes and the extent to which specific critical habitat areas are affected. Key areas of concern are addressed below.

The AFB route options from Healy to Nenana are similar in their potential for impacts to wildlife. Both options cross similar forest and wetland habitats and each option has a similar potential to affect swan and raptor nesting areas. From Nenana to Fairbanks, the two options differ in that the northern option traverses more forest habitat which includes areas of black bear concentrations. The southern option remains more in the Tanana River Flats and therefore has a greater potential to affect swan and raptor nesting areas. Selection of tower sites that avoid critical nesting areas could minimize this impact. The southern route option also has a greater risk of bird collisions. The route segment from Willow to Lorraine Lake, which is relatively short and traverses areas with relatively high levels of human development, would likely have few impacts to wildlife. The potential disturbance of swan and raptor nesting in this area is considered very low (Harza 1987).

The Northeast route crosses significant moose habitat in the Matanuska and Copper River valleys. In addition, there is caribou wintering from Sheep Mountain to Glennallen and a significant migration pathway from Gulkana to Isabel Pass. There are known brown bear concentrations between Paxson and Summit Lakes. Brown bear are also present throughout the entire Delta River area and are known to concentrate north of the Black Rapids area in spring and summer. Bison are also present from Black Rapids to Big Delta. Although these species may be affected by construction activities, the impacts would be short-term, localized, and of low magnitude for either of the Northeast Intertie options.

Trumpeter swans are present in the Matanuska River Valley and are distributed throughout the Copper River basin. The area from Snowshoe Lake on the Glenn Highway to Hogan Hill on the Richardson Highway is a known concentration area for swan nesting and rearing. The area around Glennallen is a major migration corridor for swans and is estimated to contain habitat for an estimated 20 to 25 percent of the world's trumpeter swan population. The northwestern option for this corridor crosses 3 miles of state land which is under consideration for designation as a critical habitat area for swans. As a result of this concentration of swans and other breeding waterfowl (e.g., ducks and geese), the potential of waterfowl for collisions with the transmission lines is a concern for both route options along this corridor. The level of impact would be dependent on the alignment selected, with a moderate impact possible at some locations. However, careful route placement and configuration (i.e., hanging conductors at heights below 100 feet) can mitigate these potential effects.

In summary, the effects on fish and wildlife are expected to be low on the AFB route, and low to moderate along the Northeast route.

Land Use Impacts and Ownership Status. Both major corridors include a wide range of land uses, from private residential to public undeveloped or undesignated lands. To the extent possible, all route options specifically avoid sensitive land use areas, such as designated parks or recreation areas, airports, and landing strips. The majority of land along the route options is in state or federal ownership. For approximately 15 miles south of Delta Junction, the northeastern option of the Northeast Intertie would cross through Fort Greely Military Reservation as it parallels the highway. The Healy to Fairbanks segment, extending the existing route, would pass through Fort Wainwright as it enters Fairbanks. Agreements would need to be negotiated with the U.S. Army to ensure the transmission lines do not conflict with normal operations in order to obtain easements.

Land use patterns favor the eastern option of the Healy to Nenana segment of the AFB route because it encounters fewer landing strips and airports and less residential land. The southern option from Nenana to Fairbanks is also favored from a land use perspective because the majority of the route crosses public and undeveloped lands. There is only one route option for the Willow to Lorraine Lake segment of this route and it avoids designated recreation sites in this area.

The Northeast route (northwestern option) passes within the vicinity of seven state and two federal recreation areas but will not cross them directly. As mentioned previously, it would cross 3 miles state land which is under consideration for designation as critical trumpeter swan nesting habitat. Overland access and other activities requiring permits are generally prohibited in this area from May 1 through August 31. The only other land use issue for this route relates to small plane use of passes around Sheep Mountain and in the Isabel Pass area. Small plane operators tend to use these areas when visibility is poor and the presence of transmission lines in this area represents a safety hazard to aviators.

Overall, land use impacts would be low for all segments of the AFB route provided that line placement would avoid conflicts with Army operations. Land use effects are considered low to moderate on the Northeast route.

Terrestrial Impacts (Vegetation and Wetlands). Many of the terrestrial impacts of the route alternatives have been addressed in the above sections. In forested areas crossed by the route options, substantial overstory clearing would be required. However, since understory and shrub vegetation would be unaffected over most of the rights-of-way, the impact would be low. Wetlands disturbance would be kept to a minimum by route selection, minimizing new road construction, careful tower placement, and mitigation developed in concert with state and federal agencies. Terrestrial effects are expected to be low for both route alternatives.

Recreation Resources. The primary recreational uses of the route areas include hunting, fishing, trapping, hiking, canoeing, skiing, and snowmobiling. Although there could be interference with some of these activities during construction, this disruption would be short term and localized at any one time. Increased human access could lead to increased hunting, trapping, and fishing pressure in some areas. All designated state and federal recreation areas would be avoided by all route alternatives thus minimizing impacts in these areas.

Overall, the effect on recreational resources would be low for either alternative.

Visual Impacts. Visual resources along the Healy to Fairbanks segment of the Anchorage to Fairbanks route are considered to be of moderate to high quality, and tourist use of the Parks Highway and the Alaska Railroad is very high during the summer. Between Healy and Nenana there is a view to the east of the Alaska Range from the railroad and the highway. As the highway descends into the Tanana Flats, the primary views are to the north and east across the Tanana River Valley. There are also views into the Tanana River Valley from the highway in the foothills between Nenana and Fairbanks. In this area the valley is sufficiently distant from the highway to minimize the potential view impairment if the transmission line were to follow the valley route. The visual impact of the northern option in this area would be greater since the transmission line would be visible from the highway and would cross the highway. Placement of the route to the east and south of the highway and railroad would minimize visual impacts in this area.

Most of the northwestern route for the Northeast corridor would be visually shielded from the Glenn and Richardson Highways. However, this route crosses open areas where it may be observed from other vantage points. This is an area that is frequently used by small planes, and the transmission lines would alter the views from these aircraft. Other areas of potential concern for visual impacts along the Northeast alternative are the Matanuska and Copper River Valleys and the Paxson to Isabel Pass area at the summit of the Alaska Range.

In general, it may be possible to minimize visual impacts for either major corridor through careful line placement. Since a detailed visual assessment would be expected at the time the required right-of-way permits were sought, an acceptable mitigation program could be developed at that time. Overall, the likely visual impacts are rated as low to moderate for each route.

12.6 NATURAL GAS PIPELINE SYSTEM FROM COOK INLET TO FAIRBANKS

12.6.1 Background and Route Description

Stone & Webster (1989) assessed the costs and environmental impacts of a 16-inch diameter natural gas pipeline linking Fairbanks with the Cook Inlet area. In addition to Fairbanks, where natural gas is not available at present, the pipeline could provide natural gas to at least seven other Railbelt communities and would have the potential to serve U.S. Military bases such as Fort Wainwright, Eielson, and Clear.

The gas pipeline would cost approximately $190 million, with about $34 million required for a gas distribution system in Fairbanks. Pipeline construction would include four construction spreads operating over a 16-month period. Three spreads would operate in summer and one in winter. Permanent facilities would include 298 miles of buried pipeline, a custody transfer metering station at the Beluga supply junction near Knik, a city gate valve station at Fairbanks, and take-off facilities at communities along the route. This alternative would not require compressor stations beyond those already in place on the Beluga system. Related facilities would include access roads plus gravel and riprap material sites. The area to be traversed by the pipeline is within a zone of discontinuous permafrost where a relatively large volume of non-frost-susceptible gravel materials would be required for pipeline bedding and backfill and for access road and workpad construction.

The pipeline route would extend due north from the existing Beluga gas line at Knik for approximately 7.5 miles to the George Parks Highway (near the Big Lake Road intersection), then to Fairbanks along the corridor formed by the Alaska Railroad and the highway to Fairbanks. The only deviation from that route would be an 8-mile alignment around Denali National Park and a direct cross-country alignment from an area south of Nenana for 46 miles across the Tanana Flats to Fairbanks. As mentioned above, the pipeline would be buried except for two above-ground stream crossings at Little Coal Creek and Hurricane Gulch.

12.6.2 Comparison of Impacts

Air Quality. During construction, the use of heavy construction equipment would cause temporary increases in exhaust emissions (carbon monoxide, hydrocarbons, nitrogen dioxide, sulfur dioxide, and particulate matter). Fugitive dust would increase levels of particulates during trenching operations, access road construction, work pad construction, and gravel and riprap mining. Impacts to ambient air quality would be low and temporary.

Pipeline operation would not represent a major source of pollutants. If coal or oil-fired power plants in Fairbanks or in other communities along the Railbelt were replaced by gas-fired units there would be an overall reduction in emissions of carbon monoxide, nitrogen oxide, sulfur dioxide, and particulate matter. Determining the extent of this decrease would require emissions inventories, detailed modeling, and other analyses beyond the scope of this comparison of impacts.

Ice fog is a concern in the Fairbanks area and this condition may also occur in other localized areas. Although the effect of ice fog on visibility is an obvious issue, Ohtake (1982) reported that ice fog

> "is formed usually in association with high emissions of air pollutants under a strong temperature inversion and gives an impression as being harmful to human health."

There are two atmospheric constituents of concern when evaluating the effects of fuel combustion on ice fog formation: moisture content and particulate matter. Stone and Webster (1989) indicates that additional moisture in the atmosphere may increase ice fog during cold weather conditions, and Ohtake (1982) noted that the nuclei of the ice crystals "seem to have originated from the combustion process."

Installation of the gas pipeline could result in increased use of natural gas as a fuel at facilities that are currently major sources of emissions or at new facilities that would be major sources. As compared to coal, the use of natural gas would result in substantially lower levels of particulate matter in the emissions and an increase in the moisture content in the flue gas. Stone and Webster (1989) data indicate that particulates could be reduced by as much as 98 percent and moisture content increased by about 20 percent, assuming coal facilities convert to natural gas. Localized changes in atmospheric concentrations of these constituents may also occur to some extent if natural gas replaces wood, oil, or coal as fuel in residential or commercial heating units.

At the present time, it is not known whether the concentration of particulate matter or the moisture level is most influential on ice fog formation. Assuming the effect is approximately equal, the relatively large decrease in atmospheric levels of particulate matter from conversion to natural gas suggests that the conversion of major emitters to gas could generally decrease the incidence of ice fog. However, if the current major sources continue to burn coal and new major emitters burn gas, the total particulate level would increase slightly and the moisture content would also increase, a condition that could increase the incidence of ice fog. Further study would be required to more definitively evaluate the effect of this alternative on ice fog formation.

Assuming that there would not be a major change in the incidence or level of ice fog formation, the overall impact of this alternative on air quality would be negligible to low.

Water Quality. A minimum of 144 streams would be crossed along the route and all but two would require trenching and burial of pipe to below flood scour depths. By using standard, proven mitigation measures, construction activities would result in localized short-term sedimentation in the streams. Proper timing of construction and adequate stream bank stabilization and revegetation would help to mitigate construction impacts. The potential impact on water quality would be short term, and of low-to-moderate magnitude, with the impact level dependent on construction methods and flows.

With proper stream bank stabilization following construction, water quality would be essentially unaffected by operation of the pipeline. In general, the impacts of a gas pipeline rupture would be low unless repair activities required work in streams. However, understream gas releases could result in localized impacts on water quality. In areas of discontinuous permafrost, some thaw settlement may occur, but unless errors were made in settlement designs, thermal erosion is not expected to pose a serious threat to stream water quality.

The potential long-term impact of the gas line on water quality would be low to moderate.

Fish and Wildlife. The greatest environmental concern from pipeline construction would be the potential cumulative effect on fisheries resources in streams to be crossed. Forty of the streams are used by anadromous fish and others are important for resident species. The Susitna River and its tributaries support major runs of five species of Pacific salmon, plus grayling, rainbow trout, Dolly Varden char, burbot, whitefish, and many smaller fishes. The latter species provide an important food supply for the larger predatory species. Impacts to some streams could be reduced by limiting construction to the period from May 15 to July 15. This is the period following emergence of newly hatched salmon that have spent the winter as eggs buried in stream gravels, and before returning adult salmon have deposited new eggs in the same stream gravels. However, on larger rivers winter construction may be necessary, increasing the potential for damage to overwintering fish populations and fish eggs. Construction techniques which have been used on other pipeline projects in Alaska to protect fish streams include fluming, stream channel diversion, use of filter fabric, and temporary dams. All crossings would require extensive erosion control and revegetation to quickly stabilize stream banks and eliminate sedimentation. Assuming these mitigative measures are in place, the potential for impact to fisheries resources would be moderate during the construction period.

Wildlife populations would not be significantly affected during construction activities providing that alignments are selected to avoid calving, lambing, and nesting areas or special concentration zones such as places where eagles and bears gather to feed on salmon. No threatened or endangered wildlife have been identified along the corridor. Clearing of vegetation in the construction zone would alter plant succession and result in secondary growth that would provide good forage for moose in some areas. In areas where shrub growth would be discouraged, moose habitat would decrease. In addition, the disturbance of 3,100 acres of right-of-way and disturbance of gravel pits and other project-related areas would displace the wildlife using the habitat. Since most of the areas near the disturbances are likely to be at or near their habitat-carrying capacity, the local populations would decrease by the number of individuals displaced. Although the "edge effect" (see Section 12.3) of right-of-way maintenance would be of benefit to some species, the effect of pipeline installation or wildlife would be moderate.

Erosion control and revegetation would stabilize stream banks and result in negligible impacts to fish and other aquatic organisms during pipeline operations. The occasional use of vehicles for inspection and maintenance of the line would cause only minor, short-term impacts to local wildlife populations and the impact on wildlife would be considered negligible.

Overall, the impact of the natural gas pipeline on fish and wildlife would be moderate.

Land and Use Impact and Ownership Status. The project would change unimproved land to pipeline right-of-way for the duration of the project. Land traversed by the pipeline would include state, federal, borough, and private ownership. Special areas in the vicinity of the route include Denali National Park, Denali State Park, Nancy Lake Recreation Area, Willow Creek Wayside, and Little Susitna Wayside.

Except for 7.5 miles on the southern end of the route and 46 miles from Julius to Fairbanks on the northern end, most of the route would be within the existing right-of-way for the Parks Highway and the Alaska Railroad. The right-of-way would pass through the communities of Houston, Willow, Kashwitna, Trapper Creek, Cantwell, Healy and Anderson and would result in temporary, local disruptions of road traffic during construction.

Because pipelines are considered incompatible with the purposes of National Parks, an 8-mile cross-country route was selected on state land around the Denali Park boundary on the east side of the Nenana River.

In summary, the pipeline is expected to have a negligible-to-low impact on land use.

Terrestrial Impacts (Vegetation and Wetlands). Approximately 3,100 acres of vegetation would be disturbed by construction of the pipeline and related facilities plus an unknown area for access roads and mining of about 400,000 cubic yards of non-frost-susceptible gravel and riprap.

According to data from the U.S. Department of the Interior and U.S. Army Corps of Engineers (1987), the pipeline corridor would traverse five vegetation types. These include lowland spruce-hardwood forest (39 percent of the area of the corridor), upland spruce-hardwood forest (35 percent), bottomland spruce-poplar forest (15 percent), alpine tundra (7 percent), and high shrub thicket (4 percent).

The major wetland habitats crossed by the pipeline corridor are lowland spruce-hardwood forest and lowland bogs which are most common on the Tanana Flats and in the lower Susitna River valley. Minor wetland areas include shrub thickets and moist tundra above treeline in the Alaska Range. Overall impacts to wetlands during construction could be low to moderate, although establishment of new wetlands or enhancing existing wetlands to comply with the "no net loss" policy would reduce this impact. Many of the impacts to wetlands could be avoided by winter construction from ice or snow roads. No areas of critical habitat have been identified within the proposed pipeline corridor. Although vegetation types would be altered along the right-of-way, the level of impact from construction would be low.

Operation of the pipeline would include maintenance clearing of portions of the right-of-way along the Parks Highway every 3 to 5 years. Removal of shrub growth would make this zone less attractive to moose and would reduce the incidence of moose-vehicle collisions.

The overall impact on terrestrial vegetation, including wetlands, would be low.

Recreation Resources. The Parks Highway supports a high volume of recreational travelers, including tourists, sport fishermen, trappers, hunters, campers, hikers, all-terrain vehicle users, and skiers. The presence of a large pipeline workforce and year-round construction would result in increased competition among recreational users during the construction period. New access roads in previously undeveloped areas on the north and south end of the project would provide new recreational opportunities for some users while reducing wilderness recreational values for others.

The Susitna, Nenana, and Tanana River basins are used extensively by sport and subsistence hunters. Within the Railbelt these activities focus on moose, Dall Sheep, grouse, ptarmigan, and waterfowl. Trapping of mink, beaver, marten fox, coyote, lynx, wolf, and wolverine is also very important in this area. Moose are the most important subsistence resource. In Nenana, 95 percent of surveyed households reported that they participated in moose hunting (ADF&G 1986). Pipeline construction timing and sequencing could be planned to (1) avoid periods of primary hunting and trapping activity, and (2) reduce impacts to access trails used to reach more remote areas.

Because of the abundant fish resources and ease of access from Anchorage and Fairbanks the Susitna River tributaries sustain the heaviest sport fishing activity in Alaska. Construction activities could be scheduled to accommodate the large number of anglers who use this river system each summer on foot or by boat wherever the streams cross the Parks Highway.

In areas of high recreational use, revegetation plans may require special planting to reduce visual and aesthetic impacts of right-of-way clearing and construction. Access maintenance clearing would likely provide some new access for hikers, hunters, trappers, fishermen, and all-terrain vehicle users. This improved access may increase hunting, fishing, and trapping pressure in some areas requiring increased regulation of harvest by the Alaska Boards of Fisheries and Game. The potential impact to recreation resources would be moderate to high during the construction period and low following successful revegetation during operation of the pipeline.

Overall, the impact of the gas line on recreational resources would be moderate in magnitude.

Visual Impacts. Along the Parks Highway the pipeline route would be cleared and the pipe buried in the immediate foreground of views from the highway. Except for where valve stations and permanent facilities are located, non-woody vegetation would be allowed to regrow. As a result, visual impacts would decrease over time. Portions of the alignment away from the highway would be observable only from the air. In areas of high scenic value, green belts of 100 to 200 feet beyond the edge of the highway right-of-way could be planted to protect sensitive scenic values. The visual impact of the project would be low.

12.7 COAL-FIRED POWER PLANTS

12.7.1 Background

Stone & Webster (1988) evaluated the costs and environmental impacts of coal-fired power plants at four Railbelt locations: Beluga, Matanuska, Nenana, and Healy. They initially considered fluidized bed combustion, pulverized coal combustion, and coal gasification, with atmospheric circulating fluidized bed (CFB) selected as the combustion technology most likely to be installed in the Railbelt region. Their analyses included evaluations of CFB plants of 50, 100, and 150 MW.

Although there are many fluidized bed combustion (FBC) systems in operation, FBC is a relatively new technology in the U.S. There are several different types of FBC design, including atmospheric bubbling bed, atmospheric circulating bed, and pressurized bed combustion. In the selected CFB design, air is distributed beneath the fuel bed to keep the bed in suspension and to keep the fuel circulating throughout the bed to maximize combustion. The term "fluidized bed" is derived from the observation that the materials in the suspended bed behave like a liquid.

The primary advantage of CFB technology over the traditional pulverized coal plant is that sulfur dioxide is removed from the combustion cycle without the need for an expensive flue gas desulfurization system. Sulfur dioxide removal is accomplished by either (1) the use of limestone with fuel in the bed material, or (2) by using coal that has a high calcium oxide (CaO) content. In either case, the sulfur dioxide combines with the calcium oxide and is removed from the system as either bottom ash or fly ash. Due to the relatively low combustion temperatures, CFB stack emissions are relatively low in nitrogen oxides, and the plants produce a dry solid waste that is easy to handle.

12.7.2 Plant Design Relevant to Environmental Concerns

In conducting their technical, cost, and environmental evaluations, Stone & Webster included numerous plant design assumptions. These assumptions are summarized below.

- At the three mine-mouth sites (Beluga, Matanuska, and Healy), it was assumed that the coal mining infrastructure would be in place, including access roads to the mine sites.

- The area of land required for the power plant at each site was assumed to be 50 acres, with an additional 50 acres required at the Nenana site for ash disposal. At the mine-mouth sites, it was assumed that ash would be transported to the mine by truck and disposed of at the mine. Rail transport of the ash from the Nenana site to the mine was rejected due to the high cost of the specialized handling equipment required, and truck transport was rejected due to the concerns associated with a major increase in truck traffic on the Parks Highway.

- Coal would be delivered by truck to the Beluga, Matanuska, and Healy sites. This would require construction of an access road from the mine to the plant site. The access road at Beluga would be approximately 1 mile, at Matanuska 3 miles, and at Healy 0.25 mile.

- The Nenana plant is about 50 miles from the nearest mine. Coal would be delivered by rail to an unloading area, then transported by truck to the plant. A 2-mile railroad spur would have to be constructed along with a 1-mile access road from the rail spur to the mine site.

- All coal handling facilities would include covered conveyors, baghouses, and dust suppression systems to minimize fugitive dust. Methane ventilation would also be provided at hopper locations and at reclaim pits.

- An hydraulic asphalt liner and stormwater collection system would be installed at the coal storage area.

- Limestone would not be used in the circulating beds at the Beluga, Healy, and Nenana plants since the coal that would be used in those facilities is high in CaO. Limestone would be used at Matanuska.

- Each plant would include a mechanical draft cooling tower. The tower design height is about 30 feet.

- Chemicals used on site and chemical cleaning wastes would be transported, handled, stored, and disposed of in accordance with federal and state regulations.

- Process makeup water would be obtained from Ranney wells installed near major rivers. For the Beluga plant, water would be obtained from a well near the Beluga River, and for the Matanuska, Healy, and Nenana plants the water sources would be the Matanuska River, the Nenana River, and Seventeen mile Slough, respectively. The water pipeline would extend over a distance of 11 miles for the Beluga site, 1.25 miles for Matanuska, 0.25 miles for Healy, and 0.5 miles for Nenana. In each case, a service road suitable for use by 4-wheel drive vehicles and an electrical supply line would parallel the buried water pipeline.

- Water for domestic use would be obtained either from wells that would be installed on or near the site or by treating water from the makeup source.

- Process wastewater streams would be treated and recycled to minimize the makeup water requirements and to minimize plant-related discharges.

- Sanitary wastewater would be collected and treated by either a package sewage treatment plant or a septic system with a leach field.
- The tallest structure on the plant site would be a 372-foot stack.
- The two limestone silos at the Matanuska site would be 80 feet high and 24 feet in diameter.
- A limestone dust collection system would be provided at the Matanuska site.
- Each plant would require a new transmission line to tie into the existing distribution lines. The length of transmission line required would be 13 miles for Beluga, 1 mile for Matanuska , 3 miles for Healy, and 6 miles for Nenana.
- The assumed removal rate for sulfur dioxide would be as follows: Beluga 95.1 percent, Matanuska 70 percent, Healy 86.2 percent, and Nenana 86.2 percent.

12.7.3 Comparison of Impacts

Air Quality. To evaluate the effect of plant operation on air quality, Stone & Webster (1988) compared available air quality data to emissions estimates they developed using atmospheric dispersion models. The existing data show that the air quality was generally good and that the measured concentrations of particulates and sulfur dioxide were significantly less than the applicable air quality standards, except for a single particulate measurement at Healy that was close to the standard. This single measurement was obtained at the existing power plant site and may not be representative of the particulate level at the proposed site.

The reported air quality data can only be used as indicators since the data base is limited and is not current. For example, the only available data for the Beluga site were from the Kenai area, and no data were available for the Matanuska area. Although most of these data were obtained between 1973 and 1982, they may be representative of current conditions in the area of collection since development has been limited in the general areas of sampling. To obtain more useful site-specific data, it would be necessary to install and operate meteorological and air quality sampling stations.

Two EPA-approved dispersion models were used to estimate maximum ambient pollutant concentrations of sulfur dioxide, nitrogen dioxide, carbon monoxide, and particulate matter. The input for these models included plant design, emissions estimates, assumed weather variables, and estimates of terrain height increases relative to the elevation of each plant. Thus, the results of modeling provide a useful estimate of whether or not emissions of sulfur dioxide and particulates exceed the maximum allowable degradation limits established by the Alaska Department of Environmental Conservation (ADEC) and EPA. Each site is located in a Class II area, areas in which a moderate amount of growth is permitted, and thus a moderate degradation of existing air quality is permitted.

By combining background data with the estimates of emissions, it is possible to estimate whether or not air quality standards would be violated during operation. Again, this information is representative of likely conditions during operation, and more detailed dispersion modeling using site-specific data would be necessary to more definitively evaluate air quality compliance issues at each of the four sites.

The screening modeling analyses indicate that the maximum air quality impacts at each site for the plant options considered (50, 100, and 150 MW) would be well below the applicable ambient air quality standards for all pollutants. In addition, the estimated emissions at each site for each plant option would be well below the allowable limits of air quality degradation for sulfur dioxide and particulates.

The air quality degradation limits are substantially lower for Class I areas than the limits that apply to Class II areas. The Healy site is about 7 miles from a Class I area, Denali National Park. Although the maximum plant impacts were estimated to occur within about 1.5 miles of the proposed Healy site, and the concentration of sulfur dioxide would likely be below Class I degradation limits before reaching the park boundary, detailed dispersion modeling would be necessary to more accurately evaluate this potential impact.

Further study would also be required to evaluate the potential contribution of the proposed cooling system to ice fog. If the proposed equipment is predicted to adversely affect atmospheric conditions and add to ice fog problems, alternative cooling equipment would be selected.

Overall, the impact of a coal-fired plant on air quality at the sites evaluated is low.

Water Quality. Based on preliminary design concepts, it has been assumed that all plant wastewater streams would be treated and recycled, with no process wastewater discharges. However, there would be plant-related discharges from general plant runoff, the lined coal storage piles, the sanitary landfill, and perhaps from the ash disposal area. Since the concentration limits of contaminants in each of these discharges would be stipulated in permits issued by the EPA, there will be little change in the quality of receiving waters, and the impact of project-related discharges would be negligible to low.

At three of the plants (Beluga, Matanuska, and Healy), fly and bottom ash from the combustion process would be disposed of in the mines, and at Nenana an ash disposal area would be developed. ADEC would review potential impacts and impose design requirements for ash disposal sites. At each site it is possible that precipitation could reach the ash and decrease in pH to a low acidity. This acid water would increase the solubility and mobility of trace elements in the ash, and if the discharge is uncontrolled, receiving waters could be adversely affected. Using available data, it is not possible to determine the type or extent of potential contamination from this source.

Based on the assumption that this potential source of contamination is adequately regulated and that all discharges comply with permit requirements, the potential impact for the near-term is low. However, when considering long-term storage and the potential for accidental release, the impact potential may increase to moderate.

Another water quality issue of concern is runoff from a sanitary landfill associated with plant construction and operation. Assuming that landfill construction is accomplished in compliance with state regulations and that the integrity of the landfill is maintained, the impact of a sanitary landfill on water quality would be low.

There is a potential for an increase in erosion during plant site development, installation of the makeup water pipeline, construction of the transmission line tie-in, and from maintenance of the pipeline and transmission line corridors. However, the use of standard erosion control techniques is expected to minimize these increases. The potential impact on water quality due to increased sediment loads from increases in erosion is expected to be low.

Overall, the impact of a coal-fired power plant on water quality would be of low to moderate magnitude.

Fish and Wildlife. None of the four sites includes critical habitat or any known threatened or endangered species. However, a site-specific survey would be required to further assess habitat value and to determine whether or not threatened or endangered species are present. The loss of habitat at the Beluga, Healy, and Nenana sites would have a negligible to low impact on wildlife since there is an abundance of similar habitat adjacent to each of the sites. The loss of habitat along the water supply pipeline and along the transmission line tie-ins would result in a minor displacement of individuals. In general, this is expected to have a negligible-to-low impact, however, since route alignments have not been proposed and further details on routing would be required to more definitively assess the potential for impacts on critical habitats.

The Matanuska site is in an area extensively used by moose, and development would require adherence to the management objectives of the Matanuska Valley Moose

Range Management Plan (Alaska Department of Natural Resources (ADNR) and ADF&G 1986). Moose populations could be affected by lost habitat, increases in noise, and increases in traffic. Plant development at the Matanuska site would require implementation of mitigative measures designed to provide an acceptable level of revegetation with the appropriate plant species, acquisition or enhancement of other areas to replace the lost habitat, and control of the use of access roads to minimize vehicular collisions with moose. With these or similar mitigation measures incorporated into development, the impact on moose is expected to be of low-to-moderate magnitude.

Installation of the water supply pipelines would have a short-term impact on the fish resources of the streams crossed. However, all crossings would be conducted in compliance with the requirements of the Alaska Department of Fish and Game and the U.S. Army Corps of Engineers, and the permit stipulations for this work would serve to protect the aquatic resources. The overall impact of pipeline installation on aquatic resources is expected to be low.

Since makeup water would be obtained from Ranney wells installed adjacent to the river being used to supply water, and since the amount of water withdrawn would be small in comparison to river flows, it is unlikely that there would be a measurable impact on fish resources. However, further information would be required to determine the timing of low flow conditions and whether or not there is a potential for impacts on aquatic resources due to withdrawals during low flows.

Treated stormwater runoff and other non-wastewater streams are expected to be discharged to a river or stream in the vicinity of the plant at each location. The temperature and concentrations of chemical constituents of these discharges will be in compliance with permit stipulations issued by EPA and ADEC, and the impact of these discharges on aquatic resources is expected to be negligible to low.

Land Use Impacts and Ownership Status. The Beluga site is included in the coal lease obtained from the ADNR by Diamond Alaska Coal Company. ADNR has indicated that this designation could be changed to accommodate long-term use of the site for a power plant and associated facilities. Routes for the water pipeline and transmission line would likely traverse publicly held land as well. Land identified for the Matanuska site is state land under Matanuska-Susitna Borough selection. Much of the likely route of the water pipeline traverses privately held land. The identified site at Healy is on Alaska Railroad lease property. The Nenana site is on land owned by the City of Nenana and currently designated for residential development, a designation that would not permit a power plant. Thus, the proposed uses of three of the four sites appear to be in general compliance with existing land use regulations. At Nenana additional evaluations of the potential for redesignation of the site area would be required to determine compliance. For each of the alternatives, more detailed evaluations of potential routes for access roads, water pipelines, and transmission line tie-ins would be required to evaluate compliance with existing regulations along the routes. However, it is anticipated that the facilities would generally be in compliance and that obtaining rights-of-way or easements would not be a significant issue.

Except for the Nenana site, each of the sites considered is in an area of either active or proposed coal mining. Mining has been proposed for the Beluga area, but current use of the area is typical of undeveloped areas in Alaska, i.e., there is generally a minimum of human use of the area. Project-related development, particularly the installation and maintenance of access roads along the pipeline and transmission line routes, would allow increased use of the area. Thus, there is a potential for a moderate impact on land use in the area.

At the Healy site, the area proposed for power plant development is generally devoted to mining and associated activities, and there would be relatively short routes for the water pipeline and the transmission line tie-in. Thus, the potential for impacts on land use is low.

The Matanuska area is an active coal mining area that also experiences other uses due to the proximity of population centers such as Palmer. The Glenn Highway, which is the primary transportation route in the area, is about 2 miles south of the site, and the general area north of the highway can be reached by several established secondary roads. However, the plant access road and the access roads along the water pipeline and transmission line routes would increase human use of the area. Overall, an impact of low-to-moderate magnitude is expected for the Matanuska site.

Land use in the Nenana site area is typical of that in a remote area that is adjacent to a population center. Route 3, the Parks Highway which is the main north-south route between Anchorage and Fairbanks, is located about 1 mile east of the site, and the Alaska Railroad is about 0.5 mile to the west. The Nenana Municipal Airfield is about 2 miles north, and the residential area of the City of Nenana is located about 3 miles to the north. Although the 6-mile access road along the transmission line route and the 0.5 mile access road along the water pipeline route would increase access to areas to the east and west of the site, the magnitude of the impact on existing land use is expected to be low.

The identified sites and transmission line tie-in routes are in areas where small planes are frequently used. Although the stack is expected to be lighted in accordance with the requirements of the Federal Aviation Administration, most planes used in these areas are not equipped for instrument flying and the stack and transmission lines represent potential safety hazards, particularly during periods of poor visibility.

Portions of the areas identified for location of the power plant and associated facilities may be used for subsistence activities. However, it is not likely that there would be extensive subsistence use of any of the identified sites.

At Beluga, the water pipeline corridor access road and the transmission line tie-in right-of-way may increase access for subsistence users. Although additional investigations would be necessary to definitively evaluate the potential impact of a coal plant on the subsistence activities in a specific area, the magnitude of any such impact is expected to be low.

Terrestrial Impacts (Vegetation and Wetlands). Construction and operation of a power plant would affect the vegetation and wetlands at the plant site, along access roads, and along pipeline and transmission line tie-in corridors. The vegetation at each of the four potential power plant locations is generally typical of the surrounding area, there are no known critical habitats, and there are no known occurrences of threatened or endangered plant species. However, wetlands are a concern, particularly at the Beluga and Nenana sites and along the water pipeline corridor for the Matanuska site. In addition, the Matanuska site and the associated disturbed areas are within or near an important moose range.

In spite of these concerns, the potential for adverse impacts to vegetation and wetlands is low since project development would require extensive mitigation that would offset most of the impacts. For example, we have assumed that to obtain agency approval of a permit application to fill or remove wetlands, APA would be required to comply with a "no net loss" policy of wetland protection. Thus, use of wetland areas for project-related facilities would require mitigation measures such as establishing new wetlands or enhancing the value of existing wetland areas to match the value of lost wetlands. Similarly, for plant development in the Matanuska area, mitigation measures would be included to ensure compliance with the Matanuska Valley Moose Range Management Plan and could include measures such as revegetation with browse species where appropriate and maintenance procedures that discourage invasion by browse species in other locations to minimize the potential for vehicle-moose collisions.

Recreational Resources. Recreational uses in the general area of each of the identified sites consists primarily of fishing and hunting (including moose, and in the Healy area, Dall sheep and caribou). In the more populated areas of Matanuska, Healy, and Nenana, other recreational activities may include hiking, cross country skiing, snowshoeing,and other snow-related activities. All-terrain vehicles are popular for recreational use on the secondary roads in the vicinity of the Matanuska site.

Since power plant development would not affect critical habitats or important hunting areas, there would be no measurable adverse impact on hunting. The maintenance of service roads and transmission line rights-of-way would increase human and big-game animal access and big-game browse habitat.

Assuming that ADF&G would restrict stream crossings during times when anadramous fish are migrating or spawning, it is unlikely that there would be a measurable impact on fishing.

The access roads and rights-of-way maintenance would likely increase the availability of areas usable for snow-related activities. Similarly, these maintained corridors would provide additional access for hikers and all-terrain vehicles to areas that are presently difficult to enter.

Overall, coal plant development at any of the identified sites would have a low level of impact on recreation.

Visual Impact. The physical features of concern to visual impacts include the power plant buildings, particularly the 372-foot stack, the transmission line tie-in, and the plant, pipeline, and transmission line roadways. In addition, emissions from the stack and the cooling tower may also affect views.

At the Beluga site, the plant would be observable from some viewpoints ranging southward from the northeast to southwest due to the relatively high elevation of the site compared to the surrounding land. However, it is unlikely that the plant would be observable from beyond the near vicinity of the site due to the presence of small hills and the generally rolling terrain that would minimize views of the plant from a distance. At some nearby locations, much of the plant may be observed against the skyline, and the plant would be the only major structure observable. Due to the relatively remote location of the site, few individuals are expected to be affected by these views. Both the transmission line and water pipeline routes would require forest clearing and would alter the visual environment, but again, it is unlikely that these changes would affect many individuals. Thus, the magnitude of the visual impact for the Beluga site would be low.

In the general area of the Matanuska site, there are numerous secondary roads, several settlements, and inactive coal development areas. The plant and associated facilities would be observable from many of these secondary roads. It is likely that the plant would be screened from travelers on the Glenn Highway since there is relatively steep terrain on the north side of the roadway that effectively blocks views to the north. A more detailed study would be necessary to determine whether or not the stack and plume would be visible from portions of the highway. Additional access roads through the area and the transmission lines would also alter some views. Although additional study is needed to more definitively assess the potential visual impacts of power plant development in this area, the magnitude of the impact is expected to be moderate.

The selected Healy site is in a generally flat area just east of the Nenana River and adjacent to an existing landing strip. The plant and plumes from the stack and cooling tower would likely be observable from Route 3, the roadway between Anchorage and Fairbanks, from the Alaska Railroad, from the mine access road, from portions of the Nenana River, and from some residences in the area. Transmission line structures along the 3-mile tie-in route would also alter views from nearby locations. Views in this general area include facilities associated with human activity, including the railroad, roadways, transmission lines, landing strips, and facilities and equipment involved in mining. However, the power plant would be of a greater scale than the other structures and facilities in the area and represents a low to moderate impact.

The Healy site is within about 7 miles of the nearest border of Denali National Park. Visitors to the park or those leaving the park may use the Route 3 past Healy. The plant is not likely to be visible from the main park roadway that extends from Route 3 westward since the terrain between the roadway and the plant would block essentially all views to the east. It is possible that the plant and plumes from the facility would be observable from some high points within the park, although extensive hiking and climbing would be necessary to reach these types of vistas.

Further study would be required to definitively assess the impact, but based on current information the visual impact of a plant at Healy is expected to be low to moderate in magnitude.

Due to the flat topography in the vicinity of the Nenana site, the plant and associated facilities would be readily observable from many locations, including Route 3, the Nenana River, Seventeenmile Slough, the railroad, the airport, and some residences. The stack and the plume may be observable from the main portion of the city as well. Although the general Nenana area is a relatively high use area and includes facilities and structures associated with human activities, the power plant would be of a greater scale than the other structures and facilities in the area. Further analysis would be needed to more definitively evaluate the visual impact, however, the magnitude of this impact is expected to be moderate.

12.8 ELECTRIC END-USER CONSERVATION PROGRAMS

This section reviews the environmental impacts of the alternative of reducing electrical consumption through conservation programs. The programs are aimed at increasing the efficiencies of electrical appliances and/or fixtures or conversion to gas appliances.

Nine programs were evaluated by the Institute of Social and Economic Research, with 5 aimed at residential users and 4 identified for commercial or industrial users. The commercial lighting programs generate nearly 60 percent of the expected energy savings from all 9 programs and are all based on a cash rebate for the use of energy efficient equipment. The 5 residential programs also are based on cash rebates, and include converting to gas-fueled appliances or improving the efficiencies of electrical appliances. The programs do not provide for an intensive retrofit program, but instead rely on relacing equipment as it wears out, or installing efficient equipment initially. The programs would have to be in effect for 10 to 20 years to have the potential to affect the entire appliance stock.

When considered as an isolated program, this alternative would result in a net decrease in electricity demand in the region and would therefore reduce the amount of power generation required. Because of the long timer period over which the net reduction in electricity consumption would take place, It is unlikely that there would be any measurable environmental changes to any of the environmental indicators considered. This alternative would slightly increase the use of natural gas as an energy source for appliances and may require an increase in gas line installations. However, the environmental impacts associated with installation would be short-term, minor, and limited to the local community. The additional use of gas-fueled appliances is not expected to have a measurable impact on air quality. The overall impact of the increase in natural gas usage would have a negligible impact on the environmental indicators.

12.9 REFERENCES

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Section 13

SUMMARY AND CONCLUSIONS

13.1 OVERVIEW

This section provides a summary of the overall cost-benefit results for each of the alternatives analyzed in this study. The costs and benefits that have been estimated in the previous sections are aggregated and compared.[1] In accordance with the practice followed throughout this analysis, all costs and benefits are expressed in terms of 1987 dollars.

The expected value of net benefits for each of the eight alternatives is shown in Figure 13-1. Positive net benefits are estimated for the limited upgrade of the Anchorage-Fairbanks intertie (AF100), the gas pipeline from Cook Inlet to Fairbanks (GAS), and the two groups of end-use conservation programs (END3 and END8). Net economic loss is indicated for each of the other alternatives, including the new Kenai-Anchorage line (KA), the full upgrade of the Anchorage-Fairbanks intertie (AF), the Northeast intertie (NE), and the 50-MW coal-fired power plant at Healy (COAL).

Figure 13-2 shows the expected value of costs and benefits for each of the alternatives. The costs of the capital projects include both capital costs and the present value of associated operations and maintenance costs. The difference between the estimates of cost and benefit is the estimate of net benefits.

Figure 13-3 presents this information in the form of benefit/cost ratios. The AF100 alternative, which has the lowest total cost, is estimated to provide the highest benefit per dollar expended.

[1]Attributes that have not been quantified in the previous sections, such as environmental costs and benefits, are not reflected in these summaries. Further, utility representatives have suggested there may be other less tangible benefits created by the interties such as enhanced competition among fuel suppliers and enhanced siting flexibility.

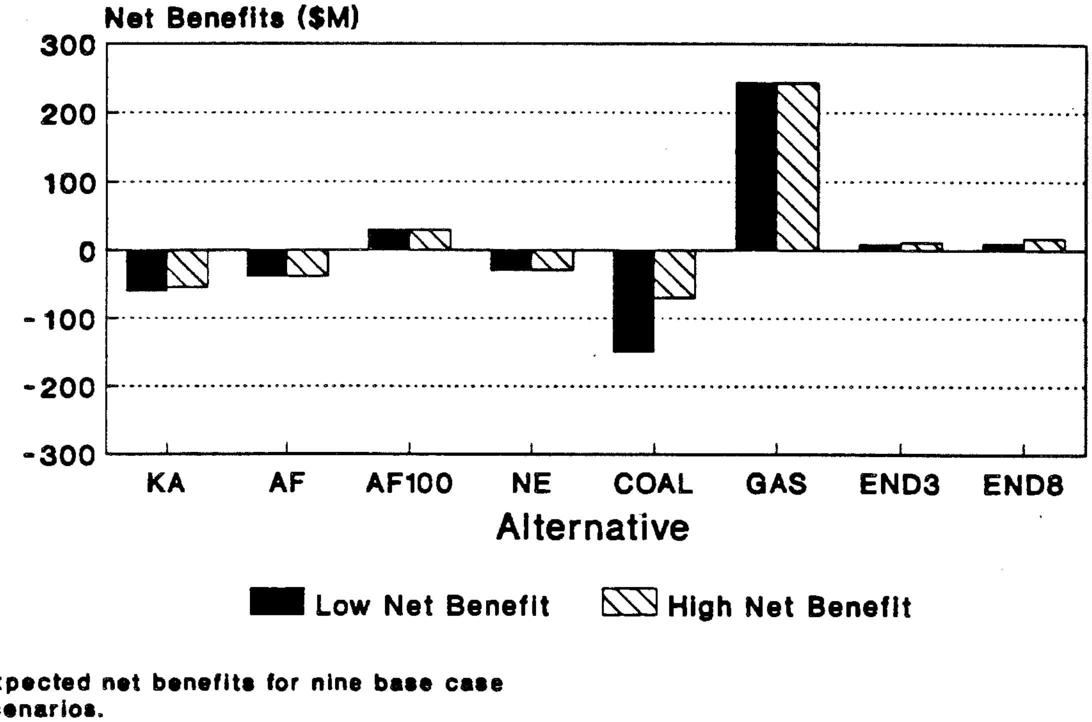


Figure 13-1. Railbelt Alternatives: Net Benefits

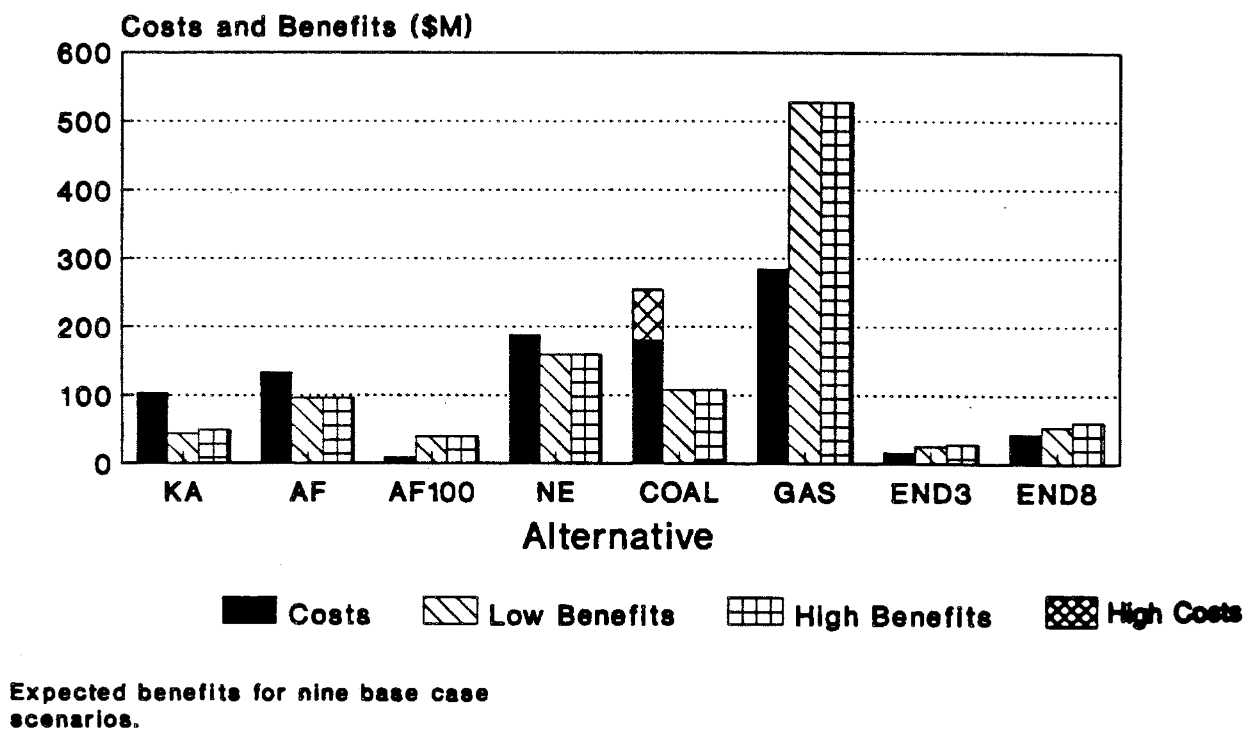
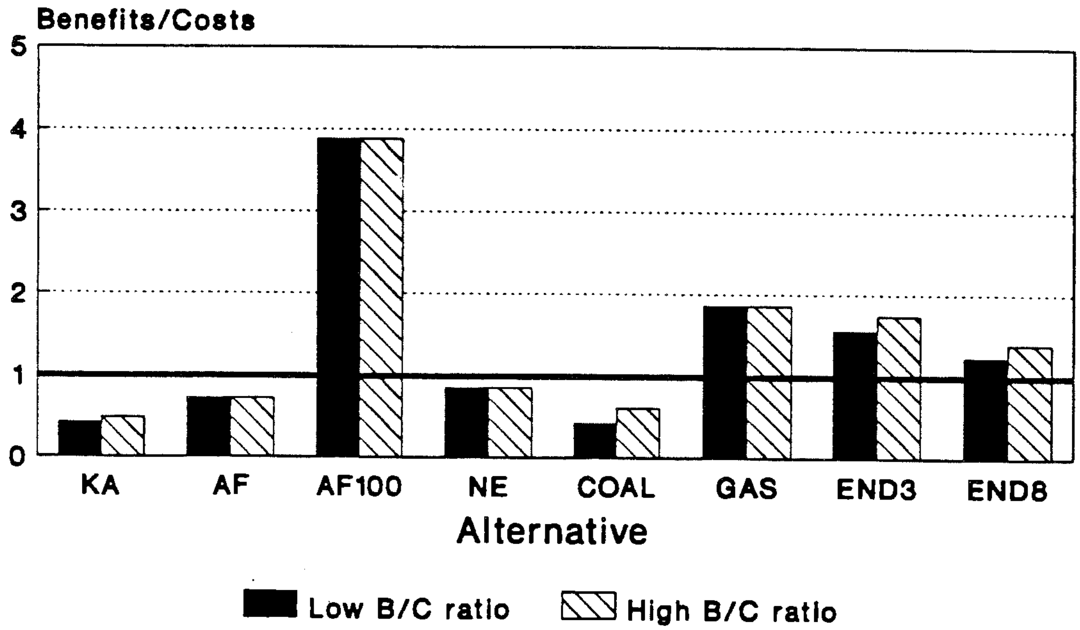


Figure 13-2. Railbelt Alternatives: Cost and Benefits



Based on expected net benefits for nine base case scenarios.

Figure 13-3. Railbelt Alternatives: Benefit/Cost Ratios

13.2 NEW KENAI-ANCHORAGE INTERTIE

Table 13-1 shows the present value of costs and benefits for the new Kenai-Anchorage line in each of the categories identified in this analysis. The expected value of net economic loss (i.e., negative net benefits) is between $54.02 million and $60.02 million. The difference between the low and high estimates of benefit reflects only the difference between the high and low reliability benefit. The estimate of total costs is comprised of the capital cost estimate for the "Enstar" route discussed in Section 2 plus the present value of operations and maintenance cost over the analysis period. If the "Tesoro" route were ultimately selected, the capital cost would be $17.7 million higher.

Figure 13-4 displays net benefits for each scenario. Figure 13-5 shows the relative contribution of each benefit category to the total expected benefits.

Table 13-1

NEW KENAI-ANCHORAGE INTERTIE: SUMMARY OF COSTS AND BENEFITS

	Prob	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Capacity Sharing Benefits	Increased Spinning Reserves Sharing	Total Benefits Low	Total Benefits High	Total Costs	Net Benefits Low	Net Benefits High
LL	0.30	8.2	5.2	15.23	0.61	43.23	49.23	103.10	-59.87	-53.87
LM	0.23	7.3	7.5	9.54	0.61	38.94	44.94	103.10	-64.16	-58.16
LH	0.06	7.1	8.8	7.68	0.61	38.08	44.08	103.10	-65.02	-59.02
ML	0.03	11.2	7.1	15.23	0.84	48.33	54.33	103.10	-54.77	-48.77
MM	0.08	10.1	10.1	9.54	0.84	44.44	50.44	103.10	-58.66	-52.66
MH	0.19	10.0	12.0	7.68	0.84	44.48	50.48	103.10	-58.62	-52.62
HL	0.00	14.0	8.9	15.23	1.06	53.23	59.23	103.10	-49.87	-43.87
HM	0.02	12.4	12.5	9.54	1.06	49.54	55.54	103.10	-53.56	-47.56
HH	0.08	12.7	14.9	7.68	1.06	50.28	56.28	103.10	-52.82	-46.82
Exp Val		8.9	8.6	10.71	0.72	43.08	49.08	103.10	-60.02	-54.02
UL	0.60	6.9	8.1	5.35	0.61	34.95	40.95	103.10	-68.15	-62.15
UM	0.30	9.7	10.9	5.35	0.84	40.75	46.75	103.10	-62.35	-56.35
UH	0.10	12.1	13.5	5.35	1.06	46.05	52.05	103.10	-57.05	-51.05
Exp Val		8.2	9.5	5.35	0.72	37.80	43.80	103.10	-65.30	-59.30
DOR		7.1	7.6	7.68	0.61	36.98	42.98	103.10	-66.12	-60.12
NM		7.1	8.7	7.68	0.61	38.08	44.08	103.10	-65.02	-59.02
DH		7.6	11.1	7.68	0.61	40.98	46.98	103.10	-62.12	-56.12
WH		7.5	7.3	7.68	0.61	37.08	43.08	103.10	-66.02	-60.02
GE		7.3	10.7	7.68	0.61	40.18	46.18	103.10	-62.92	-56.92

Notes:

1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include:

Benefit	Low	High
Reliability benefits	11.20	17.20
Stability benefits	2.77	2.77

3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.

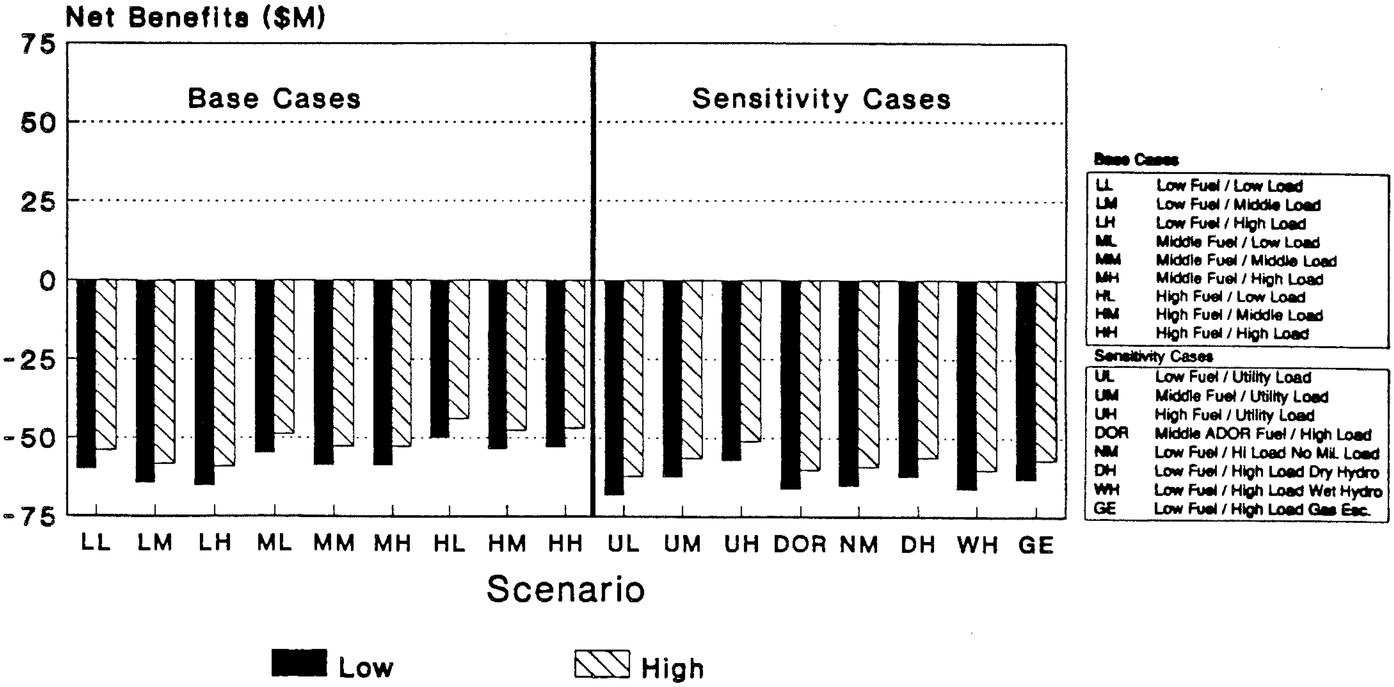
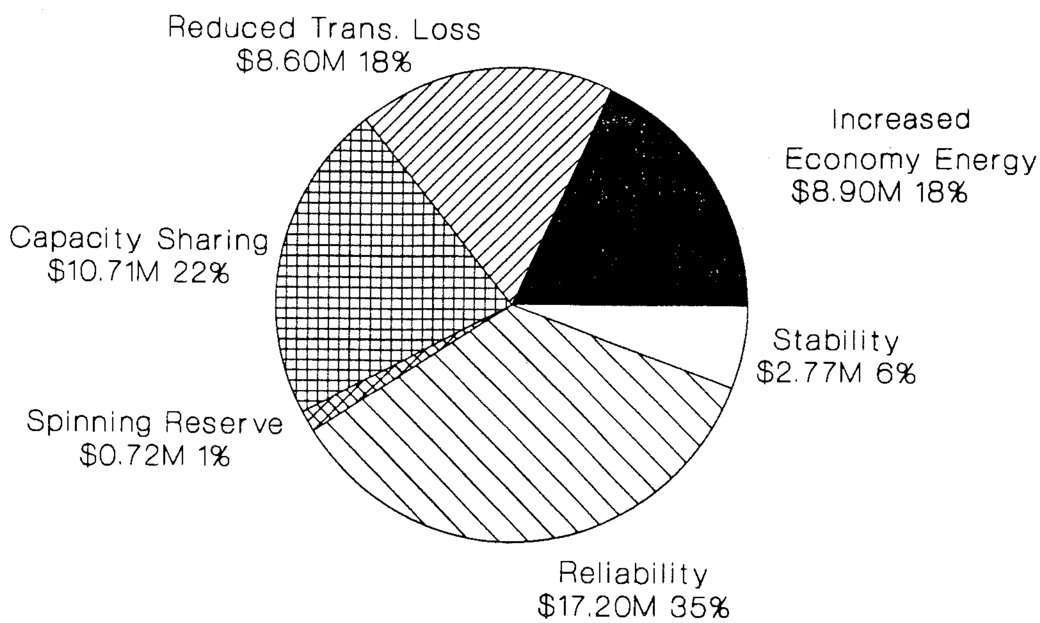


Figure 13-4. New Kenai-Anchorage Intertie: Net Benefits



Only high reliability
benefits are shown.

Figure 13-5. New Kenai-Anchorage Intertie: Breakdown of Expected Benefits

13.3 FULL UPGRADE OF ANCHORAGE-FAIRBANKS INTERTIE TO 225 MW

Table 13-2 shows the present value of costs and benefits for the full Anchorage-Fairbanks upgrade to 225 MW. The expected value of net economic loss (i.e., negative net benefits) is $37.98 million. As discussed in Section 5, the benefits are sensitive to the load forecast in the Fairbanks area. Positive net benefits are estimated when the utility load forecast[2] is combined with either the middle or the high fuel price scenario.

Figure 13-6 displays the net benefits estimated for each scenario. Figure 13-7 shows the relative contribution of each benefit category to the total expected benefits.

Table 13-2

ANCHORAGE-FAIRBANKS FULL UPGRADE: SUMMARY OF COSTS AND BENEFITS

	Prob	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits
LL	0.30	83.2	2.7	1.28	88.58	133.90	-45.32
LM	0.23	83.8	3.4	1.68	90.28	133.90	-43.62
LH	0.06	92.9	5.2	0.40	99.90	133.90	-34.00
ML	0.03	46.1	12.7	1.28	61.48	133.90	-72.42
MM	0.08	62.2	11.7	1.68	76.88	133.90	-57.02
MH	0.19	99.7	10.3	0.40	111.90	133.90	-22.00
HL	0.00	55.0	14.7	1.28	72.38	133.90	-61.52
HM	0.02	74.8	12.8	1.68	90.68	133.90	-43.22
HH	0.08	119.7	10.8	0.40	132.40	133.90	-1.50
Exp Val		87.1	6.3	1.11	95.92	133.90	-37.98
UL	0.60	104.0	5.8	0.00	111.20	133.90	-22.70
UM	0.30	134.1	8.8	0.00	144.30	133.90	10.40
UH	0.10	158.7	11.0	0.00	171.00	133.90	37.10
Exp Val		118.5	7.2	0.00	127.11	133.90	-6.79
DOR		93.6	3.8	0.40	99.20	133.90	-34.70
NM		86.3	4.8	0.40	92.90	133.90	-41.00
DH		91.3	5.6	0.40	98.70	133.90	-35.20
WH		94.4	4.6	0.40	100.80	133.90	-33.10
GE		83.3	4.5	0.40	89.60	133.90	-44.30

Notes:

1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of $1.40 million.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

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[2]The utility load forecast includes the highest load forecast for Fairbanks that is considered in this study (refer to Appendix C).

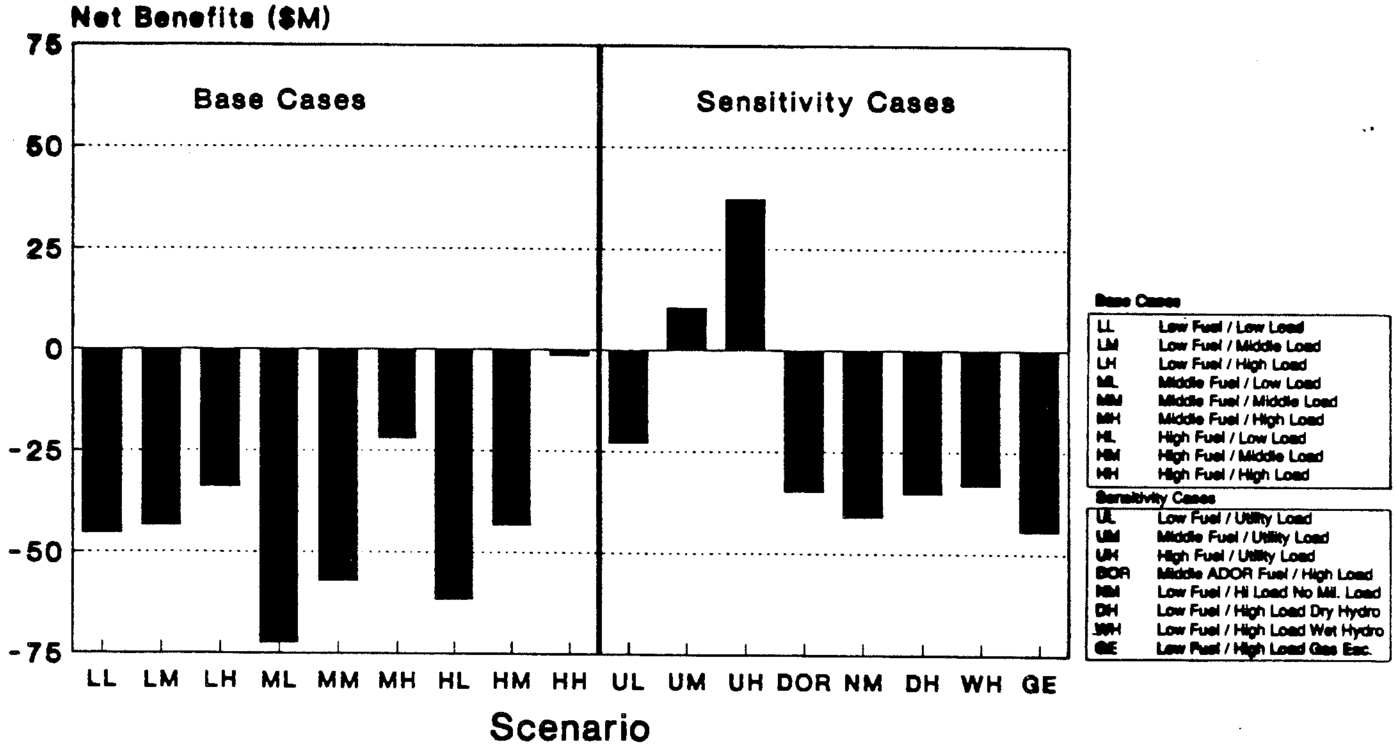
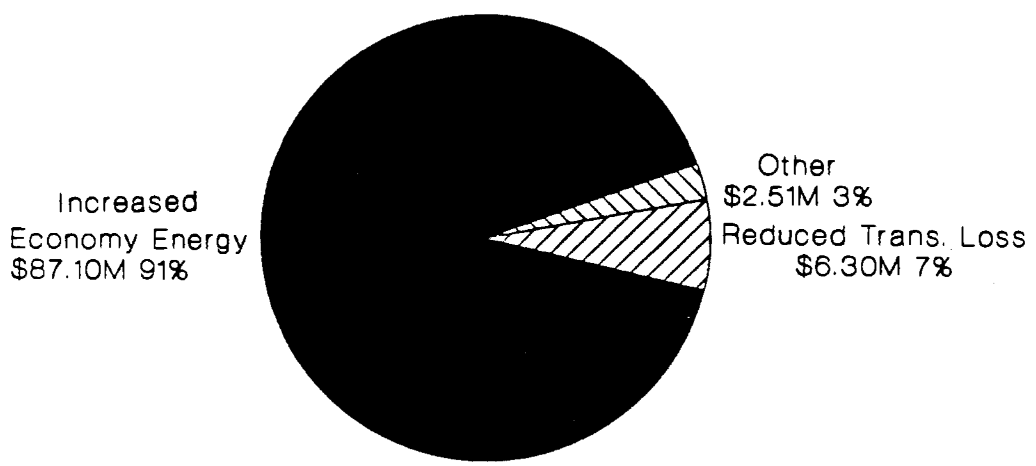


Figure 13-6. Anchorage-Fairbanks Full Upgrade: Net Benefits



Other benefits include:
Capacity Sharing $1.11M
Reliability $1.4M

Figure 13-7. Anchorage-Fairbanks Full Upgrade: Breakdown of Expected Benefits

13.4 LIMITED UPGRADE OF THE ANCHORAGE-FAIRBANKS INTERTIE TO 100 MW

Table 13-3 shows the present value of costs and benefits for the limited Anchorage-Fairbanks upgrade to 100 MW. Positive benefits are indicated for each scenario examined. The expected value of net economic benefit is $29.63 million.

Figure 13-8 displays the net benefits estimated for each scenario. Figure 13-9 shows the relative contribution of each benefit category to the total expected benefits.

Table 13-3

ANCHORAGE-FAIRBANKS UPGRADE TO 100 MW: SUMMARY OF COSTS AND BENEFITS

	Prob	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits
LL	0.30	44.2	-3.6	1.28	41.88	10.26	31.62
LM	0.23	40.6	-5.5	1.68	36.78	10.26	26.52
LH	0.06	33.4	-11.5	0.40	22.40	10.26	12.14
ML	0.03	25.6	-2.8	1.28	23.98	10.26	13.72
MM	0.08	32.8	-3.7	1.68	30.78	10.26	20.52
MH	0.19	53.1	-8.0	0.40	45.50	10.26	35.24
HL	0.00	29.3	-1.0	1.28	29.58	10.26	19.32
HM	0.02	39.0	-2.4	1.68	38.38	10.26	28.12
HH	0.08	63.1	-6.2	0.40	57.30	10.26	47.04
Exp Val		44.3	-5.5	1.11	39.89	10.26	29.63
UL	0.60	41.0	-17.0	0.00	24.10	10.26	13.84
UM	0.30	53.9	-15.8	0.00	38.10	10.26	27.84
UH	0.10	62.0	-15.6	0.00	46.30	10.26	36.04
Exp Val		47.0	-16.5	0.00	30.52	10.26	20.26
DOR		32.2	-11.8	0.40	20.90	10.26	10.64
NM		36.2	-8.4	0.40	28.20	10.26	17.94
DH		32.8	-11.6	0.40	21.70	10.26	11.44
WH		33.5	-11.5	0.40	22.50	10.26	12.24
GE		26.1	-9.1	0.40	17.50	10.26	7.24

Notes:

1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include:

Benefit	
Reliability benefits	0.00
Stability benefits	0.00

3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

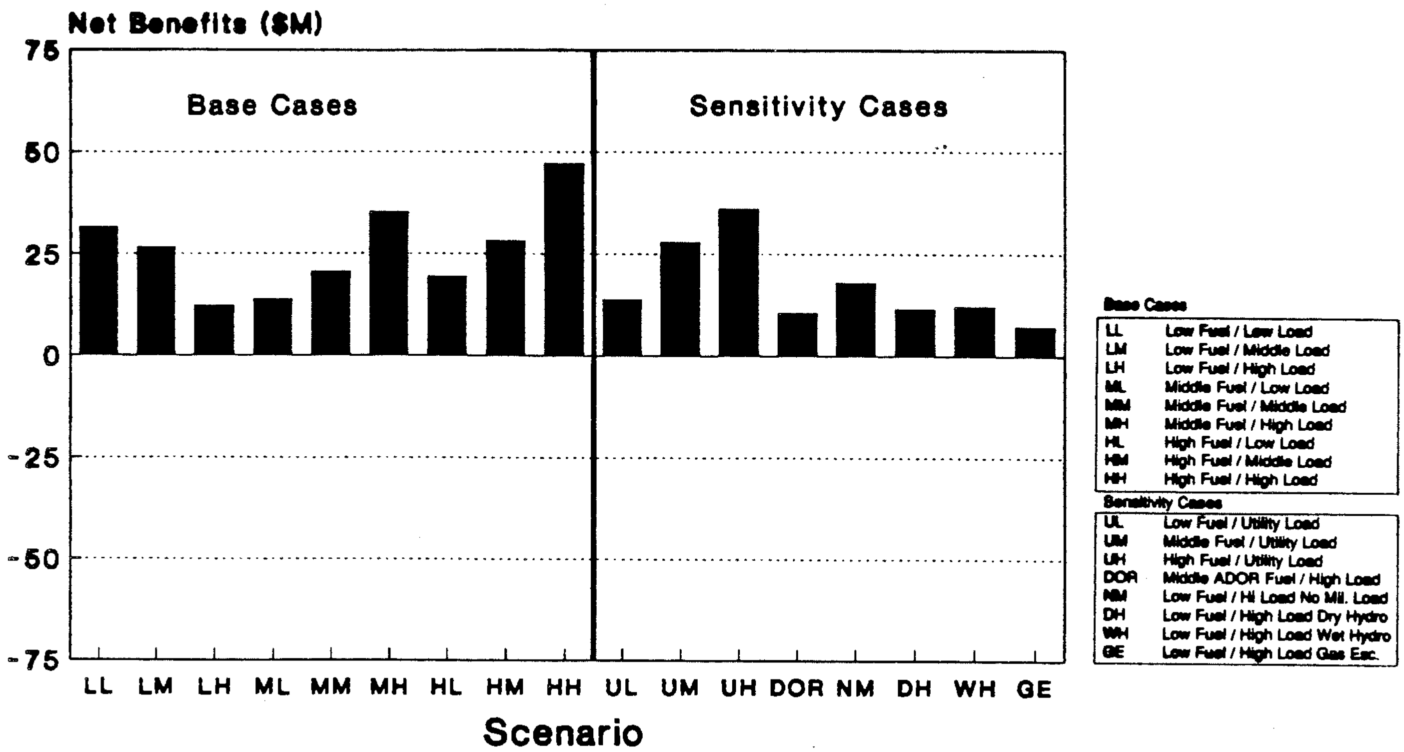
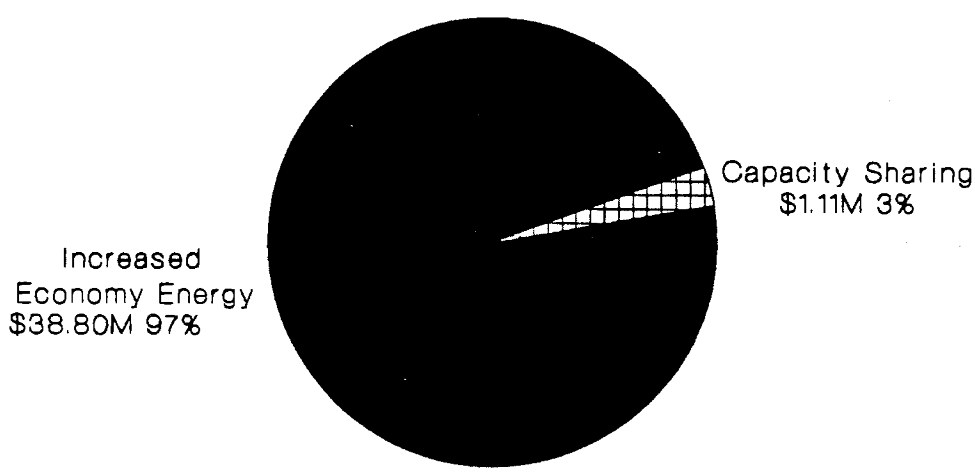


Figure 13-8. Anchorage-Fairbanks Upgrade to 100 MW: Net Benefits



Economy energy benefits include $5.5M
of increased transmission losses.

Figure 13-9. Anchorage-Fairbanks Upgrade to 100 MW: Breakdown of Expected Benefits

13.5 NORTHEAST INTERTIE

Table 13-4 shows the present value of costs and benefits for the Northeast intertie. The expected value of economic loss (i.e., negative net benefit) is $28.79 million. As in the case of the full Anchorage-Fairbanks upgrade proposal, the combination of high load forecasts and high fuel prices is needed to produce an estimate of positive economic benefit.

Figure 13-10 displays the net benefits estimated for each scenario. Figure 13-11 shows the relative contribution of each benefit category to the total expected benefits.

Table 13-4

ANCHORAGE-FAIRBANKS NORTHEAST INTERTIE: SUMMARY OF COSTS AND BENEFITS

	Prob	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits
LL	0.30	152.0	-6.0	1.28	157.58	188.10	-30.52
LM	0.23	134.4	-5.6	1.68	140.78	188.10	-47.32
LH	0.06	154.1	-4.4	0.40	160.40	188.10	-27.70
ML	0.03	121.5	3.2	1.28	136.18	188.10	-51.92
MM	0.08	119.5	1.6	1.68	132.98	188.10	-55.12
MH	0.19	169.7	-1.3	0.40	179.10	188.10	-9.00
HL	0.00	138.5	2.9	1.28	152.98	188.10	-35.12
HM	0.02	140.2	0.9	1.68	153.08	188.10	-35.02
HH	0.08	200.2	-2.5	0.40	208.50	188.10	20.40
Exp Val		151.5	-3.6	1.11	159.31	188.10	-28.79
UL	0.60	158.0	-3.9	0.00	164.40	188.10	-23.70
UM	0.30	195.9	-3.9	0.00	202.20	188.10	14.10
UH	0.10	217.8	-4.2	0.00	224.00	188.10	35.90
Exp Val		175.3	-3.9	0.00	181.70	188.10	-6.40
DOR		151.3	-4.0	0.40	158.10	188.10	-30.00
NM		146.3	-4.3	0.40	152.70	188.10	-35.40
DH		174.0	-4.0	0.40	180.70	188.10	-7.40
WH		161.0	-4.8	0.40	167.00	188.10	-21.10
GE		219.7	-5.2	0.40	225.20	188.10	37.10

Notes:

1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of $10.30 million.
3. Increased economy energy transfer is based on: Railbelt average variable O&M of ICEs (6.05 $/MWh)
4. Total costs include capital costs and O&M costs.
5. Net Benefits = Total Benefits - Total Costs.
6. Table includes North Pole adjustment.

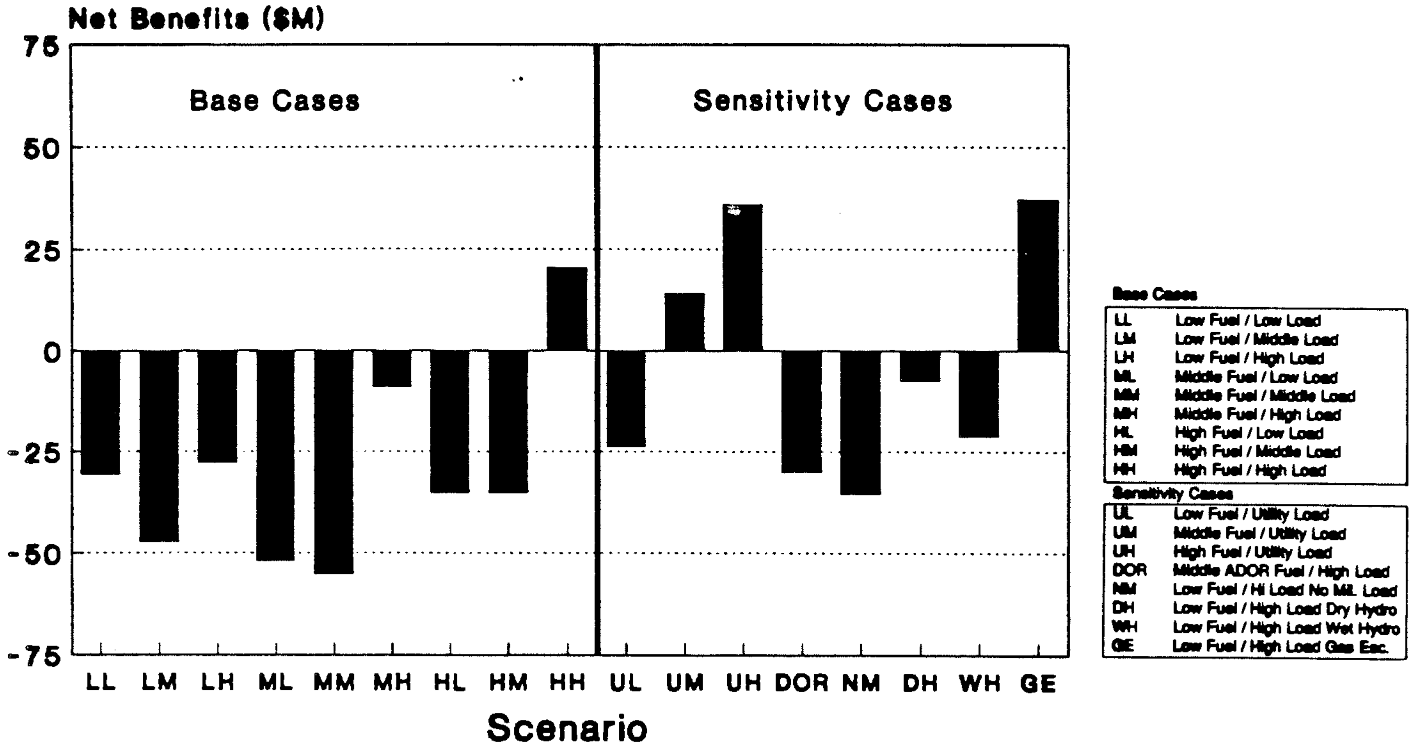
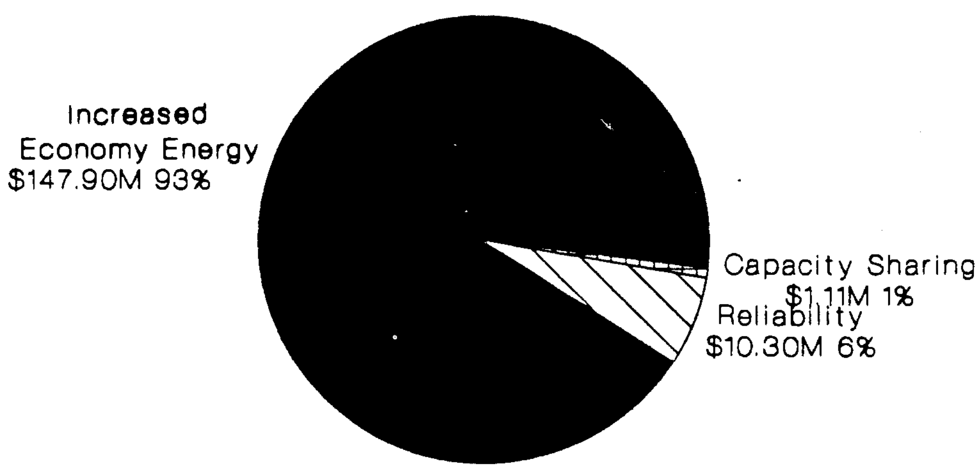


Figure 13-10. Northeast Intertie: Net Benefits



Economy energy benefits include $3.6M
of increased transmission losses.

Figure 13-11. Northeast Intertie: Breakdown of Expected Benefits

13.6 50-MW COAL-FIRED POWER PLANT AT HEALY

Table 13-5 shows the present value of costs and benefits for the 50-MW coal-fired power plant at Healy. The expected value of economic loss (i.e., negative net benefit) is between $69.72 million and $149.42 million. The difference between the low and high benefit estimates is due entirely to the capital cost estimate of the power plant. These results were based on the economics of a single-purpose power plant as discussed in Section 8. The plant economics would improve if the value of cogenerated steam to a steam purchaser (such as the operator of a coal drying facility) exceeded the incremental cost of producing the additional steam. The possibility of federal subsidy has been raised in conjunction with the proposed coal plant. This analysis has not considered such a subsidy. If there were a subsidy, it could make a substantial difference in the price of power to potential power purchasers.

Figure 13-12 displays the net benefits estimated for each scenario. Figure 13-13 shows the relative contribution of each benefit category to the total expected benefits.

Table 13-5

50-MW COAL-FIRED POWER PLANT AT HEALY: SUMMARY OF COSTS AND BENEFITS

	Prob	Reduced Energy Costs	Reduced Trans. Losses	Capacity Benefits	Total Benefits	Total Costs Low	Total Costs High	Net Benefits Low	Net Benefits High
LL	0.30	43.9	3.1	36.15	83.15	177.40	257.10	-173.95	-94.25
LM	0.23	46.4	3.3	36.15	85.85	177.40	257.10	-171.25	-91.55
LH	0.06	53.9	4.4	36.15	94.45	177.40	257.10	-162.65	-82.95
ML	0.03	75.4	5.1	36.15	116.65	177.40	257.10	-140.45	-60.75
MM	0.08	86.3	5.3	36.15	127.65	177.40	257.10	-129.45	-49.75
MH	0.19	90.5	5.7	36.15	132.35	177.40	257.10	-124.75	-45.05
HL	0.00	115.0	6.1	36.15	157.25	177.40	257.10	-99.85	-20.15
HM	0.02	129.1	6.0	36.15	171.15	177.40	257.10	-85.95	-6.25
HH	0.08	134.8	6.1	36.15	177.05	177.40	257.10	-80.05	-0.35
Exp Val		67.3	4.3	36.15	107.68	177.40	257.10	-149.42	-69.72
UL	0.60	52.7	5.3	36.15	94.15	177.40	257.10	-162.95	-83.25
UM	0.30	96.3	6.6	36.15	138.95	177.40	257.10	-118.15	-38.45
UH	0.10	142.3	7.5	36.15	185.85	177.40	257.10	-71.25	8.45
Exp Val		74.7	5.9	36.15	116.76	177.40	257.10	-140.34	-60.64
DOR		30.9	4.2	36.15	71.15	177.40	257.10	-185.95	-106.25
NM		53.1	4.0	36.15	93.15	177.40	257.10	-163.95	-84.25
DH		54.8	4.5	36.15	95.45	177.40	257.10	-161.65	-81.95
WH		51.1	4.4	36.15	91.65	177.40	257.10	-165.45	-85.75
GE		87.6	3.7	36.15	127.45	177.40	257.10	-129.65	-49.95

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total costs include:

Cost	Low	High
Capital ($/KW)	1600.00	3194.00
Fixed O&M ($M/yr)	5.58	5.58

3. Capacity benefits are based on $47/kW-yr (including Fixed O&M).
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

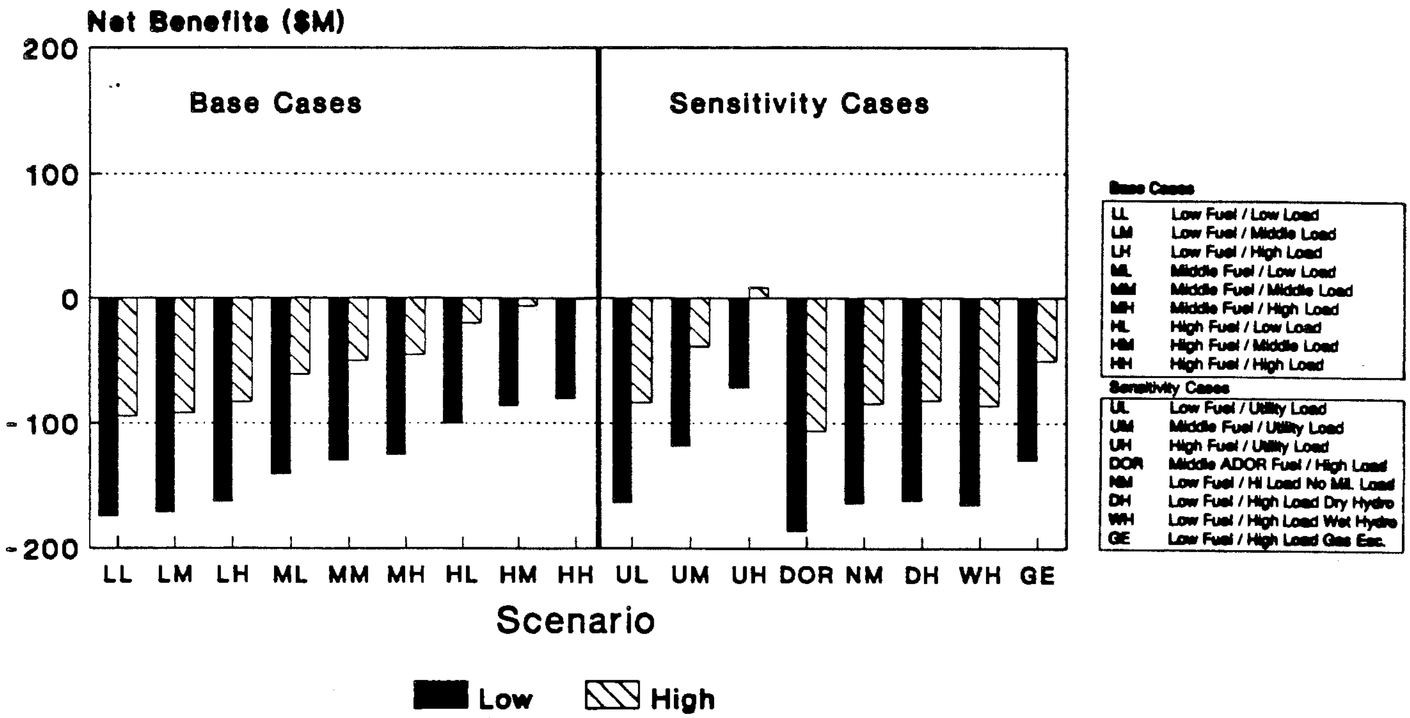


Figure 13-12. 50-MW Coal-Fired Power Plant at Healy: Net Benefits

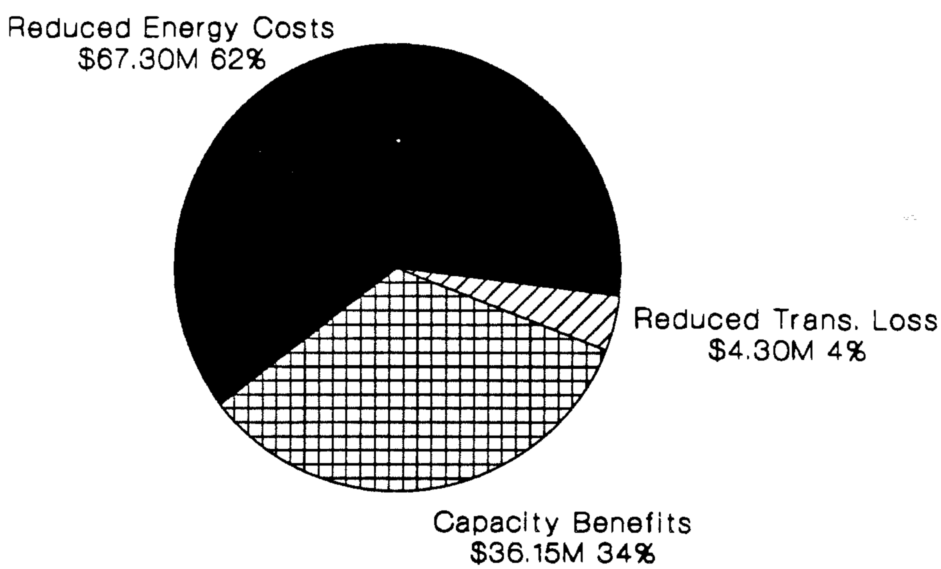


Figure 13-13. 50-MW Coal-Fired Power Plant at Healy: Breakdown of Expected Benefits

13.7 COOK INLET-FAIRBANKS GAS PIPELINE

Table 13-6 shows the present value of costs and benefits estimated for the gas pipeline from Cook Inlet to Fairbanks. The expected value of economic benefit is $243 million. Positive benefits are estimated for every scenario. Nearly 80 percent of the estimated benefits accrue outside the electric power sector, i.e., primarily in the residential and commercial heating sectors in the Fairbanks area.

Figure 13-14 displays the net benefits estimated for each scenario. Figures 13-15 and 13-16 show the allocation of benefits between the power and non-power sectors.

Table 13-6

COOK INLET-FAIRBANKS GAS PIPELINE: SUMMARY OF COSTS AND BENEFITS

	Prob	Reduced Energy Costs	Reduced Trans. Losses	Outside Elec Power Sector Benefits	Total Benefits	Total Costs	Net Benefits
LL	0.30	80.9	15.0	414.0	515.8	284.1	231.7
LM	0.23	93.6	17.7	426.0	543.1	284.1	259.0
LH	0.06	105.0	20.4	462.0	593.1	284.1	309.1
ML	0.03	53.1	14.9	334.0	407.8	284.1	123.7
MM	0.08	72.2	16.6	349.0	443.6	284.1	159.5
MH	0.19	116.7	21.0	389.0	532.5	284.1	248.4
HL	0.00	62.6	15.8	371.0	455.2	284.1	171.1
HM	0.02	85.6	17.1	388.0	496.5	284.1	212.5
HH	0.08	137.9	21.6	432.0	597.3	284.1	313.2
Exp Val		95.3	17.8	408.4	527.3	284.1	243.3
UL	0.60	123.0	21.8	462.0	612.6	284.1	328.5
UM	0.30	155.2	24.6	389.0	574.6	284.1	290.6
UH	0.10	180.6	27.0	432.0	645.4	284.1	361.3
Exp Val		138.4	23.2	437.1	604.5	284.1	320.4
DOR		110.0	19.3	462.0	597.1	284.1	313.0
NM		97.4	19.4	462.0	584.6	284.1	300.5
DH		107.4	20.6	462.0	595.8	284.1	311.7
WH		103.1	20.0	462.0	590.9	284.1	306.8
GE		90.3	16.2	351.0	463.3	284.1	179.2

Notes:
1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of $5.80 million.
3. Total costs include capital costs, O&M costs and the following costs/benefits: Conversion costs of FMUS Chena 5 = $950,000, conversion costs of North Pole = $1350,000, and reduced O&M costs for FMUS = $595,000
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.
6. Benefits outside the electric power sector for the DOR Fuel, NoMiltry, DryHydro, and WetHydro sensitivity cases are estimated based on the Low Fuel/High Load scenario.

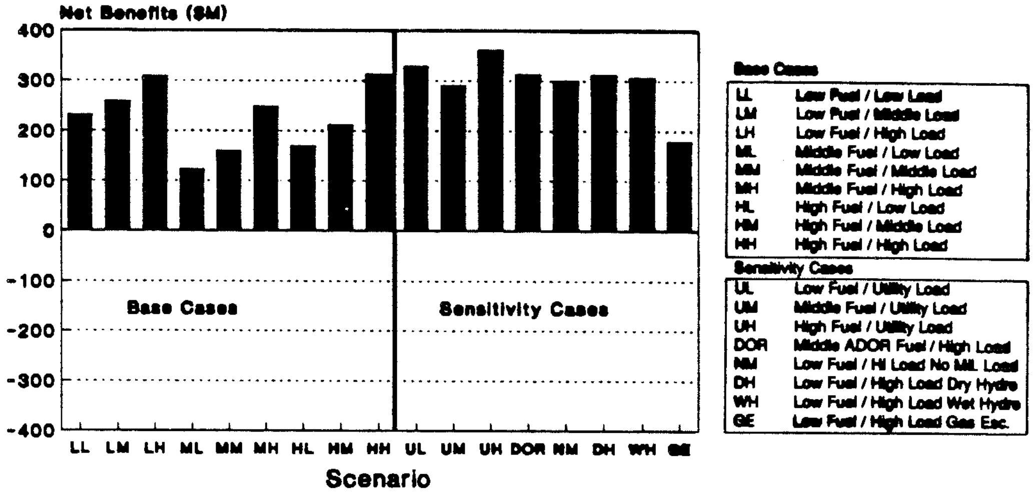


Figure 13-14. Gas Pipeline: Net Benefits

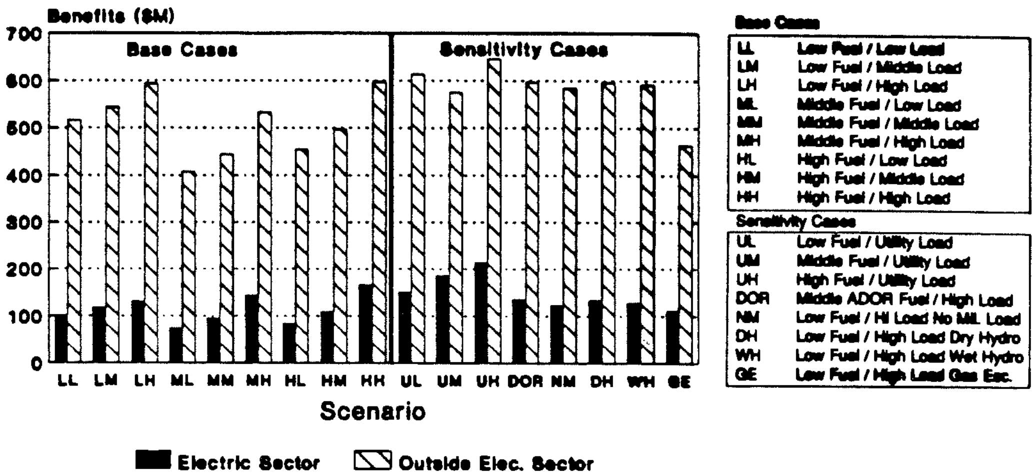


Figure 13-15. Gas Pipeline: Benefits Within Versus Outside the Electric Power Sector

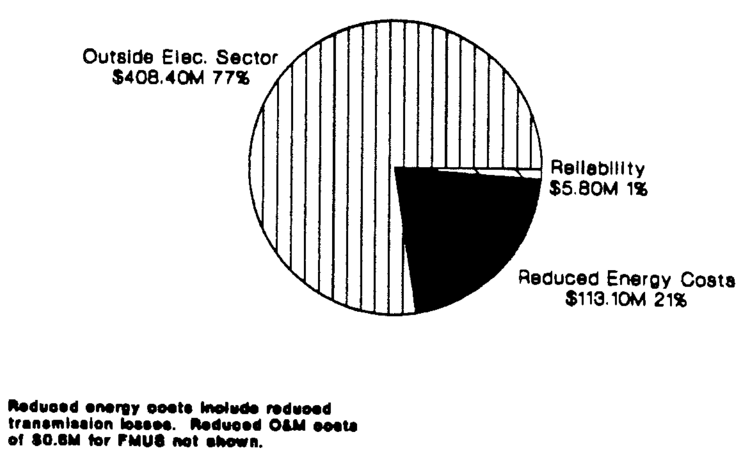


Figure 13-16. Gas Pipeline: Breakdown of Expected Benefits

13.8 END-USE CONSERVATION PROGRAMS: TOP THREE

Table 13-7 shows the present value of resource costs and benefits for the top three end-use programs. The expected value of economic benefit is between $8.95 million and $11.95 million for the top three programs. Positive benefits are estimated for all scenarios. The diffe.ence between the low and high benefit estimate is due entirely to alternative values assigned to avoided generation capacity savings.

Figures 13-17 and 13-18 display net benefits for each scenario and the breakdown of benefits into their main categories.

Table 13-7

TOP THREE END-USE PROGRAMS: SUMMARY OF COSTS AND BENEFITS

	Prob	Reduced Energy Costs	Reduced Trans. Losses	Capacity Value		Total Benefits		Total Costs	Net Benefits	
				Low	High	Low	High		Low	High
LL	0.30	16.19	0.12	5.68	8.68	21.99	24.99	15.42	6.57	9.57
LM	0.23	16.62	0.19	5.68	8.68	22.49	25.49	15.42	7.07	10.07
LH	0.06	17.46	0.19	5.68	8.68	23.33	26.33	15.42	7.91	10.91
ML	0.03	20.55	0.27	5.68	8.68	26.50	29.50	16.78	9.72	12.72
MM	0.08	21.33	0.26	5.68	8.68	27.27	30.27	16.78	10.49	13.49
MH	0.19	22.48	0.26	5.68	8.68	28.42	31.42	16.78	11.64	14.64
HL	0.00	24.85	0.21	5.68	8.68	30.74	33.74	18.01	12.73	15.73
HM	0.02	25.85	0.08	5.68	8.68	31.61	34.61	18.01	13.60	16.60
HH	0.08	27.05	0.17	5.68	8.68	32.90	35.90	18.01	14.89	17.89
Exp Val		19.17	0.19	5.68	8.68	25.04	28.04	16.09	8.95	11.95
UL	0.60	17.86	0.17	5.68	8.68	23.71	26.71	15.42	8.29	11.29
UM	0.30	23.05	0.23	5.68	8.68	28.96	31.96	16.78	12.18	15.18
UH	0.10	27.85	0.18	5.68	8.68	33.71	36.71	18.01	15.70	18.70
Exp Val		20.42	0.19	5.68	8.68	26.28	29.29	16.09	10.20	13.20
DOR		14.99	0.05	5.68	8.68	20.72	23.72	14.68	6.04	9.04
NM		17.26	0.22	5.68	8.68	23.16	26.16	15.42	7.74	10.74
DH		17.66	0.20	5.68	8.68	23.54	26.54	15.42	8.12	11.12
WH		17.36	0.20	5.68	8.68	23.24	26.24	15.42	7.82	10.82
GE		20.04	0.13	5.68	8.68	25.85	28.85	15.42	10.43	13.43

Notes:

1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include:

Benefit	
Reliability benefits	0.00
Stability benefits	0.00

3. Capacity value is 61.1$/KW-yr (High) and 40.0$/KW-yr (Low)
4. Total costs include capital costs and O&M costs.
5. Net Benefits = Total Benefits - Total Costs.

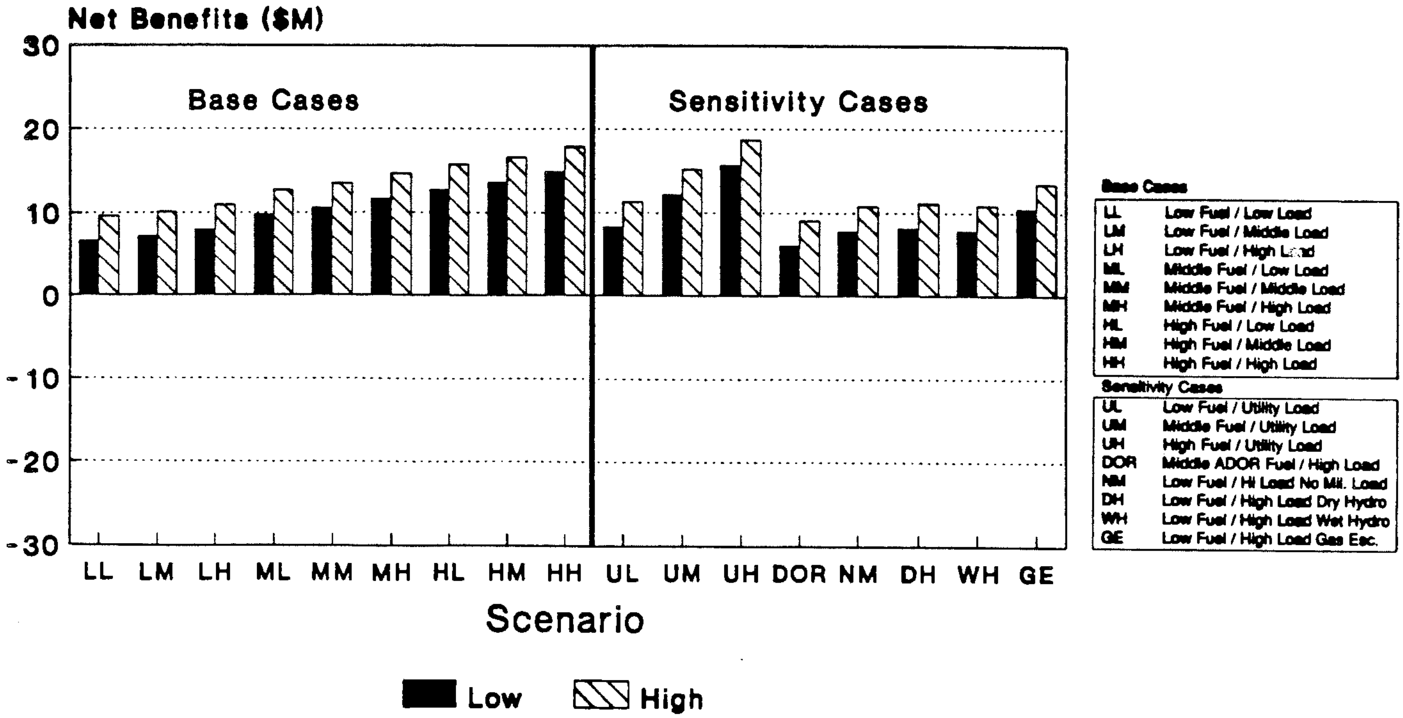
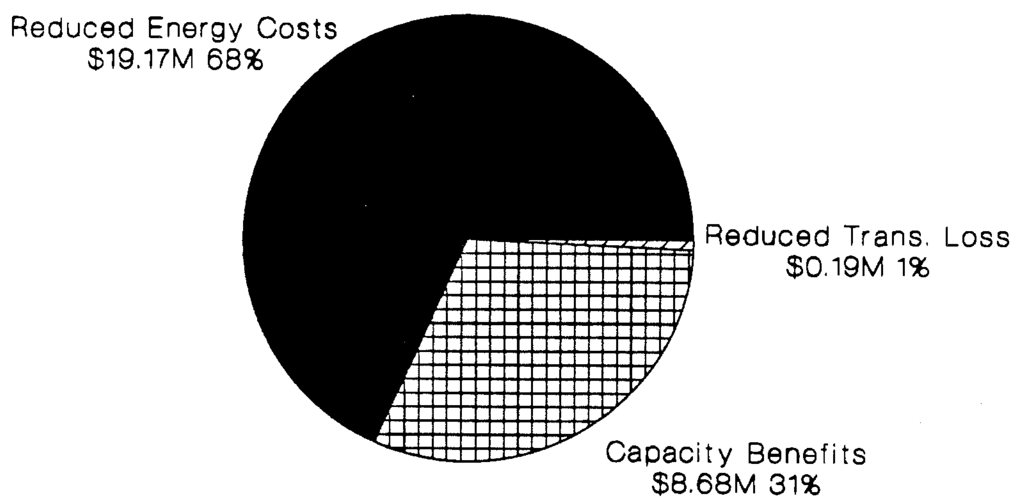


Figure 13-17. Top Three End-Use Programs: Net Benefits



Only high capacity benefits are shown.

Figure 13-18. Top Three End-Use Programs: Breakdown of Expected Benefits

13.9 END-USE CONSERVATION PROGRAMS: TOP EIGHT

Tables 13-8 shows the present value of resource costs and benefits for the top eight end-use programs. The expected value of economic benefit is between $10.20 million and $17.14 million for all eight programs. Positive benefits are estimated for all scenarios. The difference between the low and high benefit estimate is due entirely to alternative values assigned to avoided generation capacity savings.

Figures 13-19 and 13-20 display net benefits for each scenario and the breakdown of benefits into their main categories.

Table 13-8

TOP EIGHT END-USE PROGRAMS: SUMMARY OF COSTS AND BENEFITS

	Prob	Reduced Energy Costs	Reduced Trans. Losses	Capacity Value Low	Capacity Value High	Total Benefits Low	Total Benefits High	Total Costs	Net Benefits Low	Net Benefits High
LL	0.30	33.43	0.27	13.12	20.06	46.82	53.76	42.25	4.57	11.51
LM	0.23	34.58	0.46	13.12	20.06	48.16	55.10	42.25	5.91	12.85
LH	0.06	36.65	0.56	13.12	20.06	50.33	57.27	42.25	8.08	15.02
ML	0.03	42.71	0.70	13.12	20.06	56.53	63.47	44.81	11.72	18.66
MM	0.08	44.59	0.59	13.12	20.06	58.30	65.24	44.81	13.49	20.43
MH	0.19	47.51	0.74	13.12	20.06	61.37	68.31	44.81	16.56	23.50
HL	0.00	52.09	0.68	13.12	20.06	65.89	72.83	47.20	18.69	25.63
HM	0.02	54.36	0.37	13.12	20.06	67.85	74.79	47.20	20.65	27.59
HH	0.08	57.82	0.45	13.12	20.06	71.39	78.33	47.20	24.19	31.13
Exp Val		40.12	0.48	13.12	20.06	53.71	60.65	43.51	10.20	17.14
UL	0.60	37.63	0.38	13.12	20.06	51.13	58.07	42.25	8.88	15.82
UM	0.30	52.02	0.53	13.12	20.06	65.67	72.61	44.81	20.86	27.80
UH	0.10	59.76	0.50	13.12	20.06	73.38	80.32	47.20	26.18	33.12
Exp Val		44.16	0.44	13.12	20.06	57.72	64.66	43.51	14.20	21.14
DOR		30.65	0.15	13.12	20.06	43.92	50.86	40.86	3.06	10.00
NM		35.95	0.62	13.12	20.06	49.69	56.63	42.25	7.44	14.38
DH		37.05	0.52	13.12	20.06	50.69	57.63	42.25	8.44	15.38
WH		36.25	0.56	13.12	20.06	49.93	56.87	42.25	7.68	14.62
GE		40.52	0.10	13.12	20.06	53.74	60.68	42.25	11.49	18.43

Notes:

1. All values are in 1987 million dollars (present value for 1994 through 2028 discounted at 4.5%/yr).
2. Total benefits include:

Benefit	
Reliability benefits	0.00
Stability benefits	0.00

3. Capacity value is 61.1$/KW-yr (High) and 40.0$/KW-yr (Low)
4. Total costs include capital costs and O&M costs.
5. Net Benefits = Total Benefits - Total Costs.

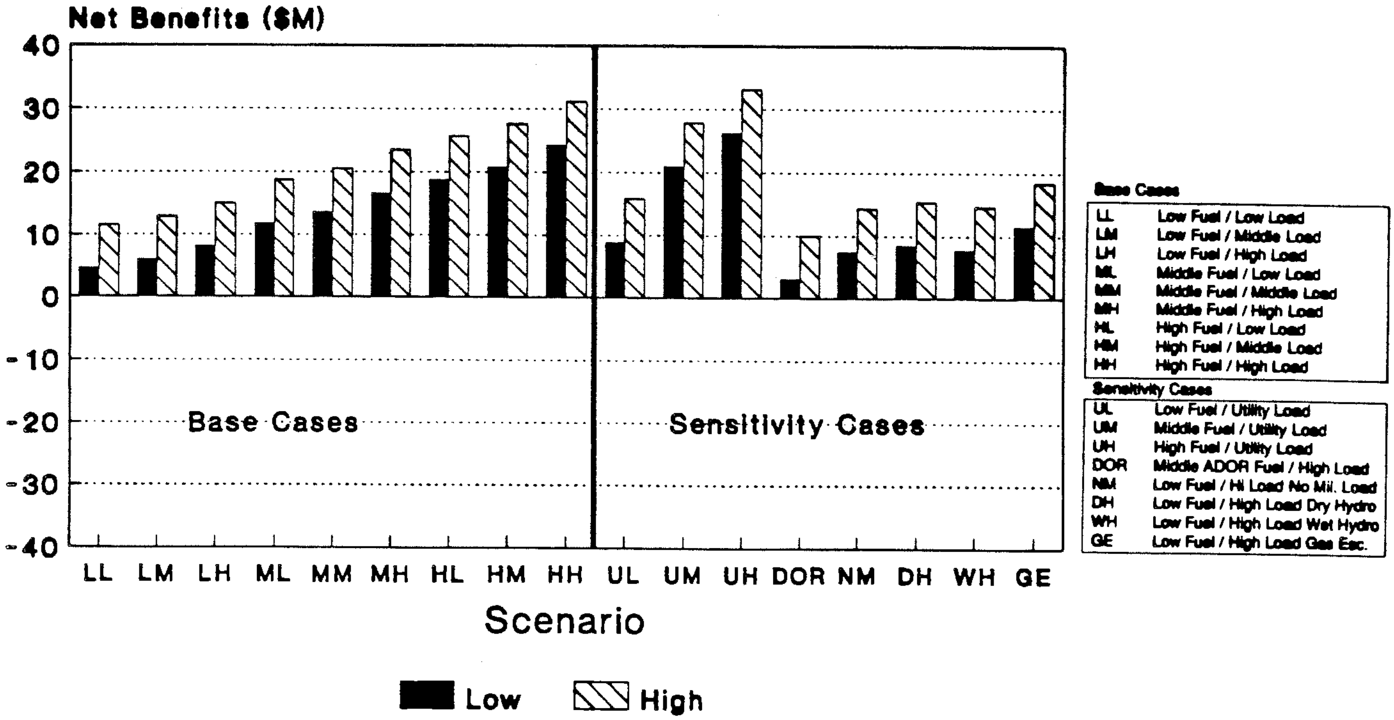
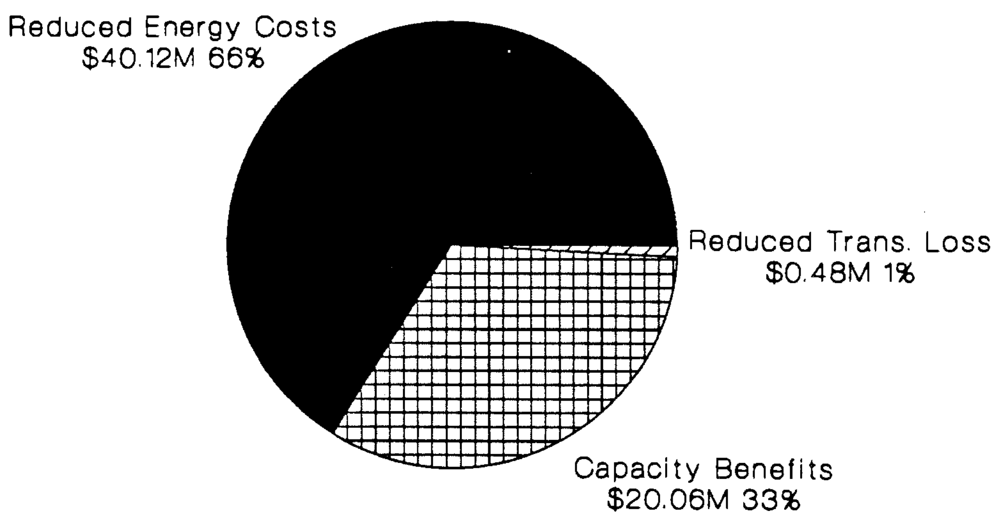


Figure 13-19. Top Eight End-Use Programs: Net Benefits



Only high capacity benefits are shown.

Figure 13-20. Top Eight End-Use Programs: Breakdown of Expected Benefits

13.10 OTHER PROPOSALS AND COMMENTS

13.10.1 Modified Intertie Proposals

Railbelt utilities have recently submitted two modified intertie proposals. Golden Valley Electric Association (GVEA) has proposed construction of a new 138-KV line between Healy and Fairbanks in conjunction with the limited upgrade of the Anchorage-Fairbanks intertie (AF100) evaluated in this study. Chugach Electric Association (CEA) has proposed construction of a new 138-KV line between Soldotna and Anchorage rather than a new 230-KV line. Time constraints did not allow detailed analyses of these proposals. It appears that the modified Kenai-Anchorage proposal from CEA would cost less than the 230-KV alternative, but would also achieve lower benefits in the form of reduced transmission losses. The GVEA proposal would apparently reduce transmission losses between Healy and Fairbanks.

13.10.2 Existing Kenai-Anchorage Line: Two Month per Year Interruptions for Maintenance

CEA has recently stated that the system modeling should reflect the idea that the existing Kenai-Anchorage transmission line will be unavailable for transfers for two months per year due to long-term maintenance. Chugach suggested that these interruptions in transfer capability be assumed to begin in 1994, the first year of the model simulation, and extend for the following ten years. Further, the Chugach preliminary analysis reflects continuing one month per year scheduled interruptions extending from 2005 (the end of the initial ten-year period) through 2028 (the last year of the simulation).

Again, this idea was not expressed in time to receive careful scrutiny in this analysis. However, we did make some rough calculations to estimate what the impact of this possibility would be on the new Kenai-Anchorage feasibility results. We considered the following benefit categories.

1. *Stability:* We see no impact on the stability benefits attributed to the new intertie.

2. *Reliability:* For the scenario with the existing line, reliability would probably improve to the extent that the line is unavailable for transfers and to the extent that the preventive maintenance program is successful. Outages in Anchorage and Kenai caused by failure of the existing line while transfers are occurring would be avoided for two months per year. Reducing the reliability benefit of the new intertie by one-sixth would mean a reduction of $1 to $2 million in net benefits for the new Kenai-Anchorage line.

3. *Capacity Sharing:* The capacity sharing benefit of the new line should be unaffected under either of the following conditions:

    a. The interruptions are scheduled during off-peak months.
    b. Transfer capability can be restored within a matter of hours, even if interruptions are scheduled during peak months.

4. *Economy Energy and Reduced Transmission Losses:* Economy energy benefits of the new line would increase and the transmission loss benefit would be slightly lower. This is because there would be lower losses in the "existing intertie" case to be reduced by the new intertie. Table 13-9 summarizes the first step in estimating the magnitude of change in economy energy benefit. The average value of each unit of increased economy energy transfer is estimated for three selected years based on the simulation results presented in Section 5.

    The next step is to estimate the value of transfer benefit lost in the "existing line" scenario due to the two-month interruptions, as shown in Table 13-10. This value can then be added to the net benefits of the new intertie, since these transfers would occur with the new line but not with the existing line. For this estimate, we assume a two-month interruption for every year between 1994 and 2028.

    The "lost transfer benefits" for the existing line shown in Column D in Table 13-10 due to the 2 month interruptions can be used as estimates of the increased transfer benefits of the new line. The annual increase in benefit from 1994 through 2010 was estimated by interpolating between the three selected years calculated in Tables 13-9 and 13-10. The value from 2011 through 2028 was assumed to be the same as 2010. The present value of this stream was then calculated at a 4.5 percent real discount rate, yielding an estimated increase in net benefit of $7.3 million.

5. *Operating Reserve Sharing:* For the scenario with the existing line, an annual two-month outage would reduce the time when operating reserves can be transferred from Kenai to Anchorage. We estimate this reduction at 517 hours per year.[3] This change in line

[3]517 hours per year represents the additional hours that operating reserves would not be available from an annual two-month outage in place of the original assumption of an annual two-week outage. The unavailable hours for two-month outage is two twelfths (2/12) of the annual 4000 hours or 667 hours. The two-week outage was estimated in Section 7.6 to result in 150 unavailable hours. The difference (667 - 150 = 517) is the increase in unavailable hours due to the two-month instead of a two-week annual outage.

availability is not sensitive to load growth. The lost benefit to the existing line scenario would increase the net benefits of the new line by the amounts shown in Table 13-11.

Table 13-9

AVERAGE VALUE OF INCREASED ECONOMY ENERGY TRANSFER

	Change in Kenai-Anchorage Transfers Due to New Line[1] (Gwh/yr)	Transfer Benefits Due To New Line[2] ($ million/yr)	($/MWh)
1994	89.6	0.5	5.6
2002	90.1	0.5	5.5
2010	77.8	0.6	7.7

1. Includes both south to north and north to south transfers. Also includes hydro-thermal coordination transfers.

2. Does not include reduced transmission loss benefits.

Table 13-10

VALUE OF TWO-MONTH TRANSFER BENEFIT

	(A)	(B)	(C)	(D)
	Kenai-Anchorage Transfers[1] With Existing Line (GWh/yr)	Lost Kenai-Anchorage Transfers Due to 2 Month Interruptions[2] (GWh/yr)	Lost Transfer Benefit[3] ($/MWh)	Lost Transfer Benefits Adjusted For Transmission Losses[4] ($million/yr)
1994	356.4	59.4	5.6	0.326
2002	371.5	61.9	5.5	0.334
2010	413.3	68.9	7.7	0.520

1. Includes both south to north and north to south transfers. Also includes hydro-thermal coordination transfers.

2. One sixth of Column A.

3. Based on transfer benefits due to new line. Does not include reduced transmission loss benefits.

4. Column B multiplied by Column C. Product reduced by two percent transmission losses of new line.

Table 13-11

IMPACT OF TWO-MONTH OUTAGE ON OPERATING RESERVE BENEFIT

	Lost Benefit ($ million)		
	Low Fuel	Mid Fuel	High Fuel
1994	0.12	0.15	0.17
2002	0.12	0.16	0.20
2010	0.14	0.18	0.23
Present Value Impact 1994-2028	2.09	2.88	3.60

The net result of these rough calculations would be to increase the net benefits estimated for the new Kenai-Anchorage line by $8 million to $9 million, given a two-month transfer interruption for maintenance on the existing line from 1994 through 2028. This estimate is comprised of (1) $7.3 million for economy energy transfer, (2) minus $1 to $2 million for reliability value, and (3) $2 to $4 million for spinning reserves. With this adjustment, the Kenai-Anchorage new intertie would have an expected net economic loss of $45 million to $52 million.

Appendix A

SUMMARY OF UTILITIES DATA ON CUSTOMER OUTAGES

Table A-1

ANCHORAGE MUNICIPAL LIGHT & POWER

Date	Duration (hours)	Number of Customers affected
87/11/27	0.42	5553
87/06/21	1.27	3602
87/06/21	0.75	6857
87/06/21	0.82	8313
87/04/01	0.50	1981
87/04/01	0.68	3684
87/04/01	0.75	10693
87/04/01	0.90	5311
86/08/30	0.80	5030
86/08/30	0.87	960
86/08/30	1.13	771
86/08/30	1.13	5115
86/08/30	1.03	3072
86/08/30	1.22	607
86/08/30	1.22	3148
86/08/30	1.22	1807
86/08/30	1.27	4914
86/08/30	1.13	5638
86/03/04	0.95	855
86/03/04	1.20	946
86/03/04	1.20	396
86/03/04	1.48	1006
86/03/04	1.87	4095
86/03/04	1.90	1055
86/03/04	1.93	5397
86/03/04	1.95	5689
86/03/04	1.98	1299
86/03/04	2.00	4695
86/03/04	2.02	1981
86/03/04	2.12	2686

Table A-2

MATANUSKA ELECTRIC ASSOCIATION

Date	Duration (hours)	Number of Customers affected
87/01/23	0.25	350
87/03/18	1.78	17137
87/04/01	4.33	11000
87/06/06	0.33	436
87/06/21	0.92	10000
87/07/26	2.33	1000
87/08/16	0.28	15000
87/08/22	0.08	1259
87/11/12	0.13	1173
87/12/23	1.00	9000
86/03/04	3.72	23000
86/05/26	1.58	1800
86/07/10	0.42	1200
86/08/30	4.38	8445

Table A-3

HOMER ELECTRIC ASSOCIATION

Date	Duration (hours)	Number of Customers affected
87/04/01	2.00	814
87/04/01	1.91	663
87/04/01	1.76	738
87/06/21	0.76	356
87/06/21	0.70	843
87/06/21	0.70	500
87/06/21	0.31	446
87/11/11	0.70	664
87/11/11	0.45	1040
87/11/11	0.68	705
87/11/11	0.63	593
87/11/11	0.33	705
87/11/11	0.30	593
87/11/11	0.31	664
87/04/01	1.85	898
87/04/01	1.33	3337
87/04/01	1.80	613
87/04/01	2.01	1481
87/04/01	2.01	550
87/05/13	0.50	5
87/06/21	1.13	3337
87/06/21	1.13	1481
87/06/21	0.90	613
87/06/21	0.90	898
87/07/26	1.08	550
87/07/26	1.05	1481
87/07/26	1.41	30
87/07/26	1.41	566
87/11/11	1.03	550
87/11/11	1.03	1481
87/11/11	1.01	30
87/11/11	0.96	566
87/11/11	0.46	613
87/11/11	0.46	898
87/11/11	0.20	775
87/11/11	0.10	3337

Table A-4

SEWARD ELECTRIC SYSTEM

Date	Duration (hours)	Number of Customers affected
87/01/09	0.25	2200
87/01/10	0.75	2200
87/01/13	0.25	2200
87/01/14	0.75	2200
87/01/15	0.25	2200
87/02/01	0.75	2200
87/02/02	0.25	2200
87/03/15	0.75	2200
87/04/26	0.25	2200
87/11/13	0.75	2200
87/11/14	0.25	2200
87/11/28	0.75	2200
87/11/30	0.25	2200
87/12/02	0.75	2200
87/12/04	0.25	2200
87/12/19	0.75	2200
87/12/23	0.25	2200
86/01/03	0.75	2200
86/01/04	0.25	2200
86/01/05	0.75	2200
86/01/10	0.25	2200
86/01/11	0.75	2200
86/01/12	0.25	2200
86/02/07	0.75	2200
86/06/17	0.25	2200
86/10/10	0.75	2200
86/11/09	0.25	2200
86/11/27	0.75	2200
86/11/28	0.25	2200
86/12/01	0.75	2200
86/12/02	0.25	2200

Table A-5

FAIRBANKS MUNICIPAL UTILITY SYSTEM

Date	Duration (hours)	Feeder Affected
87/03/18	0.28	Lathrop
87/03/18	0.28	Garden Island
87/04/01	0.08	Lathrop
87/04/01	0.08	Garden Island
87/04/01	0.12	Eagan Avenue
87/04/02	0.48	W.W.T.P.
87/04/02	0.47	Eagan Avenue
87/05/14	0.33	W.W.T.P.
87/05/14	0.50	Eagan Avenue
87/05/26	0.05	Garden Island
87/06/18	0.12	Lathrop
87/06/21	0.32	Lathrop
87/06/21	0.20	Garden Island
87/06/21	0.33	Eagan Avenue
87/07/01	0.12	Barnette
87/07/01	0.12	4th Avenue
87/07/01	0.12	Lathrop
87/07/01	0.08	West Gate
87/07/01	0.10	Garden Island
87/07/01	0.12	W.W.T.P.
87/07/01	0.12	Eagan Avenue
87/07/02	0.00	W.W.T.P.
87/07/02	0.00	Eagan Avenue
87/07/03	0.00	W.W.T.P.
87/07/03	0.00	Eagan Avenue
87/07/10	0.70	West Gate
87/07/25	0.65	West Gate
87/07/26	0.18	Lathrop
87/07/26	0.07	Cowles
87/07/26	0.17	Garden Island
87/07/26	0.58	W.W.T.P.
87/07/29	0.07	Lathrop
87/07/29	0.12	Garden Island
87/07/29	0.05	Lathrop
87/07/29	0.05	Garden Island

Table A-5 (continued)

Date	Duration (hours)	Feeder Affected
87/08/07	1.00	Eagan Avenue
87/08/16	0.17	Lathrop
87/08/16	0.18	Garden Island
87/08/22	0.67	Lathrop
87/08/22	0.70	Garden Island
87/08/22	1.53	Eagan Avenue
87/10/29	0.55	First Avenue
87/10/29	1.43	Barnette
87/10/29	1.43	4th Avenue
87/10/29	1.43	Lathrop
87/10/29	1.43	First Avenue
87/10/29	1.43	West Gate
87/10/29	1.43	Cowles
87/10/29	1.43	Garden Island
87/10/29	1.43	W.W.T.P.
87/10/29	1.43	Eagan Avenue
87/11/12	0.08	4th Avenue
87/11/12	0.08	Lathrop
87/11/12	0.10	West Gate
87/11/12	0.12	Cowles
87/11/12	0.22	Garden Island
87/11/12	0.32	W.W.T.P.
87/11/12	0.32	Eagan Avenue
87/12/04	0.17	Lathrop
87/12/04	0.17	West Gate
87/12/04	0.05	Cowles
87/12/04	0.17	Garden Island
87/12/10	0.02	4th Avenue
87/12/10	0.02	Lathrop
87/12/10	0.02	West Gate
87/12/10	0.03	Cowles
87/12/10	0.07	Garden Island
87/12/10	0.48	W.W.T.P.
87/12/10	0.48	Eagan Avenue
87/12/23	0.03	Barnette

Table A-5 (continued)

Date	Duration (hours)	Feeder Affected
87/12/23	0.03	4th Avenue
87/12/23	0.03	Lathrop
87/12/23	0.05	West Gate
87/12/23	0.25	Garden Island
86/01/17	0.28	Lathrop
86/01/17	0.23	Garden Island
86/01/17	0.27	West Gate
86/02/26	0.03	4th Avenue
86/03/04	0.17	Lathrop
86/03/04	0.18	Garden Island
86/05/14	0.05	W.W.T.P.
86/05/26	0.85	W.W.T.P.
86/06/05	0.02	W.W.T.P.
86/06/27	0.33	West Gate
86/07/06	1.75	Garden Island
86/08/08	0.50	Garden Island
86/11/27	1.50	Garden Island
86/12/08	0.15	Lathrop
86/03/04	0.35	Garden Island
86/12/11	0.15	W.W.T.P.
86/12/11	0.15	Eagan Avenue

NOTES:

1. Individual outage information was not available for CEA, GVEA, and CVEA. GVEA provided necessary information on outage distributions.

2. 1986 individual outage information was not available for HEA.

Appendix B
FUEL PRICE FORECASTS

Shown in this appendix are the price forecasts used in this analysis for crude oil, fuel oil, natural gas, and coal. The derivation of these price forecasts is also presented in summary form.

B.1 CRUDE OIL PRICE FORECASTS

The Alaska Power Authority (APA) commissioned ICF, Incorporated to provide analysis of oil and natural gas price issues. In early 1988, ICF collected a sample of 17 long-term crude oil price forecasts, most of which were produced during 1987, from a broad selection of firms and agencies in the United States and Europe. Based on the range of opinion expressed in these forecasts, three price scenarios were developed to represent the main "schools of thought." Table B-1 displays the three price scenarios.

Table B-1

CRUDE OIL PRICE SCENARIOS
Saudi Light Delivered to U.S. Gulf*
(1987 dollars per barrel)

Year	Low	Mid	High
1990	$14	$18	$20
2000	18	24	30
2010	20	30	40

*North Slope oil delivered to the U.S. Gulf is estimated at about $1 per barrel less than Saudi Light, while West Texas Intermediate is estimated at about $1 per barrel more.

An analysis of the main schools of thought, describing the reasoning and evidence put forward in support of each, was provided to the APA Board of Directors. The Board then assigned the following probabilities to each price scenario for use in this Railbelt study and for APA planning generally: low = 60%, mid = 30%, and high = 10%.

The price scenarios developed by ICF are higher than the crude oil price forecasts published by the Alaska Department of Revenue (ADOR) for Fall 1988. Table B-2 displays the comparison of the ICF crude oil price ranges and the ADOR Fall 1988 price ranges. As noted in the table, appropriate adjustments have been made to provide comparability.

Table B-2

CRUDE OIL PRICE SCENARIOS
Saudi Light Delivered to U.S. Gulf*
(1988 dollars per barrel)

Year	ADOR Low	ADOR Mid	ADOR High	ICF Low	ICF Mid	ICF High
1990	$10.25	$12.60	$16.25	$14.56	$18.72	$20.80
1995	10.62	13.82	17.47	16.64	21.84	26.00
2000	10.76	14.45	18.79	18.72	24.96	31.20
2005	10.95	15.18	20.40	19.76	28.08	36.40

*Notes: ADOR prices for Saudi Light at Ras Tanura increased by $1.50 to reflect transportation to U.S. Gulf (per C. Logsdon, ADOR). ICF prices increased from $1987 to $1988 by assuming 4 percent inflation in 1988. ADOR series terminates in 2005.

The ICF "low" case is similar to the ADOR "high" case. Although the ICF crude oil price scenarios formed the basis for most of the fuel oil and natural gas price forecasts used in the study, sensitivity testing was performed using the ADOR "mid" case as well.

B.2 COOK INLET NATURAL GAS PRICE FORECASTS

Recent contracts provide the best available indication of the current value and long-term price outlook for Cook Inlet natural gas. Two such contracts have recently been negotiated:

1. Contract between Marathon Oil Company and Enstar Natural Gas Company covering an initial commitment of 456 Bcf, with options for additional commitments in the future.

2. Contract between Marathon Oil Company and Chugach Electric Association covering an initial commitment of 215 Bcf, with options for additional commitments in the future.

Each contract specifies a base price plus a periodic price adjustment factor. For the Enstar contract, the adjustment factor is based on changes in the price of crude oil. For the Chugach contract, the adjustment factor is based on price changes for crude oil, (refined) fuel oil, and natural gas in the lower 48. Because fuel oil and lower-48 natural gas prices are expected to follow a path roughly similar to crude oil prices over the long term, APA has assumed a simplified adjustment factor for present purposes consisting of crude oil prices only. Table B-3 shows the wellhead price projections that result when the ICF crude oil price scenarios are applied according to contract terms. Table B-4 shows wellhead price projections consistent with the ADOR "mid" case.

Table B-3

COOK INLET WELLHEAD NATURAL GAS PRICES*
ICF Scenarios
(1987 dollars per MBtu)**

Year	Chugach Low	Chugach Mid	Chugach High	Enstar Low	Enstar Mid	Enstar High
1990	1.27	1.43	1.50	1.43	1.60	1.69
1995	1.31	1.69	1.98	1.54	1.98	2.31
2000	1.47	1.93	2.38	1.65	2.17	2.67
2005	1.57	2.17	2.77	1.49	2.06	2.63
2010	1.65	2.41	3.17	1.56	2.28	3.01

*Note that the Chugach prices do not account for blending in remaining quantities of lower priced, "old" Beluga gas. The Enstar prices, however, represent the blended acquisition cost to Enstar from its two main contracts (primarily the new Marathon contract), exclusive of any distribution margin to customers such as Anchorage Municipal Light & Power.

**Note also that 1 MBtu (i.e., million Btu) is approximately equal to 1 Mcf.

Table B-4

COOK INLET WELLHEAD NATURAL GAS PRICES
ADOR "Mid" Scenario*
(1987 dollars per MBtu)

Year	Chugach ADOR Mid	Enstar ADOR Mid
1990	1.11	1.26
1995	1.13	1.34
2000	1.17	1.32
2005	1.23	1.17
2010	1.28	1.22

*Though the ADOR crude oil forecast extends only through 2005, the trend has been extrapolated through 2010 for purposes of this projection.

Although the prices in Tables B-3 and B-4 are estimated through 2010, the gas delivery commitments made under recent and existing contracts do not actually provide enough gas to supply expected requirements for that long. For the Chugach price forecast, the assumption is that new contracts with Beluga producers (Chevron, ARCO, and Shell) will be negotiated at prices comparable to those in the new contract between Chugach and Marathon, and that total gas commitments to Chugach will then suffice through 2010. Although more than the initial 215 Bcf can be provided to Chugach by Marathon under their new contract, Marathon is not required to do so.

Similarly, new and existing contracts for Enstar do not provide gas commitments for expected demand beyond the 2002 to 2004 time frame. Again, more gas can be provided by Marathon to Enstar under terms of their new contract, but Marathon is not presently required to do so.

The forecast of Cook Inlet gas prices becomes more uncertain as we approach, and go beyond, the year 2010. Yet prices in that distant time frame could still be significant in the analysis, especially if they deviate substantially from prior trends.

There is a suggestion of this possibility in the work that ICF performed for APA before the two recent contracts were released for public review. Based on the "50th percentile" estimates of undiscovered Cook Inlet gas resources issued by the Potential Gas Committee, ICF produced a forecast of the marginal cost of adding new reserves sufficient to meet annual production requirements under (1) a "base case" demand scenario that provided only very gradual growth above the existing demand of approximately 200 Bcf per year, and (2) a higher demand scenario that included an additional 50 Bcf per year for new LNG export starting in 1995 (i.e., an additional 750 Bcf by 2010, equal to about four years of "normal" demand). Table B-5 shows the results.

Table B-5

MARGINAL COST OF PRODUCING NEW RESERVES
(1987 dollars per MBtu)

Year	"Base" Demand	"Higher" Demand
1990	---*	---*
1995	0.47	0.73
2000	0.86	1.65
2005	1.63	3.54
2010	3.12	5.33

*No reserve additions required until 1991.

Again, our gas price forecast in the "low" case (to which we give a 60 percent probability per APA Board direction) is in the range of $1.56 to 1.65 in 2010. However, the supply analysis noted above suggests that the marginal cost of reserve additions will be substantially higher by then. Further, the ICF cost estimates under the higher demand case suggest that marginal costs could escalate sharply from the $3.00 range to the $5.00 range perhaps within the 2010 to 2015 period, even without additional LNG export.

Although our long-term planning forecasts extend only through 2010, the feasibility assessments require extension periods beyond 2010. For projects assumed to come on-line in 1994 and remain productive over a 35-year life, the evaluation must be extended through 2028. For most of the cases examined, all prices and assumptions were held constant between 2011 and 2028 due to the low confidence level attached to such distant forecasts. However, a sensitivity case was analyzed for each of the projects under review that assumed sharp escalation of Cook Inlet natural gas prices beyond 2010, based not on crude oil price escalation but rather on the assumption that sharply rising production costs will force up the price due to depletion of Cook Inlet resources. As shown below in Table B-6, that sensitivity case begins with the ICF "low" scenario through 2010 and incorporates an assumed cost-driven price increase thereafter.

Table B-6

COOK INLET WELLHEAD NATURAL GAS PRICES
Sensitivity Case
ICF "Low" Before 2010—Sharp Escalation After 2010
(1987 dollars per MBtu)

Year	Chugach	Enstar
1990	1.27	1.43
1995	1.31	1.54
2000	1.47	1.65
2005	1.57	1.49
2010	1.65	1.56
2015	2.50	2.50
2020	4.00	4.00
2025	5.50	5.50
2030	7.00	7.00

B.3 FUEL OIL PRICE FORECASTS

There are two sets of fuel oil price forecasts that are of primary interest in this study:

1. No. 4 distillate fuel oil purchased by Golden Valley Electric Association (GVEA) in Fairbanks for use in power generation.

2. No. 2 distillate fuel oil purchased by residential and commercial customers in Fairbanks for use primarily in space heating and by Copper Valley Electric Association (CVEA) as fuel for its diesel generators in Glennallen.

GVEA has a contract with the State that extends through 1995 for the purchase of royalty oil from the North Slope. The royalty oil purchased by GVEA is assigned to the Mapco refinery in Fairbanks for processing, and the refined product (i.e., No. 4 fuel oil) is sold back to GVEA at a reduced margin. It is assumed in this forecast that future prices to GVEA will conform generally to this price-setting mechanism, the main elements of which are the wellhead price of crude oil on the North Slope and the TAPS tariff. The resulting price forecast is shown in Table B-7.

Table B-7

PRICE OF NO. 4 FUEL OIL TO GVEA
ICF Scenarios
(1987 dollars per MBtu)*

Year	Low	Mid	High
1990	2.50	3.19	3.54
1995	2.84	3.68	4.34
2000	3.19	4.16	5.13
2005	3.37	4.65	5.94
2010	3.54	5.13	6.75

*Note that 1 gallon equals approximately 0.144 MBtu

The expected price of No. 2 fuel oil to residential and commercial customers is relevant to this analysis primarily in the assessment of the proposed natural gas pipeline from Cook Inlet to Fairbanks. Price forecasts were developed based on the expected costs of crude oil acquisition to the marginal supplier, plus expected refining, transportation, and distribution costs. Table B-8 shows the results.

Table B-8

PRICE OF NO. 2 FUEL OIL IN FAIRBANKS
ICF Scenarios
(1987 dollars per MBtu)*

	Residential			Large Commercial		
Year	Low	Mid	High	Low	Mid	High
1990	5.43	6.08	6.44	4.13	4.85	5.14
1995	5.72	6.59	7.24	4.49	5.36	5.94
2000	6.08	7.10	8.11	4.85	5.86	6.88
2005	6.26	7.61	8.98	5.00	6.37	7.71
2010	6.44	8.11	9.85	5.14	6.88	8.54

* Note that 1 gallon equals approximately 0.138 MBtu

The expected price of No. 2 fuel oil to CVEA is relevant to the analysis of the proposed Northeast intertie, which would link the CVEA system with Anchorage and Fairbanks. The "large commercial" prices shown above in Table B-8 were used to represent the cost of diesel fuel to CVEA.

Table B-9 shows the fuel oil prices used for the sensitivity cases based on the ADOR "mid" crude oil price scenario.

Table B-9

FUEL OIL PRICES BASED ON ADOR "MID" SCENARIO
(1987 dollars per MBtu)

Year	No. 4 Fuel Oil	No. 2 Fuel Oil Residential	No. 2 Fuel Oil Large Commercial
1990	2.15	5.04	3.79
1995	2.37	5.25	4.00
2000	2.52	5.39	4.14
2005	2.66	5.55	4.29
2010	2.76	5.67	4.41

An additional set of fuel oil prices was generated for the sensitivity test on rising Cook Inlet gas production costs after 2010. Because gas prices were projected out to 2030 for this case (see Table B-6), a set of fuel oil prices over the same time period was also required. Because the gas price forecast began with the ICF "low" scenario through 2010, the fuel oil price forecast was based on extrapolation of the ICF "low" case through 2030, as shown in Table B-10.

Table B-10

FUEL OIL PRICE FORECASTS
Sensitivity Case
ICF "Low" Through 2010—ICF "Low" Extrapolated Through 2030
(1987 dollars per MBtu)

Year	No. 4 Fuel Oil	No. 2 Fuel Oil Residential	No. 2 Fuel Oil Large Commercial
1990	2.50	5.43	4.13
1995	2.84	5.72	4.49
2000	3.19	6.08	4.85
2005	3.37	6.26	5.00
2010	3.54	6.44	5.14
2015	3.79	6.69	5.39
2020	4.04	6.94	5.64
2025	4.29	7.19	5.89
2030	4.54	7.44	6.14

B.4 NORTH SLOPE NATURAL GAS

It is possible that North Slope gas will become available for in-state use in the Fairbanks area during the next 20 years; an event that could influence the feasibility of projects under review in this study. Consideration of this possibility within the electric power sector analysis would have required certain modifications within the simulation modeling that could not be accomplished prior to the publication of this report. However, a sensitivity case based on one North Slope gas scenario was analyzed in the context of the proposed Cook Inlet-Fairbanks gas pipeline alternative. For that case, North Slope gas availability was considered in evaluating impacts outside the power sector; i.e., in the residential and commercial heating markets.

A complete set of Cook Inlet gas, North Slope gas, and fuel oil prices through 2030 were specified for that sensitivity case. All prices through 2010 are consistent with the ICF "mid" scenario. The reason this was selected was because: (1) under the "low" scenario, the probability of North Slope gas pipeline construction was judged by APA to be low; and (2) the probability of the "high" scenario is judged by APA to be low, even though the chances of North Slope gas pipeline construction are much better in the "high" price context. The "mid" case combines a reasonably good probability of occurrence and a reasonable chance of North Slope pipeline construction in the judgment of APA.

Table B-11 shows the Cook Inlet wellhead gas prices, No. 2 fuel oil prices in Fairbanks, and Railbelt North Slope gas prices between 2010 and 2030 assumed in this case.

Table B-11

SENSITIVITY FUEL PRICES—NORTH SLOPE GAS CASE
2010 to 2030 (ICF "Mid" Scenario Through 2010)
(1987 dollars per MBtu)

Year	Cook Inlet Wellhead	North Slope Railbelt	Fairbanks No. 2 Fuel Oil Residential	Fairbanks No. 2 Fuel Oil Large Commercial
2010	2.28	3.03	8.11	6.88
2015	3.50	3.50	8.61	7.37
2020	5.00	3.98	9.10	7.85
2025	6.50	4.45	9.60	8.35
2030	8.00	4.92	10.10	8.85

The Cook Inlet gas price is assumed to escalate sharply during this period consistent with the ICF production cost analysis. North Slope gas is assumed not to be available until 2010. The price of North Slope gas in the Railbelt is estimated as the netback value from LNG sales in Japan, assuming extrapolation of the ICF "mid" crude oil scenario. The fuel oil prices are also based on extrapolation of the "mid" crude oil scenario.

B.5 RAILBELT COAL PRICE FORECASTS

For this analysis, it is assumed that minemouth coal prices will be based on the cost of production and that the cost of production will not increase in real terms over the long run. Very limited resources were made available to the Institute of Social and Economic Research (ISER) to estimate these production costs. The constant real cost assumptions developed by ISER are as follows in 1987 dollars/MBtu:

Healy Minemouth	$1.30
Healy Delivered to Fairbanks	2.52
Healy Delivered to Nenana	1.69
Beluga Minemouth	1.15
Matanuska Minemouth	1.15
Healy Waste Coal at Minemouth	0.07
Beluga Waste Coal at Minemouth	0.07

Differential cost of Healy coal delivered to Fairbanks and Nenana is based on estimates of rail transport costs.

The Beluga minemouth price depends on the development of an 8 million ton per year mine at Beluga for export. It is assumed that a mine at Beluga would not be developed solely to supply coal to a power plant in Alaska.

The current proprietors of the Matanuska field intend to develop the remaining reserves for export, not for in-state power development. However, in the event that the export plan is not realized, the Matanuska resource could still be available in the 1990s and beyond for alternative purposes. The cost estimate used here is based on production scaled to a power plant of approximately 100 MW for the 28 years that currently estimated reserves would last at that rate of depletion.

Waste coal is a mixture of coal and earth that results from the inability of the dragline to cut the edge of the coal seam cleanly. The ratio of waste coal to regular coal at the Healy mine is estimated at about 1:10. While this presently results in far less waste coal than would be necessary to fuel a 100-MW power plant, it could make a significant contribution to fuel requirements if blended with regular coal. The cost of this material at the minemouth is estimated to be low.

Because the seam width at Beluga is estimated to be similar to Healy, comparable production ratios and costs for waste coal are estimated for Beluga. Given an 8 million ton per year export mine, however, the aggregate amount of waste coal available from such an operation would be significantly higher.

Of the coal cost estimates developed by ISER and shown above, the only ones used without modification in the analysis were the cost of Healy coal at the minemouth for supplying the existing 25-MW Healy power plant ($1.30/MBtu), and the cost of Healy coal delivered to Fairbanks for supplying existing coal-fired generation in that location ($2.52/MBtu). The only new coal-fired facility examined in the economic analysis was a proposed 50-MW power plant at Healy. Based on discussion with representatives of the Usibelli coal mine, it was assumed that the proposed plant would be supplied with 50 percent waste coal valued at $0.50/MBtu and 50 percent quality coal valued at $1.20/MBtu, for a blended fuel cost of $0.85/MBtu.

B.6 FIXED AND VARIABLE COMPONENTS OF FUEL PRICES

A specified project or action may allow a utility to avoid purchasing a given amount of fuel. From the utility's perspective, the avoided cost is the full purchase price of the fuel. From a broader perspective, however, the avoided cost is only the long-run variable cost component of the fuel. The fixed cost component of the fuel price, particularly if it is already a sunk cost, may not be avoided.

For example, Cook Inlet natural gas is provided to some generation facilities at a wellhead price and to other facilities at a higher price that includes both the wellhead component and a delivery margin. The costs of delivering natural gas are primarily fixed. Once the pipeline system is in place to transport the gas, there is relatively little variable cost in actually transporting a given volume. The costs of amortizing and maintaining the pipeline system are incurred in any event. As a result, the overall savings attributable to a decline in gas purchases are limited to the wellhead component of the gas price, even if the purchasing utility avoids payment of both the wellhead component and the delivery margin.

A further argument could be made that the only true avoided cost component of the gas is not simply its wellhead price, but rather the variable cost component of producing the gas.[1] According to the ICF analysis, the cost of producing Cook Inlet gas

[1]This would be true if the gas would not be otherwise consumed. If it were, then the next best use would be the value independent of cost.

is presently well below its negotiated purchase price, though that may change in the future. Particularly if limited markets do not offer comparable opportunity values for the gas, using its expected wellhead price may still overstate the true avoided cost of saving natural gas. However, insufficient information on production costs and alternate market opportunities was available to support the adoption of this approach.

The following fuel price differentials are important in the context of this study:

1. The price of natural gas at one generating facility versus the price of natural gas at another facility.

2. The price of natural gas versus the price of fuel oil.

3. The price of natural gas versus the price of coal.

Price of natural gas at one facility versus another. For the power system simulation modeling, delivered prices anticipated for each generating facility were input to the model to produce a realistic pattern of generation dispatch that would correspond with price signals the utilities are expected to receive. Changes in gas consumption at various facilities due to proposed projects are then examined after the simulation model is run, and appropriate adjustments to the benefits are considered. For example, if the proposed Kenai-Anchorage intertie resulted in an increase in gas-fired generation on the Kenai Peninsula using wellhead gas and a corresponding decrease in Anchorage generation using gas priced at wellhead plus delivery, an appearance of savings would result based on "saved" delivery costs. An appropriate adjustment would be to net out these apparent savings. In this case, however, it turned out that the simulation model did not project any significant substitution of Kenai gas-fired generation for Anchorage gas-fired generation, and the proposed adjustment was therefore not required.

Price of natural gas versus the price of fuel oil. It was assumed for this analysis that the delivered price of fuel oil is primarily variable in the long run. The main cost components are the acquisition cost to the refinery of crude oil, the refinery margin, and the distribution cost. The acquisition cost of crude oil is assumed to be variable in the same way the wellhead price of gas is assumed to be variable; i.e., crude oil savings are assumed to be equal to the full acquisition cost. The refinery margin and distribution costs are also assumed to be fully avoidable. It is recognized that the refinery margin includes a fixed cost component, but information was not developed for this study that identified its relative magnitude. The assumption is that the fixed component of the refinery margin is a relatively small part of the total delivered price of fuel oil.[2] Unlike the natural gas distribution system, the distribution

[2]Further, refinery capacity that is freed up due to erosion of one market may ultimately be used to supply fuel to another market.

costs of fuel oil are assumed to be primarily variable. Rather than consisting of a series of pipelines, fuel oil distribution involves primarily trucks and labor, most of which is avoidable in the long run to the extent that distribution is reduced. The relevant price differential between natural gas and fuel oil assumed in this analysis is therefore the wellhead price of natural gas (excluding sunk distribution costs) and the delivered price of fuel oil (including distribution costs that are assumed to be primarily variable). For the assessment of the proposed Cook Inlet-Fairbanks gas pipeline, however, the proposed pipeline system is clearly "avoidable" and its estimated cost is therefore deducted as a lump sum in the cost-benefit comparison.

Price of natural gas versus the price of coal. As with wellhead natural gas prices and refinery acquisition costs of crude oil, it was assumed that minemouth coal costs are fully avoidable. The transportation cost of coal from the mine to the consumer was also assumed to be avoidable. Although the railroad track itself is fixed in the same way the road system used by fuel distributors is fixed, the railroad coal cars (which can be leased or sold) plus the labor and fuel used to haul the coal are variable. The relevant price differential between natural gas and coal used in this analysis is therefore the wellhead price of natural gas and the delivered cost of coal.

Attempting to refine these distinctions further may not be very helpful. The fuel price differentials would decline if the prices assumed for fuel oil and coal were reduced according to an estimate of their unavoidable cost components, while natural gas price assumptions were left alone. This would reduce the benefits identified for certain options such as the gas pipeline and the various transmission improvements between Anchorage and Fairbanks, but would increase the benefits of the proposed coal plant by further reducing its assumed fuel cost relative to natural gas. On the other hand, the price differentials could grow larger if the value of natural gas was assumed to be less than its negotiated wellhead price, and instead was set at its cost of production or even its opportunity value in other markets.

Appendix C
DEMAND FORECASTS

The electricity demand forecasts, as well as the population and employment forecasts, described in Sections C.1 through C.3 were prepared by the Institute of Social and Economic Research (ISER) in consultation with the Alaska Power Authority (APA). Most of the analysis was performed with respect to these forecasts. The utility demand forecast described in Section C.4 was subsequently submitted by Railbelt utility representatives and was used for sensitivity analysis.

C.1 RAILBELT POPULATION AND EMPLOYMENT FORECASTS

Electricity demand is dependent on the forecasts of population, households, and employment in the study area. A range of forecasts was developed based on alternative assumptions and varying combinations of assumptions. Using probabilities adopted by the Power Authority Board, a "low," "middle," and "high" case was identified, each of which is judged to be equally probable. Neither the low nor the high case is intended to represent a boundary (i.e., a "worst" or "best") case. Table C-1 shows a summary of the three population forecasts for the Railbelt. Table C-2 shows a breakdown of the middle case into the three main regions selected for purposes of the intertie analysis.

Table C-1

RAILBELT POPULATION FORECASTS
(thousands)

	Low	Middle	High
1987	388.0	388.0	388.0
1990	385.6*	383.9*	389.5
1995	399.4	405.4	418.3
2000	416.7	436.5	465.9
2005	445.7	479.7	527.1
2010	480.3	538.7	586.7

*The selection of cases was determined by the number of households and level of employment in the year 2010. As a result, there can be overlap among the selected cases in the initial years.

Table C-2

MIDDLE CASE—RAILBELT POPULATION FORECAST
(thousands)

	Anchorage and Mat-Su Boroughs	Kenai Peninsula Borough	Fairbanks North Star Borough*
1987	268.6	39.6	79.8
1990	262.1	39.7	82.2
1995	277.4	41.3	86.8
2000	300.2	44.4	91.9
2005	333.3	47.7	98.6
2010	378.5	52.3	107.9

*Includes the Southeast Fairbanks census area.

Although numerous combinations of assumptions can produce a roughly comparable forecast of population, the main assumptions underlying the selected middle case are briefly summarized below.

The price of oil is assumed to rise from $14 per barrel in 1990 (1987 dollars) to $20 in 2010. Production from existing fields continues, and technological advances combined with cost control allow the West Sak field on the North Slope to come into production after 2000. Production falls off from a peak of 723 million barrels in 1989 to 411 million in 2000 and 265 million in 2010. Frontier areas, including ANWR[1] and the OCS[2], are not developed because sufficiently large discoveries are not made and the cost of development of small fields cannot be recovered due to the low price. In spite of the decline in production, however, total employment in the industry does not fall because of the increasingly labor-intensive nature of the process of extracting the maximum amount of oil out of currently producing fields. It is assumed that a TAGS[3] gas line is not built within the forecast horizon (i.e., prior to 2010).

The federal government role as a basic industry remains constant with the exception of the deployment of the Light Infantry Division in Fairbanks.

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[1]Arctic National Wildlife Refuge

[2]Outer Continental Shelf

[3]Trans-Alaska Gas System

Tourism expansion continues at a rate of 20,000 additional tourist visitors annually. The mining industry grows in the late 1980s and 1990s at a rapid rate with the development of the Red Dog, Greens Creek, and U.S. Borax projects, a new coal facility for export in the Railbelt, and other unspecified activities projected to increase at three percent annually.

The timber industry expands into the early 1990s, at which time further growth is constrained by the size of the resource base, except in Southcentral Alaska where a modest industry develops in the 1990s. The traditional commercial fishery is constrained by the size of the resource base, but the bottomfish industry expands over time, centered in the Southwestern part of the state, but with additional activity in the Southern Railbelt and Bristol Bay.

State government gradually contracts through the 1990s in spite of revenue augmentation measures, including the use of Permanent Fund earnings beginning in 1992, the reimposition of the personal income tax in 1996, and the elimination of the Permanent Fund dividend in 1999. State petroleum revenues decline in real terms to $1241 million in 2000 and $842 million in 2010. The Permanent Fund real rate of return averages only three percent annually. Government expenditures are concentrated on the operating budget, leaving little for capital expenditures. In spite of wage levels held constant in nominal dollars for several years, government employment levels fall over time due to revenue constraints.

The Railbelt economy continues to be the support center for the majority of the state. Its economy grows in response to basic sector growth, which occurs largely outside the boundaries of the Railbelt, and also in response to per capita income growth, which is assumed to resume in the 1990s following the current recession.

C.2 RAILBELT ELECTRICITY DEMAND FORECASTS

Electricity demand forecasts have been developed for each category of electrical use and for each of the main regions of the Railbelt. (Examples of electrical use categories are commercial lighting and residential hot water heating.) The main purpose for developing the demand forecasts at the "end-use" level of detail is to provide a foundation for assessing the impacts of conservation programs. For example, to estimate the cost and effect of implementing a program to encourage more efficient commercial lighting, it is necessary to start with a forecast of electrical demand for commercial lighting based on estimates of efficiency levels that would develop over time in the absence of the program. Only then can the expected incremental effect of the program be estimated and judged.

In 1987, the seven electric utilities in the Railbelt required approximately 3400 GWh (millions of kilowatthours) to meet their customers' needs. Table C-3 shows the estimated breakdown of this energy requirement. Table C-4 shows the proportional breakdown of residential and commercial sales to each end-use category in 1987.

Table C-3

1987 USES OF UTILITY-SUPPLIED ELECTRICITY
(total Railbelt)

	GWh	Percent
Residential	1245	37
Commercial	1516	45
Industrial	256	8
Street Lights & Public Authorities	49	1
Distribution Losses & Office Use	225	7
Transmission Losses	82	2
TOTAL	3373	100

Table C-4

END-USE BREAKDOWN OF RESIDENTIAL AND COMMERCIAL SALES

1987 Residential Sales		1987 Commercial Sales	
End Use	Percent	End Use	Percent
Space Heating	19	Space Heating	3
Water Heating	15	Space Cooling	4
Refrigerators	12	Ventilation	15
Freezers	6	Water Heating	2
Cooking	5	Refrig & Freez	12
Clothes Drying	8	Cooking	3
Lighting	13	Lighting	49
Miscellaneous	22	Miscellaneous	12
TOTAL	100	TOTAL	100

Again, a range of forecasts was developed based on alternative assumptions and varying combinations of assumptions, including the following:

1. Population, households, and employment.

2. Energy prices.

3. Consumer discount rates (for modeling consumer purchase choices).

4. Technological change (e.g., possible change in efficiency options and costs).

5. Southern Railbelt natural gas market penetration (i.e., different expansion scenarios for the natural gas distribution system).

Based on probabilities established by ISER and Power Authority staff, "low," "mid," and "high" cases were selected from the distribution such that each of the three is judged to be equally probable (i.e., the low represents the bottom third of the distribution, the mid represents the middle third, and the high represents the top third). Table C-5 shows these three forecasts aggregated for the entire Railbelt. Table C-6 shows a further breakdown of the mid case for each of three main Railbelt regions.

Table C-5

RAILBELT ELECTRIC DEMAND FORECAST*
(total energy, GWh)

	Low	Mid	High
1987	3305	3305	3305
1990	3237	3225	3269
1995	3153	3271	3432
2000	3156	3395	3675
2005	3289	3641	4058
2010	3495	4053	4427

*Excludes transmission losses. Weather adjusted.

Residential electricity sales are forecast to grow more slowly than the stock of occupied housing due to higher efficiencies for new equipment (which in part reflects implementation of new federal appliance efficiency standards), assumed increase in average electricity prices due largely to the expiration of existing contracts for "old" Beluga gas supplied to Chugach Electric Association, and continued erosion of electric market share to natural gas particularly in the category of space heat.

Table C-6

MID CASE ELECTRIC DEMAND FORECAST
(three Railbelt regions, GWh)

	Anchorage and Mat-Su Boroughs	Kenai Peninsula Borough	Fairbanks North Star Borough*
1987	2262	455	588
1990	2189	438	598
1995	2219	430	622
2000	2306	442	646
2005	2493	462	685
2010	2805	497	752

*Includes Southeast Fairbanks census area

Commercial electricity sales are forecast to grow more slowly than commercial floorstock due primarily to higher efficiencies for new equipment, particularly in the lighting sector. Implementation of new federal standards for fluorescent ballasts contributes to this outlook. The relatively low level of electric space heat is expected to decline further, while miscellaneous equipment per square foot is expected to grow.

For the industrial forecast in the mid case, the Tesoro refinery on the Kenai Peninsula is projected to reduce its purchases from Homer Electric from 89.3 GWh in 1987 to 59.5 GWh in all subsequent years as a result of increased self-generation at the refinery. In the low case, Tesoro purchases from Homer Electric decline to zero in 1995 and beyond, consistent with 100 percent self-generation. For the entire Railbelt, Table C-7 shows the total industrial demand for the three selected cases.

Table C-7

RAILBELT INDUSTRIAL DEMAND FORECAST*
(total energy, GWh)

	Low	Mid	High
1987	256	256	256
1990	244	244	244
1995	172	252	311
2000	174	263	327
2005	176	270	364
2010	178	278	380

*Utility supplied, includes no self-generation

Presently, the military bases in the Fairbanks area and the University of Alaska at Fairbanks supply nearly all of their own electric power requirements by operating cogeneration plants that supply both electricity and heat to their respective facilities. Cogeneration facilities efficiently produce electricity and heat in particular proportions. If electricity needs outstrip this balance, the additional electricity is more costly to produce. Particularly for the military bases, there is evidence that electrical needs beyond the balance point could be supplied more efficiently by a local utility, and discussions are in progress between the military and Golden Valley Electric Association regarding sale and purchase of this specific increment of power. Table C-8 presents these potential purchases by the military above the cogeneration balance point.

Table C-8

POTENTIAL PURCHASES OF CIVILIAN ELECTRICITY BY THE MILITARY IN THE FAIRBANKS AREA
(GWh)

Year	Eielson	Wainwright	Greely	Total
1990	12.4	14.0	16.2	42.6
2000	15.1	17.0	16.9	48.9
2010	17.2	19.3	19.2	55.7

The estimated peak purchase in 1990 consistent with these potentials would be approximately 9.5 MW, and would occur during the summer season.

Potential power sales to the University of Alaska at Fairbanks were also considered, though the estimate is only 2 GWh per year due to the specific characteristics of the University plant and load.

Most of the cases examined for the power system modeling assumed that the potential power sales to the military and the University would occur. These loads were therefore added to the Fairbanks load forecast for purposes of the system modeling. Sensitivity analysis that excluded the military and University loads was performed to estimate the importance of this assumption to the feasibility results.

C.3 ADDITIONAL LOADS SERVED BY THE NORTHEAST INTERTIE

To assess the feasibility of the Northeast intertie proposal, the additional electrical loads that would be connected to the Railbelt grid as a result of the new intertie must be estimated. These loads occur primarily in the Glennallen-Valdez area, presently served by Copper Valley Electric Association (CVEA). Table C-9 presents the low, mid, and high forecasts of Northeast intertie loads. Peak demand in 1990 is approximately 10.5 MW. In the high case, peak demand increases to 20 MW in the year 2010.

Table C-9

NORTHEAST INTERTIE LOAD FORECASTS
(GWh)

Year	Low	Mid	High
1990	51	51	52
1995	51	83	111
2000	54	85	99
2005	55	87	121
2010	58	90	111

The backscatter radar facility will be supplied in whole or in part by on-site generation, and may or may not accept a portion of its electrical requirements from the grid. For the low, mid, and high cases, 0, 2.7-, and 3.7-MW average load from the grid were assumed respectively. The mid case assumption is consistent with the bid previously submitted by CVEA for provision of power to the site. Most of the increase in CVEA load shown in the mid case depends on this assumption.

The sharp rise in demand for the high case in 1995 reflects not only the high assumption for the radar site but also assumes construction of a major refinery in Valdez at that time. The second obvious bulge in the high case around 2005 reflects construction of the TAGS line.

Of the roughly 50 GWh presently demanded in the CVEA system, roughly 40 GWh is supplied from the Solomon Gulch hydro project in Valdez with the other 10 GWh supplied from diesel generation.

C.4 SUMMARY OF ENERGY AND PEAK DEMAND FORECASTS INPUT TO PRODUCTION SIMULATION MODEL

The demand forecasts produced by the ISER analysis were adjusted in one additional way before being input to the production simulation model: they were reduced by the amount of self-generation (i.e., commercial and industrial cogeneration of heat and power) estimated to occur over the next 20 years and not already accounted for in the ISER industrial forecast. Table C-10 shows a summary of this adjustment. The analysis that supports these estimates is presented in Appendix D.

Table C-11 presents a summary of the energy and peak demand forecasts input to the simulation model, along with a 1987 base year for comparison. Included here are the base forecasts produced by ISER plus the estimated increments of military and University load in Fairbanks, minus the self-generation adjustment. (Also included is an adjustment to reallocate a minor fraction of the Anchorage load to the Kenai Peninsula, where it physically belongs.)

Table C-10

ADJUSTMENT FOR COMMERCIAL AND INDUSTRIAL SELF-GENERATION
(annual GWh reduction)

	Anchorage & Mat-Su	Kenai Peninsula	Fairbanks
1995	12.4	0.8	1.4
2000	29.0	2.8	5.0
2005	45.6	4.9	8.5
2010	62.2	6.9	12.1

Table C-11

SUMMARY OF ENERGY AND PEAK DEMAND FORECASTS INPUT TO THE MODEL BASED ON ISER SCENARIOS

		Anchorage & Mat-Su		Kenai Peninsula		Fairbanks		Copper Valley	
		GWh	MW	GWh	MW	GWh	MW	GWh	MW
	1987*	2165.5	391.8	501.3	87.2	624.8	119.1	55.4	10.2
LOW	1994	2068.9	374.3	413.9	72.0	665.5	126.8	51.1	10.6
	2010	2229.1	403.3	428.9	74.6	749.6	142.9	57.8	12.0
MID	1994	2087.3	377.6	475.5	82.7	657.2	125.2	77.7	14.3
	2010	2617.4	473.5	549.8	95.7	792.0	150.9	89.1	16.4
HIGH	1994	2184.2	395.1	498.9	86.8	695.6	132.6	107.6	19.5
	2010	2823.4	510.8	608.3	105.9	896.7	170.9	110.4	20.0

*ISER is the source for initial year estimates. Copper Valley initial year is 1988.

C.5 UTILITY DEMAND FORECAST

During a meeting held on February 24, 1989, Railbelt utility representatives requested that the load forecasts most recently developed by the utilities be input to the simulation model as well as the APA forecasts. Peak load estimates from the utilities were provided to APA soon thereafter. These estimates were roughly translated into energy requirements (i.e., GWh per year) by application of load duration curves previously used in this analysis. Table C-12 shows the utility peak demand forecasts and resulting energy requirements calculated by region and input to the model for sensitivity testing.

Table C-12

UTILITY DEMAND FORECAST AS INPUT TO THE SIMULATION MODEL

	Anchorage and Mat-Su		Kenai Peninsula		Fairbanks		Copper Valley	
	GWh	MW	GWh	MW	GWh	MW	GWh	MW
1994	2180.6	394.5	512.6	89.2	755.6	144.0	121.4	22.0
2010	3014.7	545.4	553.4	96.3	970.7	185.0	135.2	24.5

C.6 LOAD DURATION CURVES

Using the 1987 hourly load data provided by the utilities [1], [2], [3], [4], [5], [6], [7], [8], [9], [10], we developed load duration curves for all utilities in the Railbelt. We divided the year into a peak and off-peak season. The peak demand season (winter months) include November through February. The off-peak demand season includes the remaining eight months of the year: March through October. The utilities were then aggregated into the four areas based on their service areas. Table C-13 lists the service areas of all eight utilities.

Table C-14 shows that CEA's retail load is mainly in Anchorage (96 percent); only 4 percent is in Kenai. Using the energy breakdown within each area (see Table C-15), we constructed the area load duration curves as the energy weighted sum of each utility's individual load duration curve for all utilities within each area.[4]

[4]Because of the high coincidence factor among peaks in the Railbelt (over 97 percent), we added the utility loads within each area. This is referenced in Susitna FERC License Application, Nov. 1985 draft, Exhibit B.

Table C-13

SERVICE AREAS OF RAILBELT UTILITIES

Area	Utilities
Kenai	HEA, SES, CEA*
Anchorage	AMLP, MEA, CEA*
Fairbanks	GVEA, FMUS
Copper Valley	CVEA

*CEA serves retail loads in both Anchorage and Kenai.

Table C-14

ENERGY AND DEMAND BREAKDOWN FOR CEA

	Energy		Peak Demand
Area	(GWh)	% of Total	(MW)
Kenai	34.6	4	7
Anchorage	846.4	96	161

Source: [11]

The peak and off-peak load duration curves for Kenai, Anchorage and Fairbanks are shown in Figures C-1, C-2, and C-3. In addition, a load duration curve was estimated for the Copper Valley area based on current peak demand, minimum demand, and load factor reported by CVEA.

Table C-15

ENERGY BREAKDOWN BY AREA AND BY UTILITY

Area	Utility	Energy (GWh)	Energy % of Area
Kenai	HEA	414.5	85.5
	SES	35.5	7.3
	CEA	34.6	7.1
	Total	484.6	100.0
Anchorage	CEA	846.5	40.8
	AMLP	789.2	38.0
	MEA	439.7	21.2
	Total	2075.4	100.0
Fairbanks	GVEA	409.8	75.0
	FMUS	136.9	25.0
	Total	546.7	100.0
Copper Valley	CVEA	43.6	100.0

Sources: [1], [5], [9], [10], [11]

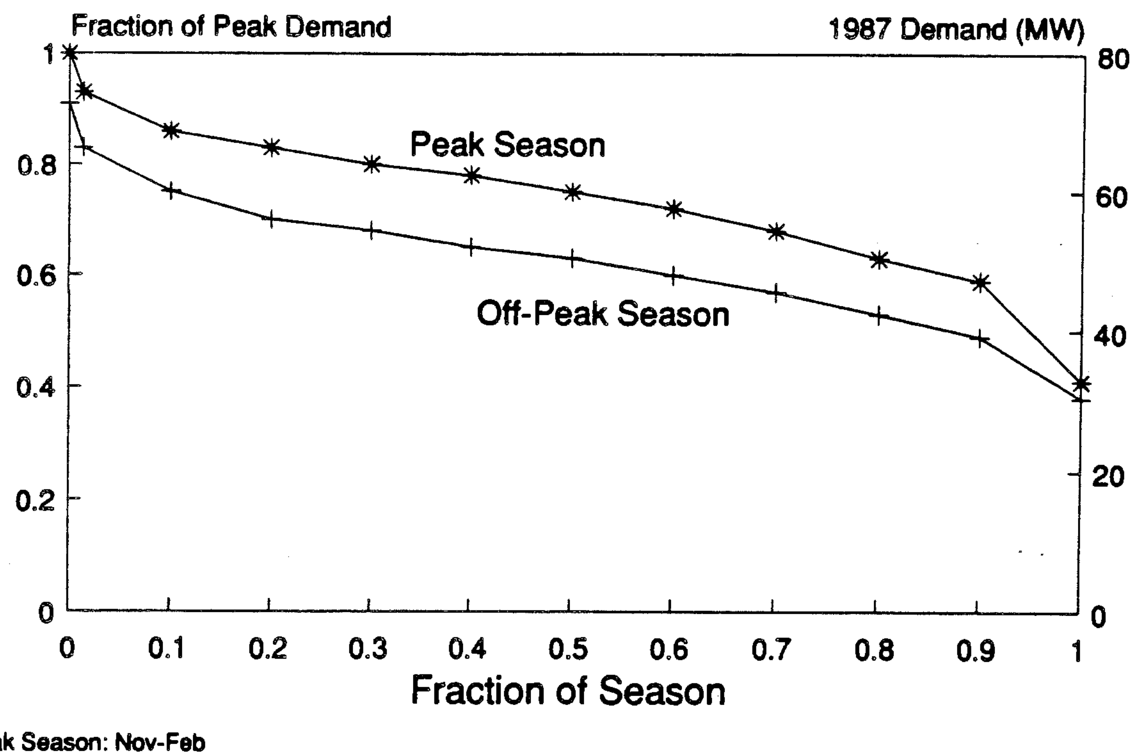

Figure C-1. Load Duration Curves for the Kenai Peninsula

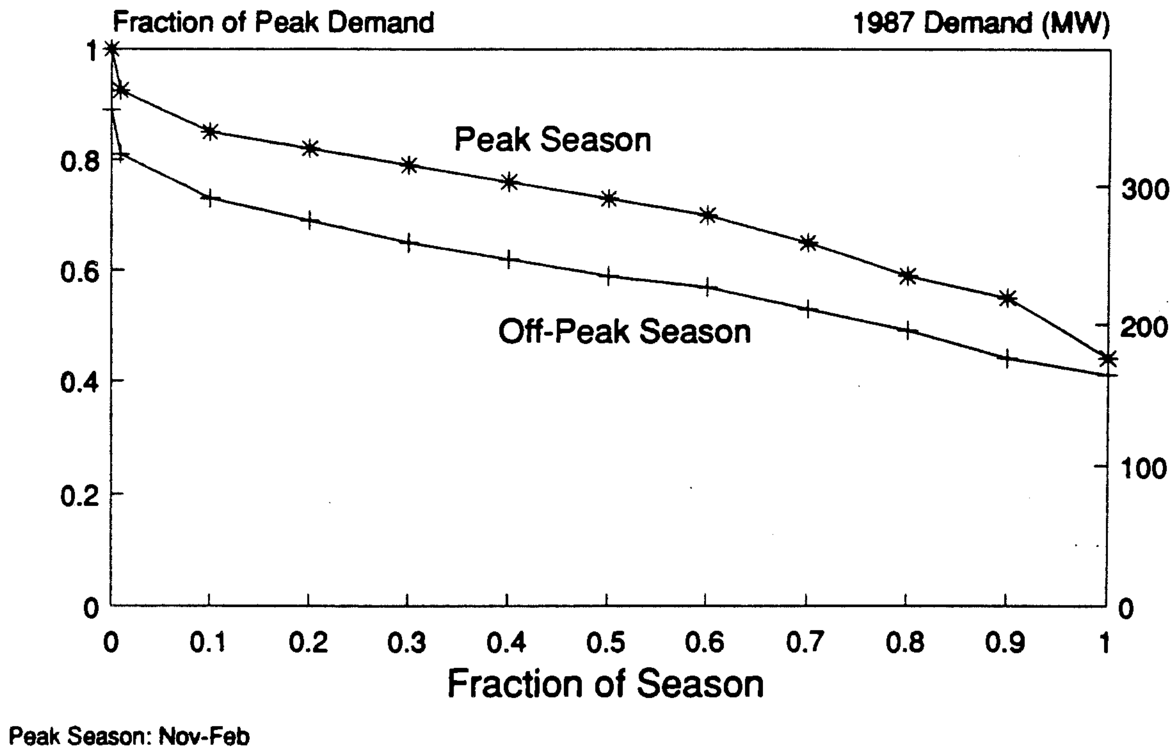

Figure C-2. Load Duration Curves for Anchorage

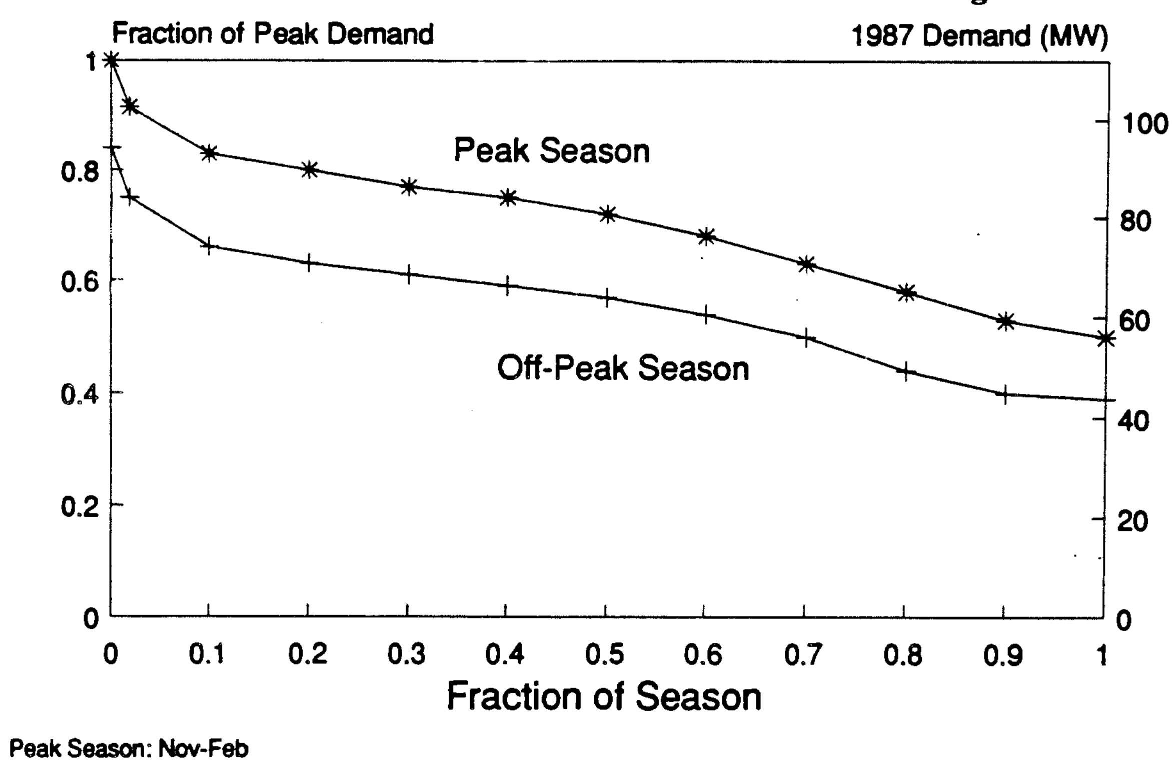

Figure C-3. Load Duration Curves for Fairbanks

C.7 REFERENCES

[1] Letter from Moe Aslam (AMLP) to Jennie Rice (DFI), 30 August 1988.

[2] Letter from Gerald Mackey (CEA) to Jennie Rice (DFI), 19 September 1988.

[3] Letter from Gerald Mackey (CEA) to Salim Jabbour (DFI), 13 October 1988.

[4] Letter from Gerald Mackey (CEA) to Mike Gordon (DFI), 12 December 1988.

[5] Letter from Lowell Highbargain (CVEA) to Jennie Rice (DFI), 26 August 1988.

[6] Phone conversation between Paul Diener (SES) and Salim Jabbour (DFI).

[7] Phone conversation between Kent Wick (HEA) and Salim Jabbour (DFI).

[8] Letter from Adam Choi (FMUS) to Salim Jabbour (DFI), 23 September 1988. Covers loads.

[9] Phone conversation between Marty Lanum (FMUS) and Salim Jabbour (DFI).

[10] Letter from Steve Haagenson (GVEA) to Jennie Rice (DFI), 24 August 1988.

[11] *1987 Power Requirements Study*, Chugach Electric Association, November 1987.

Appendix D

ANALYSIS OF COGENERATION POTENTIAL

D.1 OVERVIEW

Cogeneration is the simultaneous or sequential production of both thermal (typically hot water or steam) and electric energy. The efficiency of cogeneration systems, generally within a range of 67 to 92 percent, exceeds the efficiency of conventional systems that provide electricity or thermal energy separately.

Cogeneration equipment is available in a wide range of sizes. Large systems, similar in size to conventional power plants, are suitable for industrial applications; smaller systems, as small as 10 kilowatts, are suitable for commercial applications.

The technical and market potential of cogeneration depends on several factors, primarily:

- *Fuel/Electricity Cost Differential*: Cogeneration systems are most attractive where there is a large difference between the retail price of electricity and the price of fuel used in a cogeneration system.

- *Coincidence of Thermal and Electric Loads*: The value of cogeneration is significantly enhanced when the demands for thermal energy and electric energy coincide. Coincidence can be created by selling excess electricity to the utility or storing excess thermal energy.

- *High Thermal Load Factor*: Cogeneration is most attractive when the demand for thermal energy is relatively constant on a year-round basis.

The first factor appears to be characteristic of the Railbelt. The second and third factors are not as commonly found and depend on the nature of the business.

The objective of this analysis was to forecast installations of cogeneration equipment by the commercial and industrial sectors of the Railbelt during the period

1990 to 2010. We collected and developed information on energy needs in each sector to determine the total technical potential for cogeneration, that is, the potential without regard to economics. We then determined the market potential, taking into account the uncertainties in fuel price and electric price growth, capital cost, and customer discount rates.

The remainder of this section has the following organization. First, we describe the characterization of the potential cogeneration market in the Railbelt. Second, we present the characterization of the potential cogeneration technologies. Third, we discuss the approach to the market potential analysis. Fourth, we describe other potential Railbelt cogeneration projects brought to our attention. Finally, we present the results of the analysis.

D.2 CHARACTERIZATION OF COGENERATION TECHNICAL POTENTIAL

The cogeneration technical potential is the total capacity that could be installed regardless of its economics. Before calculating the technical potential, we performed preliminary economic analyses to determine how electric customers in the commercial and industrial sectors would size their cogeneration systems. We found that customers would typically choose a system size to meet their peak electric demand or less. Thus, the cogeneration technical potential is equivalent to the peak demand for electricity. The following subsections summarize the characterization of the technical potential within each component of the commercial sector and the industrial sector.

D.2.1 Commercial Sector

We characterized the types of customers in the commercial sector according to the fifteen building types shown in Table D-1. Our main source of information was an Institute of Social and Economic Research (ISER) survey of commercial buildings in the Anchorage, Fairbanks, Kenai, and Matsu regions [1]. The survey covered buildings representing approximately six percent of total Railbelt commercial sector electricity consumption. After reviewing the survey, we decided to exclude the miscellaneous, vacant, and assembly building types. We did this for two reasons. First, the Anchorage International Airport (AIA), which is treated separately, makes up a major portion of these groups. Second, the buildings in these groups have diverse electric and thermal requirements, making generalizations about them difficult.

Table D-1

COMMERCIAL SECTOR BUILDING TYPES

1. Small Office	6. Grocery	11. School
2. Large Office	7. Warehouse	12. College
3. Restaurant	8. Car Service	13. Assembly
4. Large Retail	9. Lodging	14. Miscellaneous
5. Small Retail	10. Medical	15. Vacant

The survey contained information on building type, annual electricity consumption, sources of space and water heating (electric, gas, or oil), floor area, and the fraction of the floor area served by these sources. Table D-2 includes the detailed customer-specific information provided by the survey. Since information was available on annual electricity consumption (kWh per year), but not peak demand (kW), we derived peak demand from the available data to estimate the technical potential.

We used a three-step approach to characterize the technical potential. First, we calculated the total annual electricity and thermal demand for each surveyed customer in each building type.[1] We assumed that the average electric and thermal demand per square foot for each building type within the survey sample was representative of all commercial buildings within that type. Second, we developed annual load duration curves to represent the different levels of thermal and electricity demand over the year for each building type. This allowed us to determine the peak electric and thermal demand for each average customer.[2] Third, we estimated the total peak electric demand for the building type based on the peak electric demand for each average customer. The sum of the peak electric demands for each building type was the technical potential.

[1]We calculated the demand for space and water heating in each building type to determine thermal energy requirements. We also considered space cooling as a possible end use to be served by cogeneration, but cooling in the Railbelt is done primarily with compression chilling and outside air. Compression chilling usually precludes a switch to absorption chillers due to the fairly extensive change in equipment that would be involved. We refer to the demand for space and water heating as "thermal" demand in this section.

[2]The peak electric and thermal demand of an average customer for each building type in the total market was assumed to be equal to the peak electric and thermal demand of the average customer for each building type in the survey.

Table D-2

SUMMARY OF ISER END USE SURVEY

Commercial End Use Survey (does not include Federal buildings)
Master Data Base - Modified by DFI 12/31/88

(1=Electric, 2=Gas, 3=Oil); 2ndary SH Fuel: (x.yy, x=fuel type, yy=% area)

1 - Small Office

ISER # (Sorted by Building Code)	NAME	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	Space Heating Area (sq ft) Electric	Space Heating Area (sq ft) Gas	Space Heating Area (sq ft) Oil	Water Heating Area (sq ft) Electric	Water Heating Area (sq ft) Gas	Water Heating Area (sq ft) Oil	Space Htg. Energy Demand Electric (kWh/yr)	Space Htg. Energy Demand Gas (MBtu/yr)	Space Htg. Energy Demand Oil (MBtu/yr)	Water Htg. Energy Demand Electric (kWh/yr)	Water Htg. Energy Demand Gas (MBtu/yr)	Water Htg. Energy Demand Oil (MBtu/yr)	Electric Demand (kWh/yr)
411.001		1		1		426	426	0	0	426	0	0	3025	0	0	426	0	0	3060
218.001		3		1		711	0	0	711	711	0	0	0	0	24	711	0	0	9415
407.001		2	1.08	1		2680	80.4	2599.6	0	2680	0	0	724	80	0	2680	0	0	
136.001		2		2		2690	0	2690	0	0	2690	0	0	83	0	0	9	0	11199
208.001		3		3		3300	0	0	3300	0	0	3300	0	0	112	0	0	11	28170
308.001		2		2		3400	0	3400	0	0	3400	0	0	104	0	0	12	0	29958
110.001		2		2		3600	0	3600	0	0	3600	0	0	111	0	0	12	0	39087
135.001		2		2		3650	0	3650	0	0	3650	0	0	112	0	0	12	0	14320
219.001		3		1		3796	0	0	3796	3796	0	0	0	0	128	3796	0	0	
46.001		2		2		3864	0	3864	0	0	3864	0	0	119	0	0	13	0	42090
309.001		2		1		4300	0	4300	0	4300	0	0	0	132	0	4300	0	0	156745
116.001		2		2		5310	0	5310	0	0	5310	0	0	163	0	0	18	0	33420
22.001		2		2		7560	0	7560	0	0	7560	0	0	232	0	0	26	0	102068
204.001		3	1.32	1		7742	2477.44	0	5264.56	7742	0	0	24527	0	170	7742	0	0	160800
148.001		2		2		10238	0	10238	0	0	10238	0	0	314	0	0	35	0	108396
418.001		1		1		11578	11578	0	0	11578	0	0	105102	0	0	11578	0	0	394676
100.001		2	1.2	1		13000	2600	10400	0	13000	0	0	23400	319	0	13000	0	0	348091
114.001		2		2	1.33	15000	0	15000	0	4950	10050	0	0	461	0	4950	34	0	147208
7.001		2		2		15000	0	15000	0	0	15000	0	0	461	0	0	51	0	242355
111.001		2		2		20000	0	20000	0	0	20000	0	0	614	0	0	68	0	344665
					Totals	131,460 sq ft						Totals	156,864	3,226	313	42,006	291	11	2,207,325
					Average	7,304 sq ft						Average	8,714	179	17	2,378	16	1	122,629

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	112	251	0.44
Total	135,745	305,028	

Reg'l 10^6 sq ft
8.889 Total
6.383 ANC
1.018 FBX
0.944 KEN
0.549 NAT

Avg. Customers - ANC 874 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 139
Avg. Customers - KEN 129
Avg. Customers - NAT 76

2 - Large Office

ISER # (Sorted by Building Code)	NAME	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	Space Heating Area (sq ft) Electric	Space Heating Area (sq ft) Gas	Space Heating Area (sq ft) Oil	Water Heating Area (sq ft) Electric	Water Heating Area (sq ft) Gas	Water Heating Area (sq ft) Oil	Space Htg. Energy Demand Electric (kWh/yr)	Space Htg. Energy Demand Gas (MBtu/yr)	Space Htg. Energy Demand Oil (MBtu/yr)	Water Htg. Energy Demand Electric (kWh/yr)	Water Htg. Energy Demand Gas (MBtu/yr)	Water Htg. Energy Demand Oil (MBtu/yr)	Electric Demand (kWh/yr)
0.202		2		2		26000	0	26000	0	0	26000	0	0	799	0	0	89	0	391647
5.002		2	1.3	1		32400	9720	22680	0	32400	0	0	87400	697	0	32400	0	0	798409
2.102		2		2		35073	0	35073	0	0	35073	0	0	1077	0	0	120	0	14014167
0.102		2		2	1.05	63000	0	63000	0	2650	60350	0	0	1628	0	2650	172	0	1273464
2.302		2		2		63637	0	63637	0	0	63637	0	0	1955	0	0	217	0	0
44.102		2		2		74600	0	74600	0	0	74600	0	0	2291	0	0	255	0	1780181
2.202		2		2		91767	0	91767	0	0	91767	0	0	2819	0	0	318	0	0
1.002		2		2		207818	0	207818	0	0	207818	0	0	6386	0	0	709	0	8477960
2.402		2		2		459568	0	459568	0	0	459568	0	0	14117	0	0	1569	0	0
					Totals	428,886 sq ft						Totals	87,400	12,876	0	35,050	1,344	0	21,730,836
					Average	47,654 sq ft						Average	9,720	1,431	0	3,894	149	0	2,414,537

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	2,401	1,626	1.48
Total	828,657	219,251	

Reg'l 10^6 sq ft
6.424 Total
6.174 ANC
0.225 FBX
0.025 KEN
0 NAT

Avg. Customers - ANC 130 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 5
Avg. Customers - KEN 1
Avg. Customers - NAT 0

Table D-2 (continued)

	(1=Electric, 2=Gas, 3=Oil) Primary SH Fuel	2ndary SH Fuel (x.yy, x=fuel type, yy=% area)	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	Space Heating Area (sq ft) Electric	Gas	Oil	Water Heating Area (sq ft) Electric	Gas	Oil	Space Htg. Energy Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Water Htg. Energy Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
3 - Restaurant																		
58.003	2		2		1099	0	1099	0	0	1099	0	0	38	0	0	26	0	28810
205.003	3		3		1440	0	0	1440	0	0	1440	0	0	52	0	0	34	
44.203	2		2		1692	0	1692	0	0	1692	0	0	55	0	0	40	0	
9.503	NA		1		3369	0	0	0	3369	0	0	0	0	0	28583	0	0	
408.003	3		2	1.33	4032	0	0	4032	1331	2701	0	0	0	131	9314	85	0	130410
217.003	3		2		4060	0	0	4060	0	4060	0	0	0	145	0	97	0	78160
57.003	2		2		4500	0	4500	0	0	4500	0	0	147	0	0	108	0	
409.103	3		3		5000	0	0	5000	0	0	5000	0	0	163	0	0	119	155968
128.003	2		2		5000	0	5000	0	0	5000	0	0	163	0	0	119	0	
60.003	2		2		5400	0	5400	0	0	5400	0	0	176	0	0	129	0	180240
55.003	2		2		5525	0	5525	0	0	5525	0	0	180	0	0	132	0	361745
0.403	2		2		8000	0	8000	0	0	8000	0	0	260	0	0	191	0	11786
56.003	2		2		12000	0	12000	0	0	12000	0	0	391	0	0	287	0	364607
59.003	2		2		12500	0	12500	0	0	12500	0	0	407	0	0	299	0	118388
Totals					57,618 sq ft							0	1,450	489	9,314	1,225	119	1,428,927
Average					6,402 sq ft							0	161	49	1,035	136	13	158,770

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	158	363	0.43
Total	50,830	115,796	

Reg'l 10^6 sq ft: 2.043 Total; 1.252 ANC; 0.35 FBX; 0.344 KEN; 0.097 MAT

Avg. Customers - ANC 196 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 55
Avg. Customers - KEN 54
Avg. Customers - MAT 15

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
4 - Large Retail																		
9.204	2	1.5	1		21470	10735	10735	0	21470	0	0	67631	281	0	17178	0	0	842098
9.304	2	1.4	1		22151	8860.4	13290.6	0	22151	0	0	55921	288	0	17721	0	0	354003
9.104	2	1.4	1		24649	9859.6	14789.4	0	24649	0	0	52115	318	0	19719	0	0	639481
212.004	3		1		40000	0	0	40000	40000	0	0	0	0	946	32000	0	0	10690
9.304	2		1		49607	0	49607	0	49607	0	0	0	1067	0	39688	0	0	875688
9.004	2		1		60220	0	60220	0	60220	0	0	0	1295	0	48176	0	0	1058670
9.404	2		2		335000	0	335000	0	0	335000	0	0	7208	0	0	915	0	4208131
Totals					553,097 sq ft							185,563	10,399	946	174,478	915	0	7,708,718
Average					79,014 sq ft							26,509	1,486	135	24,925	131	0	1,101,245

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	1,050	1,927	0.54
Total	47,300	86,621	

Reg'l 10^6 sq ft: 3.56 Total; 2.982 ANC; 0.368 FBX; 0.011 KEN; 0.204 MAT

Avg. Customers - ANC 38 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 5
Avg. Customers - KEN 0
Avg. Customers - MAT 3

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
5 - Small Retail																		
416.105	NA		1		500	0	0	0	500	0	0	0	0	0	400	0	0	
127.105	2		1		1140	0	1140	0	1140	0	0	0	26	0	912	0	0	
9.605	1		1		1150	1150	0	0	1150	0	0	7245	0	0	920	0	0	
415.005	3		NA		1178	0	0	1178	0	0	0	0	0	25	0	0	0	21051
47.005	3		1		1936	0	0	1936	1936	0	0	0	0	42	1549	0	0	79306
9.705	NA		1		1958	0	0	0	1958	0	0	0	0	0	1566	0	0	
416.205	NA		1		2688	0	0	0	2688	0	0	0	0	0	2150	0	0	
206.005	3		2		5898	0	0	5898	0	5898	0	0	0	189	0	16	0	
16.005	2		1		6900	0	6900	0	6900	0	0	0	148	0	5520	0	0	41118
184.005	2		2		9048	0	9048	0	0	9048	0	0	195	0	0	25	0	9148
308.005	2		2		11083	0	11083	0	0	11083	0	0	238	0	0	30	0	114117
126.005	2		2		12250	0	12250	0	0	12250	0	0	263	0	0	33	0	58285
9.905	2		1		14300	0	14300	0	14300	0	0	0	307	0	11440	0	0	273536
38.205	2	1.05	2		18195	909.75	17285.25	0	0	18195	0	5781	372	0	0	50	0	617940
117.005	2		2		30000	0	30000	0	0	30000	0	0	645	0	0	82	0	486618
42.005	2		1		34000	0	34000	0	34000	0	0	0	731	0	27200	0	0	522136
Totals					138,890 sq ft							5,781	2,900	67	45,709	220	0	2,228,996
Average					13,889 sq ft							578	290	7	4,571	22	0	222,400

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	217	336	0.65
Total	145,286	224,855	

Reg'l 10^6 sq ft: 9.288 Total; 5.458 ANC; 1.753 FBX; 1.248 KEN; 0.839 MAT

Avg. Customers - ANC 393 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 126
Avg. Customers - KEN 89
Avg. Customers - MAT 60

Table D-2 (continued)

	(1=Electric, 2=Gas, 3=Oil) Primary SH Fuel	2ndary SH Fuel (x.yy, x=fuel type, yy=% area)	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	Space Heating Area (sq ft) Electric	Gas	Oil	Water Heating Area (sq ft) Electric	Gas	Oil	Space Htg. Energy Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Water Htg. Energy Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
6 - Grocery																		
400.006	2		2		1998	0	1998	0	0	1998	0	0	98	0	0	3	0	37707
304.006	2		2		3100	0	3100	0	0	3100	0	0	152	0	0	18	0	208849
211.006	3		1		4000	0	0	4000	4000	0	0	0	0	216	4800	0	0	241160
30.006	2		2		5200	0	5200	0	0	5200	0	0	256	0	0	21	0	383429
38.106	2		2	1.3	74000	0	74000	0	22200	51800	0	0	3637	0	26640	212	0	2805525
Totals					88,298 sq ft							0	4,143	216	31,440	254	0	3,676,670
Average					17,660 sq ft							0	829	43	6,288	51	0	735,334

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	729	944	0.77
Total	90,204	116,822	

Reg'l 10^6 sq ft: 2.185 Total, 1.257 ANC, 0.569 FBX, 0.239 KEN, 0.12 MAT

Avg. Customers - ANC 71 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 32
Avg. Customers - KEN 14
Avg. Customers - MAT 7

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
7 - Warehouse																		
207.007	3		NA		2150	0	0	2150	0	0	0	0	0	44	0	0	0	3991
187.007	2		NA		3672	0	3672	0	0	0	0	0	68	0	0	0	0	59958
141.007	2		1		3703	0	3703	0	3703	0	0	0	70	0	3026	0	0	10427
132.007	1		1		4585	4585	0	0	4585	0	0	24759	0	0	3660	0	0	38006
189.007	2	1.1	1		4680	468	4212	0	4680	0	0	2527	78	0	3744	0	0	19365
404.007	3		1		4896	0	0	4896	4896	0	0	0	0	90	3917	0	0	38267
45.107	2		1		7200	0	7200	0	7200	0	0	0	133	0	5760	0	0	46744
188.007	2		2		8640	0	8640	0	0	8640	0	0	159	0	0	24	0	58160
84.007	2		1		10000	0	10000	0	10000	0	0	0	184	0	8000	0	0	715900
45.207	2		1		10000	0	10000	0	10000	0	0	0	184	0	8000	0	0	65056
208.007	3		1		10224	0	0	10224	10224	0	0	0	0	207	8179	0	0	112440
6.007	2		2		15132	0	15132	0	0	15132	0	0	279	0	0	41	0	35136
220.007	3		3		15300	0	0	15300	0	0	15300	0	0	310	0	0	42	141240
41.007	2		1		16200	0	16200	0	16200	0	0	0	299	0	12960	0	0	51018
140.007	2	1.1	1		21000	2100	18900	0	21000	0	0	11340	348	0	16800	0	0	315781
54.007	2		2		25500	0	25500	0	0	25500	0	0	470	0	0	70	0	168669
417.107	2		2		27000	0	27000	0	0	27000	0	0	498	0	0	74	0	190821
417.207	2		NA		29304	0	29304	0	0	0	0	0	540	0	0	0	0	0
32.007	2		2		30400	0	30400	0	0	30400	0	0	560	0	0	83	0	179248
8.007	2		2	1.15	32900	0	32900	0	4935	27965	0	0	606	0	3948	76	0	35250
Totals					253,262 sq ft							38,626	3,936	651	78,002	368	42	2,315,410
Average					12,663 sq ft							1,931	197	33	3,900	18	2	115,771

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	110	270	0.41
Total	185,188	405,182	

Reg'l 10^6 sq ft: 19.021 Total, 11.41 ANC, 4.697 FBX, 1.924 KEN, 0.99 MAT

Avg. Customers - ANC 901 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 371
Avg. Customers - KEN 152
Avg. Customers - MAT 78

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Energy Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
8 - Car Service																		
66.008	2	1.05	2		1500	75	1425	0	0	1500	0	540	35	0	0	5	0	66011
210.008	3		3		2100	0	0	2100	0	0	2100	0	0	57	0	0	7	56357
70.008	2		1		2125	0	2125	0	2125	0	0	0	52	0	2125	0	0	7307
62.008	2		2		3000	0	3000	0	0	3000	0	0	74	0	0	10	0	30453
202.008	3		1		3640	0	0	3640	3640	0	0	0	0	98	3640	0	0	34550
69.008	2	1.05	2		6700	335	6365	0	0	6700	0	2412	156	0	0	23	0	164716
78.008	2		1		7350	0	7350	0	7350	0	0	0	181	0	7350	0	0	35190
209.008	3		1		9600	0	0	9600	9600	0	0	0	0	259	9600	0	0	35569
109.008	2		2		10000	0	10000	0	0	10000	0	0	246	0	0	34	0	25775
65.008	2		2		15000	0	15000	0	0	15000	0	0	369	0	0	51	0	185374
Totals					61,015 sq ft							2,952	1,112	415	22,715	124	7	750,102
Average					6,102 sq ft							295	111	41	2,272	12	1	75,010

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	72	175	0.42
Total	37,838	89,932	

Reg'l 10^6 sq ft: 3.144 Total, 2.238 ANC, 0.343 FBX, 0.416 KEN, 0.147 MAT

Avg. Customers - ANC 367 [# Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 56
Avg. Customers - KEN 68
Avg. Customers - MAT 24

Table D-2 (continued)

	Primary SH Fuel	2ndary SH Fuel {x.yy, x=fuel type, yy=% area}	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	Space Heating Area (sq ft) Electric	Gas	Oil	Water Heating Area (sq ft) Electric	Gas	Oil	Space Htg. Energy Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Water Htg. Energy Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
9 - Lodging																		
409.209	1		1		3270	3270	0	0	3270	0	0	29480	0	0	9010	0	0	37242
200.009	3		3		20678	0	0	20678	0	0	20678	0	0	399	0	0	212	6807
4.209	2		2		50937	0	50937	0	0	50937	0	0	1565	0	0	522	0	0
339.009	2		2		60000	0	60000	0	0	60000	0	0	1843	0	0	614	0	1270887
4.109	2		2	1.4	91817	0	91817	0	36727	55090	0	0	2820	0	110180	564	0	2518967
37.009	2		2		337463	0	337463	0	0	337463	0	0	10366	0	0	3455	0	10265048
Totals												29,480	15,029	399	119,990	4,634	212	14,136,949
Average												4,905	2,505	116	19,998	772	35	2,356,158

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	2,331	3,514	0.66
Total	95,498	148,943	

Totals 513,228 sq ft
Average 85,538 sq ft

Reg'l 10^6 sq ft
3.504 Total
2.321 ANC
0.505 FBX
0.471 KEN
0.207 MAT

Avg. Customers - ANC 27 [Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 6
Avg. Customers - KEN 6
Avg. Customers - MAT 2

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
10 - Medical																		
145.010	2		2		31532	0	31532	0	0	31532	0	0	1647	0	0	301	0	562276
Totals												0	1,647	0	0	301	0	562,276
Average												0	1,647	0	0	301	0	562,276

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	562	1,948	0.29
Total	26,694	92,478	

Totals 31,532 sq ft
Average 31,532 sq ft

Reg'l 10^6 sq ft
1.497 Total
1.15 ANC
0.217 FBX
0.087 KEN
0.048 MAT

Avg. Customers - ANC 38 [Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 7
Avg. Customers - KEN 3
Avg. Customers - MAT 1

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
11 - School																		
20.211	1		NA		2400	2400	0	0	0	0	0	25056	0	0	0	0	0	
215.011	3		3		11405	0	0	11405	0	0	11405	0	0	447	0	0	70	
216.011	3		3		16230	0	0	16230	0	0	16230	0	0	638	0	0	100	143507
105.011	2		2		50160	0	50160	0	0	50160	0	0	1707	0	0	308	0	423630
20.111	2		2		50160	0	50160	0	0	50160	0	0	1707	0	0	308	0	471657
300.111	2		2		51587	0	51587	0	0	51587	0	0	1836	0	0	317	0	
91.211	2		2		55200	0	55200	0	0	55200	0	0	1967	0	0	339	0	
102.011	2		2		150675	0	150675	0	0	150675	0	0	5369	0	0	926	0	970071
91.111	2		2		350000	0	350000	0	0	350000	0	0	12471	0	0	2150	0	3077346
Totals												0	21,414	636	0	3,692	100	5,087,011
Average												0	4,283	127	0	738	20	1,177,402

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	1,177	5,180	0.23
Total	103,758	455,445	

Totals 617,225 sq ft
Average 123,445 sq ft

Reg'l 10^6 sq ft
10.078 Total
6.114 ANC
1.711 FBX
1.049 KEN
1.204 MAT

Avg. Customers - ANC 50 [Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 14
Avg. Customers - KEN 15
Avg. Customers - MAT 10

	Primary SH Fuel	2ndary SH Fuel	Primary WH Fuel	2ndary WH Fuel	Total Area (sq ft)	SH Area Electric	Gas	Oil	WH Area Electric	Gas	Oil	SH Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	WH Demand Electric (kWh/yr)	Gas (MBtu/yr)	Oil (MBtu/yr)	Electric Demand (kWh/yr)
12 - College																		
40.012	2		1		92355	0	92355	0	92355	0	0	0	2837	0	166289	0	0	2514740
Totals												0	2,837	0	166,289	0	0	2,514,740
Average												0	2,837	0	166,289	0	0	2,514,740

	Elec. MWh/yr	Thermal MBtu/yr	MWh/MBtu
Average	2,349	3,404	0.69
Total	29,079	43,311	

Totals 92,355 sq ft
Average 92,355 sq ft

Reg'l 10^6 sq ft
1.175 Total
1.175 ANC
0 FBX
0 KEN
0 MAT

Avg. Customers - ANC 13 [Avg. Customers = Reg'l sq ft/Average sq ft]
Avg. Customers - FBX 0
Avg. Customers - KEN 0
Avg. Customers - MAT 0

Step 1: Estimating Total and Average Electric and Thermal Demand. Given the ISER survey data on electricity consumption (kWh/year) and floor area by customer, we calculated the average electricity consumption and floor area for each building type. We then calculated the total electricity consumption for each building type by multiplying the average electricity consumption by the total number of average customers[3] in that building type.

Energy requirements for space and water heating were based on the ISER end-use analysis. Typical values for the twelve building types are shown in Table D-3. As this table shows, space heating requirements in Fairbanks are around 10 percent higher than in Anchorage, Kenai, and Matsu regions. Note that, although the energy requirements are expressed in terms of kilowatthour per square feet per year, this should not be interpreted as though electricity were the sole energy source for these applications. In this context, kilowatthour is used merely to represent a unit of energy and is readily convertible to Btu requirements.

Table D-3

ENERGY REQUIREMENTS
(kWh/sq ft/yr-existing buildings)

Building Type No.	Name	Water Heating	Space Heating: Anchorage/ Kenai/Matsu	Space Heating: Fairbanks
1	Small Office	1.0	9.0	9.9
2	Large Office	1.0	9.0	9.9
3	Restaurant	7.0	9.5	10.5
4	Large Retail	0.8	6.3	6.9
5	Small Retail	0.8	6.3	6.9
6	Grocery	1.2	14.4	15.8
7	Warehouse	0.8	5.4	5.9
8	Car Service	1.0	7.2	7.9
9	Lodging	3.0	9.0	9.9
10	Medical	2.8	15.3	16.8
11	School	1.8	10.4	11.5
12	College	1.8	9.0	9.9

Source: *Forecast of Electricity Demand in the Alaska Railbelt Region: 1988-2010,* Draft Report, 19 November, 1988, pp. 3-16, 3-17.

[3] The total number of average customers in a building type is the ratio of the total floor area in that building type to the average customer's floor area.

We applied the values in Table D-3 to the survey data regarding the fraction of the floor area served by the different energy sources (electric, oil, or gas) to determine the demand by energy source. For example, if a small office building in Anchorage with a floor area of 5,000 square feet had 80 percent gas-fired and 20 percent electric space heating and 100 percent electric water heating, its total thermal demand would be:

	(80%) x (5,000 sq ft) x (9.0 kWh/sq ft/yr)	{Gas-Fired}
+	(20%) x (5,000 sq ft) x (9.0 kWh/sq ft/yr)	{Electric}
+	(100%) x (5,000 sq ft) x (1.0 kWh/sq ft/yr)	{Electric}
=	36,000 (gas-fired) + 9,000 (electric) + 5,000 (electric) kWh/yr	
=	50,000 kWh/yr, or 171 MBtu/yr.[4]	

We performed this type of calculation for each surveyed customer in each building type and then calculated the average thermal demand by building type. We determined the total thermal demand for each building type in the same way as for the total electric demand: we multiplied the average thermal demand by the total number of average customers in that building type.

Table D-4 shows the results of these calculations for each building type, aggregated over the four regions. The table shows the average and total floor area, electric demand, thermal demand, and the percentage of total floor area, electric demand, and thermal demand represented by each building type.

Step 2: Developing the Load Duration Curves. A load duration curve reflects the different levels of demand that occur over a period of time. We defined an annual load duration curve with two seasons (peak and off-peak) and two periods (peak and off-peak) within each season. We chose the peak season (called "winter") to be consistent with other assumptions in this study: November through February (refer to Section 6). The off-peak season (called "summer") was therefore March through October. The number of hours in the winter season was approximately one-third (four out of twelve months) the hours in the year (8760), or 3000 hours. The summer season has 8760 - 3000 = 5760 hours.

[4]To avoid double counting, we would subtract the 14,000 kWh/yr (electric) from the annual electric demand.

Table D-4

AVERAGE AND TOTAL ELECTRIC AND THERMAL DEMAND

Building Type	Building Name	Average Area (sq ft)	Average Electric Demand (MWh/yr)	Average Thermal Demand (MBtu/yr)	Total Area (million sq ft)	Total Electric Demand (MWh/yr)	Total Thermal Demand (MBtu/yr)	% of Total Area	% of Total Electric	% of Total Thermal
1	Small Office	7,304	112	251	8.889	135,745	305,823	0.12	0.11	0.13
2	Large Office	47,654	2,401	1,626	6.424	323,657	219,251	0.09	0.26	0.10
3	Restaurant	6,402	158	363	2.043	50,338	115,796	0.03	0.04	0.05
4	Large Retail	79,014	1,050	1,927	3.560	47,300	86,821	0.05	0.04	0.04
5	Small Retail	13,889	217	336	9.288	145,285	224,855	0.13	0.12	0.10
6	Grocery	17,660	729	944	2.185	90,204	116,822	0.03	0.07	0.05
7	Warehouse	12,663	110	270	19.021	165,138	405,132	0.27	0.13	0.18
8	Car Service	6,102	72	175	3.144	37,333	89,932	0.04	0.03	0.04
9	Lodging	85,538	2,331	3,514	3.504	95,498	143,943	0.05	0.08	0.06
10	Medical	31,532	562	1,948	1.497	26,694	92,478	0.02	0.02	0.04
11	School	123,445	1,177	5,168	10.878	103,753	455,445	0.15	0.08	0.20
12	College	92,355	2,349	3,404	1.175	29,879	43,311	0.02	0.02	0.02
	TOTALS				71.608	1,250,824	2,299,609	1.00	1.00	1.00

Within each season, we referred to the peak and off-peak periods as day and night, respectively. For all building types except schools, we used a 12-hour day period and a 12-hour night period for each day in the year.[5] This even division between day and night hours meant there were 1500 hours in the winter day and winter night periods and 2880 hours in the summer day and summer night periods.

For schools, we used the same definition of day and night periods during the winter season, but we took into account the fact that most schools have lower energy requirements during the summer season (i.e., a relatively longer off-peak period). We used 100 percent of two months plus 50 percent of the hours in the other six summer months to represent the duration of lower energy requirements. This resulted in 2160 hours for the summer day period and 3600 hours for the summer night period. Table D-5 summarizes the hours in each period for the two groups of building types.

Table D-5

HOURS BY LOAD DURATION CURVE PERIOD

	Winter Day	Winter Night	Summer Day	Summer Night	Total
All Building Types Except Schools	1500	1500	2880	2880	8760
Schools	1500	1500	2160	3600	8760

Next, we determined the fraction of total electric and thermal energy requirements needed during the two seasons. For all building codes except schools, we used monthly electric billing information [2], Enstar total gas sales to the small commercial sector by month [3], the output of a small office building simulation performed by ISER [4], and information on daily load shapes provided by ISER [5]. For schools, we used available monthly billing information for electricity, gas, and oil for the Anchorage [6] and Fairbanks [7] areas.

For all building types except schools, we found that electric demand is evenly distributed over the year. The fraction of demand occurring in the winter season was therefore equivalent to the fraction of the year represented by the winter season, or 35 percent. The fraction of electric demand in the summer was thus 65 percent. For schools, however, we found that 45 percent of electric demand occurs in the winter

[5]We found that distinguishing between businesses that are open on the weekend versus those that are not was unimportant.

season, and 55 percent during the summer season. This is consistent with our observation that schools have lower energy requirements during the summer season.

For the distribution of thermal demand over the year, we found that, for all building types, 55 percent of the demand occurs in the winter season and 45 percent during the summer season. Table D-6 summarizes the fractions of electric and thermal demand by season for the two groups of building types.

Table D-6

ELECTRIC AND THERMAL DEMAND FRACTIONS BY SEASON

	Fraction of Electric Demand		Fraction of Thermal Demand	
	Winter	Summer	Winter	Summer
All Building Types Except Schools	0.35	0.65	0.55	0.45
Schools	0.45	0.55	0.55	0.45

To complete the information needed for the load duration curves, we determined the distribution of electric and thermal demand during the 24-hour daily cycle. We found that daily peak electric demand is approximately twice off-peak demand; thus, two-thirds of the demand occurs during the day and one-third at night. For thermal demand, we determined that approximately 50 percent of the demand occurs during the day and 50 percent at night [4]. We applied these fractions to all twelve building types. Table D-7 summarizes the fraction of electric and thermal demand by daily cycle.

Table D-7

ELECTRIC AND THERMAL DEMAND FRACTIONS DURING DAILY CYCLE

	Fraction of Electric Demand		Fraction of Thermal Demand	
	Day	Night	Day	Night
All Building Types	0.67	0.33	0.50	0.50

To calculate the load duration curve for the average customer in each building type, we applied the seasonal and daily fractions (shown in Tables D-6 and D-7) to the average electric and thermal demand values (shown in Table D-4), and then divided by the appropriate number of hours (shown in Table D-5). For example, the average small office customer has an electric demand of 112 MWh per year. During the winter, 35 percent of this demand occurs. Furthermore, 67 percent of the demand occurs during the day period. Thus the average electric demand during the winter day period is:

(112 MWh) x (35%) x (67%) / 1500 hours = 17 kW

We performed this type of calculation for each average customer's electric and thermal demand for each period in the load duration curve. Table D-8 shows the building type, the electric and thermal demand for the average customer, the electric and thermal load duration curves, and the ratio of electric to thermal demand in each period (MWh/MBtu). We used this last calculation later in the analysis to help determine the appropriate cogeneration technology for each building type.

Step 3: Determining Technical Potential. We sorted the building types according to their electric demand during the winter day period (the peak demand period) and identified four groups. The building types in the first group had peak demands less than 50 kW and consisted of the car service, small office, warehouse, restaurant, and small retail building types. In the second group, the building types had peak demands between 50 and 200 kW. This group included the medical, grocery, and large retail types. Schools were put in their own group because of their unique seasonal energy requirements. Their peak demand averaged about 300 kW. The fourth group contained building types with peak demands greater than 300 kW and included the lodging, college, and large office types. We calculated the average electric and thermal load duration curves and the average electric to thermal ratio for each group. Table D-9 shows these results.

To determine the technical potential for cogeneration in each group in each of the four regions, we multiplied the average peak electric demand for each group by the number of customers in that group in each region. The number of customers in each group in each region is the sum of the number of customers in each building type in the group. We estimated the regional number of customers in a building type by taking the ratio of the total regional floor area to the average customer's floor area. The total technical potential for these four groups in the Railbelt is 204.7 MW. Table D-10 shows the technical potential for groups 1 through 4.

Table D-8

LOAD DURATION CURVES FOR COMMERCIAL BUILDING TYPES

Building Type	Building Name	Average Electric (MWh/yr)	Average Thermal (MBtu/yr)	Electric Demand (kW)				Thermal Demand (MBtu)				MWh/MBtu			
				Winter Day	Winter Night	Summer Day	Summer Night	Winter Day	Winter Night	Summer Day	Summer Night	Winter Day	Winter Night	Summer Day	Summer Night
1	Small Office	112	251	17	9	17	8	0.046	0.046	0.020	0.020	0.38	0.19	0.85	0.43
2	Large Office	2,401	1,626	373	187	361	181	0.298	0.298	0.127	0.127	1.25	0.63	2.84	1.42
3	Restaurant	158	363	25	12	24	12	0.067	0.067	0.028	0.028	0.37	0.18	0.84	0.42
4	Large Retail	1,050	1,927	163	82	158	79	0.353	0.353	0.151	0.151	0.46	0.23	1.05	0.52
5	Small Retail	217	336	34	17	33	16	0.062	0.062	0.026	0.026	0.55	0.27	1.24	0.62
6	Grocery	729	944	113	57	110	55	0.173	0.173	0.074	0.074	0.66	0.33	1.49	0.74
7	Warehouse	110	270	17	9	17	8	0.049	0.049	0.021	0.021	0.35	0.17	0.79	0.39
8	Car Service	72	175	11	6	11	5	0.032	0.032	0.014	0.014	0.35	0.18	0.80	0.40
9	Lodging	2,331	3,514	363	181	351	175	0.644	0.644	0.275	0.275	0.56	0.28	1.28	0.64
10	Medical	562	1,948	87	44	85	42	0.357	0.357	0.152	0.152	0.24	0.12	0.56	0.28
11	School	1,177	5,168	235	118	200	60	0.948	0.948	0.538	0.323	0.25	0.12	0.37	0.19
12	College	2,349	3,404	365	183	353	177	0.624	0.624	0.266	0.266	0.59	0.29	1.33	0.66

Table D-9

LOAD DURATION CURVES FOR AVERAGE CUSTOMER IN EACH GROUP

Building Group	Building Type	Electric Name	Average Thermal (MWh/yr)	Average Winter (MBtu/yr)	Electric Demand (kW) Winter Day	Summer Night	Summer Day	Winter Night	Thermal Demand (MBtu) Winter Day	Summer Night	Summer Day	Winter Night	MWh/MBtu Winter Day	Summer Night	Summer Day	Night
1	8	Car Service	72	175	11	6	11	5	0.032	0.032	0.014	0.014	0.35	0.18	0.80	0.40
	7	Warehouse	110	270	17	9	17	8	0.049	0.049	0.021	0.021	0.35	0.17	0.79	0.39
	1	Small Office	112	251	17	9	17	8	0.046	0.046	0.020	0.020	0.38	0.19	0.85	0.43
	3	Restaurant	158	363	25	12	24	12	0.067	0.067	0.028	0.028	0.37	0.18	0.84	0.42
	5	Small Retail	217	336	34	17	33	16	0.062	0.062	0.026	0.026	0.55	0.27	1.24	0.62
				Averages	21	10	20	10	0.051	0.051	0.022	0.022	0.40	0.20	0.90	0.45
2	10	Medical	562	1,948	87	44	85	42	0.357	0.357	0.152	0.152	0.24	0.12	0.56	0.28
	6	Grocery	729	944	113	57	110	55	0.173	0.173	0.074	0.074	0.66	0.33	1.49	0.74
	4	Large Retail	1,050	1,927	163	82	158	79	0.353	0.353	0.151	0.151	0.46	0.23	1.05	0.52
				Averages	121	61	117	59	0.294	0.294	0.125	0.125	0.44	0.22	1.00	0.50
3	11	School	1,177	5,168	235	118	200	60	0.948	0.948	0.538	0.323	0.25	0.12	0.37	0.19
4	9	Lodging	2,331	3,514	363	181	351	175	0.644	0.644	0.275	0.275	0.56	0.28	1.28	0.64
	12	College	2,349	3,404	365	183	353	177	0.624	0.624	0.266	0.266	0.59	0.29	1.33	0.66
	2	Large Office	2,401	1,626	373	187	361	181	0.298	0.298	0.127	0.127	1.25	0.63	2.84	1.42
				Averages	367	184	355	178	0.522	0.522	0.223	0.223	0.66	0.33	1.46	0.73

Table D-10

COGENERATION TECHNICAL POTENTIAL OF GROUPS 1-4
(MW)

Group	Railbelt
1	88.6
2	26.2
3	20.7
4	69.2
Total	204.7

We identified a fifth group in the commercial sector: hospitals. Although we did not have information on hospitals from the ISER survey, we did have monthly electricity billing histories for the two hospitals in Anchorage [8]. Information was not publicly available for hospitals in Fairbanks. We determined peak electricity demand in the same way as for the other groups, using a load duration curve. To determine the thermal demand, however, we had to make an assumption regarding the ratio of electric to thermal demand because thermal demand information was not available.[6] Table D-11 shows the electric and thermal demand, the load duration curves, and the electric to thermal ratios that we used for the two hospitals in Anchorage. We used the average of these two hospitals to represent hospital demand in Fairbanks, due to lack of better information. Thus, the technical potential for hospitals in the Railbelt is the sum of the peak electric demands for the two hospitals plus the average of the two, or 6.6 MW.

The total technical potential was therefore 211.3 MW. Table D-12 summarizes the cogeneration technical potential results by group and region for the commercial sector.

D.2.2 Industrial Sector

Information on historical electric demand was available for many industrial facilities, which formed the basis for calculating their cogeneration technical potential. We obtained data on peak electric demand and consumption by industry for almost all the companies in each industry [9]. This subsection describes how we chose the industries to include in the analysis and the assumptions we used to determine the load duration curves for each industry.

[6] Personal communication with Science Applications International Corporation indicated a ratio of about 0.25 MWh/MBtu for the lower-48 states. We assumed that thermal requirements would be slightly higher in Alaska, hence the 0.20 MWh/MBtu.

Table D-11

HOSPITAL TECHNICAL POTENTIAL

	Average Electric (MWh/yr)	Average Thermal (MBtu/yr)	Electric Demand (kW) Winter Day	Winter Night	Summer Day	Summer Night	Thermal Demand (MBtu) Winter Day	Winter Night	Summer Day	Summer Night	MWh/MBtu Winter Day	Winter Night	Summer Day	Summer Night
Humana	8,000	40,000	1,244	622	1,204	602	7.333	7.333	3.125	3.125	0.17	0.08	0.39	0.19
Providence	20,000	100,000	3,111	1,556	3,009	1,505	18.333	18.333	7.813	7.813	0.17	0.08	0.39	0.19
TOTALS	28,000	140,000	4,356	2,178	4,213	2,106	25.667	25.667	10.938	10.938	0.17	0.08	0.39	0.19
Average (used for Fairbanks)	14,000	70,000	2,178	1,089	2,106	1,053	12.833	12.833	5.469	5.469	0.17	0.08	0.39	0.19

Table D-12

COMMERCIAL SECTOR COGENERATION TECHNICAL POTENTIAL

Group	Anchorage	Fairbanks	Kenai	Railbelt
1	62.6	15.7	10.3	88.6
2	18.9	5.3	2.0	26.2
3	13.9	3.3	3.5	20.7
4	63.1	3.9	2.2	69.2
5	4.4	2.2	0.0	6.6
Total	162.9	30.3	18.1	211.3

The major industries in the Railbelt are petroleum processing and transportation, manufacturing, fish processing, construction, and mining. Table D-13 shows electricity demand and consumption for each industry for the four Railbelt regions. We aggregated this information over the regions and sorted the industries by decreasing electric demand as shown in Table D-14.

Table D-13

INDUSTRIAL SECTOR ELECTRICITY DEMAND

Region	Industry	Demand (MW)	Energy (GWh)
Anchorage	Manufacturing	14	32
Fairbanks	Petroleum Processing	7	50
	Mining	3	10
	Petroleum Transportation	1	4
	Construction	1	1
Kenai	Petroleum Processing	21	129
	Manufacturing	7	20
	Fish Processing	6	9
Matsu	Construction	2	1
Totals		62	256

Source: *Forecast of Electricity Demand in the Alaska Railbelt Region: 1988-2010*, ISER, Draft Report, November 1988.

Table D-14

ELECTRICITY DEMAND BY TYPE OF INDUSTRY

Industry	Demand (MW)	Energy (GWh)
Petroleum Processing	28	179
Manufacturing	21	52
Fish Processing	6	9
Construction	3	2
Mining	3	10
Petroleum Transportation	1	4
Totals	62	256

Petroleum processing is the largest industry, with a demand of 28 MW. This industry has substantial thermal demands and several refineries have or are considering building cogeneration systems. Because Tesoro has recently installed a 4-MW cogeneration unit, we subtracted 4 MW from the technical potential for a total of 24 MW.

Although manufacturing is the second largest industry in the Railbelt in terms of electric demand, we excluded it because of the limited information and the assumption that their thermal requirements would be relatively small.

The fish processing industry is the third largest in terms of electric demand. This industry has substantial thermal demand during its summer processing season. Its technical potential is 6 MW.

We excluded the construction and petroleum transportation industries because they are not major electric consumers in the Railbelt, and probably have little or no process heat needs.

The mining industry consists of the Usibelli Coal Mine; the mining demand shown in Table D-14 includes only its present, utility-supplied consumption. A major cogeneration proposal now under consideration by Usibelli to supply thermal energy to a coal-drying process will be examined further during the next two months as part of this effort.

Based on these considerations, we defined the technical potential in the industrial sector as the sum of the technical potential in the petroleum processing and fish processing industries, for a total of 30 MW.

As input to the cogeneration technical potential analysis, we calculated electric and thermal load duration curves for the petroleum and fish processing industries. First, we used information on annual customer electric demands from ISER [10]. Table D-15 shows the customer name and annual electricity demand for selected customers in these industries. We also obtained monthly billing histories from the appropriate electric utility Power Requirements Studies [11], [12], to calculate electricity requirements by season.

Table D-15

ELECTRICITY DEMAND FOR PETROLEUM AND FISH PROCESSING

Industry	Customer	1987 Electricity Demand (MWh/yr)
Petroleum Processing	Petro Star Refinery	1,878
	Chevron USA	8,162
	ARCO Alaska	12,566
	MAPCo Petroleum	47,964
	Tesoro	89,266*
Fish Processing	Royal Pacific Fish	511
	Cook Inlet	513
	Allied Fish Processors	565
	Columbia Wards	637
	Salamotof Seafoods	807
	Dragnet Fisheries	819
	Inlet Salmon	928
	Kenai Packers	1,376
	Seward Fisheries	3,310
	Seward Fish Processor	5,356

*Prior to 4 MW installation

In the petroleum industry, operation is year-round, resulting in an even distribution of electric demand over the year. In addition, operation is continuous, 24 hours a day. The thermal demand parallels the electric demand. Thus, electric and thermal demand are coincident and constant over the year and the daily cycle, regardless of the number of hours in a period. Moreover, the fraction of the demand in each period corresponds to the fraction of the year represented by that period. For consistency, we used the same hours by period as we had for the commercial sector. Table D-16 shows the hours by period and the fraction of electric and thermal demand occurring in each period.

Table D-16

INFORMATION FOR LOAD DURATION CURVE FOR THE PETROLEUM PROCESSING INDUSTRY

	Winter Day	Winter Night	Total Winter	Summer Day	Summer Night	Total Summer	Total
Hours	1500	1500	3000	2880	2880	5760	8760
Fraction of Electric Demand by Season	--	--	0.35	--	--	0.65	1.0
Fraction of Thermal Demand by Season	--	--	0.35	--	--	0.65	1.0
Fraction of Electric Demand During Daily Cycle	0.50	0.50	1.0	0.50	0.50	1.0	--
Fraction of Thermal Demand During Daily Cycle	0.50	0.50	1.0	0.50	0.50	1.0	--

For the fish processing industry, however, the billing histories showed that approximately 90 percent of the electric demand occurs during four months of the eight-month summer season as defined for the other customer groups. So as not to underestimate the peak demands during the summer months, we defined the peak season to be the four summer months, and the off-peak season to be the other eight months. The hours by period are thus reversed, 5760 hours in the winter and 3000 hours in the summer. Since fish processing operations are also continuous, 24 hours a day (when the plants are operating), electric and thermal demand will be coincident and constant within a season and daily cycle. We continued to use the even division between day and night hours. Table D-17 shows the hours by period and the fraction of electric and thermal demand occurring in each period for the fish processing industry.

In contrast to the commercial sector, information on end-use thermal demand was not available for the industrial sector. As a result, we estimated thermal demand from an assumed ratio of electric to thermal demand. For petroleum refining, we gathered gas consumption information from Tesoro [13] and from data provided by the Dun and Bradstreet Petroleum information service [14] and decided to use a ratio of

0.07 MWh/MBtu. For the fish processing industry, however, we had only partial information from Dun and Bradstreet. We used a ratio of 0.50 MWh/MBtu.[7]

Table D-17

INFORMATION FOR LOAD DURATION CURVE FOR THE FISH PROCESSING INDUSTRY

	Winter Day	Winter Night	Total Winter	Summer Day	Summer Night	Total Summer	Total
Hours	2800	2880	5760	1500	1500	3000	8760
Fraction of Electric Demand by Season	--	--	0.08	--	--	0.92	1.0
Fraction of Thermal Demand by Season	--	--	0.08	--	--	0.92	1.0
Fraction of Electric Demand During Daily Cycle	0.50	0.50	1.0	0.50	0.50	1.0	--
Fraction of Thermal Demand During Daily Cycle	0.50	0.50	1.0	0.50	0.50	1.0	--

As with the commercial sector, we calculated the electric and thermal load duration curves for each customer as well as for the average customer in each industry.[8] We applied the information on the load duration curves shown in Tables D-16 and D-17 and the electric to thermal demand ratios to the electric demand

[7]We later performed a sensitivity analysis that showed that the choice of ratio within a reasonable range made less than a 1-MW difference in the market potential.

[8]The two large Seward fish processors were excluded from the fish processing average because including them would have produced an "average" unrepresentative of the entire group. Due to the low cogeneration market potential identified for the smaller fish processors, we assumed that the potential for the larger processors would not be appreciably better because they suffer from the same nonconstant distribution of energy demand over the year.

information in Table D-15. Tables D-18 and D-19 show the results for petroleum and fish processing industries, respectively.

D.3 CHARACTERIZATION OF POTENTIAL COGENERATION TECHNOLOGIES

Because of the small-scale potential cogeneration applications in the Railbelt, we focused on small (less than 5-MW) cogeneration technologies. Small cogeneration technologies typically use an internal combustion engine (ICE) or a combustion turbine as the prime mover. Following is a brief description of the two technologies.

D.3.1 Internal Combustion Cogeneration System

Energy conversion is achieved with good efficiency in internal combustion engines because of low heat rejection. Typical heat rates of ICEs are between 10,000 Btu/kWh and 12,000 Btu/kWh. ICEs with high compression ratios (15:1) maintain good performance (low heat rates) at low loadings (around 13,000 Btu/kWh at 25 percent loading). Low compression ratio ICEs (10:1) have higher heat rates (16,000 Btu/kWh at 25 percent loading).

Heat recovery from ICE systems is usually achieved through heat exchangers by using the available heat in both (or either) the engine exhaust and the water jacket. Steam generation is not always feasible from the water jacket. Smaller high speed engines (1200 rpm) can operate at jacket temperatures of up to 250°F, which makes steam generation at 20 to 30 psia possible. Larger lower speed engines (900 rpm) generally operate at jacket temperatures of about 180°F, which eliminates jacket heat as a source of steam. Steam generation at pressures of 30 to 165 psia must be derived from exhaust heat recovery only.

ICE cogeneration systems usually have a high electric/thermal output ratio (up to 0.5 MW/MBtu/hour). Higher pressure steam recovery lowers the amount of heat recovery without affecting electricity generation and therefore increases the electric/thermal output (to as high as 2). Thermal energy recovery is usually achieved without compromises in electricity production in most ICE applications.

Table D-18

LOAD DURATION CURVES FOR THE PETROLEUM REFINING INDUSTRY

PETROLEUM PROCESSING*	Electric Demand (MWh/yr)	Thermal Demand (MBtu/yr)	Electric Demand (kW) Winter Day	Winter Night	Summer Day	Summer Night	Thermal Demand (MBtu) Winter Day	Winter Night	Summer Day	Summer Night	MWh/MBtu Winter Day	Winter Night	Summer Day	Summer Night	Region
Petro Star Refinery	1,878	26,829	219	219	212	212	3.130	3.130	3.028	3.028	0.07	0.07	0.07	0.07	Fairbanks
Chevron USA	8,162	116,600	952	952	921	921	13.603	13.603	13.158	13.158	0.07	0.07	0.07	0.07	Kenai
ARCO Alaska	12,566	179,514	1466	1466	1418	1418	20.943	20.943	20.258	20.258	0.07	0.07	0.07	0.07	Kenai
Tesoro	89,266	1,275,229	10414	10414	10073	10073	148.777	148.777	143.906	143.906	0.07	0.07	0.07	0.07	Kenai
Average			3263	3263	3156	3156	47	47	45	45	0.07	0.07	0.07	0.07	

*MAPCo is analyzed separately (refer to Appendix E)

Table D-19

LOAD DURATION CURVES FOR THE FISH PROCESSING INDUSTRY

FISH PROCESSING	Electric Demand (MWh/yr)	Thermal Demand (MBtu/yr)	Electric Demand (kW) Winter Day	Winter Night	Summer Day	Summer Night	Thermal Demand (MBtu) Winter Day	Winter Night	Summer Day	Summer Night	MWh/MBtu Winter Day	Winter Night	Summer Day	Summer Night	Region
Allied Fish Processors	565	1,130	8	8	173	173	0.016	0.016	0.347	0.347	0.50	0.50	0.50	0.50	Kenai
Cook Inlet	513	1,026	7	7	157	157	0.014	0.014	0.315	0.315	0.50	0.50	0.50	0.50	Kenai
Dragnet Fisheries	819	1,638	11	11	251	251	0.023	0.023	0.502	0.502	0.50	0.50	0.50	0.50	Kenai
Royal Pacific Fish	511	1,022	7	7	157	157	0.014	0.014	0.313	0.313	0.50	0.50	0.50	0.50	Kenai
Inlet Salmon	928	1,856	13	13	285	285	0.026	0.026	0.569	0.569	0.50	0.50	0.50	0.50	Kenai
Salamatof Seafoods	807	1,614	11	11	247	247	0.022	0.022	0.495	0.495	0.50	0.50	0.50	0.50	Kenai
Columbia Wards	637	1,274	9	9	195	195	0.018	0.018	0.391	0.391	0.50	0.50	0.50	0.50	Kenai
Kenai Packers	1,376	2,752	19	19	422	422	0.038	0.038	0.844	0.844	0.50	0.50	0.50	0.50	Kenai
Seward Fish Processor	5,356				1200										
Seward Fisheries	3,310	27,910			1,524										
AVERAGE W/O SEWARD			11	11	236	236	0.021	0.021	0.472	0.472	0.50	0.50	0.50	0.50	

D.3.2 Combustion Turbine Cogeneration Systems

Heat rates of combustion turbine systems vary by engine type, size, and manufacturer. Typical heat rates are 12,000 Btu/kWh to 14,000 Btu/kWh. Heat rates can increase by as much as 5,000 Btu/kWh when the turbine is operated below 50 percent of rated capacity.

Heat recovery in combustion turbine systems is achieved from the turbine exhaust by using a heat recovery steam generator. The temperature of the recovered heat is usually limited by the turbine exhaust temperature. Typical turbine exhaust temperatures vary between 760°F and 1100°F. Supplementary firing may be used to increase this temperature up to 1400°F and a wide range of steam pressures (from 30 psia to over 300 psia).

Heat recovery combustion turbine systems have electric/thermal output ratios between 0.04 and 0.11. Lower ratios can be achieved through supplementary firing of the turbine exhaust. Heat recovery is achieved without compromises in electricity production.

The choice and size of prime mover can be a function of many factors. In this analysis, we focused on peak electric demand and the ratio of electric to thermal demand as the main determinants of the cogeneration system. We chose cogeneration systems that best matched the thermal and electric needs of the average customer in each group. Table D-20 shows the cogeneration unit cost and performance information used for the commercial and industrial sector analyses [15], [16].

Table D-20

COGENERATION UNIT COST AND PERFORMANCE (1987 dollars)

Group	Size* (kW)	Capital Cost ($/kW)	Fixed Initial Investment ($M)	O&M Cost ($/kW/yr)	Heat Rate (Btu/kWh)	Power to Heat Ratio (MW/MBtu/hr)
1	50	1800	0	90	12,000	0.2
2	200	1100	0.06	70	11,000	0.45
3	300	800	0.12	60	11,000	0.2
4	500	550	0.175	45	11,000	0.4
5	2500	565	0.3	35	10,000	0.50
Petroleum	4300	1072	1.027	65	12,000	0.09
Fish	200	1100	0.06	70	11,000	0.50

*All are internal combustion engines, except the 4300 kW system which is a combustion turbine with heat recovery.

D.4 COGENERATION MARKET POTENTIAL

The cogeneration market potential is the portion of the technical potential that is economic from the investor's viewpoint. We analyzed the market potential under conditions of uncertainty regarding certain major factors in the economics of cogeneration. We represented the uncertainty by combining uncertain scenarios for these factors into scenario combinations, each associated with a likelihood, or probability, of occurrence. In this way, we calculated the market potential for each scenario combination, weighted it by its associated probability, and then summed these values to achieve an estimated market potential.

We used the cogeneration computer model, COGENOPT [17], to calculate the economics of cogeneration. COGENOPT takes into account all the factors important for the economics of cogeneration, including cogeneration system cost and performance, the potential noncoincidence of electric and thermal demand, electric retail rates, utility power purchase (or buyback) rates, the value of the thermal output, and the customer's discount (or hurdle) rate for the investment. We used the net present value (NPV) of the cogeneration investment over a 20-year period (1990 to 2010) as the criterion for the economics. COGENOPT discounted the annual cash flows using the customer's hurdle rate. If the NPV was greater than or equal to zero, then the investment was considered economic from the investor's viewpoint.

The market potential analysis took into account the uncertainty in the following three factors: (1) cogeneration system capital costs; (2) the real annual compound growth rate of electric rates, gas and oil prices, and the buyback rate; and (3) the customer's nominal discount rate. We grouped the uncertainties in the energy prices together because these prices are tied together through gas and oil prices. We characterized the uncertainty in each factor with three scenarios: low, middle, and high.

The uncertainty in capital costs reflects a wide range of possible outcomes. We used the values shown in Table D-21 for the middle scenario, 75 percent of those values for the low scenario, and 125 percent of those values for the high scenario.

For the uncertainty in the real annual compound growth rate in the various energy prices, we used data provided by ISER and the Alaska Power Authority (APA) [18]. For electricity rates in the commercial sector, we used the low, middle, and high forecast of rates in each of the four Railbelt regions. In the industrial sector, we used Homer Electric Association's (HEA) wholesale rates plus a 25 percent margin to approximate the rates paid by industrial customers. We used HEA's rates because all of the fish processing and most of the petroleum processing occurs in the Kenai region. Table D-22 shows the 1987 rates, the rates in 2010, and the real annual compound growth rate for the low, middle, and high electric rate scenarios.

Table D-21

COST AND PERFORMANCE OF SELECTED COGENERATION UNITS
(1987 dollars)

Group	Size* (kW)	Capital Cost ($/kW)	Fixed Initial Investment ($M)	O&M Cost ($/kW/yr)	Heat Rate (Btu/kWh)	Power to Heat Ratio (MW/MBtu/hr)
1	50	1800	0	90	12,000	0.20
2	200	1100	0.06	70	11,000	0.45
3	300	800	0.12	60	11,000	0.20
4	500	550	0.175	45	11,000	0.40
5	2500	565	0.3	35	10,000	0.50
Petro-leum	4300	1072	1.027	65	12,000	0.09
Fish	200	1100	0.06	70	11,000	0.50

*All are internal combustion engines, except the 4300 kW system, which is a combustion turbine with heat recovery.

Table D-22

RAILBELT COMMERCIAL AND INDUSTRIAL ELECTRICITY PRICES
(1987 cents/kWh)

	BASE	LOW SCENARIO		MIDDLE SCENARIO		HIGH SCENARIO	
	1987	2010	Growth Rate	2010	Growth Rate	2010	Growth Rate
Commercial							
Anchorage	6.5	6.3	-0.1%	7.0	0.3%	7.8	0.8%
Fairbanks	9.0	9.1	0.0%	9.9	0.4%	10.8	0.8%
Kenai	8.6	9.6	0.5%	10.1	0.7%	10.6	0.9%
Matsu	7.7	9.1	0.7%	9.6	1.0%	10.2	1.2%
Industrial	4.0	5.3	1.2%	5.8	1.6%	6.3	2.0%

Source: Memo from Steve Colt to Dick Emerman, 8/23/88.

For gas prices, we used Enstar's base price in 1989 in combination with their stated margins for small commercial and large commercial (industrial) customers. The base price in 1987 was estimated at $3.03 per MBtu for the commercial sector, and $2.61 per MBtu for the industrial sector. The margins for the commercial and industrial sectors were $1.61 per MBtu and $1.15 per MBtu, respectively [19]. These prices applied to all regions. Table D-23 shows the estimate of 1987 prices, the prices in 2010, and the real annual compound growth rate for the low, middle, and high scenarios.

For oil prices, we used the price forecasts developed for this study [20]. The uncertainty in oil prices was necessary to represent the current fuel availability in Fairbanks. We also analyzed the market potential in Fairbanks assuming gas was available. Table D-24 shows the 1987 price, the prices in 2010, and the real annual compound growth rate for the low, middle, and high scenarios.

Table D-23

GAS PRICES
(1987 $/MBtu)

	BASE	LOW SCENARIO		MIDDLE SCENARIO		HIGH SCENARIO	
	1987	2010	Growth Rate	2010	Growth Rate	2010	Growth Rate
Commercial	3.030	3.174	0.2%	3.895	1.1%	4.616	1.8%
Industrial	2.611	2.714	0.2%	3.435	1.2%	4.156	2.0%

Source: ENSTAR forecast - Letter to Dick Emerman, 7/19/88

Table D-24

OIL PRICES
(1987 $/MBtu)

	BASE	LOW SCENARIO		MIDDLE SCENARIO		HIGH SCENARIO	
	1987	2010	Growth Rate	2010	Growth Rate	2010	Growth Rate
Fairbanks	4.930	5.140	0.2%	6.880	1.5%	8.550	2.4%

Source: "OIL2" used in Over/Under model for Fairbanks

For the buyback rate, we used the retail electricity rate assumptions for each customer group. Because buyback rates were unknown, we performed sensitivity analysis and found that most of the savings due to cogeneration were due to avoided electricity rates, not sales of electricity; a reduction in the buyback rate of 50 percent reduced the market potential by only two MW. (Only a few customer groups in a few regions had any significant sales of electricity.)

The third uncertainty factor was the customer's nominal hurdle rate. We used three scenarios to reflect different attitudes toward the time value of money. A low hurdle rate causes future cash flows to be weighted more heavily than a high hurdle rate. Table D-25 shows the three scenarios of hurdle rates that we used.

Table D-25

CUSTOMER NOMINAL HURDLE RATES

	Percent
Low	15
Middle	30
High	50

Given the values for each scenario for the three areas of uncertainty, we developed probabilities for each scenario. For capital costs, we used the following probability distribution for the low, middle, and high scenarios: 10, 40, and 50 percent, respectively.[9] For the uncertainty in the growth rates of energy prices for the low, middle, and high scenarios, we used 60, 30, and 10 percent, respectively, consistent with the APA directive followed throughout this study. For the hurdle rate, we used the following probability distribution for the low, middle and high scenarios: 20, 60, and 20 percent, respectively.

Figure D-1 illustrates these probability distributions with a probability tree—a typical way of showing the structure of an uncertainty analysis. This figure is a shorthand way of expressing the full combination of scenarios. For example, for each scenario of capital cost, there are three scenarios of growth in energy prices. For each scenario of energy prices, there are three scenarios of customer hurdle rate. Thus, there are 3 x 3 x 3, or 27, scenario combinations. Each scenario combination has a corresponding probability calculated by taking the product of the probabilities of each scenario.

We calculated the NPV for each of the 27 scenarios for each of the average customers in each commercial and industrial sector group in each region of the Railbelt. If the NPV was greater than zero (i.e., the investment was economic), then we

[9]Middle case cost estimates were based on lower-48 data. Consequently, we assumed that Alaska-installed costs would likely be higher rather than lower.

multiplied the probability of that scenario times the cogeneration unit size selected by the model. We summed these values over the 27 scenarios for each case. This was the probability-weighted average fraction of the technical potential which was economic from the investor's viewpoint, that is, the market potential.

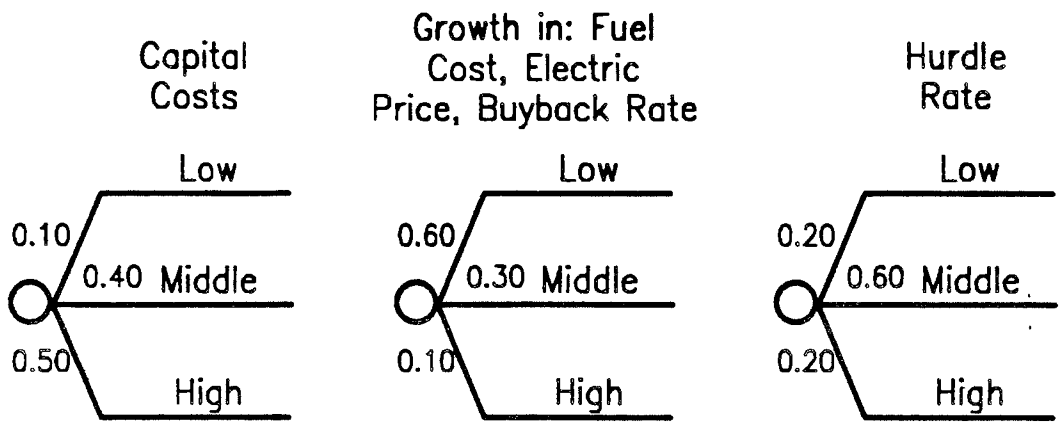

Figure D-1. Probability Tree

D.5 OTHER POTENTIAL RAILBELT COGENERATION

This subsection summarizes the information we collected on various potential cogeneration projects discussed during our meetings with Railbelt electric utility staff in the fall of 1988. The project descriptions are organized by the four main Railbelt regions: Anchorage, Kenai, Fairbanks, and Copper Valley. Table D-26 summarizes the total potential capacity of each project and its estimated likelihood of being developed. Since detailed information necessary to perform economic evaluation was not available, our judgments of the likelihood of project development were based only on the general information that was available.

D.5.1 Anchorage Region

Chugach Alaska Corporation. This has been proposed as a 5-MW project fired by hog fuel—the refuse from logging operations. The on-line date could be 1990. We were not able to gather much information on this project since the main contact, Paul Tweinten of Chugach Alaska Corporation, was out of the country during the study period. Their on-site electric demand is 3.25 MW, currently served by Chugach Electric

Association (CEA). We have insufficient information to make a judgment on the likelihood of project development.

Table D-26

SUMMARY OF OTHER POTENTIAL COGENERATION PROJECTS

Region	Total Potential MW	Likelihood
Anchorage		
Chugach Alaska Corporation	5.0	--
Anchorage International Airport	1.05	Very Likely
Post Office/Federal Express	NI*	--
Valley Energy Wood Plant	15.0	Very Unlikely
Anchorage Alaska Project	50.0	Unlikely
Water & Waste Water	NI*	--
TOTAL	71.05	
Kenai		
Tesoro	**	--
Fairbanks		
Alaska Energy Management	15.0	--
MAPCo	5.0	--
Usibelli	50.00***	--
TOTAL	70.0	
Copper Valley		
Alaska Pacific Refining Inc.	30.0	Unlikely
RAILBELT TOTAL	171.05	--

*NI: No information
**4 MW unit already installed
***Analyzed in Section 8

Anchorage International Airport. The State of Alaska, Department of Transportation and Public Facilities (DOTPF) contracted with USKH Engineers to study the technical and economic feasibility of cogeneration at the Anchorage International Airport (AIA). We received the Phase II report (December 7, 1988) from DOTPF. The study analyzed the economics of a conventional thermal plant versus gas cogeneration systems in providing the electric and thermal needs of the domestic and international terminals. The study recommended the installation of a 1.05-MW gas engine cogeneration unit to provide electricity, heating, and cooling to the domestic terminal.

The report stated that the 1.05-MW gas engine generator has a savings to investment ratio (SIR) of 1.12 relative to a conventional plant. Its lifecycle cost was $14.39 million versus $14.5 million for the conventional plant. The study found that the best operating strategy for the cogeneration plant was continuous operation. In this way, most of the electricity and thermal energy could be utilized.

USKH studied the sensitivity of the SIR to various input parameters and found it was most sensitive to electricity rates, natural gas costs, and discount rate. We believe that the discount rate is the most significant parameter because electricity and gas rates will change together. The USKH sensitivity analysis examined the impacts of electricity and gas rates separately.

The report concluded by recommending the implementation of the 1.05-MW facility and stated that "the future would need to consistently favor negative influences in order for the recommended cogeneration system not to be economically superior to a totally conventional plant" (p. 39). We conclude that the 1.05-MW system is very likely to be developed.

Note that the USKH analysis, like all of the cogeneration forecasts developed in this appendix, was performed with respect to retail electricity rates from the perspective of the investor, not the cost of generation to the electric utility.

Post Office/Federal Express. We tried to determine whether plans for cogeneration exist for the Post Office and the new Federal Express building in Anchorage. We had heard that the Post Office had spent $250,000 on a study of cogeneration. We talked with Jim Janneck of USKH about these possible projects. He said he had also heard of the Post Office study and was aware that Federal Express was building a new facility, but was not aware of any plans for cogeneration.

We were not able to get in touch with the Post Office and Federal Express. The APUC may have more information. We do not include this potential project due to the lack of evidence indicating cogeneration plans.

Valley Energy Wood Plant. This proposed 15-MW, wood-fired project is owned by Hydro Development Incorporated (HDI) of Littleton, Colorado. We spoke with Don Pope who said he would send us the engineering and economic information on the project. We have not yet received this information.

This project and another peat-fired project were previously owned by Matsu Energy, which was then bought out by HDI. Subsequently, the APUC approved an agreement that requires Matsu Electric Association (MEA) to purchase all its power from CEA. Thus potential QFs in the MEA service area will only be entitled to CEA's avoided costs. The low CEA avoided costs cast doubt on the future of the wood plant; the peat-fired plant has been abandoned. HDI told us they had spent several thousand dollars arguing this arrangement without success. Because HDI cannot commit to building the project, they cannot attract steam users to locate near the project. We believe the building of this project is very unlikely.

Anchorage Alaska Project. Originally, this was to be a 50-MW, waste coal-fired cogeneration facility potentially coming on-line in 1996 and owned by SGI International, Inc. We spoke with John Cooley at Anchorage Municipal Light & Power (AMLP) who had serious doubts that the project would ever come on-line. He said they had not heard from the developer in over five months. We spoke with the developer's lawyer, Oren Orndorff of Boise, Idaho, and were told that there is a controversy over the avoided costs to be available to this project. SGI filed a complaint against AMLP.

We received a copy of a "Memorandum on How to Proceed" (dated 11/29/88) to the APUC from the developer's lawyer stating that SGI has transferred its rights to develop the Anchorage Alaska Project to Rosebud Enterprises, Inc. The memorandum states that Rosebud Enterprises is negotiating with steam hosts in the Anchorage area and requests a six-month stay in the proceedings to finalize site selection and steam demand.

Although there is renewed effort to determine steam hosts, the history and current status of the project suggests that its development is unlikely.

Water and Waste Water. We asked John Cooley at AMLP what he knew about potential cogeneration projects having to do with water and/or waste water. He said that the local water utility has a contract to divert water from Eklutna for its water supplies with the condition that they replace the power that the water could have generated through the hydro project. Currently, the water utility makes payments to AMLP in lieu of replacing the power. It is possible that the water utility is considering building a cogeneration facility to provide this power. The AMLP forecast of the needed replacement power is 4.5 GWh in 1994, and 16 GWh in 2025 with the caveat that these numbers may be high due to assumptions regarding population growth. We do not include this potential project due to the lack of evidence indicating cogeneration plans.

D.5.2 Kenai Region: Tesoro Refinery

Tesoro has installed two 4-MW gas turbine cogeneration units with heat recovery steam generators. One is for backup purposes only. Tesoro leases the units and the facility from Solar. The facility has the capacity to hold five turbines. The unit to be operated was being tested during the fall of 1988 and was expected on-line by the end of 1988. The unit will operate at a 100 percent capacity factor and produces 55,000 pounds per hour of steam with the supplemental firing. David Brown at Tesoro told us that their power costs go down to three cents per kWh, assuming they utilize 100 percent of the steam output.

HEA is limiting Tesoro's electricity generation to 38 GWh per year or less (the 4-MW unit would produce about 35 GWh per year at 100 percent capacity factor) until 1990. At that time, if Tesoro's load has grown, it can increase its electricity generation to up to one-half of HEA's load in excess of 396 GWh per year.

Since the 4-MW unit is already installed and operating, we did not include it in the assessment of economic cogeneration potential. We have inadequate information to judge the likelihood of additional cogeneration in the future.

D.5.3 Fairbanks Region

Alaska Energy Management (AEM). This project was originally conceived of as a 25-MW cogeneration facility, but now the plans are for a 15-MW waste coal-fired fluidized bed plant. Mike Tavella at APUC estimated it could come on-line between 1992 and 1994. The developer has an order from the APUC and is negotiating with Golden Valley Electric Association (GVEA). We found out that AEM and SGI (now Rosebud Enterprises) have the same corporate officers and lawyer, Oren Orndorff of Boise, Idaho. We spoke with Oren Orndorff who told us the project had qualified as a QF and that they were actively negotiating with GVEA. He would not reveal any additional information about the project. Again, we have insufficient information to judge the likelihood of development.

MAPCo. We spoke with Jerry Fritz at the refinery who told us they were thinking about a 5- to 6-MW cogeneration unit. They plan to do an in-house study in 1989. They stated that their prime motivation for cogeneration is to increase the reliability of their electricity supply. We have insufficient information to judge the likelihood of development.

Usibelli—The Healy Project. This has been proposed as a cogeneration facility of approximately 50 MW located at the minemouth to come on-line in 1993 at the earliest. It is proposed as a coal-fired atmospheric fluidized bed combustion plant with some of the heat being used by the coal processor to dry the high moisture coal. This would increase the heat content of the coal by 10,000 to 11,000 Btu per pound. The fuel for the plant would be either waste coal (6000 Btu per pound) or the standard product (8000 Btu per pound).

The initial capacity of the drying facility is estimated to be 500,000 tons from 650,000 tons of raw feed. The economics of the plant will depend largely on the market for this coal. More details are included in Section 8.

D.5.4 Copper Valley Region: Alaska Pacific Refining Incorporated (APRI)

According to Richard Schuller of the APRI parent company, they are considering building a refinery in Valdez and plan to build a cogeneration facility with supplemental firing to supply the refinery's electric and process heat needs as well as 30 MW of additional electric demand. He stated the total capacity of the plant would be 105 MW (two gas turbines and one steam turbine). APRI believes its cost-of-service from the plant would be the lowest in the Railbelt due to the availability of cheap gas from the propane separation operation to be conducted in Valdez. Richard Schuller told us APRI was negotiating power purchase rates with CVEA.

Construction of the APRI refinery was included only in the high demand forecast prepared by APA for the Copper Valley area. Given that judgment, and the somewhat sketchy information on this project, project development appears unlikely.

D.6 RESULTS AND CONCLUSIONS

The market potential was 22 MW if Fairbanks had gas supplies, and 19 MW if it did not.[10] The results of the market potential calculations for each group in the

[10]These results do not include the potential cogeneration projects described in Section D.5.

commercial and industrial sectors are shown in Table D-27 for the case where gas is not available in Fairbanks. Table D-28 illustrates the detailed results by region.

Around one-half of the estimated market potential is in Anchorage (commercial cogeneration), one-third is in Kenai (mostly industrial cogeneration), and less than one-fourth is in Fairbanks (mostly commercial cogeneration). Commercial cogeneration contributed two-thirds to three-fourths of the estimated market potential. Schools, hospitals, lodging, colleges, and large offices contributed most of the potential in the commercial sector; petroleum refining was dominant in the industrial potential.

We performed several sensitivity analyses to determine which of the uncertain factors (capital costs, energy growth rates, hurdle rate) were most important. In these analyses, we fixed the uncertain factor at its low scenario and re-evaluated the market potential, and then repeated the calculations with the factor set to its high scenario. We judged an uncertain factor to be important if the market potential changed greatly from the low scenario to the high scenario case. Table D-29 summarizes the sensitivity analysis results. The analyses showed that, for all sectors, the most important factor was the customer hurdle rate assumption. With low hurdle rates, and gas not available in Fairbanks, the market potential would be around 70 MW. With high hurdle rates, the market potential would be less than 1 MW. These are extreme cases, but they illustrate the importance of customer attitude toward the time value of money.

Capital cost uncertainty was also very important. With low capital costs, the market potential would be around 48 MW. With high capital costs, the market potential would be only 12 MW.

In contrast, the uncertainty in the growth in electricity and fuel prices was insignificant. This was due to the fact that gas and electricity prices move together in the Railbelt, negating the impacts they would have if they moved separately.

We also examined the importance of the utility buyback rates (the analysis assumed they would be equal to retail rates). We found that most customers were not generating more electricity than they needed. We performed another sensitivity analysis in which we set the buyback rate to be one-half the retail rate. This reduced the market potential by only 2 MW (or 10 percent).

In conclusion, cogeneration has some potential in the Railbelt during the study period. The cogeneration market potential is estimated at about 20 MW, but could be much smaller under unfavorable market conditions or much larger (three to four times larger) under favorable market conditions.

Table D-27

MARKET POTENTIAL RESULTS*
(Assuming Gas Is Not Available in Fairbanks)

Commercial Sector		Technical Potential (MW)	Market Potential Fraction	Market Potential
Group	1	88.6	0.01	1.1
	2	26.2	0.07	1.7
	3	20.7	0.12	2.4
	4	69.2	0.06	3.9
	5	6.6	0.68	4.5
Industrial Sector				
Petroleum Processing		24.0	0.22	5.3
Fish Processing		6.0	0.00	0.0
		241.3		19.0

*Does not include the potential cogeneration projects described in Section D.6.

Table D-28

DETAILED MARKET POTENTIAL RESULTS BY REGION
(MW)

		Anchorage	Fairbanks w/gas	Fairbanks w/o gas	Kenai	Railbelt w/gas	Railbelt w/o gas
Commercial Sector							
Group	1	0.8	0.9	0.2	0.1	1.8	1.1
	2	1.0	0.7	0.4	0.3	2.1	1.7
	3	1.5	0.6	0.4	0.5	2.6	2.2
	4	3.2	0.5	0.4	0.3	4.0	3.9
	5	3.6	1.8	0.9	0.0	5.4	4.5
Total		10.2	4.5	2.3	1.2	15.9	13.6
Industrial Sector							
Petroleum Processing		0.0	1.8	0.9	4.4	6.2	5.3
Fish Processing		0.0	0.0	0.0	0.0	0.0	0.0
Total		0.0	1.8	0.9	4.4	6.2	5.3
Railbelt Total		10.2	6.3	3.2	5.6	22.1	19.0

Table D-29

MARKET POTENTIAL SENSITIVITY ANALYSIS RESULTS

		Capital Costs		Energy Growth Rates		Hurdle Rate	
	Base	Low	High	Low	High	Low	High
Anchorage	10.2	21.7	5.1	10.2	10.2	36.7	0.4
Kenai	5.6	18.3	4.2	5.6	5.6	21.7	0.0
Fairbanks (with gas)	6.3	15.2	4.6	6.1	7.3	20.2	0.2
Fairbanks (without gas)	3.2	7.7	2.6	3.3	3.0	11.1	0.1
Total							
w/gas in Fairbanks	22.1	55.1	13.9	21.9	23.0	78.5	0.7
w/o gas in Fairbanks	19.0	47.6	11.9	19.1	18.8	69.4	0.6

D.7 REFERENCES

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[2] Ibid.

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[6] Provided by Steve Colt, ISER, November 1988.

[7] Provided by Dave Ferree, Maintenance Manager, Fairbanks North Star Borough School District, November, 1988.

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[9] ISER industrial sector database, provided by Steve Colt, November 1988.

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[12] Homer Electric Association, Power Requirements Study, Attachment A: System Consumer and Sales Data, Large Commercial Load Data, and Commercial Class Load Summary, 1988.

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[17] P. N. Estey and S. J. Jabbour, *COGENOPT Users Manual*, September, 1983.

[18] Memo to Railbelt Utilities from Richard Emerman, Alaska Power Authority, Subject: Retail electricity price inputs to Railbelt load forecasting models, August 23, 1988.

[19] Letter to Richard Emerman, Alaska Power Authority, from Bill Hickman, ENSTAR, July 19, 1988.

[20] *Fuel Price Outlooks: Crude Oil, Natural Gas, and Fuel Oil,* report to the Alaska Power Authority, ICF Incorporated, August 1988.

Appendix E
PRODUCTION SIMULATION MODELING

E.1 THE PRODUCTION SIMULATION MODEL

We used the Over/Under model in this study. The Over/Under production simulation model computes the economic cost of system operation and the electric energy produced by each plant in the system. Many utilities use similar production simulation models with the capability to perform the required computations. However, many of these models carry such fine detail that they are too expensive to run under the large number of scenarios required to measure the effects of various intertie options. The production simulation model used here is a high-speed approximation to these more detailed models.

E.1.1 General Methodology

The model uses two input load-duration curves for each year. One represents the peak season, the other represents the off-peak season. The shape of these curves can vary over time by indicating the fraction of the year represented by the peak season curve.

Given a particular scenario, the model determines the total rated capacity of each technology type. A technology type is defined as a group of generating units that have similar performance characteristics and that are located in the same area. This rated capacity consists of plants in the system or planned at the start of the planning horizon, plus new additions minus retirements. Maintenance for each technology is scheduled in both the peak and off-peak seasons. The user can specify the minimum amount of maintenance that must be performed in each season.

Once maintenance has been scheduled, the model uses two methods to account for forced outages. For technology types consisting of "large" plants (larger than 10 MW in this study), the plants are assumed to be available with a probability equal to one minus the forced outage rate. For technology types consisting of "small" plants (smaller than 10 MW in this study), the capacity is derated by multiplying their peak and off-peak season capacity by one minus the forced outage rate and assuming this average amount of capacity to be available with a probability equal to one.

E.1.2 Simulation Algorithm

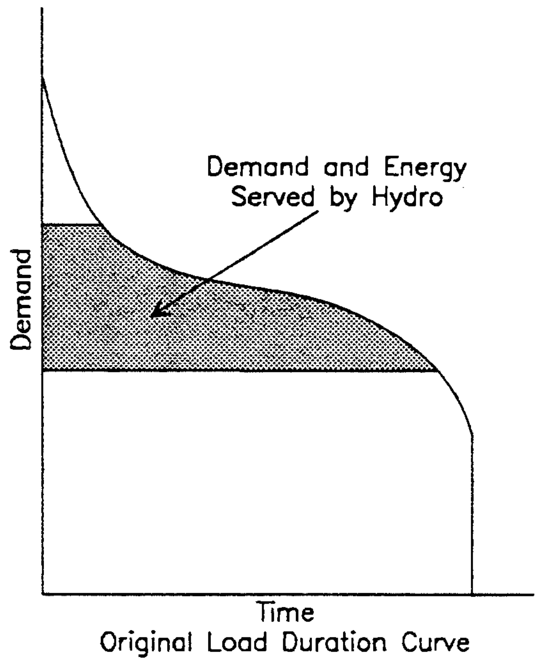
The model uses the peak and off-peak season load-duration curves and the data on generating technology types to calculate the energy served by each generating technology for each year in which the production simulation model is run. These computations are made using the Baleriaux-Booth algorithm [1], a method widely used by the industry for production costing. This algorithm probabilistically considers every possible state of generating systems—any one plant not available, any two not available, any three, etc.

The computations performed by the algorithm are repeated for each season (peak and off-peak). The algorithm proceeds in two steps for each case: the first step models energy-limited hydroelectric capacity, and the second step models the remaining plants.

The modeling of energy-limited hydroelectric capacity is illustrated in Figure E-1. Even though this capacity is usually inexpensive to operate, the energy limitation often prevents generation at the bottom of the load-duration curve at full capacity (baseload operation). The approach, therefore, is to operate hydro at the highest position on the load curve, such that its full capacity is utilized as needed and its available energy is fully consumed. The section of the load curve served by hydroelectric units is then removed to give the curve for the remaining system as shown in the figure. In performing this calculation, energy-limited hydro capacity is simply derated for maintenance and forced outages.[1] If this method does not use all of the hydro capacity, the unused capacity is dispatched when other plants are on forced outage.

Other technologies are loaded into the load duration curve in order of increasing variable cost. To minimize production cost, these plants are dispatched according to the loading order—that is, the least costly plants are operated the greatest fraction of the time. The energy and capacity served by each plant is successively removed from the load duration curve, and the expected remaining load-duration curve is used to compute the energy served by the next plant in the loading order. The expected remaining load-duration curve is the probability-weighted average of the remaining load-duration curves with and without the availability of the plant being dispatched. The probabilities used in the calculation are the plant forced outage rate provided by the user. These probabilities are assumed to be independent.

[1]This is a good assumption since hydro units are highly reliable.



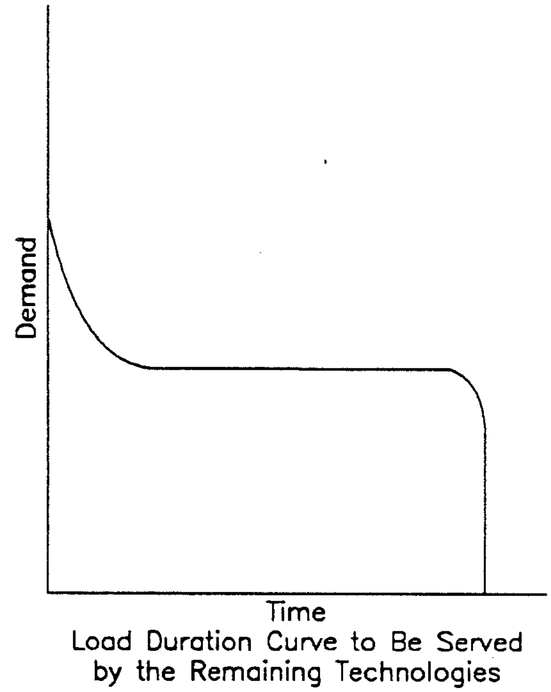


Figure E-1. Modeling of Energy-Limited Hydroelectric Capacity

The variable cost of each technology is the product of the expected energy served by that technology and its variable cost. The variable cost is increased over time according to two rates: general inflation and technology-specific escalation.

The user specifies the technology-specific fuel costs, heat rates, and variable operating and maintenance (O&M) costs as well as the escalation rates as input. For each fuel price, the fuel escalation (noninflation) rate remains constant until the specified year when the second rate is used as a replacement. The user inputs a single escalation rate for variable O&M. The variable cost represents the costs of fuel and variable O&M.

E.1.3 Multi-Area Modeling

The Over/Under model was originally designed to perform single-area production simulation. It was modified to perform multi-area production simulation using the following algorithm.

Assume that we have two areas A and B with load duration curves as shown in Figure E-2. Without an intertie between the two areas, the Over/Under dispatches the generating units in each area to meet the area load. With an intertie between the two areas, we need to modify the dispatch to allow for generating energy in an area to serve the load in the second area. The transactions between the two areas are determined using the following algorithm:

1. A load increment C is added to Area A, and subtracted from Area B. New load curves are then created for Areas A and B.

2. The plants within each area are dispatched to meet their respective new loads. In Area A, because load is added, some of the plants will experience additional generation. In Area B, because load is lost, some of the plants will have reduced generation.

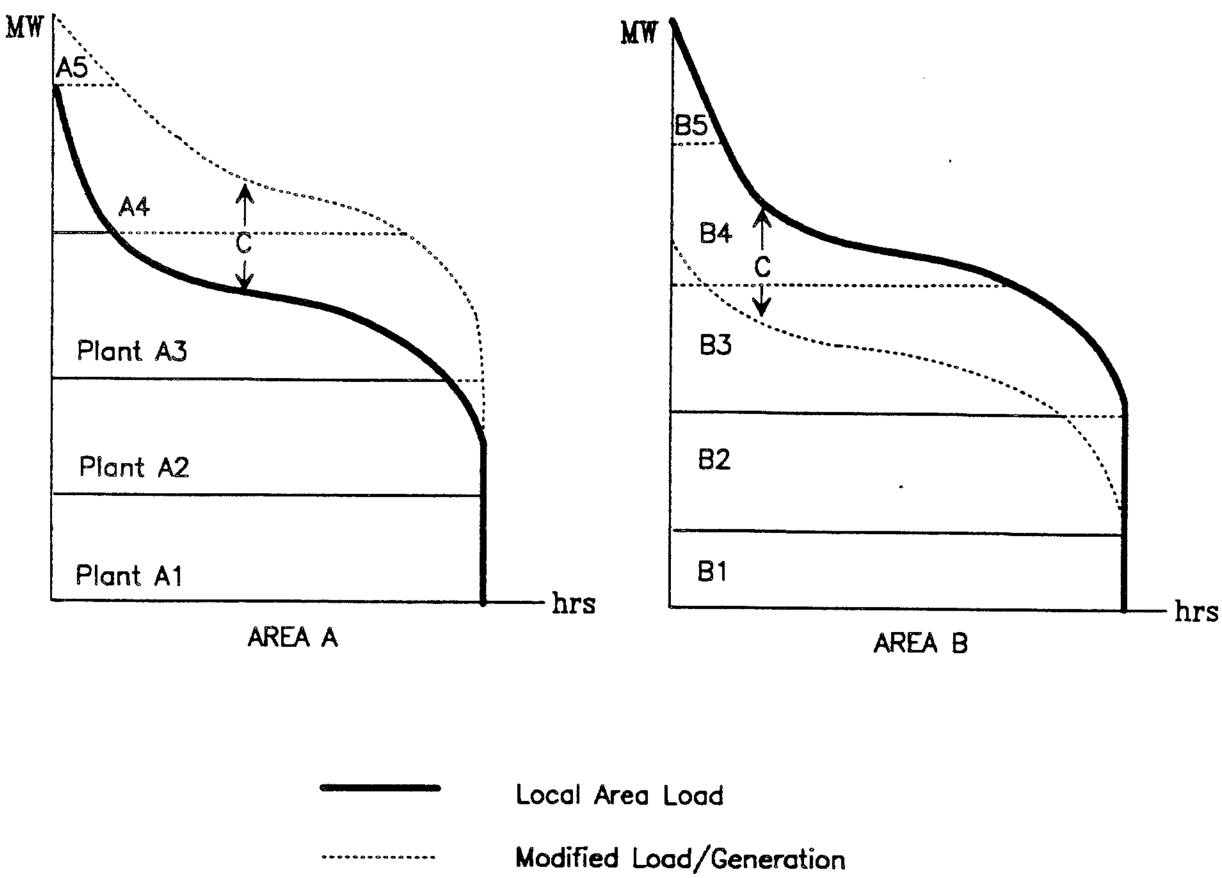


Figure E-2. Multi-Area Modeling

3. Transactions occur between areas only if they are economical. For example, with a line efficiency of 90 percent, a source plant from area A that has a generation cost of \$15.00 per MWh will export to a plant in Area B with a generation cost greater than \$15.00 MWh / 0.90 = \$16.67 MWh.

4. The algorithm is then reversed to allow Area B to export to Area A.

The model allows for six load duration curves: two seasons (peak and off-peak) and three time slots within each season (high, middle, and low). The preceding algorithm must then be followed for each load duration curve. In addition, to allow for increasing transmission losses along the lines, an intertie is divided into three segments, each with monotonically increasing losses.

E.2 NORTH POLE PLANT CONSTRAINTS

The North Pole combustion turbines in Fairbanks have poor part-load performance, with heat rates as high as 90,000 Btu/kWh at minimum load (2 MW).[2] When they are dispatched, it is more economical to load them at high loadings and scale back the intertie purchases than to run the units at part-load. This results in higher operating costs and lower intertie purchases than are captured in the Over/Under model. This type of operating constraint was handled outside of the Over/Under runs.

Essentially, the methodology involves forcing the North Pole to operate at the minimum acceptable level at any time when it is dispatched. This constraint implies that economy energy savings will be turned down and the less efficient North Pole units will be operated instead. The costs as a result of this constraint are large, anywhere from \$20 million to \$67 million over the analysis horizon.[3] Some of the intertie options, specifically the Anchorage-Fairbanks upgrade to 225 MW and the Northeast intertie, eliminate this constraint because the large capacities of the new interties permit purchases sufficient to cover the load requirements without turning on the North Pole units. The smaller Anchorage-Fairbanks upgrade to 100 MW does not eliminate this constraint, but reduces it by allowing greater intertie purchases. A new 50-MW coal plant at Healy also reduces the operation of North Pole units.

We developed the following methodology to determine the decrease in intertie purchases and consequent increase in operating costs when applying the operating

---

[2]Golden Valley Electric Association (GVEA) North Pole turbine performance data, December 14, 1988.

[3]Refer to Section 5.

constraint of the North Pole units. A load duration curve for the Fairbanks area is shown in Figure E-3. This curve represents the number of hours that the area is above a certain load per year. We assume that the Healy plant (25 MW) is base-loaded. For the middle and high fuel price forecasts, we assume that the Chena #5 coal plant (20 MW) is then loaded. Next the intertie is loaded. After this the North Pole units are loaded.

Between the hours of h_1 and h_2, the North Pole is operated by the Over/Under model at loadings below its economical minimum load of 40 MW. Because the North Pole would be operated at its minimum acceptable operating capacity (denoted by Z) during this period, costs will increase by the amount of the excess operation not calculated by Over/Under. In Figure E-3:

A_1 = amount of energy produced by North Pole according to the Over/Under model

A_2 = $Z \times (h_2-h_1)$ = amount of energy that would be generated by North Pole (due to minimum load constraint)

P_n = generation cost of North Pole units

P_i = generation cost over intertie including transmission penalty.

Without the constraint, we have the following costs:

$$A_1*P_n + A_2*P_i$$

With the constraint, we have the following costs:

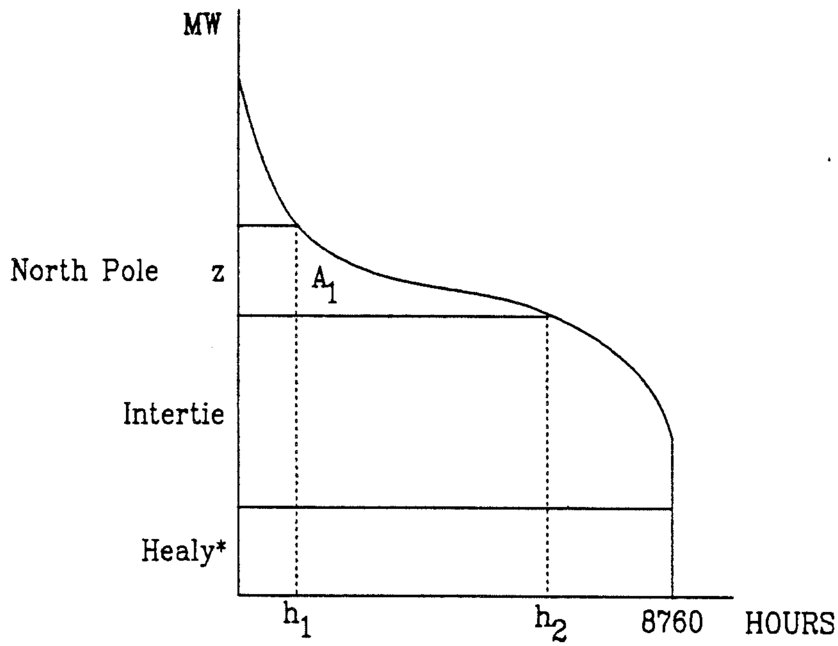
$$A_1*P_i + A_2*P_n$$

The increase in costs is therefore:

$$\begin{aligned} &= (A_1*P_i + A_2*P_n) - (A_1*P_n + A_2*P_i) \\ &= A_1*(P_i - P_n) + A_2*(P_n - P_i) \\ &= (A_2 - A_1)*(P_n - P_i) \end{aligned}$$

The decrease in intertie imports is: $A_2 - A_1$

The decrease in transmission losses is: $(A_2 - A_1)*$ Transmission Loss.



*And Chena 5 for middle and high fuel scenarios.

Figure E-3. Load Duration Curve for the Fairbanks Area

E.3 REFERENCES

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Appendix F
MODELING ASSUMPTIONS

F.1 CAPACITY EXPANSION PLAN

A capacity expansion plan for the system through 2010 was developed in consultation with the utilities [1] and is shown in Table F-1. In the majority of the cases, it was assumed that existing plants would be life extended. In most cases, this meant that the plant's useful life would be extended and that the plant would maintain the same operating characteristics, that is, heat rate, capacity, and variable O&M. For example, it was assumed that all CCs would remain in the system until at least 2008. In one case, it was assumed that certain plants would be retrofitted to extend their lives, and also improve their operating characteristics.[1] In later years, as the load in the Railbelt is assumed to grow, it became necessary to add additional capacity. In Anchorage, 340 MW of additional capacity is added to replace retirements and to maintain reserve requirements, including 200 MW of CC capacity [2]. In Fairbanks, we assumed that either a 50-MW Healy coal-fired power plant would come on line in 1995 or a 50-MW oil-fired CT would be added in 2005 to meet capacity needs. Capacity additions were not necessary in Kenai because the addition of Bradley Lake created an abundance of capacity throughout the analysis period.

F.2 POWER GENERATION PLANTS

The initial generating plants database was compiled from the Railbelt Intertie Proposal, Preliminary Economic Assessment report [3]. We then surveyed the utilities for any changes in the following plant-specific information:

- Rated capacity (MW).
- Committed capacity additions and year of additions.
- Planned retirement date.
- Fixed O&M costs ($/kW-yr).
- Forced outage rate (%), not including scheduled maintenance.

---

[1]Anchorage Municipal Light & Power (AMLP) CTs #1, #2, #3, and #4 are repowered with unit heat rates reduced to 13,500 Btu/kWh.

- Equivalent availability after maintenance and forced outages.[2]
- Fraction of maintenance scheduled during the peak season.
- Heat rate at full load (Btu/kWh).
- Variable O&M costs ($/MWh).

Table F-2 summarizes the power plants data [3], [4], [5], [6], [7], [8], [9], [10], [11], [12], [16].

F.2.1 Technology Groupings

For the purposes of this study, it was necessary to convert the plant-specific information into technology groupings. To do this, we first computed the variable operating costs of each plant.[3] Then we sorted the plants by area, fuel type, and technology. We then grouped similar plants into technologies ensuring that each technology included plants in the same area, and with similar heat rates and identical fuel and plant types. We determined the technology characteristics by taking capacity weighted averages of the individual plants in that technology. The plant technology groupings and the technology characteristics are shown in Table F-3.

F.2.2 Hydro Plants

The average energy by month for the four hydro power plants (Bradley Lake, Eklutna, Cooper Lake, and Solomon Gulch) is shown in Table F-4. The four-month winter peak season has approximately 41 percent of the annual hydro energy.

F.2.3 Notes to Tables F-2 and F-3

1. Fuels are defined as follows:

   Gas1 : Chugach natural gas (Beluga/Bernice Lake plants)
   Gas2 : Enstar natural gas (Anchorage area only, including delivery charge)
   Gas3 : Soldotna plant natural gas (including delivery charge)
   Oil2 : Fuel Oil #2 (Diesel)—Mainly ICEs
   Oil4 : Fuel Oil #4—CTs of GVEA
   Coal1 : Healy coal delivered to Fairbanks
   Coal2 : Minemouth Healy coal.

[2] Equivalent Availability = (1 - Forced Outage Rate) x (1 - Annual Maintenance Rate).

[3] Variable Operating Costs ($/MWh) = Fuel Costs ($/MWh) + Variable O&M ($/MWh). Fuel Costs ($/MWh) = Heat Rate (Btu/kWh) x Fuel Cost ($/MBtu)/1000.

2. Fairbanks Municipal Utility System (FMUS) Chena CT #4 cannot be operated (EPA restriction) and is not shown.

3. The Soldotna plant, owned by the Alaska Electric Generation and Transmission Cooperative, is listed as belonging to Homer Electric Association (HEA).

4. Variable operating costs include both fuel costs and variable O&M costs.

5. All costs are in 1987 dollars.

6. Fuel prices in Table F-3 are based on low fuel forecast.

F.3 TRANSMISSION SYSTEM

Transmission voltages and efficiencies for each of the existing, new, and upgraded interties are listed in Table F-5. Losses are shown both for the total transfer, and for that particular transfer increment.

F.4 LOAD FORECAST MODIFICATIONS

Three equally probable load forecasts representing a high, middle, and low demand scenario were developed by the Institute of Social and Economic Research (ISER) [4]. Several modifications were necessary before these forecasts could be incorporated into the Over/Under model.

First, because the Kenai area in the ISER forecasts was defined as the HEA and Seward Electric System (SES) service areas and did not include the Chugach Electric Association (CEA) Kenai load, it was necessary to remove from Anchorage the CEA demand from the Hope/Cooper Landing areas and add it to Kenai. This area represented approximately two percent of the Anchorage load. Hence, a small percentage (two percent) of the Anchorage load was added to Kenai each year [5].

Second, we subtracted from each forecast the expected cogeneration potential for each year [6]. We assumed that cogeneration would grow linearly to its assumed market potential within each area. At Anchorage, it was also assumed that the airport would start cogeneration before 1994, resulting in a load forecast adjustment of 1 MW.

Third, we assumed that Fairbanks would provide some portion of the military load at Eielson AFB, Fort Wainwright, and Fort Greely in the base case scenarios. This load was approximately 45 GWh in 1994 and grew at 1.4 percent per year to 56 GWh in 2010. Because this additional load peaks in May, that is, during the off-peak season, there was a lessened effect on the peak season demand (November through February). In addition, we assumed that the University of Alaska at Fairbanks, which currently supplies its own electricity needs, would buy approximately 2.5 GWh per year from the Fairbanks utilities [7].

After making the above adjustments, we arrived at the load forecasts shown in Appendix C, Table C-11.

Finally, it was necessary to model the reductions in load accompanying the construction of a gas pipeline to Fairbanks due to the conversion to gas operation of electric space heating, water heating, cooking, and drying appliances in the commercial and residential sectors. These figures were provided by ISER [8] and are incorporated directly into the gas pipeline scenarios.

F.5 DISCOUNT RATE FOR CALCULATION OF PRESENT VALUE

The real discount rate used in this analysis for calculating present value is 4.5 percent as established by APA for project evaluation. Sensitivity analysis at real discount rates of 3.5 percent and 5.5 percent is desirable, particularly when projects are either marginally feasible or marginally infeasible according to the base rate. However, time constraints for producing this report did not allow calculation of net benefits according to these alternative rates. Although the Over/Under model simulation results were calculated according to the selected range of discount rates, the numerous adjustments to the model results and a number of other benefit calculations performed outside the model were not.

The more that projected benefits are "tilted" towards the later years of the analysis, the more difference a change in discount rate will make. For example, looking only at the economy energy savings projected by the Over/Under model for the full Anchorage-Fairbanks upgrade, which are much higher in the later years, changing the discount rate from 4.5 percent to 3.5 percent increases the present value of those benefits on the order of 15 percent. If this were applied to all benefits categories, the present value of total benefits for the upgrade could increase by nearly $15 million. The present value of costs would increase somewhat as well, because long term O&M costs are included. Net benefits may be expected to change from minus $38.2 million to, perhaps, minus $25 million using the lower discount rate. Of course, the higher discount rate of 5.5 percent would have the opposite effect.

For projects with benefits more evenly spread across the years, the impact would be less. For example, the benefits of the new Kenai-Anchorage line are spread more evenly in time, so that the impact of a different discount rate would be expected to be less than in the previous example.

Table F-1

CAPACITY EXPANSION PLANS—RAILBELT, 1994-2010

Area	Utility	Unit	Unit Size (MW)	Retirement Schedule
Kenai		Bradley Lake	119	Stays constant
Kenai		Cooper Lake	17	Stays constant
Kenai	SES	ICE	10.5	Stays constant
Kenai	HEA	ICE	2.1	Stays constant
Kenai	HEA	Soldotna CT	39	Stays constant
Kenai	CEA	Bernice Lake CT #1	8	Retires before 1994
Kenai	CEA	Bernice Lake CT #2	18	Retires at end of 2006
Kenai	CEA	Bernice Lake CT #3	25	Stays constant
Kenai	CEA	Bernice Lake CT #4	25	Moves to International before 1994
Anchorage		Eklutna	30	Stays constant
Anchorage	MEA	No plants		
Anchorage	CEA	International CT #1	16	Retires at end of 1996
Anchorage	CEA	International CT #2	16	Retires at end of 1997
Anchorage	CEA	International CT #3	19	Retires at end of 1998
Anchorage	CEA	International CT #4	25(new)	Stays constant
Anchorage	CEA	International CT #5	40	Comes on-line at beginning of 2000 and stays constant
Anchorage	CEA	Beluga CT #1	17	Renewed until end of 2002
Anchorage	CEA	Beluga CT #2	17	Renewed until end of 2006
Anchorage	CEA	Beluga CT #3	55	Retires at end of 2003
Anchorage	CEA	Beluga CT #4	9	Retires before 1994
Anchorage	CEA	Beluga CT #5	66	Renewed to end of 2006
Anchorage	CEA	Beluga CC #6&8	101	Renewed to end of 2008, 51 MW retired at end of 2008, remaining 50 MW stays constant
Anchorage	CEA	Beluga CC #7&8	101	Renewed to end of 2008, 31 MW retires at end of 2008, drops to 50 MW in 2010
Anchorage	CEA	New CC	100	Comes on-line in 2003
Anchorage	CEA	New CT	100	Comes on-line in 2006
Anchorage	CEA	New CC	100	Comes on-line in 2008
Anchorage	AMLP	AMLP CT #1	16	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CT #2	16	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CT #3	19	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CT #4	33	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CC #5&6	47	Retrofitted and remains constant
Anchorage	AMLP	AMLP CC #7&6	109	Retrofitted and remains constant
Anchorage	AMLP	AMLP CT #8	87	Stays constant

Fairbanks	FMUS	ICE #1	2.8	Retires before 1994
Fairbanks	FMUS	ICE #2	2.8	Retires before 1994
Fairbanks	FMUS	ICE #3	2.8	Retires at end of 1996 but is assumed to remain constant because it will either be replaced or retrofitted
Fairbanks	FMUS	Chena ST #1	5	Stays constant
Fairbanks	FMUS	Chena ST #2	2	Retires at end of 2000
Fairbanks	FMUS	Chena ST #3	1.5	Retires at end of 1995
Fairbanks	FMUS	Chena ST #4		Cannot be operated (EPA)
Fairbanks	FMUS	Chena ST #5	20	Life extended to 2010
Fairbanks	FMUS	Chena ST #6	23	Retires at end of 2006
Fairbanks	GVEA	Healy ST #1	25	Extended or replaced in kind, stays constant
Fairbanks	GVEA	Healy ICE #2	2.8	Retires at end of 1997
Fairbanks	GVEA	North Pole CT #1	61	Extended or replaced in kind, stays constant
Fairbanks	GVEA	North Pole CT #2	61	Extended or replaced in kind, stays constant
Fairbanks	GVEA	Zender CT #1	18	Extended or replaced in kind, stays constant
Fairbanks	GVEA	Zender CT #2	18	Retires at end of 2002
Fairbanks	GVEA	ICEs	14.7	Stays constant
Copper Valley	CVEA	Solomon Gulch	12	Stays constant
Copper Valley	CVEA	Glenallen ICEs	10.4	Stays constant
Copper Valley	CVEA	Valdez ICEs	7.2	Stays constant

Notes:

1. Bradley Lake capacity = 114 MW delivered at Soldotna
2. For Fairbanks, it is assumed that either a 50-MW coal plant at Healy comes on-line in 1995 (coal case) or a 50-MW CT (oil- or gas-fired depending on availability of gas in Fairbanks) comes on-line in 2005 (all other cases).

Table F-2

RAILBELT UNITS BY UTILITY

UNIT NAME	OWNER	AREA	CAPACITY (MW)	PLANT TYPE	FUEL TYPE	HEAT RATE (Btu/kWh)	FORCED OUTAGE RATE (1/yr)	PLANNED OUTAGE RATE (1/yr)	EQUIV. AVAIL. (1/yr)	VAR O&M ($/MWh)
AMLPCT#1	AMLP	Anchorage	16.0	CT	Gas2	14808	0.060	0.154	0.795	6.75
AMLPCT#2	AMLP	Anchorage	16.0	CT	Gas2	14703	0.060	0.154	0.795	6.75
AMLPCT#3	AMLP	Anchorage	19.0	CT	Gas2	17807	0.060	0.154	0.795	6.75
AMLPCT#4	AMLP	Anchorage	33.0	CT	Gas2	13541	0.060	0.154	0.795	6.75
AMLPCC56	AMLP	Anchorage	47.0	CC	Gas2	10400	0.020	0.238	0.747	0.81
AMLPCC76	AMLP	Anchorage	109.0	CC	Gas2	8625	0.020	0.144	0.839	0.81
AMLPCT#8	AMLP	Anchorage	87.0	CT	Gas2	11732	0.040	0.154	0.812	0.81
		Total	327.0							
CHENST#1	FMUS	Fairbanks	5.0	ST	Coal1	15968	0.060	0.060	0.884	1.29
CHENST#2	FMUS	Fairbanks	2.0	ST	Coal1	18049	0.060	0.060	0.884	1.29
CHENST#3	FMUS	Fairbanks	1.5	ST	Coal1	18091	0.060	0.060	0.884	1.29
CHENST#5	FMUS	Fairbanks	20.0	ST	Coal1	14236	0.060	0.060	0.884	0.68
CHENCT#6	FMUS	Fairbanks	23.0	CT	Oil2	12733	0.080	0.030	0.892	0.61
FMUSIC#1	FMUS	Fairbanks	2.8	IC	Oil2	12128	0.050	0.020	0.931	24.12
FMUSIC#2	FMUS	Fairbanks	2.8	IC	Oil2	12128	0.050	0.020	0.931	24.12
FMUSIC#3	FMUS	Fairbanks	2.8	IC	Oil2	12128	0.050	0.020	0.931	24.12
		Total	59.9							
BELCT#1	CEA	Anchorage	17.0	CT	Gas1	15600	0.050	0.103	0.852	1.48
BELCT#2	CEA	Anchorage	17.0	CT	Gas1	17300	0.050	0.090	0.865	1.48
BELCT#3	CEA	Anchorage	55.0	CT	Gas1	12800	0.050	0.128	0.828	1.48
BELCT#4	CEA	Anchorage	9.0	CT	Gas1	18900	0.050	0.115	0.841	1.48
BELCT#5	CEA	Anchorage	66.0	CT	Gas1	12600	0.050	0.128	0.828	1.48
BELCC68	CEA	Anchorage	101.0	CC	Gas1	9250	0.060	0.115	0.832	1.48
BELCC78	CEA	Anchorage	101.0	CC	Gas1	9250	0.060	0.115	0.832	1.48
BERNCT#1	CEA	Kenai	8.0	CT	Gas1	20000	0.050	0.090	0.865	2.31
BERNCT#2	CEA	Kenai	18.0	CT	Gas1	15000	0.050	0.090	0.865	2.31
BERNCT#3	CEA	Kenai	25.0	CT	Gas1	13300	0.050	0.103	0.852	2.31
BERNCT#4	CEA	Kenai	25.0	CT	Gas1	13500	0.050	0.128	0.828	2.31
INTCT#1	CEA	Anchorage	16.0	CT	Gas2	15700	0.050	0.077	0.877	14.24
INTCT#2	CEA	Anchorage	16.0	CT	Gas2	15700	0.050	0.077	0.877	14.24
INTCT#3	CEA	Anchorage	19.0	CT	Gas2	14400	0.050	0.154	0.804	14.24
COOPER	CEA	Kenai	17.0	HYDRO	HYDRO		0.000	0.000	1.000	0.00
		Total	510.0							
SESIC#1	SES	Kenai	1.5	IC	Oil2	15000	0.050	0.010	0.941	6.05
SESIC#2	SES	Kenai	1.5	IC	Oil2	15000	0.050	0.010	0.941	6.05
SESIC#3	SES	Kenai	2.5	IC	Oil2	15000	0.050	0.010	0.941	6.05
SESIC#4	SES	Kenai	2.5	IC	Oil2	15000	0.050	0.010	0.941	6.05
SESIC#5	SES	Kenai	2.5	IC	Oil2	15000	0.050	0.010	0.941	6.05
		Total	10.5							

Table F-2 (continued)

UNIT NAME	OWNER	AREA	CAPACITY (MW)	PLANT TYPE	FUEL TYPE	HEAT RATE (Btu/kWh)	FORCED OUTAGE RATE (1/yr)	PLANNED OUTAGE RATE (1/yr)	EQUIV. AVAIL. (1/yr)	VAR O&M ($/MWh)
SELDIC#1	HEA	Kenai	0.3	IC	Oil2	14998	0.050	0.040	0.912	41.01
SELDIC#2	HEA	Kenai	0.6	IC	Oil2	12006	0.050	0.040	0.912	41.01
SELDIC#3	HEA	Kenai	0.6	IC	Oil2	12006	0.050	0.040	0.912	41.01
SELDIC#4	HEA	Kenai	0.6	IC	Oil2	12006	0.050	0.040	0.912	41.01
SOLDOTCT	HEA	Kenai	39.0	CT	Gas3	11900	0.050	0.120	0.836	25.00
		Total	41.1							
HEALST#1	GVEA	Fairbanks	25.0	ST	Coal2	12750	0.018	0.070	0.913	4.34
HEALIC#2	GVEA	Fairbanks	2.6	IC	Oil2	11210	0.010	0.200	0.792	6.05
NOPOCT#1	GVEA	Fairbanks	61.0	CT	Oil4	10900	0.010	0.150	0.842	1.51
NOPOCT#2	GVEA	Fairbanks	61.0	CT	Oil4	10900	0.010	0.150	0.842	1.51
ZENGT#1	GVEA	Fairbanks	18.0	CT	Oil4	14869	0.010	0.150	0.842	0.62
ZENGT#2	GVEA	Fairbanks	18.0	CT	Oil4	14869	0.010	0.150	0.842	0.62
DSLIC#1	GVEA	Fairbanks	1.9	IC	Oil2	11209	0.050	0.200	0.760	6.05
DSLIC#2	GVEA	Fairbanks	1.9	IC	Oil2	11209	0.050	0.200	0.760	6.05
DSLIC#3	GVEA	Fairbanks	1.9	IC	Oil2	11209	0.050	0.200	0.760	6.05
DSLIC#5	GVEA	Fairbanks	2.6	IC	Oil2	11210	0.050	0.200	0.760	6.05
DSLIC#6	GVEA	Fairbanks	2.6	IC	Oil2	11210	0.050	0.200	0.760	6.05
UAFIC#7	GVEA	Fairbanks	1.9	IC	Oil2	11209	0.050	0.200	0.760	6.05
UAFIC#8	GVEA	Fairbanks	1.9	IC	Oil2	11209	0.050	0.200	0.760	6.05
		Total	200.3							
SOLGCH#1	CVEA	Copper Valley	6.0	HYDRO	HYDRO		0.000	0.000	1.000	0.00
SOLGCH#2	CVEA	Copper Valley	6.0	HYDRO	HYDRO		0.000	0.000	1.000	0.00
GLNDSL#1	CVEA	Copper Valley	0.3	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#2	CVEA	Copper Valley	0.3	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#3	CVEA	Copper Valley	0.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#4	CVEA	Copper Valley	0.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#5	CVEA	Copper Valley	0.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#6	CVEA	Copper Valley	2.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#7	CVEA	Copper Valley	2.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
GLNDSL#8	CVEA	Copper Valley	2.8	IC	Oil2	13403	0.018	0.014	0.968	6.05
VALDSL#1	CVEA	Copper Valley	0.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
VALDSL#2	CVEA	Copper Valley	0.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
VALDSL#3	CVEA	Copper Valley	0.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
VALDSL#4	CVEA	Copper Valley	1.8	IC	Oil2	13403	0.018	0.014	0.968	6.05
VALDSL#5	CVEA	Copper Valley	2.6	IC	Oil2	13403	0.018	0.014	0.968	6.05
VALDSL#6	CVEA	Copper Valley	1.0	IC	Oil2	13403	0.018	0.014	0.968	6.05
		Total	29.6							
BRADLEY	APA	Kenai	119.0	HYDRO	HYDRO		0.000	0.000	1.000	0.00
EKLUTNA	APA	Anchorage	30.0	HYDRO	HYDRO		0.000	0.000	1.000	0.00
		Total	149.0							

Table F-3

OVER/UNDER MODEL TECHNOLOGIES

TECHNOLOGY NAME	UNIT NAME	OWNER	AREA	UNIT CAPACITY (MW)	PLANT TYPE	FUEL TYPE	HEAT RATE (Btu/kWh)	1994 FUEL COST ($/MBtu)	FORCED OUTAGE RATE (1/yr)	PLANNED OUTAGE RATE (1/yr)	EQUIV. AVAIL. (1/yr)	VAR O&M ($/MWh)	VAR OPER. COST ($/MWh)
	BELCC78	CEA	Anchorage	101.0	CC	Gas1	9250	1.28	0.060	0.115	0.832	1.48	13.35
	BELCC68	CEA	Anchorage	101.0	CC	Gas1	9250	1.28	0.060	0.115	0.832	1.48	13.35
ACC1				202.0			9250		0.060		0.832	1.48	
	BELCT#5	CEA	Anchorage	66.0	CT	Gas1	12600	1.28	0.050	0.128	0.828	1.48	17.65
	BELCT#3	CEA	Anchorage	55.0	CT	Gas1	12800	1.28	0.050	0.128	0.828	1.48	17.90
ACT1				121.0		Gas1	12691		0.050		0.828	1.48	
	BELCT#1	CEA	Anchorage	17.0	CT	Gas1	15600	1.28	0.050	0.103	0.852	1.48	21.49
	BELCT#2	CEA	Anchorage	17.0	CT	Gas1	17300	1.28	0.050	0.090	0.865	1.48	23.68
	BELCT#4	CEA	Anchorage	9.0	CT	Gas1	18900	1.28	0.050	0.115	0.841	1.48	25.73
ACT2				43.0			16982		0.050		0.855	1.48	
	AMLPCC76	AMLP	Anchorage	109.0	CC	Gas2	8625	1.88	0.020	0.144	0.839	0.81	17.04
	AMLPCC56	AMLP	Anchorage	47.0	CC	Gas2	10400	1.88	0.020	0.238	0.747	0.81	20.38
ACC2				156.0			9162		0.020		0.811	0.81	
ACT3	AMLPCT#8	AMLP	Anchorage	87.0	CT	Gas2	11732	1.88	0.040	0.154	0.812	0.81	22.89
	AMLPCT#4	AMLP	Anchorage	33.0	CT	Gas2	13541	1.88	0.060	0.154	0.795	6.75	32.16
	AMLPCT#2	AMLP	Anchorage	16.0	CT	Gas2	14703	1.88	0.060	0.154	0.795	6.75	34.42
	AMLPCT#1	AMLP	Anchorage	16.0	CT	Gas2	14808	1.88	0.060	0.154	0.795	6.75	34.62
	AMLPCT#3	AMLP	Anchorage	19.0	CT	Gas2	17807	1.88	0.060	0.154	0.795	6.75	40.26
ACT4				85.0			14978		0.060		0.795	6.75	
	INTCT#3	CEA	Anchorage	19.0	CT	Gas2	14400	1.88	.050	0.154	0.804	14.24	41.34
	INTCT#1	CEA	Anchorage	16.0	CT	Gas2	15700	1.88	0.050	0.077	0.877	14.24	43.79
	INTCT#2	CEA	Anchorage	16.0	CT	Gas2	15700	1.88	0.050	0.077	0.877	14.24	43.79
ACT5				51.0			15213	1.88	0.050		0.849	14.24	
	CHENST#5	FMUS	Fairbanks	20.0	ST	Coal1	14236	2.52	0.060	0.060	0.884	0.68	36.55
	CHENST#1	FMUS	Fairbanks	5.0	ST	Coal1	15968	2.52	0.060	0.060	0.884	1.29	41.53
	CHENST#2	FMUS	Fairbanks	2.0	ST	Coal1	18049	2.52	0.060	0.060	0.884	1.29	46.77
	CHENST#3	FMUS	Fairbanks	1.5	ST	Coal1	18091	2.52	0.060	0.060	0.884	1.29	46.88
FST1				28.5			15014		0.060		0.884	0.86	
FST2	HEALST#1	GVEA	Fairbanks	25.0	ST	Coal2	12750	1.30	0.018	0.070	0.913	4.34	20.92
	NOPOCT#1	GVEA	Fairbanks	61.0	CT	Oil4	10900	2.77	0.010	0.150	0.842	1.51	31.70
	NOPOCT#2	GVEA	Fairbanks	61.0	CT	Oil4	10900	2.77	0.010	0.150	0.842	1.51	31.70
FCT1				122.0			10900		0.010		0.842	1.51	

Table F-3 (continued)

TECHNOLOGY NAME	UNIT NAME	OWNER	AREA	UNIT CAPACITY (MW)	PLANT TYPE	FUEL TYPE	HEAT RATE (Btu/kWh)	1994 FUEL COST ($/MBtu)	FORCED OUTAGE RATE (1/yr)	PLANNED OUTAGE RATE (1/yr)	EQUIV. AVAIL. (1/yr)	VAR O&M ($/MWh)	VAR OPER. COST ($/MWh)
FCT2	CHENCT#6	FMUS	Fairbanks	23.0	CT	Oil2	12733	4.42	0.080	0.030	0.892	0.61	56.89
	ZENCT#1	GVEA	Fairbanks	18.0	CT	Oil4	14869	2.77	0.010	0.150	0.842	0.62	41.81
	ZENCT#2	GVEA	Fairbanks	18.0	CT	Oil4	14869	2.77	0.010	0.150	0.842	0.62	41.81
FCT3				36.0			14869		0.010		0.842	0.62	
	BERNCT#3	CEA	Kenai	25.0	CT	Gas1	13300	1.28	0.050	0.103	0.852	2.31	19.37
	BERNCT#4	CEA	Kenai	25.0	CT	Gas1	13500	1.28	0.050	0.128	0.828	2.31	19.63
	BERNCT#2	CEA	Kenai	18.0	CT	Gas1	15000	1.28	0.050	0.090	0.865	2.31	21.56
KCT1				68.0			13824		0.050		0.847	2.31	
KCT2	SOLDOTCT	HEA	Kenai	39.0	CT	Gas3	11900	2.20	0.050	0.120	0.836	25.00	51.18
	BRADLEY	APA	Kenai	119.0	HYDRO	HYDRO		0.00	0.000	0.000	1.000	0.00	00.00
	COOPER	CEA	Kenai	17.0	HYDRO	HYDRO		0.00	0.000	0.000	1.000	0.00	00.00
	EKLUTNA	APA	Anchorage	30.0	HYDRO	HYDRO		0.00	0.000	0.000	1.000	0.00	00.00
	SOLGCH#2	CVEA	Copper Valley	6.0	HYDRO	HYDRO		0.00	0.000	0.000	1.000	0.00	00.00
	SOLGCH#1	CVEA	Copper Valley	6.0	HYDRO	HYDRO		0.00	0.000	0.000	1.000	0.00	00.00
HYDRO				175.0									
	DSLIC#3	GVEA	Fairbanks	1.9	IC	Oil2	11209	4.42	0.050	0.200	0.760	6.05	55.59
	UAFIC#7	GVEA	Fairbanks	1.9	IC	Oil2	11209	4.42	0.050	0.200	0.760	6.05	55.59
	DSLIC#1	GVEA	Fairbanks	1.9	IC	Oil2	11209	4.42	0.050	0.200	0.760	6.05	55.59
	DSLIC#2	GVEA	Fairbanks	1.9	IC	Oil2	11209	4.42	0.050	0.200	0.760	6.05	55.59
	UAFIC#8	GVEA	Fairbanks	1.9	IC	Oil2	11209	4.42	0.050	0.200	0.760	6.05	55.59
	DSLIC#6	GVEA	Fairbanks	2.6	IC	Oil2	11210	4.42	0.050	0.200	0.760	6.05	55.59
	HEALIC#2	GVEA	Fairbanks	2.6	IC	Oil2	11210	4.42	0.010	0.200	0.792	6.05	55.59
	DSLIC#5	GVEA	Fairbanks	2.6	IC	Oil2	11210	4.42	0.050	0.200	0.760	6.05	55.59
FICE1				17.3			11209		0.044		0.765	6.05	
	FMUSIC#1	FMUS	Fairbanks	2.8	IC	Oil2	12128	4.42	0.050	0.020	0.931	24.12	77.73
	FMUSIC#2	FMUS	Fairbanks	2.8	IC	Oil2	12128	4.42	0.050	0.020	0.931	24.12	77.73
	FMUSIC#3	FMUS	Fairbanks	2.8	IC	Oil2	12128	4.42	0.050	0.020	0.931	24.12	77.73
FICE2				8.4			12128		0.050		0.931	24.12	
	SESIC#4	SES	Kenai	2.5	IC	Oil2	15000	4.42	0.050	0.010	0.941	6.05	72.35
	SESIC#2	SES	Kenai	1.5	IC	Oil2	15000	4.42	0.050	0.010	0.941	6.05	72.35
	SESIC#5	SES	Kenai	2.5	IC	Oil2	15000	4.42	0.050	0.010	0.941	6.05	72.35
	SESIC#3	SES	Kenai	2.5	IC	Oil2	15000	4.42	0.050	0.010	0.941	6.05	72.35
	SESIC#1	SES	Kenai	1.5	IC	Oil2	15000	4.42	0.050	0.010	0.941	6.05	72.35
KICE1				10.5			15000		0.050		0.941	6.05	

Table F-3 (continued)

TECHNOLOGY NAME	UNIT NAME	OWNER	AREA	UNIT CAPACITY (MW)	PLANT TYPE	FUEL TYPE	HEAT RATE (Btu/kWh)	1994 FUEL COST ($/MBtu)	FORCED OUTAGE RATE (1/yr)	PLANNED OUTAGE RATE (1/yr)	EQUIV. AVAIL. (1/yr)	VAR O&M ($/MWh)	VAR OPER. COST ($/MWh)
	SELDIC#4	HEA	Kenai	0.6	IC	Oil2	12006	4.42	0.050	0.040	0.912	41.01	94.08
	SELDIC#3	HEA	Kenai	0.6	IC	Oil2	12006	4.42	0.050	0.040	0.912	41.01	94.08
	SELDIC#2	HEA	Kenai	0.6	IC	Oil2	12006	4.42	0.050	0.040	0.912	41.01	94.08
	SELDIC#1	HEA	Kenai	0.3	IC	Oil2	14998	4.42	0.050	0.040	0.912	41.01	107.30
KICE2				2.1			12433		0.050		0.912	41.01	
	GLNDSL#6	CVEA	Copper Valley	2.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#2	CVEA	Copper Valley	0.3	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	VALDSL#2	CVEA	Copper Valley	0.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#1	CVEA	Copper Valley	0.3	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#7	CVEA	Copper Valley	2.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#8	CVEA	Copper Valley	2.8	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	VALDSL#4	CVEA	Copper Valley	1.8	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	VALDSL#5	CVEA	Copper Valley	2.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	VALDSL#1	CVEA	Copper Valley	0.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	VALDSL#3	CVEA	Copper Valley	0.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#3	CVEA	Copper Valley	0.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	VALDSL#6	CVEA	Copper Valley	1.0	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#5	CVEA	Copper Valley	0.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
	GLNDSL#4	CVEA	Copper Valley	0.6	IC	Oil2	13403	4.42	0.018	0.014	0.968	6.05	142.24
CICE1				17.6			13403		0.018		0.968	6.05	

Table F-4

ENERGY OF RAILBELT HYDRO POWER PLANTS
(GWh/yr)

	Eklutna	Solomon Gulch	Bradley Lake	Cooper Lake
Area:	Anchorage	Copper Valley	Kenai	Kenai
Jan	14.0	2.9	49.7	6.0
Feb	12.0	3.1	43.6	4.0
Mar	12.0	3.1	31.2	3.0
Apr	10.0	2.2	16.4	4.0
May	12.0	3.6	14.6	1.5
Jun	12.0	4.0	7.2	1.5
Jul	13.0	4.3	14.0	1.0
Aug	13.0	4.1	28.5	2.0
Sep	13.0	4.2	31.0	2.0
Oct	14.0	4.3	36.8	4.0
Nov	14.0	3.4	42.6	6.0
Dec	14.0	3.3	50.7	6.0
Total	153.0	42.5	366.4	41.0
Peak	54.0	12.7	186.6	22.0
Off-Peak	99.0	29.8	179.8	19.0

Area	(GWH/yr)	(% on Peak)
Kenai	407.4	51.2
Anchorage	153.0	35.3
Fairbanks	0.0	NA
Copper Valley	42.5	29.9
Railbelt	560.4	49.19

Source: [9]

Table F-5

INTERTIE MODELING ASSUMPTIONS

1. Existing Anchorage-Fairbanks line

    1st 40 MW transferred at 7.3% loss
    Remaining transfers at 17.2% loss

-> Total loss at 70 MW = 12%.

Capacity from Anchorage to Fairbanks = 70 MW
Capacity from Fairbanks to Anchorage = 70 MW

2. Anchorage-Fairbanks upgrade to 100 MW capacity

    1st 40 MW transferred at 7.3% loss
    Next 30 MW transferred at 17.2% loss
    Final 30 MW transferred at 24.75% loss

3. Anchorage-Fairbanks Upgrade

    1st 70 MW transferred at 3% loss
    Remaining transfers at 7.4% loss

-> Total loss at 225 MW = 6%

Capacity from Anchorage to Fairbanks = 225 MW
Capacity from Fairbanks to Anchorage = 225 MW

4. Northeast Intertie

    1st 130 MW transferred at 7.3% loss
    Remaining transfers at 19.2% loss

Capacity from Anchorage to Fairbanks = 220 MW
Capacity from Fairbanks to Anchorage = 220 MW

-> Maximum capacity equals capacity of combined lines.

Table F-5 (continued)

5. Existing Soldotna-Anchorage line

 1st 40 MW transferred at 8.9% loss
 Nex' 20 MW transferred at 16.6% loss
 Remaining transfers at 19.2% loss

-> Total loss at 60 MW = 11.5%

Capacity from Soldotna to Anchorage = 60 MW
Capacity from Anchorage to Soldotna = 70 MW

-> Kenai load along line = 10 MW.

6. Bradley Lake to Soldotna line

 Assume 4% average losses.

Energy changes from 366 GWh/yr to 351 GWh/yr.
Capacity decreases from 119 MW to 114 MW.

7. New Anchorage-Soldotna line

 All transfers at 2% loss.

Capacity from Soldotna to Anchorage = 250 MW
Capacity from Anchorage to Soldotna = 250 MW

F.6 REFERENCES

[1] Anchorage meeting February 21, 1989.

[2] CEA capacity expansion plan.

[3] Railbelt Intertie Proposal, Preliminary Economic Assessment, March 1987.

[4] ISER, *Forecast of Electricity Demand in the Alaska Railbelt Region: 1988-2010*,

[5] Letter from Steve Colt to Dick Emerman, February 7, 1989.

[6] Refer to Appendix D of this report.

[7] ISER, *Additional Fairbanks Load Impacts: Military Installations and the University of Alaska*, January 12, 1989.

[8] Letter from Alan Mitchell (ISER) to Mike Gordon (DFI), February 27, 1989.

[9] Letter from Dick Emerman (APA) to Salim Jabbour (DFI).

Appendix G

SCREENING ANALYSIS OF POWER SUPPLY ALTERNATIVES AND END-USE PROGRAMS

G.1 OVERVIEW

Technology screening is a method commonly used to eliminate uneconomic power generation technologies from further study. By removing technologies that are not advantageous under any anticipated circumstances, one can scrutinize the remaining technologies more fully and find the scenarios under which each remaining technology is optimal. In addition, technology screening allows a comparison of supply-side technologies with end-use conservation techniques to determine which technologies and conservation programs are least expensive on a lifecycle cost basis per measure of energy served or reduced.

This section begins by describing the technology screening method and then the evaluated technologies and their costs. Next, we perform some sensitivity tests to help determine the least expensive power supply technologies under various assumptions. Finally, we compare the costs of supplying loads (per unit of energy) with the costs of reducing loads (per unit of energy) by implementing end-use conservation programs. This helps us gain insight into which end-use programs may be economically attractive.

G.2 INTRODUCTION TO THE TECHNOLOGY SCREENING METHOD

Despite the abundance of power generation technologies, no single technology is optimal for supplying all loads. For example, it would be inefficient to use a nuclear plant for peaking purposes. It cannot follow load changes quickly enough, and it has such large fixed costs that producing small amounts of energy would be prohibitively expensive per unit of energy. Conversely, a small combustion turbine, though well suited for following load swings, would be inefficient to operate for baseload service because its variable costs of operation are high relative to other technologies.

Typically, technologies with higher capital costs exhibit higher efficiencies compared with lower capital cost technologies. By producing a screening diagram (see Figure G-1), a visual representation of the tradeoffs between higher capital costs/higher efficiency on the one hand, and lower capital costs/lower efficiency on the other hand, can be made to determine the least expensive technologies at each capacity factor and under various economic and performance assumptions. In the diagram, each technology is represented by a curve that relates the unit cost of producing energy (on the vertical axis) plotted against various capacity factors[1] under which the technology is assumed to be operating (on the horizontal axis).

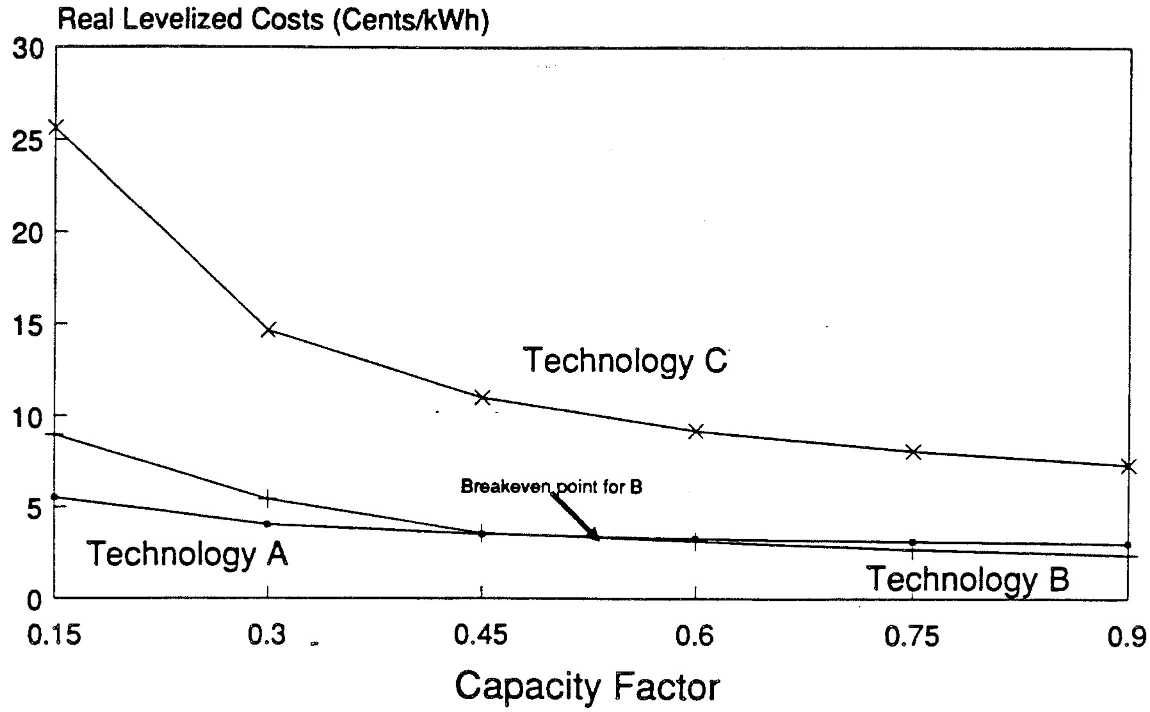


Figure G-1. A Screening Diagram

In Figure G-1, three technologies are represented. Technology A has the lowest fixed and highest variable costs. This is typical of technologies used for peaking operation (combustion turbines and internal combustion engines) that are inexpensive to build but expensive to operate. Technology B has the next lowest fixed costs and next highest variable costs. The point where Technology B intersects Technology A is the breakeven point for Technology B, i.e., beyond this capacity factor, Technology B is more economical than Technology A. If Technology A is expected to operate at a capacity factor greater than the breakeven point, then Technology B would be less expensive to operate per unit of energy produced. Finally, Technology C could be ruled out from further study because it is not economical at any capacity factor.

[1]Capacity factor represents the average capacity utilization of a plant over a time period, typically one year. For example, a 100 percent capacity factor represents use of a plant at full load year round; a 50 percent capacity factor can represent use of a plant at full load for half the year, or use of the plant at half load for the full year.

G.3 TECHNOLOGIES EVALUATED

We focused on several technologies currently available or proposed for use in the Railbelt. We evaluated four fuel types: natural gas, coal, wood, and refuse. Within each fuel type, we selected sizes that would exhibit economies of scale yet still represent reasonable capacity additions in the area. The initial data on the technologies were obtained from two sources. For coal-fired CFBs, we used the Stone & Webster report to Alaska Power Authority (APA) dated November 1988 [1], and for all other technologies, we used the Electric Power Research Institute (EPRI) *Technical Assessment Guide (TAG), Volume 1: Electricity Supply-1986* [2]. These data were also checked against available information on similar plants in the Railbelt area. A brief description of each technology follows.

G.3.1 Coal-Fired Circulating Atmospheric Fluidized Bed Combustion (CFB)

Stone & Webster identified CFB as the preferred technology for future coal-fired plants in the Railbelt primarily due to expected capital cost savings relative to conventional plants. In a CFB, fuel is combusted on a bed of ash that is fluidized by a mass of air levitating it from below. CFBs have excellent fuel flexibility and can be operated with blends of standard coal and low-cost waste coal. Although the Stone & Webster report evaluated three different sizes (150, 100, and 50 MW), we initially decided to analyze only the 150-MW plant. Due to economies of scale, we assume that if a technology is uneconomic at the largest size, it would be uneconomic at the smaller, more expensive (per installed kilowatt) sizes. To eliminate delivery charges, we examined minemouth plants located at Beluga and Healy. Coal price forecasts at both locations were developed by the Institute of Social and Economic Research (ISER) (refer to Appendix B). In addition, we include a third coal plant located at Healy that can handle a 25 percent waste coal blend. In a later sensitivity, we also evaluate a 50-MW plant utilizing a 75 percent waste coal blend.

The estimates of waste coal percentages were derived as follows. Presently the Usibelli Coal Mine produces approximately 1.6 million tons of coal per year. If existing sales are maintained, production would increase further if a new coal plant were developed in the Interior. The following estimates of waste coal utilization are based on standard coal production of 2.0 million tons per year.

It is estimated that waste coal is produced at the Healy mine in approximately a 1:10 ratio compared with standard coal. As a result, waste coal production of about 200,000 tons per year would be consistent with the selected coal production scenario.

A 150-MW coal plant operating at a 75 percent capacity factor would require approximately 10,000,000 MBtu per year in fuel, given a heat rate of 10,000 Btu/kWh. Of this amount, 200,000 tons per year of waste coal could supply about 2,400,000 MBtu, assuming 6000 Btu per pound. Therefore, in the base case adopted for the coal plant screening analysis based on the costs and characteristics of a 150-MW plant, it is assumed that waste coal could supply 25 percent of the fuel requirement. For a 50-MW plant, the same amount of waste coal could supply nearly 75 percent of annual fuel requirements.

G.3.2 Combined Cycle (CC)

In a CC plant, natural gas is first burned in a combustion turbine/electric generator. The hot exhaust gases from the turbine are then passed through a heat recovery steam generator that produces steam for a conventional steam turbine/electric generator. This results in greater efficiency than would be obtained from the combustion turbine alone. Our analysis used a 220-MW plant size.

G.3.3 Conventional Combustion Turbine (CT)

Because the exhaust gases from the CTs are not utilized, they are less efficient than CCs. However, because they do not include a heat recovery steam generator, CTs are much less expensive than CCs. We used a 75-MW plant for this analysis.

G.3.4 Wood-Fired Steam Turbine (WST)

In a WST plant, wood wastes (sawmill or refuse) are burned in a boiler that produces steam to drive a steam turbine. Some of the steam can be extracted from the turbine for cogeneration purposes. We assume that this plant is operated for cogeneration, and as such, the plant produces 3.8 pounds per kWh of steam at a value of $3 per 1000 pounds. In addition, we assumed that this 24-MW plant was located where wood wastes could be obtained relatively inexpensively.

G.3.5 RDF Steam Turbine (RST)

In an RST plant, municipal solid wastes are burned on a moving grate in a water wall incinerator to produce steam to drive a steam turbine. Although the fuel has a low heating value and high moisture content, it is usually free of negative cost because the plant operator may be able to collect a tipping fee for the refuse. The plant we analyzed was 45 MW.

Because we were focusing on large capacity additions, we did not consider internal combustion engines as they are not usually economical for large capacity additions and function mainly as emergency backup.

G.4 EVALUATING COSTS FOR EACH TECHNOLOGY

We evaluated costs for each technology by computing the net present value of total capital, operating, and fuel costs at several capacity factors over the life of each plant. Each of these cost streams was analyzed separately and discounted back to the initial operating year. We then levelized the sum of these costs to obtain real levelized yearly costs. The levelized costs were reported in cents per kWh. It was assumed that each plant is brought on line in 1995. All costs are expressed in 1987 dollars. The next two subsections explain how we calculated these costs.

G.5 FIXED COSTS

Fixed costs are usually divided into two main groups: the carrying charges (total plant investment costs) and the fixed operating and maintenance (O&M) costs (typically labor, some maintenance charges, and overhead).

G.5.1 Carrying Charges

The carrying charges on a plant are those costs associated with amortizing the total plant investment (i.e., the total capital requirement of the plant). The total plant investment is comprised of two primary parts.

1. *The total cost for construction, materials, and land including any royalties on the technology.* This is usually expressed in overnight construction costs. For the coal-fired plants, estimates were obtained from the Stone & Webster report. For all other technologies, we obtained estimates from the EPRI *TAG*. We adjusted these estimates for Alaska costs and conditions. These adjustments were based on the estimated time, complexity, and skilled labor requirement for plant construction. For the CC, WST, and RDF, we assumed that costs would be 50 percent higher in Alaska than in the lower 48 states. For the CT, we assumed that costs are 25 percent higher. These factors were selected to maintain a level of consistency with the high labor cost adjustment implied in the Stone & Webster coal plant estimates.

2. *Allowance for funds used during construction (AFUDC)*, i.e., interest paid on the funds used during construction. AFUDC was computed for each technology by assuming a uniform construction expenditure schedule over an assumed construction period.

The total plant investment costs (1987$/kW) are shown in Table G-1. Because it has been proposed that the coal plants could be built for as little as $1600 per kW (refer to Section 2), we include such an assumption in a later sensitivity case.

Table G-1

TOTAL PLANT INVESTMENT COSTS

Technology*	Size (MW)	Original Plant Cost (87$/kW)	Alaska Plant Cost Multiplier	Total Plant Investment (87$/kW)
BCFB	150	2167	1.00	2343
HCFB	150	2079	1.00	2247
HCFB-WC	150	2136	1.00	2309
CC	220	579	1.50	928
CT	75	341	1.25	446
WST	24	2107	1.50	3454
RDF	45	4414	1.50	7237

*NOTE:

Technology Name	Plant Type	Fuel Type
BCFB	Beluga/Circulating Fluidized Bed	Beluga Coal
HCFB	Healy/Circulating Fluidized Bed	Healy Coal
HCFB-WC	Healy/Circulating Fluidized Bed/Waste coal	Healy Coal & Waste Coal
CC	Combined Cycle	Gas
CT	Combustion Turbine	Gas
WST	Wood Steam Turbine	Wood
RDF	Refuse Derived Fuel	Refuse

(1) The Original Plant Cost column shows plant costs ($/kW) in 1987 dollars before any multipliers have been applied. The Stone & Webster coal plant estimates already incorporate Alaska cost adjustments, and also include one-time training and commissioning costs. For the Healy waste coal plant, the equipment necessary to allow processing of a 25% waste coal blend is included. Finally, the coal plant costs are discounted to 1987 dollars (from 1988 dollars).

(2) The Total Plant Investment column shows plant costs with AFUDC, and adjusted for Alaska.

G.5.2 Fixed O&M Costs

Fixed O&M costs are those expenses incurred even when a plant is not utilized, and that do not increase when the plant is operated. Typical fixed O&M costs are: labor, a portion of the maintenance, administration, and general overhead. In general, baseloaded plants exhibit higher fixed O&M costs than peaking plants. The fixed O&M costs for each of the technologies were determined as follows:

1. *Coal Plants*—Fixed O&M costs for the coal plants were obtained from the Stone & Webster report (Table 7-11). Because the Stone & Webster report does not show a breakdown between fixed and variable O&M costs, we assumed that all the labor and administration and overhead expenses, along with half the maintenance and replacement costs were fixed, the remaining portion of the O&M costs (consumables and the other half of the maintenance and replacement costs) were assumed to be variable.

2. *CC and CT*—Fixed O&M costs for combined cycle and combustion turbine plants were established consistent with existing plants in the Railbelt.

3. *WST and RST*—Fixed O&M costs for wood and refuse plants were obtained from the EPRI data with a 25 percent adjustment for Alaska costs.

The fixed O&M costs (in 1987 dollars) for all the technologies are shown in Table G-2.

Table G-2

FIXED O&M COSTS

	(87$/kW/Yr)
BCFB	57.77
HCFB	58.16
HCFB-WC	58.16
CC	10.00
CT	12.00
WST	75.82
RDF	141.81

G.6 VARIABLE COSTS

Variable costs are those costs that vary as a plant is operated. They are comprised of fuel costs and variable O&M costs.

G.6.1 Fuel Costs

Fuel costs for each technology are a function of the unit's heat rate (i.e., efficiency), the fuel price, and the capacity factor of the unit. Full-load heat rates were used in this screening analysis.

The Beluga and Healy coal prices shown are for minemouth plants, and the natural gas prices are based on Enstar contract terms (refer to Appendix B). The wood prices are for bone-dry saw mill dust at $10 per ton and 6000 Btu per pound. The refuse prices are for a tipping fee of $15 per ton and 4900 Btu per pound.[2] All fuel prices remain constant in real terms except for natural gas. We used the low natural gas price scenario in the base case (probability = 60%). In that scenario, gas escalates at 0.16 percent real until 2010 (i.e., negligible real escalation), and then remains constant in real terms. In a later sensitivity, we analyze higher gas prices and look at very high gas escalation in the post 2010 period due to assumed resource depletion. The fuel cost of the Healy CFB with coal technology (HCFB-WC) assumes a 25 percent coal blend. Table G-3 lists the fuel costs for all technologies.

Table G-3

1995 FUEL COSTS
(1987 dollars)

Tech	Heat Rate (Btu/kWh)	Fuel Cost* (87$/MBtu)	Fuel Cost* (87$/MWh)
BCFB	10113	1.15	11.63
HCFB	10114	1.30	13.15
HCFB-WC	10114	0.99	10.04
CC	8394	1.54	12.93
CT	11600	1.54	17.86
WST	16250	0.75	12.19
RDF**	16300	-1.39	-22.58

*Waste coal cost = 0.07 $/MBtu
**The negative RDF fuel cost reflects a tipping fee usually paid to the RDF plant operator for collecting refuse.

[2]Based on phone conversation with Babcock & Wilcox conveying their experience with wood- and refuse-fired cogeneration facilities around the country.

G.6.2 Variable O&M

Variable O&M costs are comprised mainly of maintenance charges and consumables such as water, oil, sorbents, and so on. Variable O&M costs for each of the technologies were estimated as follows:

1. *Coal Plants*—Variable O&M costs for the coal plants were obtained from the Stone & Webster report (Table 7-11). As reported in Section G.5.2, these costs were assumed to be all of the consumables' expenses and half of the maintenance and replacement costs. It was also assumed that the O&M costs shown were for a plant operating at 75 percent capacity factor.

2. *CC and CT*—Variable O&M costs for the combined cycle and combustion turbine plants were established consistent with existing plants in the Railbelt.

3. *WST and RST*—Variable O&M costs for the wood and refuse plants were obtained from the EPRI TAG report; an adjustment of 25 percent was applied over the EPRI data.

The variable O&M costs (in $/MWh) for each of the technologies are shown in Table G-4. The total plant variable O&M costs are proportionate to the capacity factor.

Table G-4

VARIABLE O&M COSTS

Tech	Variable O&M Costs (87$/MWh)
BCFB	3.89
HCFB	3.83
HCFB-WC	3.83
CC	1.50
CT	1.50
WST*	-1.11
RDF	14.47

*The negative WST variable O&M costs include a "credit" for the steam produced by the plant.

G.7 ECONOMIC ASSUMPTIONS

The following economic assumptions were made:

Real Discount Rate = 4.5%
O&M Real Escalation Rate = 0%
Capital Real Escalation Rate = 0%
Unit Life = 30 years

G.8 BASE CASE RESULTS

Using the previous assumptions, we found that the gas-fired technologies (CT and CC) were more economic than all other technologies at all capacity factors examined.[3] The least expensive coal plant was the Healy waste coal plant. However, even at high capacity factors, the CC was less expensive. As an illustration, at 75 percent capacity factor, the levelized cost of the Healy waste coal plant was 4.43 cents per kWh while the levelized cost of the CC was 2.48 cents per kWh. On a lifecycle cost basis, the cost of the coal plant was 79 percent higher. The refuse and wood technologies were not economically viable under the base case assumptions. The refuse technology was burdened too heavily with high fixed costs. The wood-fired plant was burdened with both high fixed costs and high variable costs. Table G-5 lists the levelized costs for each plant at various capacity factors. Figure G-2 shows the base case screening diagram for all plants except the regular Healy coal (its costs are very close to the Beluga plant). Figure G-3 focuses exclusively on the CT, the CC, and the Healy waste coal plant.

Table G-5

BASE CASE

Levelized Total Costs at Various Capacity Factors (87 cents/KWh)

Tech	0.15	0.3	0.45	0.6	0.75	0.9
BCFB	16.89	9.22	6.67	5.39	4.62	4.11
HCFB	16.62	9.16	6.67	5.43	4.68	4.18
HCFB-WC	16.60	8.99	6.46	5.19	4.43	3.92
CC	6.56	4.01	3.16	2.73	2.48	2.31
CT	4.96	3.46	2.96	2.71	2.56	2.46
WST	23.02	12.06	8.41	6.58	5.49	4.76
RDF	43.79	21.49	14.06	10.34	8.11	6.62

[3] In practice, capacity factors over 90 percent are difficult to achieve because plant equivalent availabilities are limited by planned and unplanned outages.

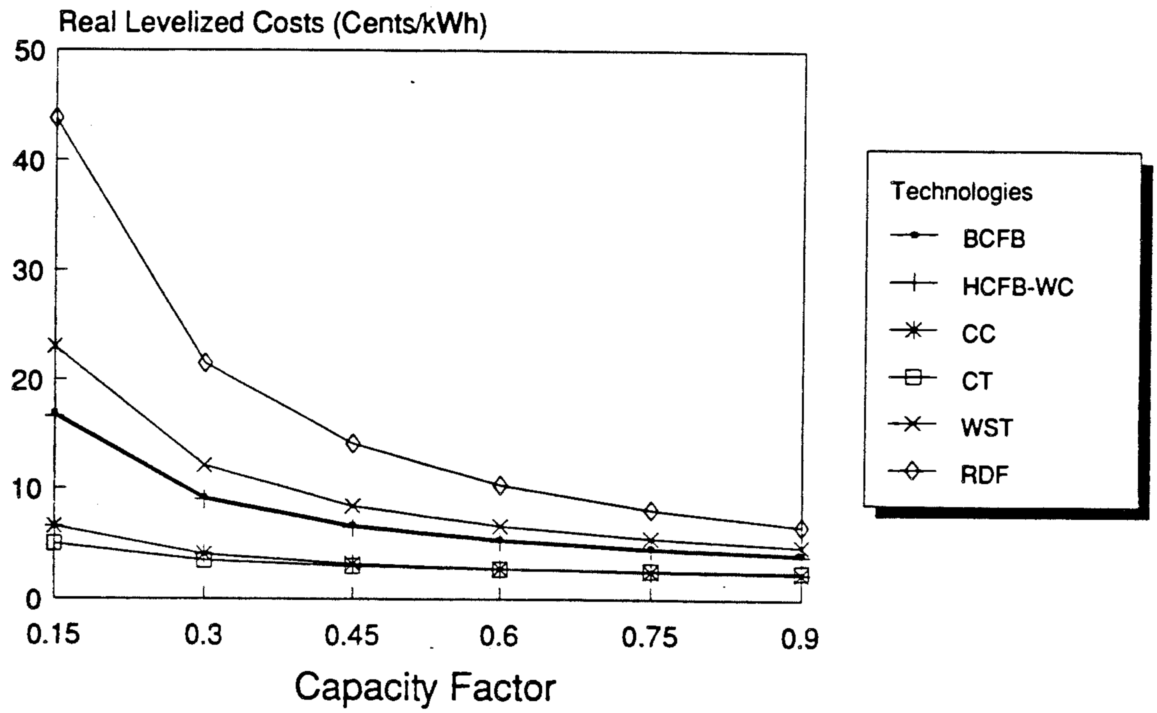


Figure G-2. Technology Screening (Base Case—All Technologies)

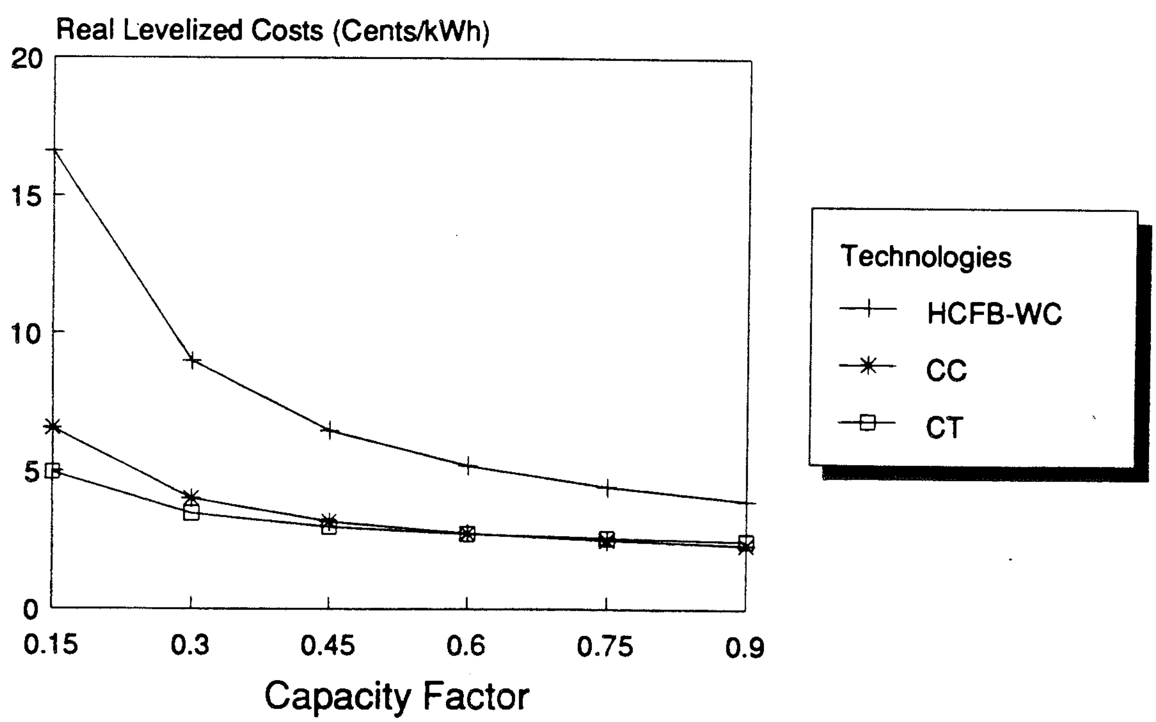


Figure G-3. Technology Screening (Base Case—Selected Technologies)

G.9 SENSITIVITY ANALYSIS

To test the stability of the base case results, and to see under what circumstances they would change, the following sensitivity studies were done:

1. Middle gas prices.
2. High gas prices.
3. Low coal plant capital costs.
4. Low coal plant capital costs combined with high fraction of waste coal.

G.9.1 Sensitivity #1: Middle Gas Prices

In this case, we modified the gas prices to reflect APA middle gas price scenario (Probability = 30%) between 1995 and 2010, followed by sharp escalation during the following 15 years (refer to Appendix B):

	Period	Period
Years	1995-2010	2010-2025
Price (1st Year)	\$1.98/MBtu	\$2.28/MBtu
Real Escalation per Year	0.9%	7.2%
Price in Year 2025 =	\$6.50/MBtu	

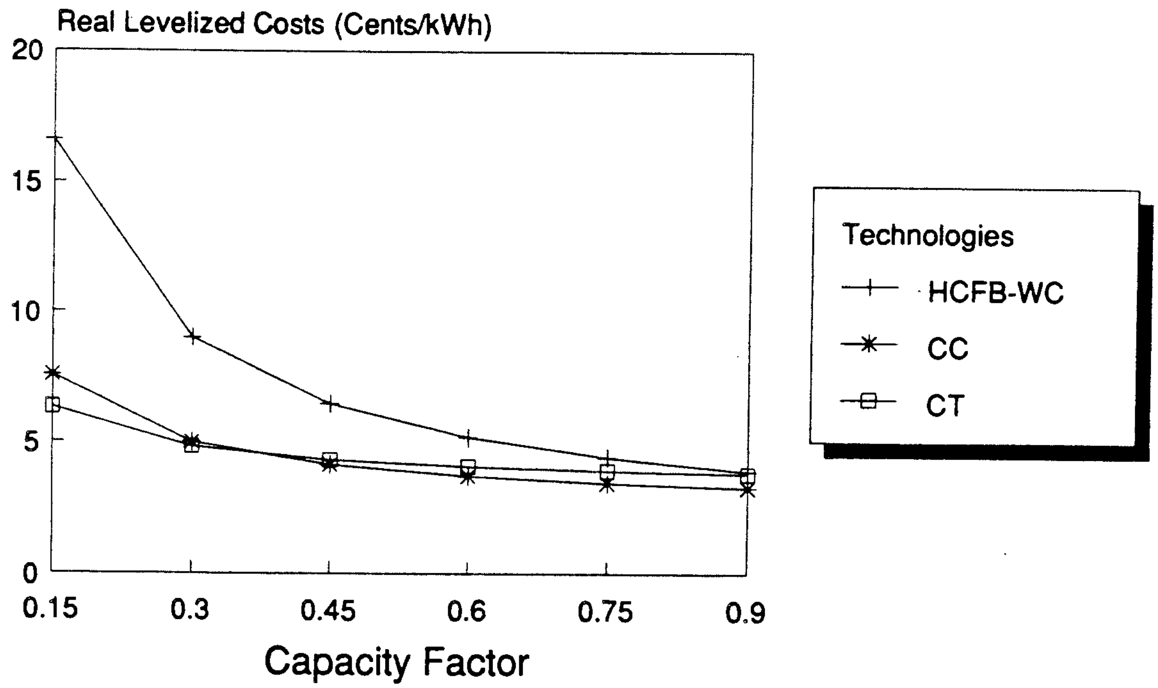
As expected, this change increased the production costs of the gas-fired technologies. However, the CC plant still maintained a clear economic advantage over the Healy waste coal plant, even at high capacity factors. At 75 percent capacity factor, the levelized cost of the CC was 3.47 cents per kWh, while the levelized cost of the Healy waste coal plant (which was the lowest cost coal plant), was 4.43 cents per kWh. On a lifecycle cost basis, the cost of the coal plant was 28 percent higher. Table G-6 displays the levelized costs for all technologies at various capacity factors, and Figure G-4 shows the screening curve for the CT, the CC, and the Healy waste coal plant.

Table G-6

SENSITIVITY CASE #1: MIDDLE GAS PRICES

Levelized Total Costs at Various Capacity Factors (87 cents/KWh)

Tech	0.15	0.3	0.45	0.6	0.75	0.9
BCFB	16.89	9.22	6.67	5.39	4.62	4.11
HCFB	16.62	9.16	6.67	5.43	4.68	4.18
HCFB-WC	16.60	8.99	6.46	5.19	4.43	3.92
CC	7.55	5.00	4.15	3.72	3.47	3.30
CT	6.32	4.83	4.33	4.08	3.93	3.83
WST	23.02	12.06	8.41	6.58	5.49	4.76
RDF	43.79	21.49	14.06	10.34	8.11	6.62



Middle gas price scenario as defined by the APA. Probability = 30%.

Figure G-4. Technology Screening (Middle Gas Price)

G.9.2 Sensitivity #2: High Gas Prices

In this case, we modified the gas prices to reflect APA high gas price scenario (Probability = 10%) between 1995 and 2010, followed by sharp escalation during the following 15 years (refer to Appendix B):

	Period	Period
Years	1995-2010	2010-2025
Price (1st Year)	\$2.31/MBtu	\$3.01/MBtu
Real Escalation per Year	1.8%	6.3%

Final Price in Year 2025 = \$7.50/MBtu

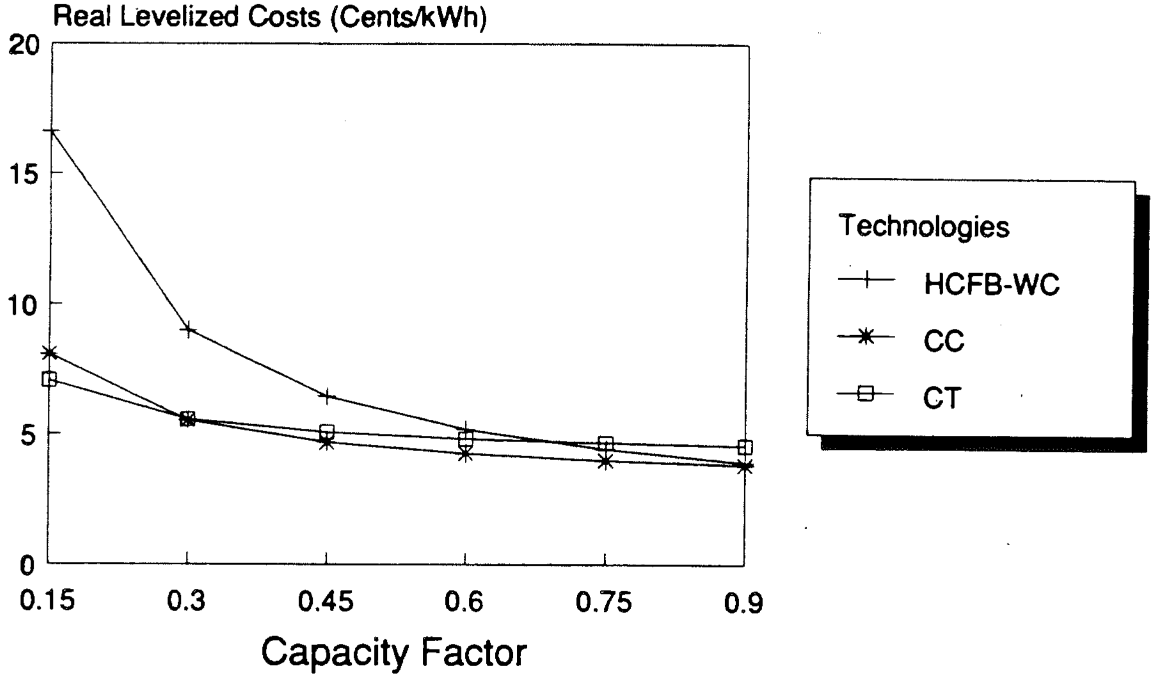
In this sensitivity case, the CC plant still maintained an economic advantage over the Healy waste coal plant. For example, at 75 percent capacity factor, the levelized cost of the CC was 4.00 cents per kWh while the levelized cost of the Healy waste coal plant was 4.43 cents per kWh. On a lifecycle cost basis, the cost of the coal plant was 11 percent higher. Table G-7 shows the levelized costs for all technologies. Figure G-5 illustrates the CT, CC, and Healy waste coal costs.

Table G-7

SENSITIVITY CASE #2: HIGH GAS PRICES

Levelized Total Costs at Various Capacity Factors (87 cents/KWh)

Tech	0.15	0.3	0.45	0.6	0.75	0.9
BCFB	16.89	9.22	6.67	5.39	4.62	4.11
HCFB	16.62	9.16	6.67	5.43	4.68	4.18
HCFB-WC	16.60	8.99	6.46	5.19	4.43	3.92
CC	8.08	5.53	4.68	4.26	4.00	3.83
CT	7.07	5.57	5.07	4.82	4.67	4.57
WST	23.02	12.06	8.41	6.58	5.49	4.76
RDF	43.79	21.49	14.06	10.34	8.11	6.62



High gas price scenario as defined by the APA. Probability = 10%.

Figure G-5. Technology Screening (High Gas Price)

G.9.3 Sensitivity #3: Low Coal Plant Capital Costs

In this case, we assumed gas prices as in the base case but reduced the coal plant capital costs by 33 percent. This was equivalent to assuming a 25 percent adjustment factor for Alaska costs and conditions, instead of the 87 percent cost differential implied by the Stone & Webster cost analysis. The coal plant costs were reduced as follows:

Plant	Plant Cost ($/kW) Base Case	Plant Cost ($/kW) Sensitivity #3
Beluga	2343	1566
Healy	2247	1502
Healy Waste	2309	1543

The gas-fired technologies remained most economic at all capacity factors. At 75 percent capacity factor, for example, the levelized cost of the Healy waste coal plant was 3.71 cents per kWh compared to 2.48 cents per kWh for the CC. Table G-8 shows the levelized costs for all technologies, and Figure G-6 illustrates the costs of the CT, CC, and Healy waste coal plants.

Table G-8

SENSITIVITY CASE #3: LOW COAL PLANT CAPITAL COSTS

1. COAL PLANT CAPITAL COSTS = (1.25/1.87) * BASE CASE COSTS
2. BASE CASE GAS PI ICES.

Levelized Total Costs at Various Capacity Factors (87 cents/KWh)

Tech	0.15	0.3	0.45	0.6	0.75	0.9
BCFB	13.26	7.41	5.46	4.48	3.89	3.50
HCFB	13.14	7.42	5.51	4.56	3.99	3.60
HCFB-WC	13.03	7.21	5.27	4.30	3.71	3.33
CC	6.56	4.01	3.16	2.73	2.48	2.31
CT	4.96	3.46	2.96	2.71	2.56	2.46
WST	23.02	12.06	8.41	6.58	5.49	4.76
RDF	43.79	21.49	14.06	10.34	8.11	6.62

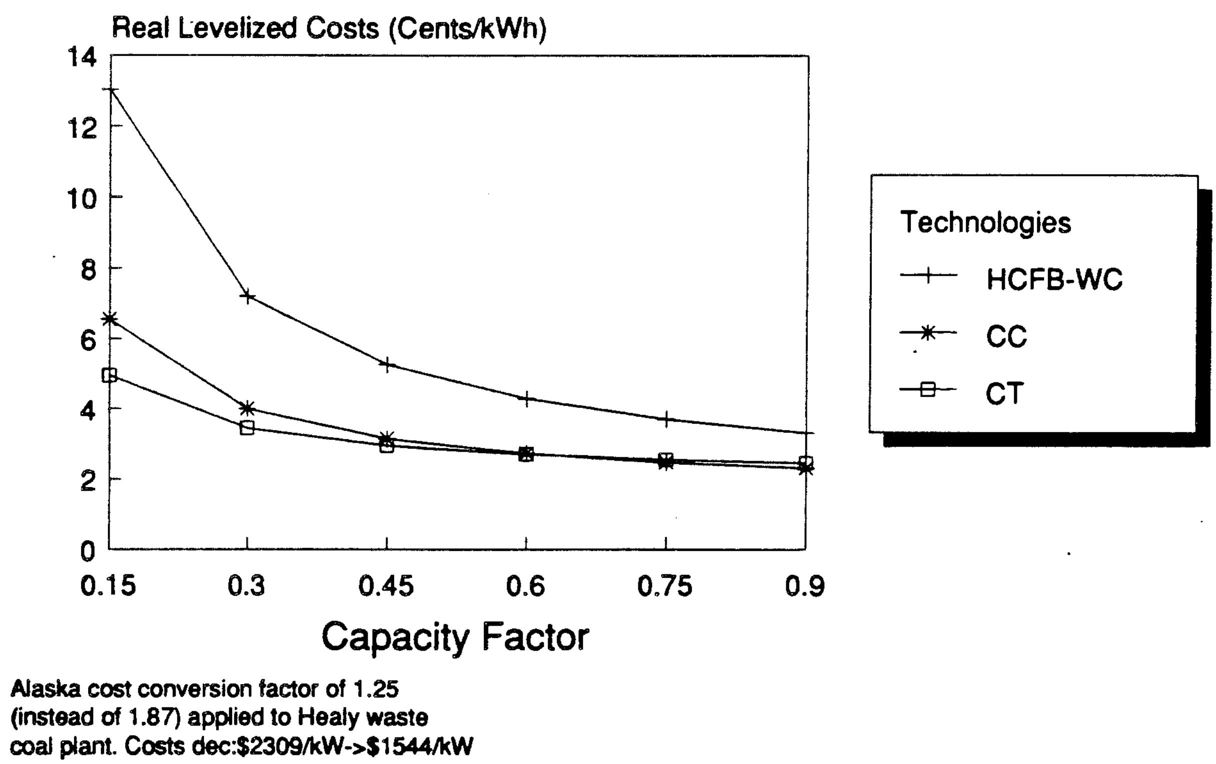


Figure G-6. Technology Screening (Low Coal Plant Capital Costs)

G.9.4 Sensitivity #4: Low Coal Plant Capital Cost Combined with High Fraction of Waste Coal

This sensitivity case incorporates the following assumptions:

1. A 50-MW plant with construction costs of $1600 per kW is used.
2. Waste coal supplies 75 percent (rather than 25 percent) of the fuel requirement.
3. Fixed O&M costs are assumed at $75 per kW (rather than $115 per kW for the 50-MW plant in the Stone & Webster estimates).
4. Gas prices are set consistent with the base case.

Under these assumptions, the gas-fired technologies continued to be most economic at all capacity factors. The levelized cost of a waste coal plant at 75 percent capacity factor fell to 3.44 cents per kWh compared with 2.48 cents per kWh for the CC. Table G-9 shows the levelized costs for all technologies, and Figure G-7 displays the costs of the CT, CC, and the 50-MW Healy waste coal plant.

Table G-9

SENSITIVITY CASE #4: LOW COAL PLANT CAPITAL COSTS COMBINED WITH HIGH FRACTION OF WASTE COAL

1. CAPITAL COSTS = $1600/KW
2. SIZE = 50 MW
3. WASTE COAL FRACTION = 75%
4. FIXED O&M AT $75/KW, VARIABLE O&M AT $4.34/MWH
5. BASE CASE GAS PRICES.

Levelized Total Costs at Various Capacity Factors (87 cents/KWh)

Tech	0.15	0.3	0.45	0.6	0.75	0.9
HCFB-WC	13.98	7.39	5.19	4.10	3.44	3.00
CC	6.56	4.01	3.16	2.73	2.48	2.31
CT	4.96	3.46	2.96	2.71	2.56	2.46
WST	23.02	12.06	8.41	6.58	5.49	4.76
RDF	43.79	21.49	14.06	10.34	8.11	6.62

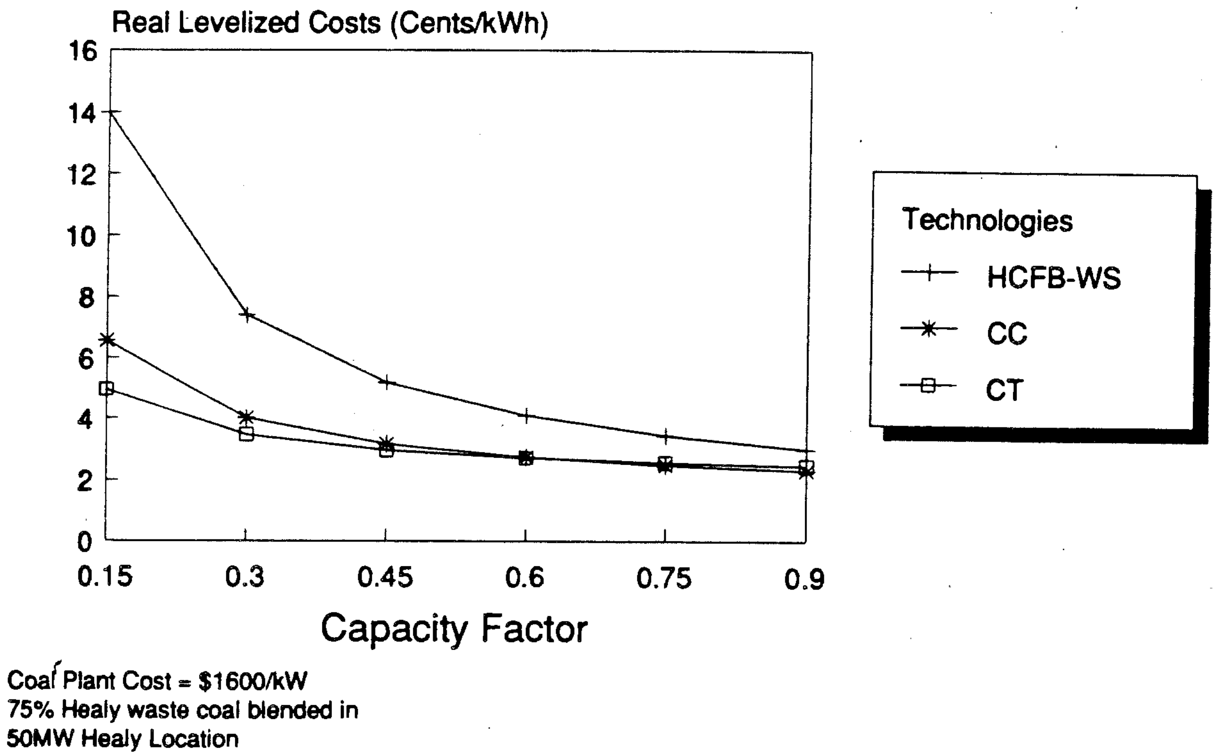


Figure G-7. Technology Screening (Low Coal Plant Capital Costs and High Fraction of Waste Coal)

G.10 COMPARATIVE EVALUATION OF SUPPLY-SIDE TECHNOLOGIES AND END-USE CONSERVATION PROGRAMS

We then compared the least expensive supply-side options to the demand-side alternatives.[4] Table G-10 lists the nine programs evaluated and their respective levelized costs [3]. The programs were evaluated with respect to base case and middle case gas prices. The results are shown in Figures G-8 and G-9. The base case comparison clearly suggests that three of the programs are likely to be economic: two of the commercial programs (more efficient fluorescent lamps and conversions from incandescent to fluorescent lighting), and one residential program (conversions from electric to gas water heating). In the middle case, all the other programs (except the efficient freezer program) emerge as promising candidates for implementation.

[4]The demand-side alternatives are end-use conservation programs designed to reduce loads by increasing the average efficiency of residential and commercial appliances and equipment and by converting certain electric appliances to natural gas operation. By providing consumers with monetary incentives to upgrade or replace their equipment, reductions in load can be achieved.

Table G-10

END-USE PROGRAMS

	Program	Cents/kWh Saved	Annual* Load Factor
A	Water Heater Conversions	2.0	.64
B	Efficient Water Heaters	2.3	.85
C	Gas Dryer Rebates	3.2	.59
D	Efficient Refrigerators	3.1	.88
E	Efficient Freezers	3.5	1.02
F	Efficient Fluorescent Lamps	2.1	.49
G	Electronic Ballasts	3.5	.49
H	Incandescent Conversions	1.8	.41
I	Sliding-Scale Rebates	2.7	.48

Source (Table 1-2 ISER End use report)

$$\text{* Annual Load Factor} = \frac{\text{Annual Energy Saved (kWh)}}{\text{Load Reduction on Peak (kW) x 8760 (hrs/year)}}$$

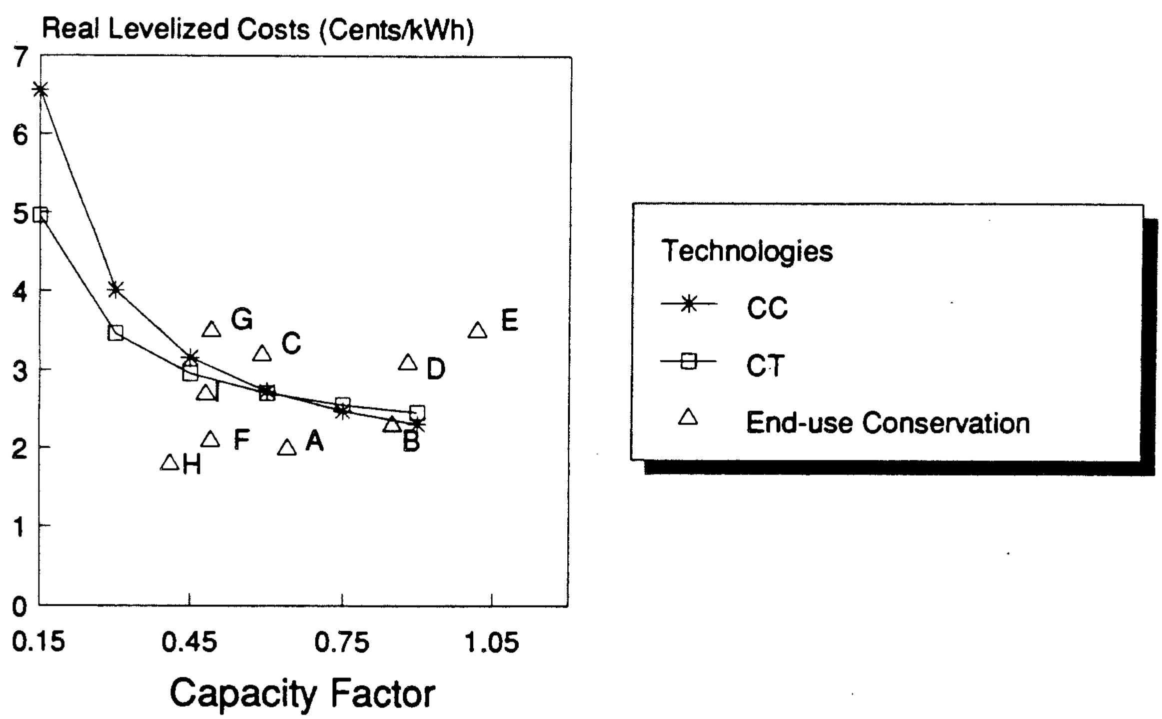
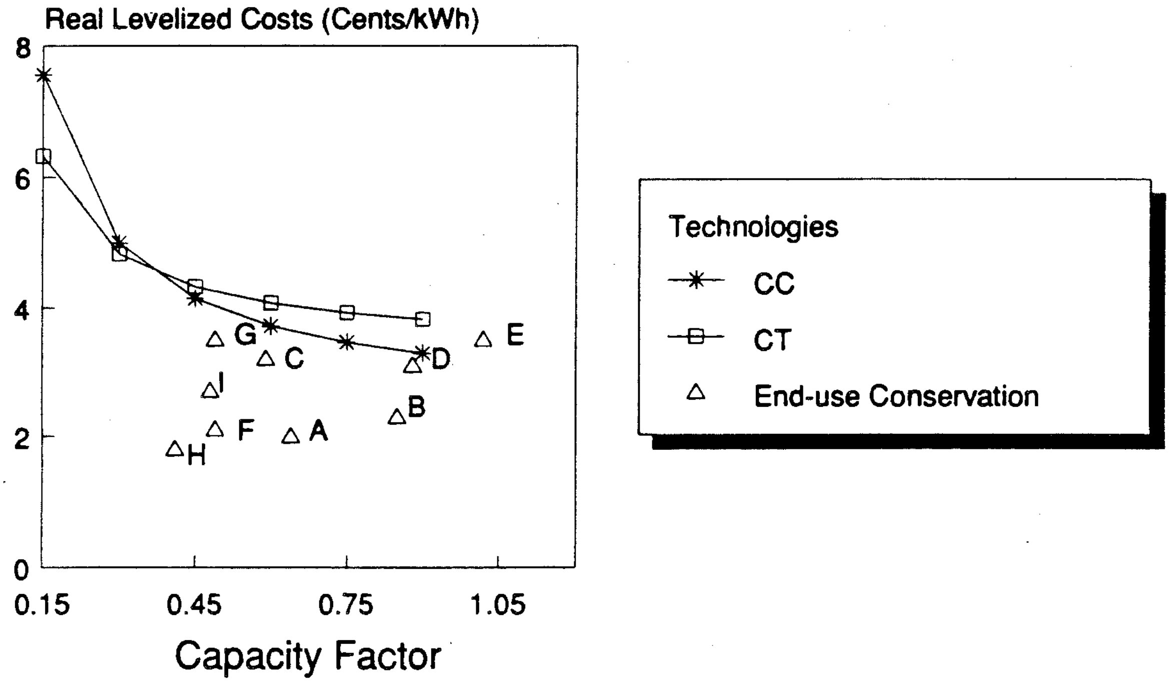


Figure G-8. Supply-Side Technologies and End-Use Conservation Programs (Base Case)



Middle gas price scenario as defined by the APA. Probability = 30%.

Figure G-9. Supply-Side Technologies and End-Use Conservation Programs (Middle Gas Prices)

G.11 CONCLUSIONS

Gas-fired technologies were identified as the most economic power supply alternatives under all assumptions tested. In the base case, the levelized cost of coal-fired generation exceeded the gas alternative by around 75 percent at high capacity factors. Coal-fired generation was not identified as economic under any of the assumptions tested. Wood- and refuse-fired technologies were more expensive than both gas and coal. Three of the end-use conservation programs showed high potential for economic feasibility in the base case; five others may be economic under higher (middle case) gas price assumptions.

G.12 REFERENCES

[1] *"Estimated Costs and Environmental Impacts of Coal-Fired Power Plants in the Alaska Railbelt Region,"* Stone & Webster Engineering Corporation report to Alaska Power Authority, November 1988.

[2] *Technical Assessment Guide (TAG), Volume 1: Electricity Supply 1986*, Electric Power Research Institute.

[3] *Analysis of Electrical End-Use Efficiency Programs for the Alaskan Railbelt*, Institute of Social and Economic Research, University of Alaska, Anchorage, November 1988, Draft.

Appendix H

BENEFITS OF INCREASED HYDRO-THERMAL COORDINATION

The efficiency of thermal generation depends on the output level of the power plant. Thermal power plants typically operate most efficiently at or near full loading. While dispatchers try to achieve the least-cost operation, the electric demand often does not match the most efficient power-plant operating level of output. Coordination between two (or more) areas allows a more efficient use of generation resources. For example, hydroelectric generation in Kenai can be utilized to increase the generating efficiency of the thermal power plants in Anchorage. By adjusting the output level of hydroelectric generation in Kenai, the demand served by Anchorage thermal power plants can be reshaped by either adding to or subtracting from the natural Anchorage electric demand. By properly reshaping the demand served by Anchorage generation, more efficient output levels of the Anchorage thermal power plants can be obtained, and therefore savings in operating costs can be achieved. Much of these savings, called benefits of hydro-thermal coordination, are the result of Bradley Lake; however, a new Kenai-Anchorage intertie could increase these savings by increasing the coordination capability between the Kenai hydro and the Anchorage thermal systems. The realized savings, called benefits of increased hydro-thermal coordination, depend on the following four factors:

1. Savings from reshaping Anchorage thermal generation
2. Transmission capacity between Anchorage and Kenai
3. Transmission losses
4. Flexible generating capability in Kenai.

All of these are discussed in more detail in the following subsections. Approximately $750,000 (in 1987 dollars) of annual benefits accrue to the new intertie. These benefits result from increased economy transfers due to the new intertie's higher transfer capability and lower transmission losses.

H.1 SAVINGS FROM RESHAPING ANCHORAGE THERMAL GENERATION

The efficiency of thermal power plants changes over the range of power-plant output.[1] For example, Table H-1 lists performance data for the Beluga CT #5.

Table H-1

OPERATING PERFORMANCE OF BELUGA CT #5

Output (MW)	Percent of Maximum	Heat Rate (Btu/kWh)	Fuel Use (MBtu/hr)
33	50	15012	495.4
66	100	12963	855.6

Source: [1]

Ignoring transmission losses for the moment, if Beluga CT #5 needed to operate at 50 percent loading to serve Anchorage local demand, the Kenai hydro energy could meet the demand half the time and Beluga CT #5 could operate at 100 percent loading the other half of the time. When Beluga CT #5 operates at full output, half of its energy would be transferred to Kenai. At the end of this half-on/half-off cycle of Beluga CT #5, the Kenai hydroelectric energy would be unaffected, Beluga CT #5 total electric generation would be unaffected, but the energy transfer between Kenai and Anchorage would have increased by 396 MWh in each direction; Figure H-1 illustrates the process.

During this cycle, the cost of thermal generation would be significantly reduced. For example, from Table H-1 one can calculate that operating Beluga CT #5 at 50 percent loading for 24 hours requires 11,890 MBtu. Operating Beluga CT #5 at 100 percent loading for 12 hours generates an equivalent amount of electricity but only requires 10,267 MBtu. Fuel savings of 1623 MBtu (i.e., 11,890 MBtu minus 10,267 MBtu) are realized by reshaping 396 MWh of energy. On a per unit of energy reshaped (or moved) basis, this amounts to 4098 Btu/kWh (i.e., 1623 MBtu divided by 396 MWh.) As the calculation below illustrates, this saving is equivalent to the difference between the heat rate at 50 percent loading and the incremental heat rate between 50 percent loading and 100 percent loading:

[1] The efficiency of a thermal power plant is typically measured in terms of fuel input requirements per unit of electric output, called heat rates. Efficiency increases with reduced heat rates, i.e., with reduced fuel input per unit of electric output.

Total heat rate at 50% loading	15012 Btu/kWh
Incremental heat rate between 50% and 100% loadings	10914[2] Btu/kWh
Difference	4098 Btu/kWh

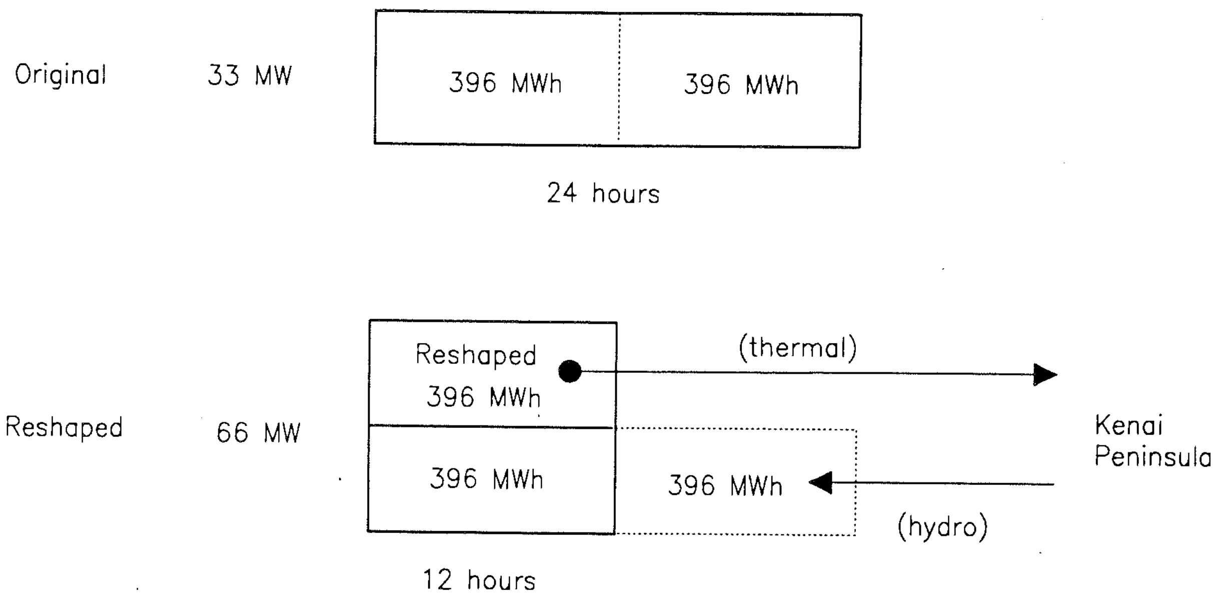


Figure H-1. Reshaping Thermal Energy Generation

The most expensive or marginal generating units in operation are the likely candidates for thermal energy generation reshaping. Table H-2 lists the heat rate performance characteristics for these units in Anchorage. In terms of the difference between the total heat rate at 50 percent output and the incremental heat rate between 50 percent and 100 percent output, Beluga CT #5 with a value of 4098 Btu/kWh is representative of this group.

[2]Using the values in Table H-1: (885.6 - 495.4)MBtu/(66 - 33)MW = 10.914 MBtu/MWh or 10,914 Btu/kWh.

Table H-2

HEAT RATE PERFORMANCE CHARACTERISTICS OF SELECTED ANCHORAGE AREA GENERATING UNITS

(1) Name	(2) Full Output (MW)	(3) Total Heat Rate @ 50% Output (Btu/kWh)	(4) Incremental Heat Rate 50% to 100% of output (Btu/kWh)	(5) Col (3) Minus Col (4)
Beluga CC #8	101	10,981	7,801	3,180
AMLP CC #56	47	13,700	8,718	4,982
Beluga CT #3	55	13,136	9,552	3,584
AMLP CT #8	87	14,029	9,591	4,438
Beluga CT #5	66	15,012	10,914	4,098
AMLP CT #4	33	18,475	9,372	9,148

Source: [1]

H.2 KENAI-ANCHORAGE TRANSMISSION CAPACITY

Reshaping thermal energy generation in Anchorage requires sufficient transmission capacity between Kenai and Anchorage to transfer energy in both directions. With the new intertie capable of transferring 250 MW, transmission will not constrain any plausible reshaping. With the existing line limited to 60 MW, there will be a constraint. As explained in the next subsection, the transmission losses that increase with increased loading of the existing line limit economic reshaping to 30 MW. As a result, after accounting for the likely amount of unit reshaping required and the 30 MW limit on the existing Kenai-Anchorage intertie, our analysis estimates that the average amount of capacity reshaped with the existing line will be approximately 27 MW; with the new line, it will be increased to 40 MW.

H.3 TRANSMISSION LOSSES

Transmission losses reduce the benefits of reshaping thermal generation because (a) they increase the required amount of input energy transfer, and (b) they limit the potential for economic energy transfer between areas. For the existing line, transmission losses are 8 percent for the first 30 MW and an incremental 20 percent for the second 30 MW; for the new intertie, transmission losses will be 2 percent. We will use 8 percent losses as an example now. In order to have 1.0 MWh for reshaping in Anchorage, 1.087 MWh {1.0 MWh/(100% - 8%)} must be generated in Kenai. Furthermore, to return this 1.087 MWh to Kenai,[3] 1.181 MWh {1.087 MWh/(100% - 8%)} must be generated in Anchorage. As a result, the savings for reshaping Beluga CT #5 after accounting for transmission losses are listed in Table H-3.

Table H-3

SAVINGS FROM RESHAPING BELUGA CT #5

(1) One-Way Transmission Loss	(2) MWh needed to reshape 1 MWh at 50% Output	(3) Total Heat Rate at 50% Output (Btu/kWh)	(4) Btu needed to serve (3) (Btu)	(5) Savings (Btu/kWh)
0%	1.0000	15,012	10,914	4,098
2%	1.0412	15,012	11,364	3,648
8%	1.1815	15,012	12,895	2,117
20%	1.5625	15,012	17,053	none

(1) Percent of input
(2) Based on $1/(1 - \text{one-way transmission loss})^2$
(3) Based on Beluga CT #5
(4) Based on incremental heat rate of Beluga CT #5 (from 50% to 100% output) x Column #2
(5) Column #3 - Column #4

H.4 KENAI GENERATING CAPABILITY

Reshaping Anchorage thermal generation with imported Kenai hydroelectric generation requires sufficient amounts of efficient generating capacity on the Kenai Peninsula. With the addition of Bradley Lake, Kenai hydroelectric generation delivered

[3]Section H.4 illustrates that the Kenai hydro-energy would be used for reshaping thermal energy generation in Anchorage. Since Kenai hydro-energy is less than the energy requirements in Kenai for all load forecasts, any Kenai hydro-energy transferred to Anchorage would have to be replaced by transferring back energy generation from Anchorage.

to Soldotna will increase from 17 MW to 133 MW.[4] Since Kenai's load rarely exceeds 70 MW,[5] Kenai generating capability will seldom limit transactions on the existing 60 MW interconnection to Anchorage.

The new intertie's capacity does not provide an equivalent constraint. Thus, if the need for Kenai generation in Anchorage exceeded the capabilities of Kenai hydroelectric generation, either thermal generation in Kenai would be necessary or the need would not be served.[6] Given the current generating resources and fuel supply agreements, these economy transactions may be limited to surplus hydroelectric capability. Based on current loads, this surplus hydro capacity for export out of Kenai would be at least 75 MW, 75 percent of the time. However, a future addition of a moderate size (about 25 to 50 MW) efficient gas turbine or combined cycle would effectively overcome this constraint. In our analysis, we have assumed that with the new intertie, transactions of this type would seldom be constrained by Kenai supply but instead by Anchorage demand. If we were to limit these transactions to 45 MW,[7] the average transaction would reduce from the 40 MW cited in Section H.2 to 34 MW.

H.5 FREQUENCY OF TRANSACTIONS

Transactions to reshape Anchorage thermal generation should occur a substantial amount of the time. Our analysis assumes that these transactions would occur about 90 percent of the time absent transmission constraints. Reshaping one kilowatthour requires transmitting two kilowatthours over a two hour time period using one kilowatt of transmission capacity (see Figure H-1). As a result each kilowatt results in reshaping approximately 4000 kilowatthours per year.[8]

With only the existing Kenai-Anchorage transmission line, other uses may preclude these reshaping transactions. The other uses depend on fuel price and load growth scenario. Based on analyzing the detailed simulation model results, we estimate that each GWh of energy transferred for other uses from Kenai to Anchorage precludes ten hours of transfer for Anchorage thermal energy reshaping.

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[4]Based on 114 MW of Bradley Lake energy delivered to Soldotna.

[5]Please see Figure C-1 that shows that Kenai's current load exceeds 70 MW approximately less than 5 percent of the time; it exceeds 60 MW less than 25 percent of the time.

[6]Since these are economy energy transactions, insufficient capability does not affect reliability.

[7]This would allow 30 MW of operating reserve sharing as described in Section 7.

[8]For each kilowatt of used transmission capacity (90%) * (8764 hours per year) / (2 kWh transferred per 1 kWh reshaped) = 3943.8 kWh reshaped per year per kilowatt of used transmission capacity.

H.6 BENEFITS OF NEW KENAI-ANCHORAGE LINE

Table H-4 shows that, with the existing line, the thermal energy transfers between Kenai and Anchorage would be around 110 to 120 GWh per year. Table H-5 shows that these transfers would increase by 40 to 50 GWh per year with the new line. The net benefits of these increased transfers are around 0.6 to 1.1 million dollars per year and are listed in Table H-6.

Table H-4

KENAI-ANCHORAGE TRANSFERS DUE TO HYDRO-THERMAL COORDINATION WITH EXISTING INTERTIE

Scenario	Fuel	Load	Joint Probab.	Thermal Energy Reshaping Transfers (GWh/yr): South ----> North 1994	2002	2010	North ----> South 1994	2002	2010	Associated Transmission Loss (GWh/yr) 1994	2002	2010
Base	Low	Low	0.30	104	105	107	114	114	117	17	17	18
		Middle	0.23	110	117	117	120	127	127	18	19	20
		High	0.06	115	116	117	125	126	127	19	19	19
	Middle	Low	0.03	105	105	107	115	114	117	18	17	18
		Middle	0.08	111	117	117	121	127	127	19	19	20
		High	0.19	117	116	117	127	126	127	19	19	20
	High	Low	0.00	105	105	107	115	114	117	18	17	18
		Middle	0.02	111	117	117	121	127	127	19	20	20
		High	0.08	117	117	117	127	127	127	19	19	20
Base Case Expected Values				110	113	114	120	122	124	18	18	19
Utility Load Forecast	Low		0.60	104	105	107	114	114	117	17	17	18
	Middle		0.30	105	105	107	115	114	117	18	17	18
	High		0.10	105	105	107	115	114	117	18	17	18
Utility Load Forecast Exp. Values				104	105	107	114	114	117	17	17	18
DOR Fuel	Middle	High		115	116	117	125	126	127	19	19	19
NoMiltry	Low	High		115	116	117	125	126	127	19	19	19
DryHydro	Low	High		115	116	117	125	126	127	19	19	19
WetHydro	Low	High		115	116	117	125	126	127	19	19	19
GasEscal	Low	High		115	116	117	125	126	127	19	19	19

Note : Years for GasEscal sensistivity are: 1994, 2010, and 2028.

Table H-5

NET INCREASES (DECREASES) IN KENAI-ANCHORAGE HYDRO-TERMAL COORDINATION TRANSFERS DUE TO THE NEW INTERTIE

Assumptions: Scenario	Fuel	Load	Joint Probab.	Increase in Thermal Energy Reshaping Transfers (GWh/yr): South ----> North 1994	South ----> North 2002	South ----> North 2010	North ----> South 1994	North ----> South 2002	North ----> South 2010	Change in Associated Transmission Loss (GWh/yr) 1994	2002	2010
Base	Low	Low	0.30	57	57	54	51	51	48	-11	-11	-11
		Middle	0.23	51	45	45	45	38	48	-12	-13	-13
		High	0.06	46	45	45	39	39	38	-13	-13	-13
	Middle	Low	0.03	56	57	54	50	51	48	-11	-11	-11
		Middle	0.08	51	45	45	44	38	38	-12	-13	-13
		High	0.19	45	45	45	38	39	38	-13	-13	-13
	High	Low	0.00	56	57	54	50	51	48	-11	-11	-11
		Middle	0.02	51	45	45	44	38	38	-12	-13	-13
		High	0.08	45	45	45	38	38	38	-13	-13	-13
Base Case Expected Values				51	49	48	45	43	44	-12	-12	-12
Utility Load Forecast	Low		0.60	57	57	54	51	51	48	-11	-11	-11
	Middle		0.30	56	57	54	50	51	48	-11	-11	-11
	High		0.10	56	57	54	50	51	48	-11	-11	-11
Utility Load Forecast Exp. Values				57	57	54	51	51	48	-11	-11	-11
DOR Fuel	Middle	High		46	45	45	39	39	38	-13	-13	-13
NoMiltry	Low	High		46	45	45	39	39	38	-13	-13	-13
DryHydro	Low	High		46	45	45	39	39	38	-13	-13	-13
WetHydro	Low	High		46	45	45	39	39	38	-13	-13	-13
GasEscal	Low	High		46	45	45	39	39	38	-13	-13	-13

Notes: 1. Negative change in transmission losses is a saving.
2. Years for GasEscal sensistivity are: 1994, 2010, and 2028.

Table H-6

NET BENEFITS OF INCREASED HYDROTHERMAL COORDINATION DUE TO THE NEW KENAI-ANCHORAGE INTERTIE

(M$/Yr)

	Assumptions			Increased Transfer Benefits (M$/yr)			Reduced Transmission Loss (M$/yr)			Net Benefits (M$/yr)		
Scenario	Fuel	Load	Joint Probab.	1994	2002	2010	1994	2002	2010	1994	2002	2010
Base	Low	Low	0.30	0.42	0.42	0.41	0.20	0.20	0.21	0.62	0.62	0.62
		Middle	0.23	0.38	0.35	0.35	0.21	0.23	0.23	0.59	0.58	0.58
		High	0.06	0.35	0.35	0.35	0.22	0.22	0.23	0.57	0.57	0.58
	Middle	Low	0.03	0.52	0.51	0.60	0.25	0.27	0.31	0.77	0.78	0.91
		Middle	0.08	0.47	0.47	0.51	0.26	0.30	0.33	0.73	0.77	0.84
		High	0.19	0.43	0.47	0.51	0.28	0.30	0.33	0.71	0.77	0.84
	High	Low	0.00	0.59	0.70	0.79	0.29	0.34	0.40	0.88	1.04	1.19
		Middle	0.02	0.54	0.58	0.68	0.31	0.38	0.44	0.85	0.96	1.12
		High	0.08	0.49	0.38	0.68	0.32	0.38	0.44	0.81	0.76	1.12
Base Case Expected Values				0.42	0.42	0.45	0.24	0.26	0.27	0.66	0.67	0.73
Utility	Low		0.60	0.42	0.42	0.41	0.20	0.20	0.21	0.62	0.62	0.62
Load	Middle		0.30	0.52	0.51	0.60	0.25	0.27	0.31	0.77	0.78	0.91
Forecast	High		0.10	0.59	0.70	0.79	0.29	0.34	0.40	0.88	1.04	1.19
Utility Load Forecast Exp. Values				0.47	0.48	0.51	0.22	0.24	0.26	0.69	0.71	0.76
DOR Fuel	Middle	High		0.35	0.35	0.35	0.22	0.22	0.23	0.57	0.57	0.58
NoMiltry	Low	High		0.35	0.35	0.35	0.22	0.22	0.23	0.57	0.57	0.58
DryHydro	Low	High		0.35	0.35	0.35	0.22	0.22	0.23	0.57	0.57	0.58
WetHydro	Low	High		0.35	0.35	0.35	0.22	0.22	0.23	0.57	0.57	0.58
GasEscal	Low	High		0.35	0.35	0.35	0.22	0.22	0.23	0.57	0.57	0.58

Note : Years for GasEscal sensistivity are: 1994, 2010, and 2028.

H.7 REFERENCES

[1] Alaska Power Authority, Railbelt Intertie Proposal Preliminary Economic Assessment, March 1987, p. 8.2.11.

Appendix I

GAS PIPELINE BETWEEN COOK INLET AND FAIRBANKS: BENEFITS OUTSIDE THE ELECTRIC POWER SECTOR[1]

I.1 OBJECTIVE

Costs and benefits of the proposed Cook Inlet-Fairbanks natural gas pipeline estimated in this appendix include the cost savings from using natural gas for space heating, water heating, cooking, and clothes drying in both residential and commercial buildings. Also included are the cost savings from converting the coal-fired steam/electric plants to natural gas at the University of Alaska; the Fairbanks Municipal Utility System (FMUS) district heating system; and the Fort Wainwright, Eielson, and Clear military facilities. These coal conversions are assumed to occur only in particular fuel price scenarios, because natural gas does not show a cost advantage over coal in some scenarios.

Finally, one fuel price scenario assumes that natural gas from the North Slope becomes available in Fairbanks in 2010. The scenario also assumes that the gas is priced less than Cook Inlet gas for the years 2015 through 2030. For this fuel price scenario, the benefits of delivering this gas to the southern Railbelt for consumption in the residential and commercial/industrial sectors are estimated.

The costs and benefits presented in this appendix are combined with the power benefits and gas transmission and distribution (T&D) costs presented in Section 10. In this appendix, all net benefit and gas demand figures do not include electric power system impacts and gas T&D costs. They are referred to as "net" benefits because heating system and appliance conversion costs are netted out of the gross benefits from conversion to gas.

No analysis was done of alternative methods for reducing the cost of energy services in the Fairbanks area. Weatherization of existing buildings and the upgrade of energy efficiency levels in new construction have been suggested. Also, expanding the district heating system in downtown Fairbanks provides a way to substitute coal for

[1]This appendix was prepared by the Institute of Social and Economic Research at the University of Alaska, Anchorage. Project Manager: O. Scott Goldsmith, Principal Investigator: Alan Mitchell, and Research Assistant: Marybeth Holleman.

more expensive fuel oil for space and water heating purposes. Preliminary analysis suggests that such alternatives show promise; however, they have not been compared to the Cook Inlet-Fairbanks gas pipeline proposal in this study.

I.2 RESULTS

I.2.1 Variation in Net Benefits Across Fuel Price Scenarios

The net benefits of the gas pipeline were calculated for every combination of seven fuel price scenarios and three demographic scenarios (i.e., household and commercial floorstock growth scenarios). These fuel and demographic scenarios were not developed in this study, but were developed as part of the overall Railbelt Intertie analysis. Figure I-1 shows the variation in net benefits across the seven different fuel price scenarios. The mid demographic scenario is assumed in all cases. A full summary of net benefits for all fuel price and demographic scenarios is provided in Table I-1.

Each vertical bar in the graph displays the net benefits for a particular fuel price case. The results are expressed in constant 1987 dollars. However, the present value calculation used 1994 as the base year, the first year of gas availability in Fairbanks. The segments of each bar show the different types of benefits:

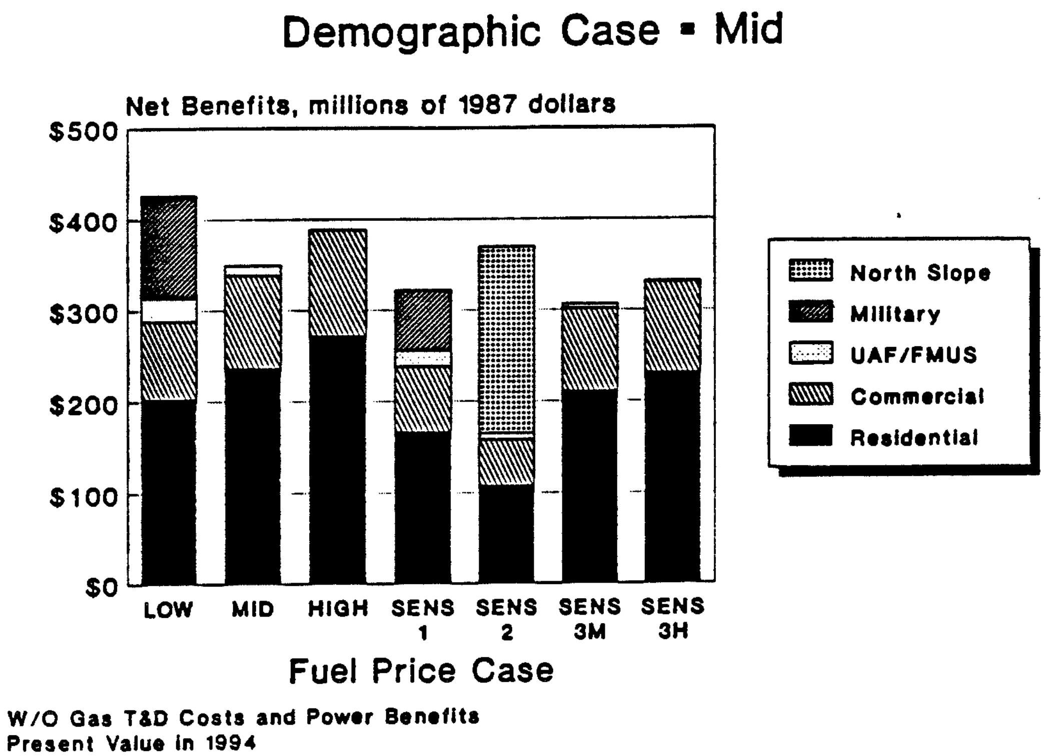
Residential. Benefits due to lowered space heating, water heating, cooking, and clothes drying costs in Fairbanks area residences.

Commercial. Benefits due to lowered space heating, water heating, and cooking costs in Fairbanks area commercial buildings.

UAF/FMUS. Fuel and operation and maintenance (O&M) savings (minus conversion costs) due to converting the University of Alaska Fairbanks electricity/steam generation plant from coal to natural gas, and fuel and O&M savings from converting the FMUS district heating plant from coal to gas. No benefits are included from the conversion of the associated FMUS coal-fired *electric* power generation plant: these are included in the scope of Section 10.

Military. Fuel and O&M savings (minus conversion costs) due to converting the Fort Wainwright, Eielson AFB, and Clear AFB electricity/steam generation plants from coal to natural gas.

North Slope. Benefits from transporting North Slope gas south from Fairbanks to Anchorage to supply residential and commercial consumers. Also included are the benefits of already having a gas distribution system



Benefit Types

Residential - Benefits from using natural gas for space heating, water heating, cooking, and clothes drying in the Fairbanks residential sector.

Commercial - Benefit from using natural gas for space heating, water heating, and cooking in the Fairbanks commercial/industrial sector.

UAF/FMUS - Benefit from converting the UAF steam/electric plant from coal to natural gas, and benefit from converting the FMUS steam heat system from coal to gas.

Military - Benefit from converting the coal-fired steam/electric plants at Fort Wainwright, Eielson AFB, and Clear AFB to natural gas.

North Slope - Benefit of transporting North Slope gas south in the fuel price Sensitivity Case 2. Also includes the benefit of already having a gas distribution system and gas-using heating systems/appliances in the Fairbanks area when North Slope gas arrives in 2010.

Fuel Price Cases

Low: Low world oil price escalation.

Mid: Mid world oil price escalation.

High: High world oil price escalation.

Sensitivity Case 1: Low prices with post-2010 Cook Inlet gas depletion.

Sensitivity Case 2: Mid prices with post-2010 Cook Inlet gas depletion. North Slope gas available in Fairbanks in 2010 priced at LNG netback value.

Sensitivity Case 3M: Mid prices with constant (in real terms) fuel oil - natural gas price differential after 2000.

Sensitivity Case 3H: High prices with constant (in real terms) fuel oil - natural gas price differential after 2000.

Figure I-1. Net Benefits of Gas Pipeline for each Fuel Price Scenario

Table I-1

SUMMARY OF NET BENEFITS

1994 Present Values, (1987 dollars)

FUEL PRICE CASE	DEMOGRAPHIC CASE: LOW		MID		HIGH	
LOW	R -	$192	R -	$203	R -	$226
	C -	$83	C -	$85	C -	$96
	F,U -	$25	F,U -	$25	F,U -	$27
	M -	$113	M -	$113	M -	$113
	NS -	$0	NS -	$0	NS -	$0
	Total	$414	Total	$426	Total	$462
MID	R -	$224	R -	$237	R -	$263
	C -	$98	C -	$101	C -	$113
	F,U -	$11	F,U -	$11	F,U -	$12
	M -	$0	M -	$0	M -	$0
	NS -	$0	NS -	$0	NS -	$0
	Total	$334	Total	$349	Total	$389
HIGH	R -	$257	R -	$272	R -	$300
	C -	$115	C -	$116	C -	$132
	F,U -	$0	F,U -	$0	F,U -	$0
	M -	$0	M -	$0	M -	$0
	NS -	$0	NS -	$0	NS -	$0
	Total	$371	Total	$388	Total	$432
SENSITIVITY 1: Low Fuel Prices with Rising Gas Prices after 2010	R -	$158	R -	$167	R -	$186
	C -	$70	C -	$71	C -	$80
	F,U -	$17	F,U -	$17	F,U -	$19
	M -	$67	M -	$67	M -	$67
	NS -	$0	NS -	$0	NS -	$0
	Total	$313	Total	$323	Total	$351
SENSITIVITY 2: Mid Fuel Prices with Rising Gas Prices after 2010, + North Slope Gas in 2010	R -	$105	R -	$108	R -	$121
	C -	$50	C -	$50	C -	$57
	F,U -	$7	F,U -	$7	F,U -	$9
	M -	$0	M -	$0	M -	$0
	NS -	$187	NS -	$204	NS -	$217
	Total	$349	Total	$370	Total	$404
SENSITIVITY 3M: Mid Fuel Prices with Constant Gas-Oil Price Differential after 2000	R -	$199	R -	$211	R -	$233
	C -	$88	C -	$90	C -	$101
	F,U -	$5	F,U -	$5	F,U -	$5
	M -	$0	M -	$0	M -	$0
	NS -	$0	NS -	$0	NS -	$0
	Total	$293	Total	$305	Total	$339
SENSITIVITY 3H: High Fuel Prices with Constant Gas-Oil Price Differential after 2000	R -	$218	R -	$231	R -	$254
	C -	$98	C -	$100	C -	$112
	F,U -	$0	F,U -	$0	F,U -	$0
	M -	$0	M -	$0	M -	$0
	NS -	$0	NS -	$0	NS -	$0
	Total	$317	Total	$330	Total	$366

and gas-using heating systems/appliances in the Fairbanks area when North Slope gas becomes available in the area. Only one of the seven fuel price cases assumes that a North Slope gas pipeline is built; this benefit category is zero for the other six cases.

The variation in net benefit across fuel price scenarios can be explained primarily by the difference between the price of natural gas and fuel oil for residential and commercial benefits, and the difference between the price of natural gas and coal for UAF/FMUS and military benefits. Wellhead prices for natural gas are currently less than both Fairbanks fuel oil prices and delivered coal prices.[2] In price scenarios where these differences persist or increase over time, benefits from the use of natural gas will be large. In fuel price scenarios where these differences decrease, benefits will be smaller. Figure I-2 shows the residential fuel oil, delivered coal, and wellhead natural gas prices for each fuel price scenario.

Figure I-1 shows that the residential and commercial benefits rise from the low to the high fuel price case. In the high case, both fuel oil and natural gas prices rise more rapidly over time than in the low case. What is critical, however, is that the difference between the price of natural gas and fuel oil grows more rapidly in the high price scenario. This larger price advantage for natural gas results in larger benefits of the gas pipeline in the Fairbanks residential and commercial sectors.

The UAF/FMUS and military benefits decline from the low to the high fuel price scenarios. In all fuel price scenarios, the price of coal is assumed to stay constant in real (inflation-adjusted) terms. In the mid and high fuel price scenarios, the price of natural gas rises and eventually exceeds the price of coal, eliminating benefits from that point on. However, in the low fuel price scenario, the wellhead price of gas remains below the price of delivered coal for the length of the analysis period. Significant benefits accrue from the substitution of natural gas for coal.

The military is expected to convert their coal-fired steam/electric plants only in the low fuel price scenario and sensitivity case 1, a modification of the low fuel price scenario. Since we assume that conversion of the military plants would not occur before 1999, because of institutional inertia and political pressures to use coal, insufficient economic incentive exists to convert in the mid and high price scenarios. In these scenarios, natural gas prices are near the price of coal by 1999 and have been exhibiting a rising trend. For UAF and FMUS, conversion of their coal-fired facilities is assumed to occur in all price scenarios but the high and sensitivity 3H, a modification of the high scenario. This is because these plants are assumed to be able to convert in 1994. In 1994, significant differentials between coal and natural gas exist in most price scenarios.

[2]Comparing delivered oil prices and delivered coal prices to wellhead natural gas prices is correct in this instance. The costs of transporting the gas to Fairbanks and distributing it to consumers are added in elsewhere in this report, as explained in the first subsection.

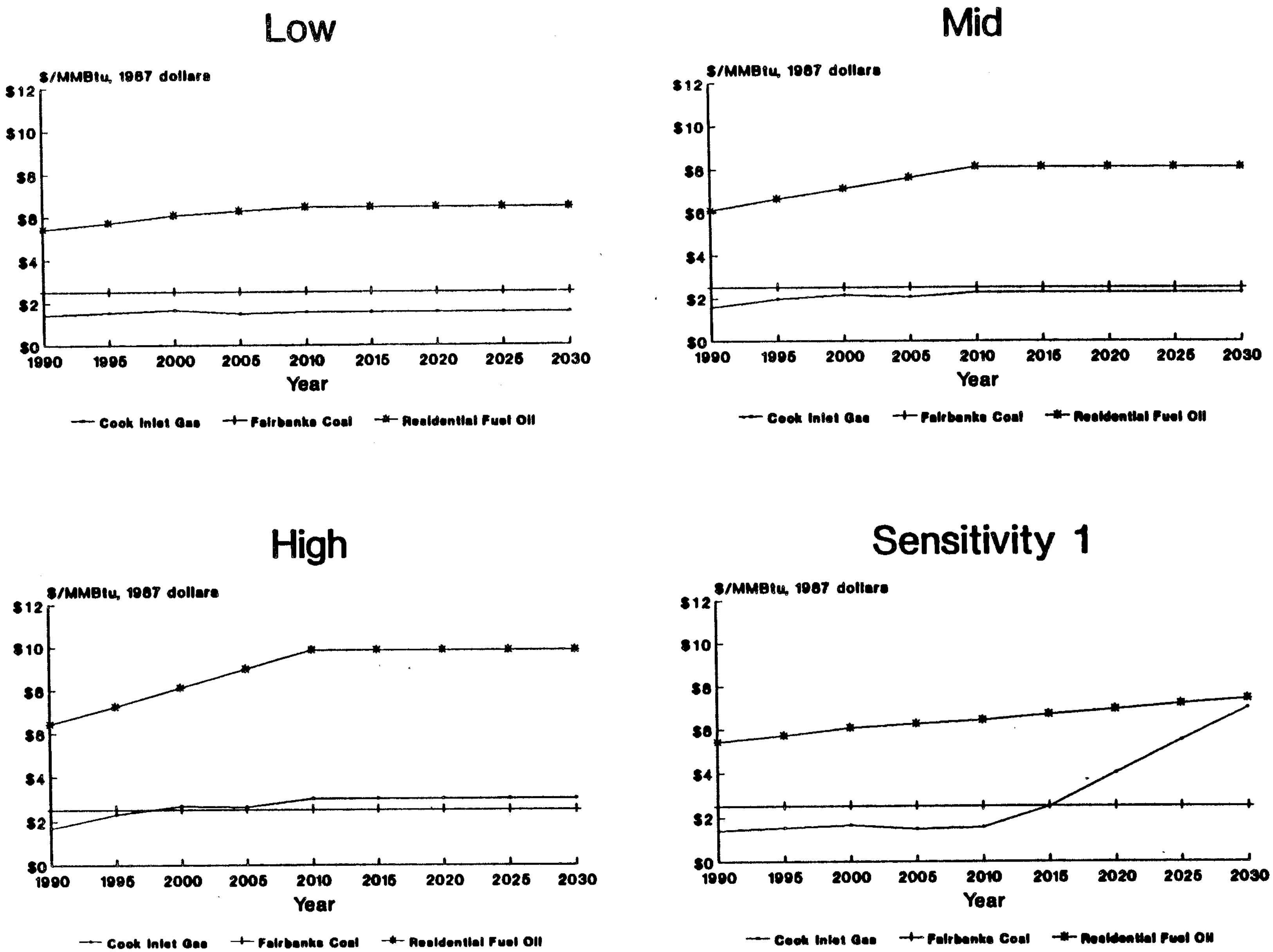
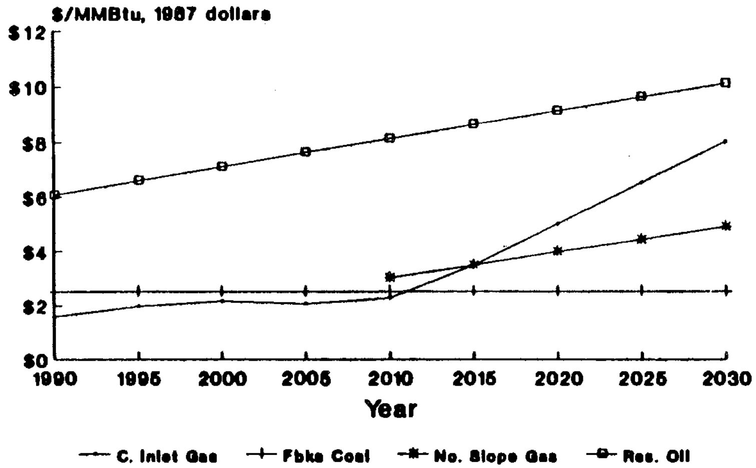
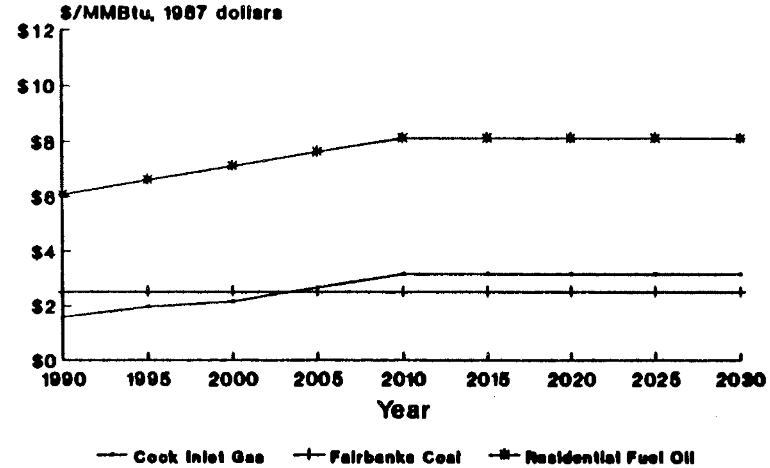


Figure I-2. Fuel Price Scenarios

Sensitivity 2



Sensitivity 3M



Sensitivity 3H

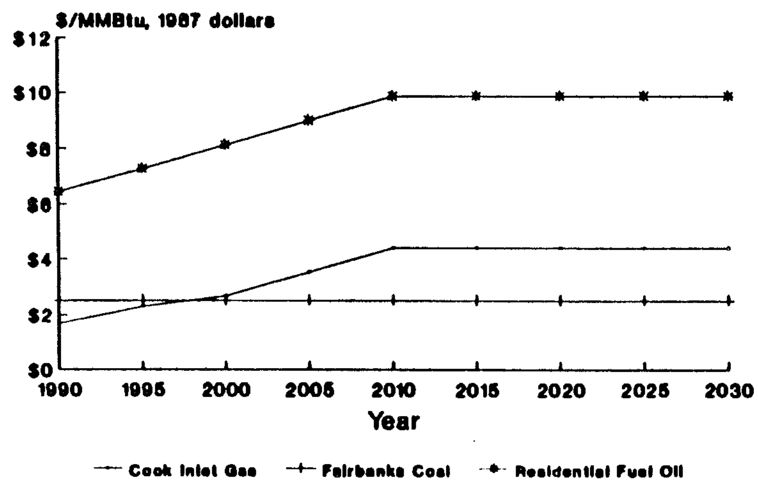


Figure I-2 (continued)

Four variants of the low, mid, and high fuel price scenarios are analyzed for sensitivity analysis. Sensitivity case 1 initially follows the low price scenario, but Cook Inlet natural gas is assumed to rise rapidly in price after 2010 because of resource depletion. All benefit categories are reduced in this scenario by a diminishing natural gas price advantage.

Sensitivity case 3M follows the mid price case until 2000. From that point on, the difference in price between natural gas and fuel oil is assumed constant in real terms instead of growing further as in the mid price case. Sensitivity case 3H follows the high price scenario but also holds the natural gas-fuel oil price differential constant after 2000. These two cases show diminished benefits relative to their base price scenarios because of diminished price differentials.

Finally, sensitivity case 2 uses the mid price scenario until 2010, but then assumes that resource depletion causes the price of Cook Inlet gas to rise rapidly. Also in 2010, a natural gas pipeline brings North Slope gas to the Fairbanks area. The North Slope gas is assumed to be priced at the netback value from liquefied natural gas (LNG) sales in Japan. The North Slope gas price undercuts the Cook Inlet price in 2015, and the differential widens through the end of the analysis in 2030.

In this scenario, the Fairbanks-area residential and commercial benefits attributable to the Cook Inlet-Fairbanks pipeline are substantially smaller than other cases, because the pipeline only provides benefits through 2010. Benefits of using natural gas in the Fairbanks area from 2010 onward would be provided with or without the Cook Inlet-Fairbanks pipeline, since natural gas from the North Slope would become available then.

However, an additional benefit of the Cook Inlet-Fairbanks gas line in this scenario is its ability to carry North Slope gas to the southern Railbelt. North Slope gas is assumed to be cheaper than Cook Inlet gas after 2015, and economic benefit accrues from substituting it for Cook Inlet gas. The capacity of the proposed 16-inch pipeline with compression is sufficient to supply the bulk of the expected residential and commercial needs of the southern Railbelt. (We attribute no benefits to supplying power plants in the southern Railbelt because of uncertainty regarding power plant fuel sources at that date and seasonal limitations in pipeline capacity.) Approximately $170 million of present value benefit is received from the southward flow of cheaper natural gas.

The Southern Railbelt benefits are contingent on a differential between North Slope gas and Cook Inlet gas from 2015 through 2030. If Cook Inlet gas remained plentiful during this period, its price could be close to the North Slope gas price. Much or all of the $170 million of southward-flow benefit would not occur, and such a price scenario would show relatively low benefits for the Cook Inlet-Fairbanks pipeline.

Another untested fuel price scenario that would show even less benefits for the Cook Inlet-Fairbanks gas pipeline is one where North Slope gas becomes available earlier in time, for example the year 2000, and the price of North Slope gas and Cook Inlet gas are similar, for example the LNG netback value. In such a case, the Cook Inlet-Fairbanks pipeline would provide benefits to Fairbanks for the relatively short 1994 through 2000 period, but beyond 2000, gas would have been available in Fairbanks with or without the Cook Inlet-Fairbanks pipeline. Further, since the Cook Inlet and North Slope gas price are assumed to be the same, the Cook Inlet-Fairbanks pipeline would provide no southward-flow benefits.

I.2.2 Variation in Net Benefit Across Demographic Scenarios

Figure I-3 shows the variation in benefit across the three demographic scenarios. For each case shown, the low fuel price scenario is used because it is considered most likely by the APA Board of Directors. Because total demands for energy are larger in the high demographic scenario, benefits from substitution of natural gas for more expensive fuels are greater.

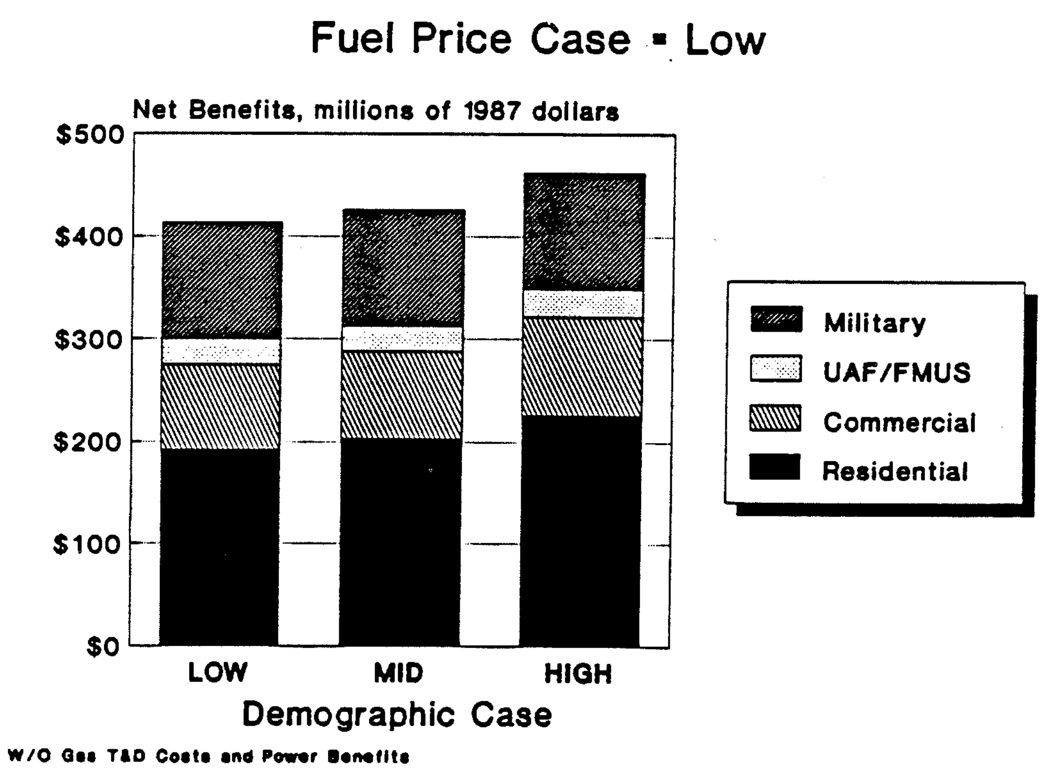


Figure I-3. Net Benefits versus Demographic Scenario

I.2.3 Variable Versus Fixed Costs of Fuels

Fuel prices have variable and fixed cost components. To the extent that the prices used in this study have fixed cost components that are significant and are fixed over much of the 35-year analysis period, the prices may overstate the relevant marginal fuel costs. This issue is addressed in more detail in Appendix B of this report.

Further attention to these fixed fuel price effects could change the benefit calculations. The effect would be greatest for those benefits that involve substituting natural gas for coal (i.e., military, UAF/FMUS). This is because the price difference between delivered Fairbanks coal and wellhead natural gas is relatively small (about $1/MBtu), and small changes in either price could result in large percentage changes in this price differential.

The benefits that rely on substituting natural gas for fuel oil are less variable. The difference between residential fuel oil prices and wellhead natural gas prices is about $4/MBtu. Changes in either price would amount to a smaller fraction of this differential.

These fuel price sensitivities are also implied in Figure I-1. The UAF/FMUS and military benefits (gas for coal substitutions) vary dramatically across fuel price scenarios. The residential and commercial benefits (gas for oil substitutions) are less variable across fuel price scenarios.

I.2.4 Gas Distribution System Coverage and Heating System Conversion Rates

The amount of coverage provided by the gas distribution system in the Fairbanks area is critical in estimating the benefits of the Cook Inlet-Fairbanks gas pipeline. Enstar was consulted to determine the areas in Fairbanks covered by the proposed gas distribution system that would be consistent with the Stone and Webster cost estimate. Then, Fairbanks census data providing household counts by district was used to determine the fraction of the residential households that would have access to gas. Our research indicated that approximately 47 percent of Fairbanks North Star Borough (FNSB) households would have access to gas after a three-year distribution system construction period. Subsequent expansion of the distribution system would increase the coverage to 58 percent.

These estimates are close to Enstar and House Research Agency estimates; however, we feel a more detailed estimate is needed involving building densities and incremental distribution expansion costs. If an additional 5 percent of the Fairbanks households might be covered by the distribution system, calculated residential benefits of the gas line will increase by about 9 percent. If 8 percent fewer households (8 percent of the *total* Fairbanks households) will be covered by the distribution system, calculated residential benefits will decrease by about 14 percent.

The distribution coverage issue has less effect on commercial benefits, because little commercial floorspace is found in outlying areas where distribution coverage is uncertain. We assumed that 95 percent of the commercial floorstock not served by the district heating system (this floorstock was analyzed separately) would have access to natural gas by the end of the third year of construction. Jim Hage of Heinz & Price, Inc., who was involved in a 1986 commercial building inventory, estimated that 98 percent of the FNSB commercial floorstock would be within the gas distribution territory.

An estimate of 98 percent commercial floorstock coverage would increase the commercial net benefits by about 3 percent. An estimate of 85 percent commercial floorstock coverage would decrease the commercial net benefits by about 10 percent.

Our analysis does not assume that everyone converts to natural gas immediately. Instead, ultimate saturations of natural gas use (less than 100 percent) were determined. Based on data from our end-use survey for Anchorage, an area that has had gas for a long period of time, we assume that 91 percent of the residential households that have access to gas would ultimately use natural gas for space heating, 76 percent will ultimately use gas for hot water heating, 32 percent will ultimately use gas for cooking, and 21 percent will ultimately use gas for clothes drying. Further, these saturation levels are not achieved immediately. Existing residences convert their heating systems and appliances over the course of time. However, the stock of new buildings each year is assumed to have these ultimate fuel split characteristics.

The most critical rate of conversion in the analysis is the rate at which existing residences using oil heat convert their space heating systems to natural gas. It was estimated that 40 percent of the households with oil heating systems would convert to gas each year. Based on their experience in Eagle River and Anchorage, Enstar estimated the rate to be 75 percent in the first year and 50 percent of the remaining residences in subsequent years. We conservatively chose a lower rate and tested two sensitivity cases. Residential benefits dropped 9 percent when the conversion rate was lowered to 20 percent per year, and residential benefits increased 4 percent when the conversion rate was increased to 60 percent per year. Residential benefits are relatively insensitive to the conversion rate because, within this range of rates, the majority of oil-heated homes are converted within 7 years (for a 20 percent conversion rate, 80 percent of the oil-heated homes are converted in 7 years). Seven years is short relative to the 35-year analysis period of the pipeline.

Because of the increased capital cost of electric heat to gas heat conversions, the rate of conversion is assumed to be substantially less, only 5 percent per year. This rate was also used for wood conversions. Propane conversions are assumed to occur very rapidly because of both the low conversion capital cost and the high fuel cost of propane. A 70 percent conversion rate was assumed. Because the bulk of space heating is accomplished with oil, the conversion rates of these other fuel types are less important.

The rate of conversion is primarily a function of the rate at which a consumer's investment in a conversion is paid back. If the payback is quick, conversions will occur more rapidly. In this analysis, fuel cost savings for the residential oil heat sector were calculated based on the difference between the delivered oil price and the wellhead gas price. The fixed costs of transporting the gas and operating and maintaining the gas transmission and distribution system are accounted for elsewhere in this report. However, the retail price paid by the consumer is not equal to the wellhead price of gas. The retail price would be set by the Alaska Public Utilities Commission and would include the wellhead price of gas, administrative costs, and any costs attributable to the Fairbanks gas delivery operation. The amount of state subsidy for the gas pipeline would significantly affect the retail rate that will be charged for gas in Fairbanks and, therefore, the rate of conversion.

If the state pays for the transmission pipeline but not the distribution system and O&M and the military converts their steam/electric plants, gas rates in Fairbanks could be approximately equal to those in the southern Railbelt. The margins earned on sales would be sufficient to pay off the distribution system and pay operation and maintenance costs. At the gas rates charged in the southern Railbelt, a residential fuel oil to gas space heating conversion in Fairbanks would have a payback of about three years.[3] If the military does not convert their steam/electric plants, residential rates would be approximately $0.90/MBtu higher to make up for the lost margins on military sales (also assuming proportional increases in margins for other rate classes). A residential oil to gas space heat conversion would have a payback of about four years under this scenario. Because of economies of scale, conversions in the commercial sector would have faster paybacks.

We feel these paybacks are roughly consistent with a 20 to 60 percent per year rate of conversion for oil-heated residences, especially given the marketing likely to occur by the gas distribution utility. However, if conversion rates were to fall significantly below this level because of high consumer discount rates, it would behoove the state to sponsor a conversion incentive program so that its investment in a gas pipeline is well utilized. Such a program could have a budgetary cost of approximately $10 million and a resource cost of less than $1 million, given the total conversion cost estimates presented later in this appendix.

[3]Based on a heat demand (heating system output) of 126 MBtu/year and conversion cost of $1,840, fuel oil costing $5.72/MBtu and burned at 65 percent efficiency, natural gas costing $3.02/MBtu burned at 72 percent efficiency, and an O&M savings of $40/year. All dollar figures are 1987 constant dollars. The gas heating system is assumed to be more fuel efficient because it will be purchased after the enactment of the Federal Appliance Efficiency Standards, which will require a 78 percent seasonal efficiency for all gas and oil heating systems; 72 percent efficiency was assumed because some conversions will only involve changing the burner in the furnace or boiler—not the entire system.

I.2.5 Fuel Use Intensity

Although reasonable data are available concerning the number of households in the Fairbanks area and amount of commercial floorstock, less data are available on the fuel use of these buildings. Our estimates of fuel use per residential household and fuel use per square foot of commercial floorstock are therefore uncertain. If actual fuel use intensity is 10 percent below our estimate, then the net benefits are about 11 percent lower. If actual fuel use intensity is 10 percent above our estimate, then the net benefits are about 11 percent higher.

For estimating use per residential household, we adjusted actual Enstar natural gas consumption data for the southern Railbelt for differences in weather and housing characteristics (e.g., insulation, size). The adjustment factor was derived by using an engineering heat loss model to estimate the fuel consumption of typical single-family, multi-family, and mobile homes in both the southern Railbelt and in Fairbanks. Fairbanks single-family homes are on average 13 percent smaller than Enstar-served single-family homes in the southern Railbelt. Also, the insulating characteristics determined from our Railbelt end-use survey indicate that Fairbanks homes are better insulated than southern Railbelt homes. Thus, our engineering model showed that the fuel consumption of a typical Fairbanks single-family home is essentially equal to the fuel consumption of a southern Railbelt home, despite the colder weather in Fairbanks. This is reasonable considering that heating with fuel oil is more expensive per Btu than gas; fuel oil consumers will receive better paybacks from their insulation investments, so are likely to insulate more. Also, there are more comfort and maintenance benefits from insulation in the colder Fairbanks climate. Fuel use for space heating, water heating, and a portion of cooking and clothes drying was estimated at 222 MBtu/household/year.

For the commercial sector, we conducted a limited nonrandom canvass of commercial building owners in the Fairbanks area to determine fuel oil use per square foot of floor area for space heating, water heating, and cooking. Because of the record-keeping involved in commercial enterprises, such fuel consumption data are reasonably reliable. We obtained fuel use records for 2 million square feet of commercial floorspace, which represents 15 percent of the FNSB commercial floorstock (1.5 million square feet were schools). However, removing the school data from the sample changed the average fuel use per square foot very little, indicating that the school data did not significantly bias the answer. The fuel use for space heating, water heating, and cooking was estimated to be 87,000 Btus per square foot per year.

I.2.6 Conversion Costs, Savings in New Construction, and O&M Costs

The estimated net benefits of the gas pipeline are not very sensitive to the cost of converting heating systems and appliances to natural gas. Conversion costs are a small fraction of the total fuel savings, so changes in cost have only a small effect on net benefits. A plus or minus 30 percent change in conversion costs causes a plus or minus 4 percent change in net benefits.

Figure I-4 shows the breakdown of residential costs and benefits for the base case scenario, i.e., mid demographics and low fuel prices. On the benefit side, fuel savings are virtually all of the benefits. Savings in heating system operation and maintenance costs contribute some benefits (approximately $40 per year per household), and savings in the capital cost of heating and hot water systems in new residences also add a small amount of benefits. The only economic costs (aside from gas transmission and distribution costs) are the cost of converting heating and hot water systems. As shown in the chart, these amount to about 11 percent of benefits. For commercial buildings and UAF/FMUS/military steam plants, conversion costs are even a smaller fraction of total benefits because of the economies of scale of converting larger heating systems.

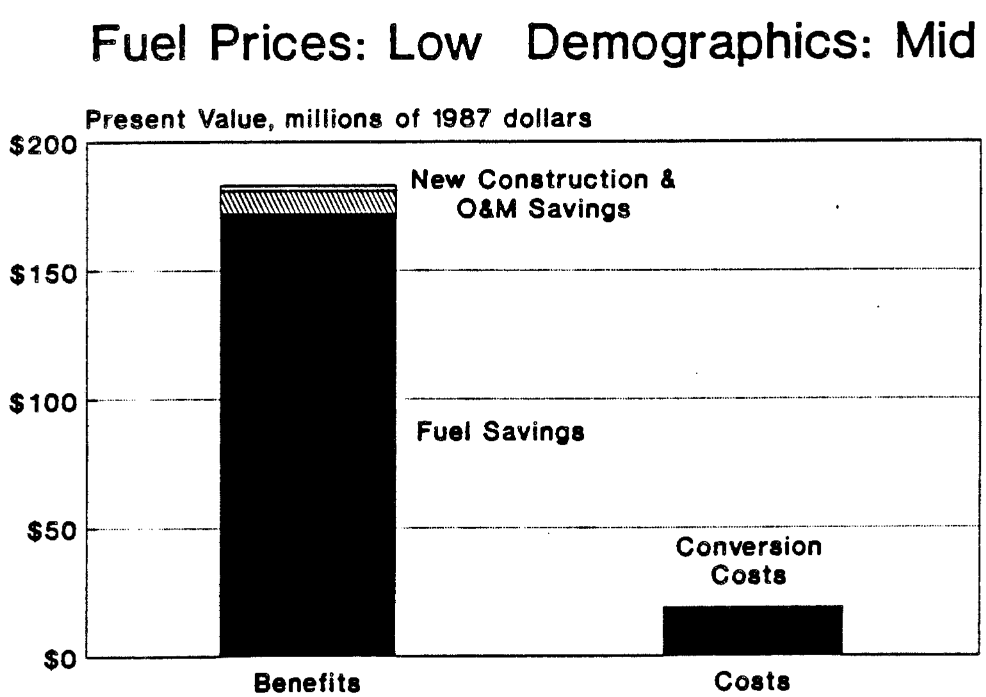


Figure I-4. Residential Benefits and Costs by Type

I.2.7 Discount Rate

The discount rate used for this analysis was 4.5 percent real (i.e., subtracting out inflation). The discount rate is used in calculating the present value of benefits and costs. Any benefits or costs occurring in the future are discounted by 4.5 percent for each year in the future before being added together. Because of the gas pipeline's long life, many of the benefits occur in the future. Thus, the choice of a discount rate has a significant effect on the calculated present value benefits. For the residential analysis, using a 3.5 percent discount rate instead of a 4.5 percent rate increases the present value of the net benefits by 26 percent. Using a 5.5 percent discount rate decreases the present value of residential net benefits by 20 percent.

I.3 RESULTANT GAS DEMAND FORECAST AND COMPARISON WITH OTHER FORECASTS

Figure I-5 shows the Fairbanks area natural gas demand consistent with the low fuel price scenario and the mid demographic scenario (one TeraBtu = 10^{12} Btus). The gas demand forecast does not include the gas requirements for Golden Valley Electric Association (GVEA) and FMUS electric power generation in the Fairbanks area.

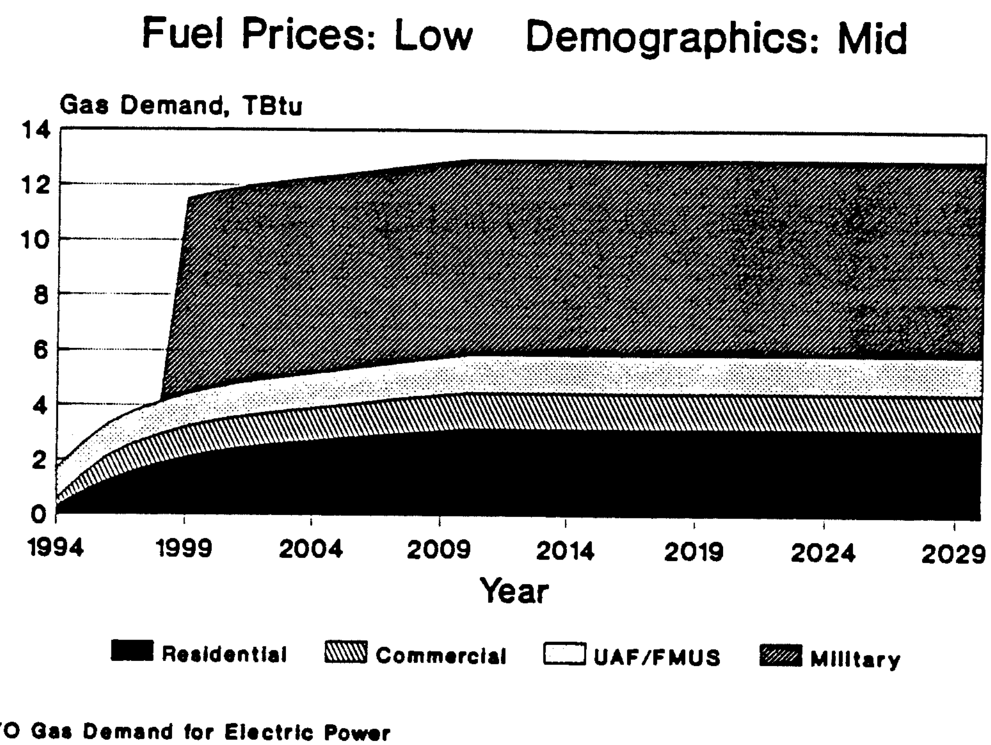


Figure I-5. Fairbanks Natural Gas Demand

Gas demand grows relatively rapidly in the early years because of conversions of existing heating systems and appliances to gas. Additional growth in demand is caused by general growth in the size of the building stock over time. Demand from 2010 through 2030 was assumed to be constant. This simple assumption was used for all demand analyses in the Railbelt Intertie studies.

From 1999 onward, the military demand constitutes a large portion of the gas demand in the Fairbanks area. However, the net benefits associated with this demand are not large. The current fuel for the military is coal, and the price differential between coal and natural gas is relatively small. Figure I-6 shows the pipeline net benefits over time for the low fuel and mid demographics scenario.[4] Relative to the demand graph, the residential and commercial components are amplified by the high oil-gas price differential, and the military and UAF/FMUS components are diminished by the small coal-gas price differential.

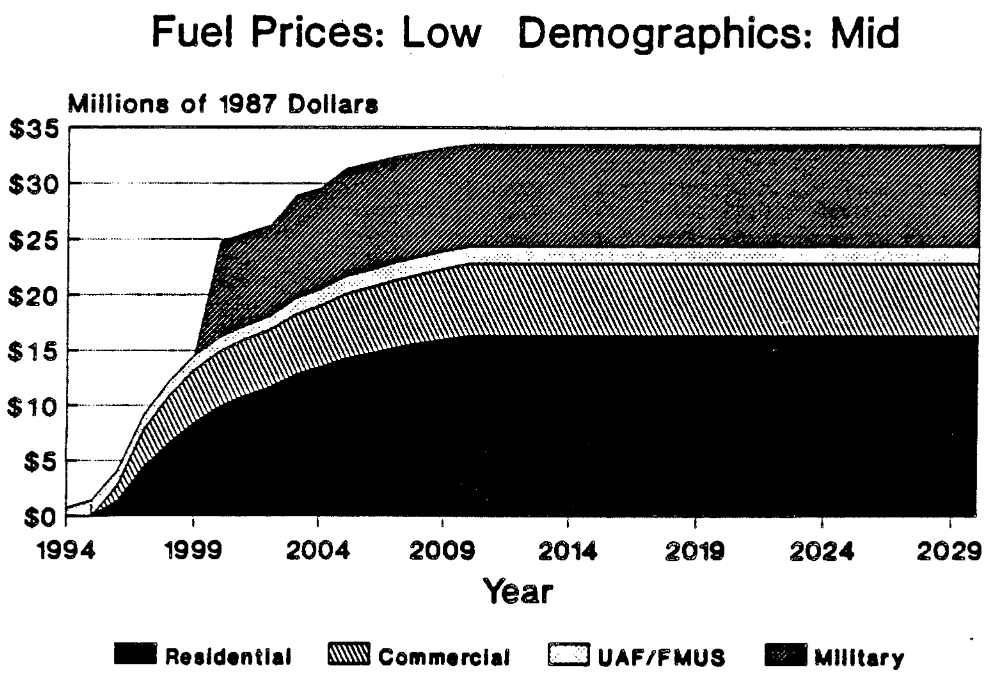


Figure I-6. Net Benefits of Gas Pipeline Over Time

As stated before, the military gas demand is only projected to occur in low fuel price scenarios. In other fuel price scenarios, gas price escalation leads to unfavorable conversion economics by 1999, the date when the military is assumed ready to convert.

The most recent analyses of potential gas demand in the Fairbanks area are those done by the House Research Agency ("Enstar's Wasilla-Fairbanks Gas Pipeline

[4]This graph is not entirely accurate. Net benefits are slightly negative in the years 1994 and 1995 because of high conversion costs in those years. A "stacked area" graph, such as this one, is unable to display these negative values.

Proposal", Ginny Fay and Gretchen Keiser, April 13, 1988.) and by Enstar. The figure most directly comparable across these studies is the sum of Residential and Commercial demand. This is because the gas consumption of some multi-family residences is included in Enstar's and House Research's commercial consumption category. In our projection, all multi-family consumption is included in the residential category. Both House Research and Enstar did not attempt to project demand over a number of years. Instead, one demand estimate was developed that represents the ultimate gas demand of the existing stock of residential and commercial buildings. House Research estimated this to be 4.3 TBtu, and Enstar estimated 5.1 TBtu. Our estimate varies over time, but Figure I-5 shows that our demand estimate is less than both the House Research and Enstar estimates for most of the 1994 through 2030 period.

Our residential consumption analysis uses space heating demand per household estimates similar to House Research estimates. These estimates are less than Enstar's, because we adjusted the insulation levels and building sizes of southern Railbelt consumption data. Our demand forecast also involves an adjustment to gas demand for improved heating system efficiency in Fairbanks. If built, the gas pipeline will not be completed until about 1994, which is after the effective date of the federal appliance efficiency standards. These standards will require that any new residential heating systems have seasonal efficiencies greater than 78 percent, substantially better than the existing Fairbanks average of about 65 percent.[5] Thus, 1 Btu of residential oil use will be replaced by less than 1 Btu of residential natural gas use because of improved heating system efficiency. Since the gas line stimulates the purchase of more efficient heating systems, this is an additional benefit attributable to the line over and above the reduced heating fuel price.

House Research and Enstar used the same commercial sector demand figure based on a Fairbanks building count and a weather adjustment of the gas use per southern Railbelt commercial customer. Our analysis projected commercial consumption on a per square foot basis instead of a per building basis. This was done because commercial buildings vary widely in size, and the average size of southern Railbelt commercial buildings may be quite different than Fairbanks commercial buildings. Also, our analysis relied on a canvass of commercial buildings in Fairbanks to estimate fuel use per square foot. As explained before, our commercial figure is not directly comparable to the House Research and Enstar estimate because of their inclusion of some multi-family residential households in the commercial figure. However, with an adjustment to remove multi-family consumption from their commercial figure, our estimate of commercial use is lower. This implies that either our use per square foot or our total square footage estimate is less than that represented in the Enstar method. We were unable to specifically identify the difference.

[5]The efficiency standards will not apply to conversion burners used to convert existing oil heating systems to natural gas. Because some of the conversions in the residential sector will use these conversion burners instead of new boilers or forced-air furnaces, the efficiency improvement will not be as great as indicated by the 65 and 78 percent figures.

The largest discrepancy between all three forecasts concerns the large coal-fired steam/power generation plants in the Fairbanks area. Both Enstar and House Research include no military gas consumption in their demand estimate. House Research indicated that federal regulations prohibit the conversion of the military coal plants. Upon further investigation (discussed in Appendix I.4.3), we concluded that there were no binding federal regulations prohibiting conversion, but there may be political pressure against converting. Therefore, we delayed our projected conversion time to 1999 for the military and only assumed conversion in the low fuel price scenario, where the conversion economics for the military are very favorable (benefit/cost ratios of about 10 to 1).

Our demand estimates include conversion of the UAF coal-fired electric/steam system and the FMUS steam district heat system in the low and mid fuel price scenarios. This conclusion is contrary to the House Research analysis but consistent with the Enstar analysis.

House Research concluded that UAF would not displace their coal consumption with gas but would only displace their small amount of oil use. Our discussions with UAF indicated that the relative prices of coal and gas would be critical to their decision to convert. They also felt that the availability of gas in Fairbanks would cause their coal supplier to drop their coal price. To remain consistent with the fuel price forecasts provided to this study, we did not assume that this price drop would occur. Thus, the delivered fuel prices seen by UAF in 1994 (the year gas becomes available in Fairbanks) would be $2.52/MBtu (1987 dollars) for coal in all fuel price scenarios, $1.97/MBtu for gas in the low fuel price scenario, $2.38/MBtu for gas in the mid fuel price scenario, and $2.67/MBtu in the high fuel price scenario.[6] The price advantage of gas in the low and mid scenarios coupled with the substantial operation and maintenance savings from natural gas use predicted by a Stone & Webster study ($280,000/year for UAF)[7] compelled us to include UAF conversion in the low and mid fuel price scenarios. Benefit to cost ratios for the UAF conversion were about 20 in the low fuel price scenario and 4 in the mid fuel price scenario.

I.4 CALCULATION METHODS

To determine the net benefits of the pipeline, we identified potential uses of natural gas in the Fairbanks area and developed simple models for determining the

[6]These gas prices are not wellhead prices. They include an expected margin charged by the gas distribution utility. These margins were estimated by the Alaska Power Authority (APA) and provided to this study.

[7]As summarized in a 11/30/88 memo from Dick Emerman of APA to Salim Jabbour of Decision Focus Incorporated.

cost of these energy uses. For example, the space heating, water heating, cooking, and clothes drying energy end uses in the residential sector were identified as potential uses of natural gas. A model was developed that estimates the cost of serving these end uses from 1989 through 2030—including fuel costs, operation and maintenance costs, and capital costs of the necessary heating systems and appliances. The cost model was run assuming that no gas will be available in the Fairbanks area, and the present value of the costs through 2030 was calculated. Then, the cost model was run assuming that natural gas would be available in a portion of the Fairbanks area. Some consumers choose to convert their heating systems and/or appliances to use the less expensive natural gas in this scenario. Also, new residences are constructed with natural gas appliances and heating systems. An associated present value of costs was calculated. The net benefits attributable to the gas pipeline for the residential sector are equal to the difference in present value costs between the two model runs. This process was repeated to determine the benefits for other potential uses of natural gas in the Fairbanks area.

All dollar figures in the analysis are expressed in constant 1987 dollars. When present value figures or time-discounted sums are presented, these were calculated with a 4.5 percent real discount rate and are discounted to the year 1994, the first year of gas availability in Fairbanks.

The cost model is run in detail for 1988 through 2010. For the period from 2010 through 2030, all variables in the analysis such as building stock size and appliance efficiency are held constant except fuel prices, and these are assumed only to change in fuel price sensitivity cases 1 and 2.

Separate cost models were developed for the Fairbanks residential sector, the commercial sector, the UAF/FMUS/military steam/electric plants, and the southern Railbelt energy uses that might be supplied by North Slope gas through the Cook Inlet-Fairbanks pipeline. The following subsections provide additional detail concerning the energy cost models. At the end of this appendix in Table I-2, sample output from each one of the models is presented. The output corresponds to the low fuel price case and the mid demographic case. The exception is the North Slope gas model output, which corresponds to the sensitivity 2 fuel price case and the mid demographic case. The North Slope gas pipeline is built only in the sensitivity 2 fuel price case.

I.4.1 Residential Sector Cost Model

The economic benefit to the residential market is calculated as the present value of the savings from using gas to heat residences, heat water, cook, and dry clothes if natural gas were available in Fairbanks. The primary fuels displaced in the Fairbanks market are fuel oil, electricity, wood, and propane. There are three positive elements in the calculation of the savings—fuel cost savings, operations and maintenance cost savings, and capital (appliance) cost savings; and one negative element—conversion costs. The fuel cost savings is the dominant factor, averaging about $12 million annually (1987 dollars).

We assume that a consumer choosing natural gas would always use it for space heat. This use is projected to account for about 90 percent of residential gas use. In addition, some consumers would also immediately use gas for water heating, cooking, and clothes drying, and over time the gas demand from this "bundle" of uses would approach the observed demand pattern in Anchorage. For modeling purposes, space heating is treated as one end use and water heating, cooking, and clothes drying as another end use.

We project that the average fuel demand per household for space heating will decrease at an initial rate of about one percent per year because of continued growth in the size of the average housing unit, existing federal regulations requiring higher combustion efficiency in new furnaces, and state regulations requiring improved insulating characteristics in new construction. This one percent decline rate decreases over time as the stock is saturated with more efficient buildings.

The fuel cost savings depends upon the fuel which would have been used in the absence of natural gas: alternate fuels have different projected prices, and different types of furnaces have different efficiencies. Most of the savings result from the substitution of gas for fuel oil, which implies a substitution of new gas heating systems meeting the federal efficiency standard for less-efficient existing oil heating systems.

A second cost element in the difference between the no-gas and the gas scenario is the operation and maintenance cost of heating systems. Gas units burn cleaner and do not experience fuel line blockage like their oil counterparts. Thus, they require less maintenance. We estimate the annual O&M costs for gas and fuel oil units to be $30 per year and $70 per year, respectively, based upon the cost and frequency of service calls.

A third cost element in the difference between the no gas and the gas scenario is the difference in the purchase price of gas and oil appliances for new construction. On the average, new gas space heating systems are about $700 less expensive than oil heating systems because of reduced flue costs and slightly reduced furnace/boiler costs. Also, gas water heating systems are less expensive than oil water heating systems. A $190 capital cost savings was attributed to use of gas water heating systems.

The final cost element in the difference between the two cases is the extra cost incurred by consumers who convert their current appliances to gas. The predominant conversion will be the replacement of an oil space heating system with a natural gas system. This cost was estimated at $1,840 based upon information from plumbing and heating contractors and Enstar. Two options are available for converting an oil heating system: (1) replacing the entire boiler/furnace with a new gas boiler/furnace, and (2) replacing the burner unit in the existing boiler/furnace with a gas conversion burner unit. The $1,840 cost represents a weighted average of the two options.

We distinguish two groups of natural gas users: housing units that convert from fuel oil and other fuels when gas becomes available and housing units that are built after gas becomes available and choose gas. In the latter group, we assume that 91 percent of the residences built will choose to heat with natural gas. This percentage is similar to the gas market share in the Anchorage area. For existing Fairbanks residences that were built prior to gas availability, a conversion rate is estimated. As discussed in Appendix I.2.4, these conversion rates vary according to the type of heating fuel used prior to gas availability.

The number of new housing units, including replacement units, is taken from the economic and demographic study for the Railbelt Intertie study. The units are distributed between the area where gas would be available and where it would not be available. The proportions are determined by the relative proportions of existing households in those areas. Outside the potential gas service area, consumers' space heating fuel choices are the same in the "with pipeline" and "without pipeline" scenarios.

I.4.2 Commercial Sector Cost Model

As is indicated by the model output in Table I-2, the commercial sector cost model has a structure similar to the residential model. Instead of the basic analysis unit being the household, the basic unit is 1,000 square feet of commercial floorspace. Also, all end uses addressed—space heating, water heating, and cooking—are combined together for purposes of analysis. Thus, rates of conversion and trends in efficiency are assumed to be the same for all of these end uses.

Efficiency trends are assumed to be less than those expected to occur in the residential sector because of no federal appliance efficiency standards and no state thermal building standards. Fuel demand per square foot for the above commercial end uses is assumed to decline at approximately 0.4 percent per year.

Conversion costs per annual MBtu of energy demand are less for commercial buildings than for residential buildings because of economies of scale. Thus, conversion paybacks are better. Because conversion costs do not exert much influence in the net benefit calculation, little data collection was done to estimate them. Instead, judgement was used to adjust residential conversion costs per annual MBtu of energy demand, and this unit cost was applied to the commercial energy demand to estimate conversion costs.

For our estimate of total commercial floorstock, we used the total floorstock figure from the Fairbanks North Star Borough property appraisal database. We increased the figure by 15 percent to account for buildings that did not appear in the database. This undercount was partially confirmed in the calibration process of the Fairbanks area electrical load forecast done for the Railbelt Intertie analysis. Based on the floorstock count in the database and electrical use per square foot derived from an end-use survey, the estimate of the Fairbanks electrical load was 27 percent below actual commercial electrical use. Some of this error was probably due to error in the use per square foot estimate, but some was also due to underestimating the floorstock. Borough personnel confirmed this by indicating that the property appraisal database does not include some state, federal, and tax-exempt buildings.

To avoid double-counting the buildings that are served by the FMUS district heating system and the UAF steam heating system, we estimated their size and subtracted them from the total.[8] The benefits of using gas for these buildings are captured in the UAF/FMUS analysis.

I.4.3 UAF/FMUS/Military Cost Model

A model was developed to estimate the net benefits of gas use for a number of large coal users in the Fairbanks area, including the military bases, the UAF steam/electric plant, and FMUS steam and hot water district heating system (not the electric power plant). The net benefit calculation involved two types of benefits, fuel savings and O&M savings; and one cost, the cost of converting the coal plants to natural gas.

Stone & Webster provided both the initial conversion cost estimates and expected annual O&M savings. We determined the fuel consumption at each of the coal facilities, projected the fuel use over time, and determined fuel savings for each of the fuel price scenarios. In all fuel price scenarios, the price of coal was assumed to stay constant in real terms. Coal prices for each facility are shown in the model output and average about $2.52/MBtu.

For the UAF and FMUS plants, fuel use is projected to grow at the Fairbanks commercial-floorstock growth rate minus a 0.2 percent efficiency adjustment. For the military plants, no fuel use growth is assumed except growth through 1993 at Fort Wainwright due to the new Light Infantry Division.

Note that the net benefit figures calculated for the military assume that they continue to produce all of their electricity on-site. If they instead buy electricity for

[8]FMUS steam and water heating customers were estimated to total 1.9 million square feet. University buildings were not included in the property tax database so did not need to be deducted. Approximately 0.3 million square feet of non-University buildings are served by the UAF steam heating system and were deducted from the floorstock total.

electrical needs beyond their steam balance point,[9] the net benefits from converting the military plants will be $11 million less in the low fuel price scenario, and $6 million less in the sensitivity 1 fuel price scenario (the only cases having military benefits). The fuel savings from natural gas use are diminished because of reduced fuel use.

Stone & Webster indicated that when the converted coal plants operate on natural gas, their efficiency will drop by about 3 percent. This adjustment was made in the analysis.

As well as determining total net benefits, the model also determines the percentage of the net benefits that go to the military versus the percentage of the benefits that flow back to the gas distribution utility to help pay for fixed gas transmission and distribution costs. This contribution towards fixed cost benefits the other consumers on the gas distribution system. It is primarily a function of the actual price that the military is charged for gas, and this was estimated in the fuel price forecasts provided by APA. The percentage of the net benefits accruing to the military was calculated to be 70 percent in the low fuel price case and 64 percent in the sensitivity 1 fuel price case.

Regulations Affecting Conversion of Military Bases. There has been some question over whether federal regulations would prevent military bases from converting to natural gas. House Research Agency projections do not include military bases; they state that federal regulations such as the National Fuel Use Act would prevent their conversions from coal. Stone & Webster excluded military installations in their base-case forecasts, citing Department of Defense policies such as the 1982 Military Construction Codification Act and the 1986 Defense Appropriation Report that encourage the use of coal. However, those we talked to said that while political pressure may impede a decision to convert from coal, as it did with Anchorage bases (they use gas now), no regulations prohibit a conversion. A decision would rely solely on economic benefits.

Millard Carr, Assistant for Energy Policy, Office of the Secretary of Defense, said there is no law or policy that would prevent a conversion. Carr said the Department of Defense has a general law which defines their energy policy. This law, Title 10 USC Sec. 2690, states that the primary fuel source for military installations must be the most cost-effective over the lifecycle of the facility. While political pressure may encourage increased use of coal, decisions on energy use must be based first on this guiding policy.

The Powerplant and Industrial Fuel Use Act of 1978 (P.L. 95-620) did mandate that electric power plants and major fuel-burning installations (over 100 MBtu/hour for public, over 50 MBtu/hr for military) use coal or other alternate fuels in lieu of oil and

[9]See "Additional Fairbanks Load Impacts: Military Installations and the University of Alaska," Alan Mitchell, *Institute of Social and Economic Research,* January 12, 1989.

natural gas to further national energy self-sufficiency. However, the Fuel Use Act of 1987 (P.L. 100-42) modified this law significantly to promote domestic production of oil and natural gas. The only remaining requirement is that new baseload (greater than 350 hours per year) boilers are solid-fuel capable. Carr said exceptions to the 1978 act were granted where economic benefit was shown, and exceptions to the revised regulation are granted even more frequently.

The 1982 Military Construction Codification Act referred to by Stone & Webster is the annual budget for new facility construction. The report for this Act prohibited major power plant construction projects by the military unless no public sector contractor could be found. This would not affect a conversion from coal to natural gas.

The 1986 Department of Defense Appropriations Act (P.L. 99-190, sec. 8110) sets aside part of the Army Industrial Fund for a program to "...rehabilitate and convert current steam generating plants at defense facilities in the United States to coal burning facilities in order to achieve a coal consumption target of 1,600,000 short tons of coal per year above current consumption levels...by fiscal year 1994." Similar language is included in the current legislation, the 1989 Defense Appropriations Act (P.L. 100-463, Sec. 8113).

Most of the political pressure to increase Department of Defense use of coal comes from the eastern coal lobby, though some comes from coal interests in Alaska. Eielson, Wainwright, and Clear consume 25 percent of Usibelli's total production. In 1985, the Department of Defense agreed to increase anthracite consumption in the United States where cost-effective in exchange for ending the transport of U.S. coal to Defense facilities in Germany. In the past three years, they have received direct orders to use more coal. They currently use 20,000 tons, but have a five-year contract for 300,000 tons. Several contracts in progress would increase coal use by 1.2 million tons annually. Carr said they are trying to keep their agreement, but will only meet these targets where coal makes economic sense and they can get private sector financing. In any case, said Carr, the pressures that gave rise to this regulation could slow down a decision to convert Fairbanks bases, but do not prohibit it.

According to Craig Valentine, Civil Engineer, Alaska Air Command, this law mandates that the Air Force burn an additional 600,000 tons of coal. To meet these requirements, the Air Force is directing a study by Oak Ridge National Labs to determine which U.S. sites can most economically convert to coal. Valentine said this does not prohibit converting Eielson and Clear to natural gas, but may indicate political considerations that could affect such a decision. He said there are no regulations which specifically prohibit the Air Force from converting from coal to natural gas.

Lee Gail, General Utilities Engineer at Alaska Army Headquarters, said there were no federal regulations prohibiting them from converting, although they would expect a lobbying effort in Congress against switching. As was the case at Fort

Richardson, they would expect eventual approval to convert, providing there were substantial savings.

I.4.4 North Slope Gas Model

In the sensitivity 2 fuel price scenario, it was assumed that North Slope gas is available in Fairbanks in 2010. To analyze this scenario, we used the previous three models to calculate benefits for the 1994 through 2009 period. Then, the North Slope gas model was developed to analyze the benefits during the 2010 through 2030 period.

Note that the output of the other three models in Table I-2 is for the low fuel price scenario. The North Slope model output is for the sensitivity 2 fuel price case, so should not be associated with residential, commercial, and UAF/FMUS/military results shown.

In the sensitivity 2 scenario, most of the benefits to Fairbanks of the Cook Inlet-Fairbanks pipeline would end after 2009. Because of North Slope gas, gas would be available in Fairbanks with or without the Cook Inlet-Fairbanks pipeline. However, there are still some benefits to account for. When North Slope gas arrives in Fairbanks, there already is a gas distribution system and many buildings with gas-using heating systems and appliances. These costs have already been incurred and charged to the Cook Inlet-Fairbanks line. Thus, the Cook Inlet-Fairbanks line has eliminated the need for these investments when North Slope gas is brought to Fairbanks in 2010. The avoided distribution system cost is about $34 million, and the avoided investment in gas heating and appliance conversions is about $31 million. In the model output in Table I-2, these benefits are included in the "other benefits/costs" column for the year 2010. Deducted from the $65 million benefit is a $1 million cost to interconnect the Cook Inlet-Fairbanks pipeline with the North Slope pipeline.

The next benefit attributable to the Cook Inlet-Fairbanks line in this scenario is the gas cost savings from 2010 through 2014. The scenario assumes that Cook Inlet gas is still less expensive than North Slope gas for this period, so Fairbanks will continue to be served from the south for these five years. The model output shows that the benefits are small because the price differential between Cook Inlet gas and North Slope gas is small. Also, under this price scenario, the military, UAF, and FMUS have converted back to coal by 2010 because of rising gas prices. The gas demand in Fairbanks is only 4.5 TBtu per year.

After 2015, North Slope gas becomes less expensive than Cook Inlet gas, and North Slope gas flows south through the Cook Inlet-Fairbanks gas line to serve the residential and commercial needs of the southern Railbelt. A $4 million compressor cost is incurred to increase the pipeline flow capacity.[10] Large annual benefits are realized from transporting large volumes of North Slope gas southward to displace Cook Inlet gas.

The magnitude of the southward flow was determined by assuming the Enstar demand in the southern Railbelt grows by 0.7, 1.4, and 1.8 percent per year for the low, mid, and high demographic scenarios, respectively. Pipeline flow was determined by slightly reducing this demand figure to account for periods when the southern Railbelt demand will exceed the capacity of the 16-inch pipe, approximately 0.15 TBtu/day.

I.5 ISSUES FOR FURTHER INVESTIGATION

This subsection outlines some issues related to the economic costs and benefits of the Cook Inlet-Fairbanks gas pipeline that warrant additional investigation.

I.5.1 Penetration of Distribution System

The number of residential households that will eventually gain access to gas in the Fairbanks area is relatively uncertain yet critical to the cost/benefit analysis. A more detailed estimate of the number of households that can be economically accessed by the gas distribution system would be valuable.

I.5.2 Commercial Sector Gas Use

There are significant discrepancies between estimates of commercial sector gas demand between our study, House Research's study, and Enstar's study. Additional data concerning fuel use intensities and total commercial square footage are necessary to resolve these differences.

I.5.3 UAF/Military Benefits

The military and UAF benefits are quite uncertain. The benefits vary according to whether or not these energy users decide to substitute natural gas for coal, and the benefits vary according to expected fuel prices. Additional work to better determine the financial criteria employed by these users and better determine the institutional barriers present would help resolve some of the uncertainty.

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[10]The North Slope gas line will operate at high enough pressure to pressurize the Fairbanks inlet of the Cook Inlet-Fairbanks gas line. The $4 million cost is for an intermediate compressor station between Anchorage and Fairbanks.

I.5.4 Space Heating Reliability

The use of natural gas may affect the reliability of space heating systems in Fairbanks buildings. On the positive side, gas heating appliances are more reliable than oil heating appliances because of the cleanliness of gas. On the negative side, the delivery of gas to a building may be less reliable than the delivery of oil. A multitude of oil trucks are more reliable than one gas line. For large users with critical reliability requirements such as the military bases, dual-fuel capability can economically solve the problem. The costs of dual-fuel systems are more significant for smaller buildings. Further investigation into reliability issues and the cost of solutions is appropriate.

I.5.5 Long-Run Marginal Fuel Costs

Relative fuel costs are critical in the analysis of the pipeline. Further investigation would be useful on the extent to which there are unavoidable or sunk costs in the production, refining, and transport of existing or additional volumes of coal and fuel oil. Further investigation would also be useful on the relationship between contract prices and true marginal costs for natural gas.

I.5.6 Other North Slope Gas Scenarios

Only one scenario that includes the availability of North Slope gas in Fairbanks was investigated. Other scenarios with different North Slope gas availability dates and different Cook Inlet/North Slope gas price relationships are possible. Net benefits of the Cook Inlet-Fairbanks gas pipeline will vary significantly across such scenarios.

Table I-2

SAMPLE MODEL OUTPUT

RESIDENTIAL WASILLA-FAIRBANKS GAS LINE MODEL

Real Discount Rate = 4.5%   INPUTS: BASE

SPACE HEAT ENERGY REQUIREMENTS

Base Space Heat Demand per Housing Unit = 126 MMBtu/year
Growth Rate = -0.3% /yr

1988 Total Households, 000s = 26.89

	OIL	ELEC	WOOD	PROP	GAS
1988 Fuel Type Split	80%	6%	13%	1%	--
New Construction Fuel Type Split					
With Access	0%	4%	5%	0%	91%
Without Access	80%	6%	13%	1%	0%
Rates of Conversion to Gas for Non-Gas Housing Units w/ Access, %/year	40%	5%	5%	70%	--
Stock Avg Heating System Efficiency	65%	100%	47%	65%	72%
Asymptotic Heating Efficiency	78%	100%	65%	78%	78%
Avg->Best Approach Rate, %/year	3.6%	0.0%	1.5%	3.6%	2.2%
Conversion to Gas Capital Cost	$1,840	$5,000	$2,200	$300	NA
New Construction Capital Cost	$4,700	$2,000	$2,600	$4,070	$4,000
O&M Cost, $/year	$70	$10	$200	$30	$30

WATER HEATER + MISC ENERGY REQUIREMENTS

Water Heater + Misc Energy Demand per Unit = 14.1 MMBtu
Growth Rate = 0.0% /year

% of Space Heat Conversions that Immed. Convert Water Heater = 60%
Ultimate % of Gas Space Heat HH that Convert Water Heater = 83%
Approach Rate, % per year = 6%

Water + Misc Fuel Type --->	BLEND	GAS
% Oil	57.2%	NA
% Electricity	25.0%	NA
% Wood	1.6%	NA
% Propane	16.2%	NA
Stock Avg Appliance Efficiency	61%	60%
Asymptotic Appliance Efficiency	68%	65%
Avg->Best Approach Rate, %/year	7.1%	0.8%
Conversion to Gas Capital Cost	$260	NA
New Construction Capital Cost	$790	$600
O&M Cost, $/year	$5	$5

Table I-2 (continued)

Fuel Price Case: LOW **Other Inputs:** BASE
Households: MID

YEAR	TOTAL HOUS UNITS	RETIRE-MENTS	GAIN GAS ACCESS	----- Fuel Prices ($/MMBtu) ----- OIL	ELEC	WOOD	PROP	GAS
1988	26.89	--	--	6.05	0.00	4.15	12.20	1.59
1989	26.78	0.11	0.0%	5.65	0.00	3.97	11.80	1.51
1990	26.74	0.05	0.0%	5.43	0.00	3.87	11.58	1.43
1991	26.68	0.06	0.0%	5.49	0.00	3.90	11.64	1.37
1992	26.62	0.06	0.0%	5.55	0.00	3.92	11.70	1.41
1993	26.57	0.05	0.0%	5.61	0.00	3.95	11.76	1.44
1994	26.52	0.05	19.0%	5.67	0.00	3.98	11.82	1.48
1995	26.79	0.05	19.0%	5.72	0.00	4.00	11.87	1.54
1996	27.19	0.05	9.0%	5.80	0.00	4.04	11.95	1.54
1997	27.57	0.05	3.0%	5.87	0.00	4.07	12.02	1.58
1998	27.97	0.06	3.0%	5.94	0.00	4.10	12.09	1.61
1999	28.51	0.06	2.0%	6.01	0.00	4.13	12.16	1.62
2000	29.07	0.06	1.0%	6.08	0.00	4.17	12.23	1.65
2001	29.63	0.06	1.0%	6.12	0.00	4.18	12.27	1.69
2002	30.17	0.06	1.0%	6.16	0.00	4.20	12.31	1.70
2003	30.66	0.06	0.0%	6.19	0.00	4.21	12.34	1.56
2004	31.24	0.06	0.0%	6.23	0.00	4.23	12.38	1.57
2005	31.88	0.06	0.0%	6.26	0.00	4.24	12.41	1.49
2006	32.57	0.06	0.0%	6.30	0.00	4.26	12.45	1.50
2007	33.34	0.07	0.0%	6.34	0.00	4.28	12.49	1.52
2008	34.11	0.07	0.0%	6.37	0.00	4.30	12.52	1.53
2009	34.87	0.07	0.0%	6.41	0.00	4.31	12.56	1.55
2010	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2011	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2012	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2013	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2014	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2015	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2016	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2017	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2018	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2019	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2020	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2021	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2022	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2023	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2024	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2025	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2026	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2027	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2028	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2029	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56
2030	35.59	0.07	0.0%	6.44	0.00	4.33	12.59	1.56

SUMMARY OUTPUT

Total Discounted Costs 1994 - 2030 ($ million)	Fuel	O&M	New	Convert	TOTAL
With Gas Line	$416	$38	$33	$24	$511
Without Gas Line	$630	$50	$35	$0	$714
Gas Line Benefits	$214	$11	$2	($24)	$204

RESIDENTIAL WASILLA-FAIRBANKS GASLINE MODEL

FUEL PRICE: LOW

HOUSEHOLDS: MID
OTHER INPUTS: BASE

GAS LINE?: NO

	TOTAL COSTS, $ million					SPACE HEAT HOUSEHOLDS, 000s						FUEL USE, TBtu = 1,000,000 MMBtu = 1e12 Btu							FUEL USE / HOUSEHOLD, MMBtu	
YEAR	Fuel Cost	O&M Cost	New Capital Cost	Convert Cap. Cost	TOTAL	TOTAL	OIL	ELEC	WOOD	PROP	GAS	TOTAL	OIL	ELEC	WOOD	PROP	GAS	BLEND	TOTAL FUEL	GAS / GAS HH
1988	$33.0	$2.4	$0.0	$0.0	$35.4	26.89	21.43	1.72	3.47	0.27	0.00	5.97	4.15	0.22	0.93	0.05	0.00	0.62	222	ERR
1989	$30.6	$2.3	($0.0)	$0.0	$32.9	26.78	21.35	1.71	3.46	0.27	0.00	5.89	4.10	0.22	0.92	0.05	0.00	0.61	220	ERR
1990	$29.2	$2.3	$0.0	$0.0	$31.5	26.74	21.31	1.71	3.45	0.27	0.00	5.83	4.05	0.21	0.91	0.05	0.00	0.60	218	ERR
1991	$29.1	$2.3	($0.0)	$0.0	$31.4	26.68	21.26	1.71	3.44	0.27	0.00	5.76	4.00	0.21	0.90	0.05	0.00	0.60	216	ERR
1992	$29.1	$2.3	($0.0)	$0.0	$31.4	26.62	21.22	1.70	3.43	0.27	0.00	5.70	3.96	0.21	0.89	0.05	0.00	0.59	214	ERR
1993	$29.0	$2.3	$0.0	$0.0	$31.4	26.57	21.18	1.70	3.43	0.27	0.00	5.64	3.91	0.21	0.88	0.05	0.00	0.59	212	ERR
1994	$29.0	$2.3	($0.0)	$0.0	$31.3	26.52	21.13	1.70	3.42	0.27	0.00	5.59	3.87	0.21	0.87	0.05	0.00	0.59	211	ERR
1995	$29.4	$2.3	$1.7	$0.0	$33.4	26.79	21.35	1.71	3.46	0.27	0.00	5.60	3.88	0.21	0.87	0.05	0.00	0.59	209	ERR
1996	$29.9	$2.4	$2.3	$0.0	$34.6	27.19	21.67	1.74	3.51	0.27	0.00	5.64	3.90	0.21	0.88	0.05	0.00	0.59	207	ERR
1997	$30.4	$2.4	$2.2	$0.0	$35.0	27.57	21.97	1.76	3.56	0.28	0.00	5.68	3.92	0.22	0.89	0.05	0.00	0.60	206	ERR
1998	$31.0	$2.4	$2.3	$0.0	$35.7	27.97	22.29	1.79	3.61	0.28	0.00	5.72	3.95	0.22	0.89	0.05	0.00	0.61	204	ERR
1999	$31.7	$2.5	$3.0	$0.0	$37.2	28.51	22.72	1.82	3.68	0.29	0.00	5.79	4.00	0.22	0.90	0.05	0.00	0.62	203	ERR
2000	$32.5	$2.5	$3.1	$0.0	$38.1	29.07	23.17	1.86	3.75	0.29	0.00	5.86	4.04	0.23	0.91	0.05	0.00	0.63	202	ERR
2001	$33.1	$2.6	$3.1	$0.0	$38.8	29.63	23.62	1.90	3.82	0.30	0.00	5.93	4.09	0.23	0.92	0.05	0.00	0.64	200	ERR
2002	$33.6	$2.6	$3.0	$0.0	$39.2	30.17	24.04	1.93	3.89	0.30	0.00	6.00	4.13	0.23	0.93	0.05	0.00	0.65	199	ERR
2003	$34.1	$2.7	$2.8	$0.0	$39.6	30.66	24.44	1.96	3.96	0.31	0.00	6.06	4.17	0.24	0.94	0.05	0.00	0.65	198	ERR
2004	$34.7	$2.7	$3.2	$0.0	$40.7	31.24	24.90	2.00	4.03	0.31	0.00	6.14	4.22	0.24	0.95	0.05	0.00	0.67	196	ERR
2005	$35.4	$2.8	$3.6	$0.0	$41.8	31.88	25.41	2.04	4.11	0.32	0.00	6.22	4.28	0.24	0.97	0.05	0.00	0.68	195	ERR
2006	$36.1	$2.9	$3.8	$0.0	$42.8	32.57	25.96	2.08	4.20	0.33	0.00	6.32	4.35	0.25	0.98	0.05	0.00	0.69	194	ERR
2007	$37.0	$2.9	$4.2	$0.0	$44.1	33.34	26.57	2.13	4.30	0.33	0.00	6.43	4.42	0.25	1.00	0.06	0.00	0.71	193	ERR
2008	$37.8	$3.0	$4.2	$0.0	$45.0	34.11	27.18	2.18	4.40	0.34	0.00	6.54	4.49	0.26	1.01	0.06	0.00	0.72	192	ERR
2009	$38.7	$3.1	$4.2	$0.0	$45.9	34.87	27.79	2.23	4.50	0.35	0.00	6.65	4.57	0.26	1.03	0.06	0.00	0.74	191	ERR
2010	$39.4	$3.1	$4.0	$0.0	$46.5	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2011	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2012	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2013	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2014	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2015	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2016	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2017	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2018	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2019	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2020	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2021	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2022	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2023	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2024	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2025	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2026	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2027	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2028	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2029	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR
2030	$39.4	$3.1	$0.4	$0.0	$42.9	35.59	28.37	2.28	4.59	0.36	0.00	6.75	4.63	0.27	1.04	0.06	0.00	0.75	190	ERR

Table I-2 (continued)

Table I-2 (continued)

RESIDENTIAL WASILLA-FAIRBANKS GASLINE MODEL

FUEL PRICE: LOW

HOUSEHOLDS: MID
OTHER INPUTS: BASE

GAS LINE?: YES

	TOTAL COSTS, $ million					SPACE HEAT HOUSEHOLDS, 000s						FUEL USE, TBtu = 1,000,000 MMBtu = 1e12 Btu							FUEL USE / HOUSEHOLD, MMBtu	
YEAR	Fuel Cost	O&M Cost	New Capital Cost	Convert Cap. Cost	TOTAL	TOTAL	OIL	ELEC	WOOD	PROP	GAS	TOTAL	OIL	ELEC	WOOD	PROP	GAS	BLEND	TOTAL FUEL	GAS / GAS HH
1988	$33.0	$2.4	$0.0	$0.0	$35.4	26.89	21.43	1.72	3.47	0.27	0.00	5.97	4.15	0.22	0.93	0.05	0.00	0.62	222	ERR
1989	$30.6	$2.3	($0.0)	$0.0	$32.9	26.78	21.35	1.71	3.46	0.27	0.00	5.89	4.10	0.22	0.92	0.05	0.00	0.61	220	ERR
1990	$29.2	$2.3	$0.0	$0.0	$31.5	26.74	21.31	1.71	3.45	0.27	0.00	5.83	4.05	0.21	0.91	0.05	0.00	0.60	218	ERR
1991	$29.1	$2.3	($0.0)	$0.0	$31.4	26.68	21.26	1.71	3.44	0.27	0.00	5.76	4.00	0.21	0.90	0.05	0.00	0.60	216	ERR
1992	$29.1	$2.3	($0.0)	$0.0	$31.4	26.62	21.22	1.70	3.43	0.27	0.00	5.70	3.96	0.21	0.89	0.05	0.00	0.59	214	ERR
1993	$29.0	$2.3	$0.0	$0.0	$31.4	26.57	21.18	1.70	3.43	0.27	0.00	5.64	3.91	0.21	0.88	0.05	0.00	0.59	212	ERR
1994	$27.6	$2.3	($0.0)	$3.3	$33.1	26.52	19.53	1.69	3.40	0.23	1.67	5.57	3.58	0.21	0.87	0.04	0.31	0.56	210	184
1995	$25.7	$2.2	$1.6	$5.3	$34.8	26.79	17.11	1.70	3.39	0.19	4.41	5.55	3.11	0.21	0.86	0.03	0.81	0.53	207	184
1996	$24.0	$2.1	$2.2	$4.9	$33.2	27.19	14.97	1.70	3.38	0.16	6.99	5.56	2.69	0.21	0.85	0.03	1.28	0.50	204	183
1997	$22.9	$2.0	$2.1	$3.5	$30.6	27.57	13.46	1.70	3.36	0.14	8.90	5.58	2.40	0.21	0.84	0.03	1.63	0.48	202	183
1998	$22.2	$2.0	$2.2	$2.7	$29.1	27.97	12.35	1.71	3.34	0.14	10.44	5.61	2.19	0.21	0.83	0.02	1.90	0.46	201	182
1999	$21.8	$2.0	$2.8	$2.1	$28.8	28.51	11.61	1.72	3.33	0.13	11.72	5.67	2.04	0.21	0.82	0.02	2.13	0.45	199	182
2000	$21.8	$2.0	$2.9	$1.5	$28.2	29.07	11.16	1.73	3.33	0.13	12.72	5.74	1.95	0.21	0.81	0.02	2.30	0.44	197	181
2001	$21.8	$2.0	$2.9	$1.2	$27.9	29.63	10.87	1.74	3.33	0.13	13.55	5.81	1.88	0.21	0.81	0.02	2.45	0.44	196	181
2002	$21.7	$2.0	$2.8	$1.0	$27.5	30.17	10.67	1.76	3.33	0.13	14.27	5.88	1.84	0.21	0.80	0.02	2.57	0.44	195	180
2003	$21.4	$2.0	$2.6	$0.7	$26.7	30.66	10.61	1.77	3.33	0.13	14.82	5.94	1.81	0.21	0.79	0.02	2.66	0.44	194	180
2004	$21.6	$2.1	$3.0	$0.5	$27.2	31.24	10.66	1.79	3.34	0.13	15.32	6.02	1.81	0.21	0.79	0.02	2.74	0.44	193	179
2005	$21.7	$2.1	$3.3	$0.3	$27.5	31.88	10.80	1.81	3.36	0.13	15.79	6.11	1.82	0.22	0.79	0.02	2.82	0.44	192	179
2006	$22.1	$2.1	$3.5	$0.3	$28.0	32.57	10.98	1.83	3.38	0.14	16.25	6.20	1.84	0.22	0.79	0.02	2.90	0.44	190	178
2007	$22.5	$2.2	$3.9	$0.2	$28.9	33.34	11.20	1.86	3.40	0.14	16.73	6.32	1.86	0.22	0.79	0.02	2.97	0.45	189	178
2008	$23.0	$2.2	$4.0	$0.2	$29.4	34.11	11.44	1.89	3.44	0.14	17.20	6.43	1.89	0.22	0.79	0.02	3.05	0.45	189	177
2009	$23.5	$2.2	$3.9	$0.2	$29.8	34.87	11.69	1.92	3.47	0.15	17.65	6.54	1.92	0.23	0.79	0.02	3.12	0.46	188	177
2010	$24.0	$2.3	$3.7	$0.1	$30.1	35.59	11.92	1.94	3.50	0.15	18.08	6.64	1.95	0.23	0.79	0.02	3.18	0.46	187	176
2011	$23.9	$2.3	$0.3	$0.1	$26.7	35.59	11.92	1.94	3.47	0.15	18.12	6.64	1.95	0.23	0.79	0.02	3.19	0.46	187	176
2012	$23.9	$2.3	$0.3	$0.1	$26.6	35.59	11.92	1.93	3.44	0.15	18.15	6.64	1.95	0.23	0.78	0.02	3.20	0.46	187	176
2013	$23.9	$2.3	$0.3	$0.1	$26.6	35.59	11.92	1.92	3.42	0.15	18.19	6.64	1.95	0.23	0.78	0.02	3.21	0.46	187	176
2014	$23.8	$2.3	$0.3	$0.1	$26.5	35.59	11.91	1.91	3.40	0.15	18.22	6.64	1.95	0.23	0.77	0.02	3.22	0.45	187	177
2015	$23.8	$2.3	$0.3	$0.1	$26.5	35.59	11.91	1.91	3.37	0.15	18.25	6.64	1.95	0.22	0.77	0.02	3.22	0.45	186	177
2016	$23.8	$2.3	$0.3	$0.1	$26.5	35.59	11.91	1.90	3.35	0.15	18.28	6.64	1.95	0.22	0.76	0.02	3.23	0.45	186	177
2017	$23.8	$2.3	$0.3	$0.1	$26.5	35.59	11.91	1.89	3.33	0.15	18.30	6.63	1.95	0.22	0.76	0.02	3.24	0.45	186	177
2018	$23.8	$2.2	$0.3	$0.1	$26.4	35.59	11.91	1.89	3.31	0.15	18.33	6.63	1.95	0.22	0.75	0.02	3.24	0.45	186	177
2019	$23.7	$2.2	$0.3	$0.1	$26.4	35.59	11.91	1.88	3.29	0.15	18.35	6.63	1.95	0.22	0.75	0.02	3.25	0.45	186	177
2020	$23.7	$2.2	$0.3	$0.1	$26.4	35.59	11.91	1.88	3.28	0.15	18.37	6.63	1.95	0.22	0.74	0.02	3.25	0.45	186	177
2021	$23.7	$2.2	$0.3	$0.1	$26.4	35.59	11.91	1.87	3.26	0.15	18.40	6.63	1.95	0.22	0.74	0.02	3.26	0.44	186	177
2022	$23.7	$2.2	$0.3	$0.1	$26.3	35.59	11.91	1.87	3.24	0.15	18.42	6.63	1.95	0.22	0.74	0.02	3.26	0.44	186	177
2023	$23.7	$2.2	$0.3	$0.1	$26.3	35.59	11.91	1.86	3.23	0.15	18.43	6.63	1.95	0.22	0.73	0.02	3.27	0.44	186	177
2024	$23.7	$2.2	$0.3	$0.1	$26.3	35.59	11.91	1.86	3.22	0.15	18.45	6.63	1.95	0.22	0.73	0.02	3.27	0.44	186	177
2025	$23.7	$2.2	$0.3	$0.1	$26.3	35.59	11.91	1.85	3.20	0.15	18.47	6.63	1.95	0.22	0.73	0.02	3.27	0.44	186	177
2026	$23.6	$2.2	$0.3	$0.1	$26.3	35.59	11.91	1.85	3.19	0.15	18.49	6.63	1.95	0.22	0.72	0.02	3.28	0.44	186	177
2027	$23.6	$2.2	$0.3	$0.1	$26.2	35.59	11.91	1.85	3.18	0.15	18.50	6.63	1.95	0.22	0.72	0.02	3.28	0.44	186	177
2028	$23.6	$2.2	$0.3	$0.1	$26.2	35.59	11.91	1.84	3.17	0.15	18.52	6.63	1.95	0.22	0.72	0.02	3.28	0.44	186	177
2029	$23.6	$2.2	$0.3	$0.0	$26.2	35.59	11.91	1.84	3.16	0.15	18.53	6.63	1.95	0.22	0.72	0.02	3.29	0.44	186	177
2030	$23.6	$2.2	$0.3	$0.0	$26.2	35.59	11.91	1.84	3.15	0.15	18.54	6.63	1.95	0.22	0.71	0.02	3.29	0.43	186	177

Table I-2 (continued)

COMMERCIAL WASILLA-FAIRBANKS GAS LINE MODEL

Real Discount Rate = 4.5%   INPUTS: BASE

SPACE + WATER + COOK ENERGY REQUIREMENTS

Energy Demand per 1,000 square feet = 62 MMBtu/year
Growth Rate = -0.15% /yr

Total Commercial Square Feet, 1988 = 13.66 million ft2

	OIL	ELEC	WOOD	PROP	GAS
1988 Fuel Type Split	85.7%	8.2%	0.9%	5.2%	--
New Construction Fuel Type Split					
With Access	0.0%	5.2%	0.9%	0.0%	93.9%
Without Access	87.0%	6.2%	0.9%	5.9%	0.0%
Rates of Conversion to Gas for Non-Gas Housing Units w/ Access, %/year	60%	7%	7%	75%	--
Stock Avg Fuel Efficiency	70%	90%	47%	70%	74%
Asymptotic Fuel Efficiency	78%	100%	65%	78%	78%
Avg->Best Approach Rate, %/year	2.5%	1.5%	1.5%	2.5%	1.5%
All costs are for 1,000 ft2:					
Conversion to Gas Capital Cost	$657	$2,158	$893	$62	NA
New Construction Capital Cost	$1,910	$918	$1,190	$1,655	$1,624
O&M Cost, $/year	$29	$4	$92	$12	$12

Table I-2 (continued)

Fuel Price Case: LOW **Other Inputs:** BASE
Floorstock: MID

YEAR	TOTAL MIL. FT2	RETIRE-MENTS	GAIN GAS ACCESS	----- Fuel Prices ($/MMBtu) ----- OIL	ELEC	WOOD	PROP	GAS
1988	13.66	--	--	5.42	0.00	4.15	12.20	1.59
1989	13.77	0.068	0.0%	5.02	0.00	3.97	11.80	1.51
1990	13.73	0.055	0.0%	4.80	0.00	3.87	11.58	1.43
1991	13.79	0.027	0.0%	4.86	0.00	3.90	11.64	1.37
1992	14.08	0.028	0.0%	4.92	0.00	3.92	11.70	1.41
1993	14.20	0.028	0.0%	4.98	0.00	3.95	11.76	1.44
1994	14.46	0.028	38.0%	5.04	0.00	3.98	11.82	1.48
1995	14.62	0.029	38.0%	5.09	0.00	4.00	11.87	1.54
1996	14.76	0.029	19.0%	5.17	0.00	4.04	11.95	1.54
1997	14.91	0.030	0.0%	5.24	0.00	4.07	12.02	1.58
1998	15.09	0.030	0.0%	5.31	0.00	4.10	12.09	1.61
1999	15.39	0.030	0.0%	5.38	0.00	4.13	12.16	1.62
2000	15.62	0.031	0.0%	5.45	0.00	4.17	12.23	1.65
2001	15.80	0.031	0.0%	5.49	0.00	4.18	12.27	1.69
2002	15.98	0.032	0.0%	5.53	0.00	4.20	12.31	1.70
2003	16.13	0.032	0.0%	5.56	0.00	4.21	12.34	1.56
2004	16.40	0.032	0.0%	5.60	0.00	4.23	12.38	1.57
2005	16.71	0.033	0.0%	5.63	0.00	4.24	12.41	1.49
2006	17.04	0.033	0.0%	5.67	0.00	4.26	12.45	1.50
2007	17.42	0.034	0.0%	5.71	0.00	4.28	12.49	1.52
2008	17.76	0.035	0.0%	5.74	0.00	4.30	12.52	1.53
2009	18.10	0.036	0.0%	5.78	0.00	4.31	12.56	1.55
2010	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2011	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2012	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2013	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2014	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2015	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2016	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2017	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2018	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2019	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2020	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2021	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2022	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2023	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2024	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2025	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2026	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2027	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2028	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2029	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56
2030	18.38	0.036	0.0%	5.81	0.00	4.33	12.59	1.56

SUMMARY OUTPUT

Total Discounted Costs 1994 - 2030 ($ million)	Fuel	O&M	New	Convert	TOTAL
With Gas Line	$47	$6	$8	$10	$70
Without Gas Line	$137	$9	$9	$0	$155
Gas Line Benefits	$90	$4	$1	($10)	$85

Table I-2 (continued)

COMMERCIAL WASILLA-FAIRBANKS GASLINE MODEL

FUEL PRICE: LOW

FLOORSTOCK: MID GAS LINE?: NO
OTHER INPUTS: BASE

YEAR	TOTAL COSTS, $ million Fuel Cost	O&M Cost	New Capital Cost	Convert Cap. Cost	TOTAL	Total Floorstock mil. ft2	FUEL USE, TBtu = 1,000,000 MMBtu = 1e12 Btu TOTAL	OIL	ELEC	WOOD	PROP	GAS	FUEL USE MMBtu / 1000 ft2
1988	$6.5	$0.4	$0.0	$0.0	$6.9	13.66	1.19	1.04	0.08	0.02	0.06	0.00	87
1989	$6.0	$0.4	$0.5	$0.0	$6.9	13.77	1.20	1.04	0.08	0.02	0.06	0.00	87
1990	$5.8	$0.4	$0.0	$0.0	$6.2	13.73	1.19	1.03	0.08	0.02	0.06	0.00	87
1991	$5.8	$0.4	$0.2	$0.0	$6.5	13.79	1.19	1.03	0.08	0.02	0.06	0.00	86
1992	$6.0	$0.4	$0.8	$0.0	$7.2	14.08	1.21	1.05	0.08	0.02	0.06	0.00	86
1993	$6.1	$0.4	$0.4	$0.0	$6.9	14.20	1.21	1.06	0.08	0.02	0.06	0.00	86
1994	$6.2	$0.5	$0.7	$0.0	$7.4	14.46	1.23	1.07	0.08	0.02	0.07	0.00	85
1995	$6.4	$0.5	$0.5	$0.0	$7.3	14.62	1.24	1.08	0.08	0.02	0.07	0.00	85
1996	$6.5	$0.5	$0.4	$0.0	$7.4	14.76	1.25	1.09	0.08	0.02	0.07	0.00	85
1997	$6.6	$0.5	$0.5	$0.0	$7.5	14.91	1.26	1.09	0.08	0.02	0.07	0.00	84
1998	$6.7	$0.5	$0.6	$0.0	$7.8	15.09	1.27	1.10	0.08	0.02	0.07	0.00	84
1999	$6.9	$0.5	$0.8	$0.0	$8.3	15.39	1.29	1.12	0.08	0.02	0.07	0.00	84
2000	$7.1	$0.5	$0.7	$0.0	$8.3	15.62	1.30	1.13	0.08	0.02	0.07	0.00	83
2001	$7.2	$0.5	$0.5	$0.0	$8.2	15.80	1.31	1.14	0.08	0.02	0.07	0.00	83
2002	$7.3	$0.5	$0.6	$0.0	$8.4	15.98	1.32	1.15	0.08	0.02	0.07	0.00	83
2003	$7.4	$0.5	$0.5	$0.0	$8.4	16.13	1.33	1.16	0.08	0.02	0.07	0.00	83
2004	$7.5	$0.5	$0.8	$0.0	$8.9	16.40	1.35	1.17	0.08	0.02	0.07	0.00	82
2005	$7.7	$0.5	$0.9	$0.0	$9.1	16.71	1.37	1.19	0.09	0.02	0.07	0.00	82
2006	$7.9	$0.5	$1.0	$0.0	$9.4	17.04	1.39	1.21	0.09	0.02	0.08	0.00	82
2007	$8.1	$0.5	$1.1	$0.0	$9.7	17.42	1.42	1.24	0.09	0.02	0.08	0.00	81
2008	$8.3	$0.6	$1.0	$0.0	$9.8	17.76	1.44	1.26	0.09	0.02	0.08	0.00	81
2009	$8.5	$0.6	$1.0	$0.0	$10.0	18.10	1.47	1.28	0.09	0.02	0.08	0.00	81
2010	$8.6	$0.6	$0.8	$0.0	$10.0	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2011	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2012	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2013	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2014	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2015	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2016	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2017	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2018	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2019	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2020	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2021	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2022	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2023	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2024	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2025	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2026	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2027	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2028	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2029	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81
2030	$8.6	$0.6	$0.1	$0.0	$9.3	18.38	1.48	1.29	0.09	0.02	0.08	0.00	81

Table I-2 (continued)

COMMERCIAL WASILLA-FAIRBANKS GASLINE MODEL

FUEL PRICE: LOW

FLOORSTOCK: MID GAS LINE?: YES
OTHER INPUTS: BASE

	TOTAL COSTS, $ million						FUEL USE, TBtu = 1,000,000 MMBtu = 1e12 Btu						FUEL USE
YEAR	Fuel Cost	O&M Cost	New Capital Cost	Convert Cap. Cost	TOTAL	Total Floorstock mil. ft2	TOTAL	OIL	ELEC	WOOD	PROP	GAS	MMBtu / 1000 ft2
1988	$6.5	$0.4	$0.0	$0.0	$6.9	13.66	1.19	1.04	0.08	0.02	0.06	0.00	87
1989	$6.0	$0.4	$0.5	$0.0	$6.9	13.77	1.20	1.04	0.08	0.02	0.06	0.00	87
1990	$5.8	$0.4	$0.0	$0.0	$6.2	13.73	1.19	1.03	0.08	0.02	0.06	0.00	87
1991	$5.8	$0.4	$0.2	$0.0	$6.5	13.79	1.19	1.03	0.08	0.02	0.06	0.00	86
1992	$6.0	$0.4	$0.8	$0.0	$7.2	14.08	1.21	1.05	0.08	0.02	0.06	0.00	86
1993	$6.1	$0.4	$0.4	$0.0	$6.9	14.20	1.21	1.06	0.08	0.02	0.06	0.00	86
1994	$5.2	$0.4	$0.7	$2.4	$8.7	14.46	1.22	0.83	0.08	0.02	0.05	0.25	84
1995	$3.8	$0.3	$0.5	$3.4	$8.0	14.62	1.22	0.49	0.08	0.02	0.02	0.61	83
1996	$2.7	$0.3	$0.4	$2.6	$6.0	14.76	1.21	0.23	0.08	0.02	0.01	0.89	82
1997	$2.3	$0.3	$0.4	$1.1	$4.1	14.91	1.22	0.12	0.07	0.02	0.00	1.00	82
1998	$2.2	$0.3	$0.5	$0.5	$3.5	15.09	1.23	0.08	0.07	0.02	0.00	1.06	81
1999	$2.2	$0.3	$0.7	$0.2	$3.5	15.39	1.25	0.07	0.07	0.02	0.00	1.09	81
2000	$2.3	$0.3	$0.6	$0.1	$3.3	15.62	1.27	0.06	0.07	0.02	0.00	1.12	81
2001	$2.3	$0.3	$0.5	$0.1	$3.2	15.80	1.28	0.06	0.07	0.02	0.00	1.13	81
2002	$2.4	$0.3	$0.5	$0.1	$3.2	15.98	1.29	0.06	0.07	0.02	0.00	1.14	81
2003	$2.2	$0.3	$0.4	$0.1	$3.0	16.13	1.30	0.06	0.07	0.02	0.00	1.15	81
2004	$2.3	$0.3	$0.7	$0.1	$3.3	16.40	1.32	0.06	0.07	0.02	0.00	1.17	80
2005	$2.2	$0.3	$0.8	$0.1	$3.3	16.71	1.34	0.06	0.07	0.02	0.00	1.19	80
2006	$2.3	$0.3	$0.8	$0.0	$3.5	17.04	1.36	0.06	0.07	0.02	0.00	1.21	80
2007	$2.4	$0.3	$0.9	$0.0	$3.7	17.42	1.39	0.06	0.07	0.02	0.00	1.24	80
2008	$2.4	$0.3	$0.8	$0.0	$3.6	17.76	1.42	0.06	0.07	0.02	0.00	1.26	80
2009	$2.5	$0.3	$0.8	$0.0	$3.7	18.10	1.44	0.06	0.07	0.02	0.00	1.28	80
2010	$2.5	$0.3	$0.7	$0.0	$3.6	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2011	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2012	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2013	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2014	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2015	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2016	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.30	79
2017	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2018	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2019	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2020	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2021	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2022	$2.5	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2023	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2024	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2025	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2026	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.07	0.02	0.00	1.31	79
2027	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.06	0.02	0.00	1.31	79
2028	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.06	0.02	0.00	1.31	79
2029	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.06	0.02	0.00	1.31	79
2030	$2.6	$0.3	$0.1	$0.0	$3.0	18.38	1.46	0.06	0.06	0.02	0.00	1.31	79

MILITARY/UAF/FMUS WASILLA-FAIRBANKS GASLINE MODEL

Gas Price Case: LOW **Fuel Growth Case:** MID
General Inputs: BASE

	UAF	FMUS Steam	Sub-total	Wain-wright	Eielson	Clear	Sub-total	Total
Year of Conversion	1994	1994		1999	1999	1999		
Conversion Cost, $ mil.	$0.75	$0.00	$0.75	$2.9	$4.9	$3.0	$10.8	$11.6
O&M Savings, $ mil./year	$0.28	$0.05	$0.33	$0.93	$0.99	$0.62	$2.54	$2.87
1988 Coal Consumption, TBtu	0.88	0.16	1.04	2.52	2.45	1.26	6.24	7.28
Coal Cost, $/MMBtu	$2.52	$2.52		$2.59	$2.68	$2.30		
1988-1993 Fuel Use Growth	0.58%	0.58%		4.6%	0.0%	0.0%		
1993-2010 Fuel Use Growth	1.33%	1.33%		0.0%	0.0%	0.0%		

Gas Efficiency / Coal Efficiency = 97.1%

Real Discount Rate = 4.5%

RESULTS

Discounted Costs/Benefits 1994 - 2030 ($ million)	UAF	FMUS Steam	Sub-total	Wain-wright	Eielson	Clear	Sub-total	Total
Fuel Savings	$17.1	$3.1	$20.2	$41.1	$35.0	$11.5	$87.6	$107.8
O&M Savings	$5.1	$0.9	$6.0	$12.5	$13.3	$8.4	$34.2	$40.1
Conversion Cost	($0.7)	$0.0	($0.7)	($2.2)	($3.8)	($2.3)	($8.3)	($9.0)
Net Benefit	$21.4	$4.0	$25.4	$51.4	$44.5	$17.6	$113.5	$138.9
% Accruing to Gas User	65.8%	66.9%	66.0%	69.9%	72.9%	64.7%	70.3%	69.5%
User Return per $ of Cost	20.6			17.1	9.6	5.9	10.6	11.7

MILITARY/UAF/FMUS WASILLA-FAIRBANKS GASLINE MODEL

Gas Price Case: LOW   Fuel Growth Case: MID   General Inputs: BASE

	Gas Prices, $/MMBtu		UAF				FMUS Steam				FORT WAINWRIGHT				EIELSON				CLEAR AFB				
YEAR	Well-head Price	Purchas Price	Fuel Use TBtu	Total Fuel Cost Saving $ mil	O&M Saving $ mil	Convert Cost $ mil	Fuel Use TBtu	Total Fuel Cost Saving $ mil	O&M Saving $ mil	Convert Cost $ mil	Fuel Use TBtu	Total Fuel Cost Saving $ mil	O&M Saving $ mil	Convert Cost $ mil	Fuel Use TBtu	Total Fuel Cost Saving $ mil	O&M Saving $ mil	Convert Cost $ mil	Fuel Use TBtu	Total Fuel Cost Saving $ mil	O&M Saving $ mil	Convert Cost $ mil	Total Gas Use TBtu
1988	1.59	2.17	0.88	$0.00	$0.00	$0.00	0.16	$0.00	$0.00	$0.00	2.52	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1989	1.51	2.07	0.89	$0.00	$0.00	$0.00	0.16	$0.00	$0.00	$0.00	2.64	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1990	1.43	1.97	0.89	$0.00	$0.00	$0.00	0.16	$0.00	$0.00	$0.00	2.76	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1991	1.37	1.90	0.90	$0.00	$0.00	$0.00	0.16	$0.00	$0.00	$0.00	2.88	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1992	1.41	1.93	0.90	$0.00	$0.00	$0.00	0.16	$0.00	$0.00	$0.00	3.02	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1993	1.44	1.94	0.91	$0.00	$0.00	$0.00	0.16	$0.00	$0.00	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1994	1.48	1.97	0.95	$0.92	$0.28	($0.75)	0.17	$0.17	$0.05	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	0.00
1995	1.54	2.02	0.96	$0.88	$0.28	$0.00	0.17	$0.16	$0.05	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	1.12
1996	1.54	2.01	0.98	$0.88	$0.28	$0.00	0.18	$0.16	$0.05	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	1.14
1997	1.58	2.03	0.99	$0.86	$0.28	$0.00	0.18	$0.16	$0.05	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	1.15
1998	1.61	2.05	1.00	$0.84	$0.28	$0.00	0.18	$0.15	$0.05	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	1.17
1999	1.62	2.05	1.01	$0.84	$0.28	$0.00	0.18	$0.15	$0.05	$0.00	3.16	$0.00	$0.00	$0.00	2.45	$0.00	$0.00	$0.00	1.26	$0.00	$0.00	$0.00	1.18
2000	1.65	2.07	1.03	$0.82	$0.28	$0.00	0.19	$0.15	$0.05	$0.00	3.25	$2.91	$0.93	($2.90)	2.53	$2.49	$0.99	($4.90)	1.30	$0.80	$0.62	($3.00)	8.28
2001	1.69	2.10	1.04	$0.79	$0.28	$0.00	0.19	$0.14	$0.05	$0.00	3.25	$2.80	$0.93	$0.00	2.53	$2.40	$0.99	$0.00	1.30	$0.75	$0.62	$0.00	8.29
2002	1.70	2.11	1.06	$0.78	$0.28	$0.00	0.19	$0.14	$0.05	$0.00	3.25	$2.69	$0.93	$0.00	2.53	$2.31	$0.99	$0.00	1.30	$0.71	$0.62	$0.00	8.31
2003	1.56	1.96	1.07	$0.95	$0.28	$0.00	0.19	$0.17	$0.05	$0.00	3.25	$2.63	$0.93	$0.00	2.53	$2.27	$0.99	$0.00	1.30	$0.69	$0.62	$0.00	8.33
2004	1.57	1.96	1.08	$0.95	$0.28	$0.00	0.20	$0.17	$0.05	$0.00	3.25	$3.11	$0.93	$0.00	2.53	$2.64	$0.99	$0.00	1.30	$0.88	$0.62	$0.00	8.34
2005	1.49	1.87	1.10	$1.05	$0.28	$0.00	0.20	$0.19	$0.05	$0.00	3.25	$3.06	$0.93	$0.00	2.53	$2.60	$0.99	$0.00	1.30	$0.86	$0.62	$0.00	8.36
2006	1.50	1.87	1.11	$1.05	$0.28	$0.00	0.20	$0.19	$0.05	$0.00	3.25	$3.34	$0.93	$0.00	2.53	$2.82	$0.99	$0.00	1.30	$0.97	$0.62	$0.00	8.38
2007	1.52	1.89	1.13	$1.05	$0.28	$0.00	0.20	$0.19	$0.05	$0.00	3.25	$3.29	$0.93	$0.00	2.53	$2.78	$0.99	$0.00	1.30	$0.95	$0.62	$0.00	8.39
2008	1.53	1.89	1.14	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.24	$0.93	$0.00	2.53	$2.74	$0.99	$0.00	1.30	$0.93	$0.62	$0.00	8.41
2009	1.55	1.91	1.16	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.19	$0.93	$0.00	2.53	$2.70	$0.99	$0.00	1.30	$0.91	$0.62	$0.00	8.43
2010	1.56	1.91	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.14	$0.93	$0.00	2.53	$2.66	$0.99	$0.00	1.30	$0.89	$0.62	$0.00	8.45
2011	1.56	1.90	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2012	1.56	1.90	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2013	1.56	1.89	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2014	1.56	1.89	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2015	1.56	1.88	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2016	1.56	1.88	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2017	1.56	1.87	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2018	1.56	1.87	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2019	1.56	1.87	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2020	1.56	1.86	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2021	1.56	1.86	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2022	1.56	1.86	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2023	1.56	1.85	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2024	1.56	1.85	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2025	1.56	1.85	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2026	1.56	1.84	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2027	1.56	1.84	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2028	1.56	1.84	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2029	1.56	1.84	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47
2030	1.56	1.84	1.17	$1.04	$0.28	$0.00	0.21	$0.19	$0.05	$0.00	3.25	$3.09	$0.93	$0.00	2.53	$2.63	$0.99	$0.00	1.30	$0.87	$0.62	$0.00	8.47

Table I-2 (continued)

NORTH SLOPE GAS MODEL

Discount Rate = 4.5%
Demographic Case: MID

1994 Present Value = $205

YEAR	Pipeline Flow TBtu	N-Slope Gas Price $/MBtu	Cook-In Gas Price $/MBtu	Pipeline Effic.	Gas Cost Benefit $ mil.	Other Benefits/ Costs $ mil.	Total Benefit $ mil.
2010	4.5	$3.03	$2.28	100.0%	$3	$64	$67
2011	4.5	$3.12	$2.53	100.0%	$3		$3
2012	4.5	$3.22	$2.77	100.0%	$2		$2
2013	4.5	$3.31	$3.01	100.0%	$1		$1
2014	4.5	$3.41	$3.26	100.0%	$1		$1
2015	0.0	$3.50	$3.50	100.0%	$0	($4)	($4)
2016	-29.0	$3.60	$3.80	99.5%	$5		$5
2017	-29.0	$3.69	$4.10	99.5%	$11		$11
2018	-29.0	$3.79	$4.40	99.5%	$17		$17
2019	-29.0	$3.88	$4.70	99.5%	$23		$23
2020	-29.0	$3.98	$5.00	99.5%	$29		$29
2021	-29.0	$4.07	$5.30	99.5%	$35		$35
2022	-29.0	$4.17	$5.60	99.5%	$41		$41
2023	-29.0	$4.26	$5.90	99.5%	$47		$47
2024	-29.0	$4.35	$6.20	99.5%	$53		$53
2025	-29.0	$4.45	$6.50	99.5%	$59		$59
2026	-29.0	$4.54	$6.80	99.5%	$65		$65
2027	-29.0	$4.64	$7.10	99.5%	$71		$71
2028	-29.0	$4.73	$7.40	99.5%	$77		$77
2029	-29.0	$4.83	$7.70	99.5%	$83		$83
2030	-29.0	$4.92	$8.00	99.5%	$89		$89

Description of "Other Benefits/Costs" Column:

The $64 Million in 2010 = $34 million avoided distrbution system cost +
$31 million avoided conversion costs -
$1 million interconnection cost

The ($4) million in 2015 = $4 million compressor cost

Appendix J

RESPONSES TO COMMENTS ON DRAFT FINAL REPORT

Following the distribution of a draft of this final report (dated April 1989), we received comments from:

Chugach Electric Association, Inc.	June 9, 1989
Matanuska Electric Association, Inc.	May 12, 1989
Anchorage Municipal Light & Power	June 9, 1989
Copper Valley Electric Association, Inc.	June 7, 1989
Usibelli Coal Mine, Inc.	May 8, 1989
Kurt S. Dzinich, Alaska State Legislature	May 5, 1989
Petro Star Inc.	June 7, 1989
Saupe Enterprises, Inc.	June 9, 1989
Nelchina/Mendeltna Community Corporation	May 5, 1989

This appendix includes a copy of all comments and responses.

Chugach ELECTRIC ASSOCIATION, INC.

5601 MINNESOTA DRIVE • P.O. BOX 196300 • ANCHORAGE, ALASKA 99519-6300 • PHONE 907-563-7494
FACSIMILE:
907-562-0027

June 9, 1989

Alaska Power Authority
P.O. Box 190869
Anchorage, Alaska 99519-0869

Attention: Mr. Richard Emerman
Senior Economist

Subject: Comments on the "Railbelt Intertie Feasibility Study" Draft Final Report, April 1989

Dear Mr. Emerman:

Chugach appreciates the opportunity to comment on the draft final report of the Railbelt Intertie Feasibility Study. This study provides preliminary conclusions from the evaluation of the economic feasibility of several energy related projects suggested for the Railbelt. While we continue to take exception to certain assumptions and believe that additional analysis is required for ultimate conclusions to be drawn from the report, we express our appreciation that the Alaska Power Authority (APA) provided continuing opportunity for us to assist in the development of various parts of the study. In particular, between the distribution of the Interim Report and the draft final, some of the concerns expressed by the utilities were incorporated.

Decision Focus, Inc., APA's contractor, has done well in preparing a comprehensive report summarizing these complex issues. However, as would be expected as the study progressed, a number of issues arose that suggested the analysis had to be revised. For the report to be as reasonable as possible for a 35-year forecast of utility operations, it is important for the contractor to fully understand Alaska Railbelt utility operations and the responsibility of the utilities to assure a reliable and adequate system to serve current and future Railbelt electric consumers.

In reviewing the data and results presented in the draft report, as well as the findings of analysis performed by Chugach and other utilities, and taking into account benefits less tangible than those discussed in the report, we continue to believe that the benefits of an Anchorage-Kenai Intertie are significant enough to

C-1 warrant continued investigation and construction. Chugach agrees with Power Technologies, Inc.'s suggestion that a 138-kV Anchorage-Kenai Intertie rather than a 230-kV line has merit in that a lower voltage would provide greater stability benefits. On behalf of the Railbelt utilities, POWER Engineers, Inc. (which provided the original 230-kV cost estimate) revised the cost to reflect the installation of a lower-voltage circuit. The POWER estimate for a 138-kV line was $61.5 million in 1989 dollars. For comparison, since APA's draft Feasibility Study quantifies costs and benefits in 1987 dollars, the deflated cost of the 138-kV option in 1987 dollars would be $59.1 million.

The Railbelt utilities are in the process of a thorough evaluation of the 138-kV alternative, and expect to work closely with the APA as the study progresses. However, until such work is completed, formal conclusions on the potential benefits of a downsized transmission intertie would be premature.

Here are our specific comments in regard to the draft final report:

C-2 1. As stated previously by Chugach and as recognized by APA Executive Director Robert LeResche in the memorandum transmitting the report, we continue to support use of the 3 percent discount rate which the APA has established for those projects qualifying for tax-exempt status. The issue of the choice between a 3 percent and 4.5 percent discount rate revolves around the source of funding for the capital expenditures and reflects differing points of view. If alternative uses of funds reserved by the state qualify for tax-exempt status, the long-term benefits of Railbelt energy alternatives should be evaluated on the same basis. We ask that the summary tables of Section 1 include the results on the basis of a 3 percent discount rate. The benefits calculated on the basis of 3 percent were summarized in Dr. LeResche's memorandum.

Since the projects included in the report may well be evaluated against other types of projects that would not normally be evaluated by discounted benefits, we ask also that the results obtained using no discount rate (i.e., 0%) be included as an appendix for future reference.

C-3 2. APA and its contractor have estimated that the incremental operating costs of the existing Anchorage-Kenai Intertie, with upgrades for stability that were suggested by PTI, would be $4,500 per year. We believe that the additional operating complexity and resulting maintenance requirements render this estimate to be far too low. Our estimates indicate that approximately two additional man-years of labor plus support and equipment would be required to operate the stability aids on the existing intertie. This is a reasonable estimate since additional studies are required to finalize the design and assess the reliability of the final configuration, if in fact such an installation would operate as intended. To our knowledge, the PTI proposal is a unique application of utility technology and as such poses unknown operating conditions. At $100,000 per man-year, the present value of the benefits of a new intertie would be increased by $4.3 million assuming the 3.0 percent discount rate, or $3.5 million using 4.5 percent.

C-4 3. It is important to acknowledge the age and condition of the existing Kenai intertie and recognize that upgrades and maintenance requirements affect continued reliance on that single line. We appreciate the inclusion in the draft final report of the effects of annually recurring cumulative two-month maintenance outages on the existing Anchorage-Kenai Intertie, as we suggested earlier. However, the results were included in a note to the summary results of Table 1.1, and not in the total. The benefits of $8 - $9 million must be incorporated in the final results for the base case.

In addition, the existing transmission line is almost 30 years old and will be subject to a rebuild program over a period of time. Over half the transmission line will be subject to winter-only construction, eliminating any reserve and power transfer benefits during that period.

C-4 4. With a second Kenai Peninsula intertie, the level of maintenance for the existing 115-kV line could probably be reduced by 30%. using DFI's numbers for maintenance of the new circuit, savings in excess of $6.3 million could be anticipated for the existing line. The comprehensive maintenance program for the single line would include replacement of questionable structures, insulators and hardware, with a large part of the work planned to be undertaken while the line is energized. Energized line construction, of course, is much more costly than de-energized work.

Moreover, some expensive reconstruction such as avalanche barriers or relocation from avalanche zones might be avoided if a second circuit was available. Avalanche protection for one mile of transmission line is estimated at $2 million; reduction in design and construction criteria such as this could lower reconstruction costs by more than 25%.

C-5 5. It has been suggested that the system dispatch analysis performed by Decision Focus assumed a transfer limit on the 230-kV intertie in excess of the operational limit and that the benefits may be revised. Clarification of this issue would be pursued in the additional analysis by PTI, since specific stability studies to identify operational limits have not been provided to the utilities for review. However, it should be noted that additional operating reserves may be shared among areas if two transmission lines are in service.

C-6 6. The capacity-sharing benefits discussed in Section 6 are based on an amortization period of 30 years for a combustion turbine. Analysis by Chugach of the gas turbine units in use in Alaska indicates that the actual life of such a unit may be less than 30 years without significant expenditures. For the purposes of evaluating capacity deferral, it would be appropriate to adjust the analysis for reduced lifetimes. Assuming a useful life of 20 years for simple-cycle combustion turbines, the annual value for saved capacity would be $47/KW-year at 4.5 percent and $42/KW-year at 3.0 percent

C-7 7. The final report should clearly distinguish between construction costs and operating and maintenance costs that would be borne by the utilities.

C-8 8. In anticipation of continuing reference to the report, recognition should be made of changing oil price expectations that would influence the electrical demand forecasts. Projections at this time may reflect an improved economic climate and the potential for higher demands than included in the study forecast.

C-9 In addition to those benefits identified and discussed in the draft final report, certain benefits accrue from intertie construction that are not readily quantifiable within a study of this nature. These include reduced dependence on particular generating technologies, enhanced flexibility for resource location through improved transmission access, the expanded potential for firm power transactions among utilities (as opposed to geographic locations), and the potential for increased competition among fuel sources and fuel types for generation. Additionally, parallel transmission paths provide protection for contingencies such as extended outages on one of the circuits.

We strongly urge that recognition of the above "non-quantifiable" items be included in the final report, because interties constitute basic infrastructure that provide substantial public benefits.

Thank you for allowing our comments to be included in the final report. Our assistance in the preparation of the final document will be expeditiously provided at your request.

Very truly yours,

CHUGACH ELECTRIC ASSOCIATION, INC.

David L. Highers
General Manager

DLH/TAL/ts
1034.TAL

XC: R. LeResche
B. Rhie
M. Isaacs
D. Shira

RESPONSES TO THE CHUGACH ELECTRIC ASSOCIATION, INC. LETTER DATED JUNE 9, 1989

C-1 According to PTI, failure of a new 138 KV line would be expected to disrupt the system less than failure of a new 230 KV line. If the new line were constructed at 138 KV, a marginal reduction may be possible in the size of the recommended stability aids as a result, depending on the level of design refinement. However, PTI advises that a marginal reduction of this nature, for example in the size of the SVS, would not produce significant savings in the overall cost of the stability aids.

C-2 The idea behind the Power Authority discount rate policy is to set the rate equal to the expected cost of funds for project financing. However, the source of funds for project financing is often unknown at the time of project evaluation. In view of this uncertainty, our approach has been to evaluate all projects as though they were to be financed with market debt, based on the view that this will provide a reasonable test of economic feasibility. If market debt were issued to finance any of the energy projects evaluated in this study, interest on such debt would be taxable.

Even if it were known that a particular project would be fully financed with State appropriations, the opportunity cost of State funds is not easily defined. If the funds would otherwise be deposited in the Permanent Fund and invested, the opportunity cost would be the expected rate of return on taxable securities. If the funds would otherwise be spent on alternative projects, the opportunity cost could be considered either higher or lower than Permanent Fund investment, depending on one's point of view. However, the State's ability to issue tax-exempt debt for certain types of projects does not mean that the opportunity cost of State general funds is equal to the tax-exempt interest rate.

Based on forecasts of inflation rates and Corporate AAA bond interest rates, the Power Authority adopted a real discount rate of 4.5 percent. It is certainly possible, however, that real rates of return on taxable debt could be as low as 3 percent. The table below displays the Benefit/Cost ratios that are produced with a 4.5 percent and a 3 percent real discount rate:

BENEFIT/COST RATIOS

	Discount Rate	
	3%	4.5%
New Kenai-Anchorage Intertie	0.47 to 0.54	0.42 to 0.48
Full Upgrade of Anchorage-Fairbanks Intertie	0.88	0.72
Limited Upgrade of Anchorage-Fairbanks Intertie	4.85	3.88
Northeast Intertie	1.00	0.85
50-MW Coal-Fired Power Plant	0.48 to 0.67	0.42 to 0.61
Gas Pipeline Between Cook Inlet and Fairbanks	NA	1.86
Top Three End-Use Conservation Programs	1.78 to 1.99	1.56 to 1.74
Top Eight End-Use Conservation Programs*	1.45 to 1.64	1.23 to 1.39

* Incremental Benefit/cost ratio of remaining five programs is 1.26 to 1.43 at 3% and 1.05 to 1.19 at 4.5%.

A 0 percent real discount rate would imply that there is no time value of money. In other words, it would mean that we are indifferent between receiving one hundred dollars today and receiving one hundred dollars 30 years from now. This is implausible and should not be considered in an economic feasibility determination.

C-3 The estimate of $4,500 per year refers to the difference in O&M cost for the stability aids recommended with and without the new intertie. Assuming the proposed new intertie is built, PTI concluded that two series capacitors and one small SVS would be needed to provide stability under the prescribed conditions. If the proposed new intertie is not built, PTI concluded that three series capacitors and a larger SVS would be needed to provide stability. The $4,500 figure refers to the additional O&M cost incurred without the new intertie due to the need for one additional series capacitor and a larger SVS. In other words, most of the additional O&M cost for the stability aids will be incurred whether or not the proposed new intertie is built. It is not an estimate of the total O&M cost for the stability aids.

C-4 Because the issue of a long-term maintenance program removing the existing line from service for two months per year was brought to our attention several days before publication of the draft final report, we were unable to arrange for any examination of the issue and produced the $8-9 million benefit estimate very quickly. We do not know more about it now than we did then, and feel therefore that these benefits are still handled more appropriately as a footnote at this time.

Regarding winter vs. summer construction, this has the potential for affecting the capacity sharing benefit category discussed on page 13-21. If the line were out of service for extended periods during the peak months, and could not be brought back into service within a reasonably short period of time, then presumably the existing line would lose its capacity sharing benefit. However, if the line could be brought back into service within a matter of hours if necessary, then it would evidently retain its capacity sharing function in spite of winter construction requirements. Regarding transfers for hydro-thermal coordination, we have no reason at present to predict that transfer levels for this purpose would vary substantially among seasons.

The issue of energized line construction adds another variable to consider. If all of the line maintenance were performed while the line were energized, then a maintenance cost penalty would be paid (relative to the cost of de-energized work) but the estimated $8-9 million "maintenance down time" benefits of the new line would not be realized. If the down time benefits are realized, then the cost penalty for energized work would not be incurred. We do not have sufficient information to consider these trade-offs further at this time.

Regarding relocation of the existing line around avalanche hazards, it may be that this would not be pursued and its associated costs not incurred if the new line were built. Part of that decision would probably be based on the long term costs of repairing those segments after avalanche damage is suffered compared with the cost of relocation. On the other hand, relocation of the existing line around avalanche hazards was not considered in estimating the reliability benefits of the new line. If it is intended that such relocation occur, then the reliability of the existing line would presumably improve, and the reliability benefits of the new line would show a corresponding decline.

C-5 As stated in the comment, a question has arisen regarding the operational transfer limit between the Kenai Peninsula and Anchorage assuming construction of the proposed new line. This question is summarized in the paragraphs below:

> The transfer capability question in this case rests on the distinction between thermal limits and stability limits. The thermal limit of the existing 115 KV line will be 145 MW after the program of reconductoring now in progress is completed, but the stability limit is lower. Given the stability aids recommended by PTI, the stability limit is 90 MW. This means that, if transfers are above 90 MW, instability may occur as a consequence of certain system failures or disturbances. PTI has advised the Power Authority that operation right at the stability limit is not desirable, i.e. operators should allow some margin. As a result, system dispatch was modeled in the "base case" (no new intertie) with a maximum of 75 MW exported from the Kenai Peninsula, with 60 MW received in Anchorage after allowance for losses and demand along the route.
>
> The thermal limit of the new 230 KV line is 250 MW or above. We assumed for the economic modeling that transfer capacity with the new line would be 250 MW, which means that transfers are unlimited given the size of the Kenai and Anchorage loads and generating systems. PTI also recommended a package of stability aids to accompany the new line. It was understood that these stability aids were necessary in order to operate Bradley Lake at peak output (under low load conditions, no other generators operating on the Kenai etc.). However, PTI has now advised the Power Authority that stability considerations would still limit Kenai-Anchorage transfers to 90 MW even with the new 230 KV line, unless additional stability aids were added. In other words, given the $7.0 million of stability aids in the base case, and the $4.2 million of stability aids in the 230 KV line case, the stability limit for transfers from Kenai to Anchorage would be 90 MW under either alternative. Further, with the new 230 KV line, it would not be advisable to operate right up to the 90 MW limit. Export of 75 MW, as in the base case, would provide a reasonable comfort margin.
>
> The stability limit can be raised in either case by adding additional stability aids. To increase the limit by a given amount, for example 25 MW, would require approximately the same

incremental investment in the base case as in the 230 KV line case. The thermal limit of the existing line would place a ceiling on this comparability, but a thermal limit of 145 MW is high enough to allow virtually all of the transfers modeled in our economic analysis.

The benefits of the proposed Kenai-Anchorage line would be reduced if our understanding of the issue described above is correct. However, we have not reduced the benefits reported in this analysis because the utilities have not felt that sufficient evidence is before them to accept the stability limit argument.

Regarding the possibility of further reliance on the Kenai Peninsula for operating reserves given the proposed new line, please refer to item M-6 in the reply to Matanuska Electric Association.

C-6 We agree with this comment. Increasing the capacity value from $39 to $47 per kilowatt per year increased the benefits of capacity sharing as follows:

	$39/KW/yr	$47/KW/yr
Kenai-Anchorage intertie	4.44 to 12.64	5.35 to 15.23
New/upgraded Anchorage-Fairbanks Intertie	0.00 to 1.07	0.00 to 1.68

C-7 These costs are clearly distinguished in several areas of the text, including (for the Kenai-Anchorage intertie) Figure 1-1, Section 1.4.1, and Section 2.1. Costs that are borne by utility customers are no less relevant to the economic analysis than are costs borne by the State treasury. Note that the benefits also accrue to utility customers. A benefit/cost analysis that was limited to impacts on State government would show a substantial construction cost but no benefits. If the impact on utility customers is to be considered, this impact has to be the net of expected cost increases and cost reductions.

C-8 See reply to letter from Usibelli Coal Mine, item U-17. The oil price today is still below the "Mid" price forecast for 1990, and is therefore roughly consistent in the near term with the outlook previously expressed by the Power Authority Board. It is not clear that short-term price movements are sufficient cause for changing long-term expectations. The report displays feasibility results for a range of electrical demand forecasts.

C-9 It is difficult to translate these categories of "non-quantifiable" benefit into specific scenarios through which the benefits could be better understood. For example, it is not clear how the proposed Kenai-Anchorage intertie (i.e. the "KA line") would reduce dependence on particular generating technologies. Would gas or hydro be relied upon less? How would the KA line change the location of new generating resources in the foreseeable future, and with what effect? A substantial surplus of capacity will already exist on the Kenai Peninsula after Bradley Lake completion, which would tend to discourage further additions in that area. However, if more gas-fired capacity were installed on the Kenai in any event to take advantage of wellhead gas prices, this would not necessarily benefit energy consumers in southcentral Alaska as discussed in Section B.6 of the report. It is not clear how the "expanded potential for firm power transactions" adds to the value of improved transmission reliability, which is accounted for in the analysis. And given the predominance of gas throughout southcentral Alaska, it is not clear how the KA line would increase competition among fuel sources and fuel types.

We do not conclude that there are no additional benefits in these categories, but we do not have a sufficient grasp of them to warrant their inclusion within the report at this time.

It is clear, however, that parallel transmission paths provide protection against extended outages on one of the circuits. The cost of such extended outages is the foregone benefit of energy transfer and operating reserve sharing over their duration. Although the foregone benefit of operating reserve sharing due to extended line outages was accounted for in the analysis, the foregone benefit of energy transfer during such outages was not. This could be considered part of the $8-9 million benefit estimated for the new KA line due to 2-month annual outages on the existing KA line.

MATANUSKA ELECTRIC ASSOCIATION, INC.

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May 12, 1989

Mr. Richard Emerman
Alaska Power Authority
P. O. Box 190869
Anchorage, Alaska 99519-0869

Dear Mr. Emerman:

SUBJECT: Comments on "Railbelt Intertie Feasibility Study" Draft Final Report Dated April, 1989

Thank you for the copy and the opportunity to provide our comments. We have carefully reviewed this document and believe Decision Focus Inc. (DFI) has done a good job summarizing the relative benefits/costs of the candidate projects. Considering the magnitude of this study and the uncertainty of future assumptions, we must believe the conclusions reasonably indicate the relative economics of the alternatives. In particular, the study noted the minimum long term capacity benefits of the 230 KV lines and accordingly the utilities have evaluated "downsized" 138 KV lines. The focus of our comments will be on those items which should receive additional study if and when additional 138 KV feasibility analysis is conducted. For convenience we will group our comments by corresponding study section.

M-1 . Section 1

This section and particularly Table 1-1 should be updated to include the various changes in benefit/cost numbers. This primarily concerns the following additional work on the Kenai-Anchorage Line.

a. Revised benefits with new 230 KV line limited to 90 MW capacity.

b. Approximately $8M additional benefits from maintenance down time of the existing Kenai 115 KV line.

c. Additional reliability benefits (See Appendix I - attached).

Section 2 - No comment.

M-2 Section 3

The second paragraph on page 3-1 states, in part, "Railbelt utility representative have been concerned that the risk of occurrence of instability..." Again, Matanuska Electric Association (MEA), Railbelt utilities, and the Alaska Power Authority (APA), all are concerned with this problem. We like to believe the Technical Coordinating Committee (TCC) has acted as it was intended, to represent all our interests. Although differences may arise, we do not view the "utilities" in an adversarial position with APA.

For the record, the TCC did not support or agree with the PTI conclusions and cost estimates discussed on page 3-3 of the report. Further, MEA review of the final PTI work indicates a continued need for additional case by case analysis including the SSO/SSR analysis to validate the PTI conclusions. We are not convinced that the revised solutions recommended by PTI will actually maintain stability under the agreed upon criteria (page 3-4). Hopefully, we will be able to continue this work following completion of the legislative session.

M-3 Section 4

Part 4.3.1 assumes Kenai export 40% of the time and import 60% of the time. Does this analysis include economy generation by CEA per recent CEA/Marathon/GVEA agreement?

As you know, MEA does not agree with the PTI estimates of reduced Kenai outage times with Bradley on line. This area provides significant economic benefits and should receive significant additional analysis in the updated study. We have completed additional analysis which we attach as Appendix I for your review. We believe this analysis corrects minor errors and utilizes more supportable assumptions.

The Kenai Import assumptions (page 4-12) assume the "spinning reserve" benefit of Bradley Lake will effectively reduce the duration of outages by half. Most agree that under this scenario, the Kenai will incur an outage and all generation will trip off line. Restoration of power cannot be provided by Bradley Lake due to slow throttle operation time. (See Railbelt Stability Study, PTI, 3/30/89, page 21, third paragraph.) Restoration will require start up of gas turbines in "normal" restoration times.

M-4 Section 5

In reviewing this section, it became apparent that the analysis did not adequately evaluate the benefits of economic dispatch and unit commitment. Section 5.2.4 attempts to evaluate this benefit but the analysis simplicity misses the true hour to hour benefits of economic dispatch and the start up/shut down costs associated with unit commitment. Furthermore, the use of Kenai gas turbines to provide economy energy to Fairbanks per the new CEA/Marathon/GVEA agreement must be considered. We suggest an expanded analysis in this area when evaluation of the 138 KV "downsized" lines is conducted.

M-5 Section 6

The assumptions related to "lumpy" future capacity additions deserve additional consideration. Certainly, when additional capacity is added, it will not be added in increments as needed or paid for as it is needed. It is not unreasonable to consider such an installation to be a combined cycle base load plant. The addition of new production capacity has the largest impact to utility rates.

Gas turbines in Alaska are used for base load as well as peaking resulting in significant hours of annual operation. This combined with ongoing efficiency improvements significantly reduces the useful life in years of gas turbines. We suggest evaluating simple cycle gas turbines on a 20 year life basis and combined cycle plants on a 30 year basis. Accordingly, the unit capacity cost of $39/KW-year should be reevaluated.

M-6 Section 7

Again, as with Section 5, we feel that the analysis is overly simplistic and that hour to hour economic dispatch benefits may be overlooked. We again suggest reevaluation using a more sophisticated model which can consider at least daily scheduling and utility operating constraints.

In terms of reserve scheduling, Section 7.6 may have missed an important reserve scheduling benefit of the Kenai-Anchorage Intertie. That is, without the new intertie, Kenai spinning reserves must be limited to the available capacity of the existing line (capacity minus actual power flow toward Anchorage). This is a stability limit since flows exceeding the capacity would result in system stability problems. However, with the new 138 KV line (or 230 KV), single contingency loss criteria will allow scheduling of Kenai spinning reserves in excess of the existing single line limit since such flows, on a single contingency event, will not result in system instability.

Section 8-12. No Comment.

Appendix A-I. No Comment.

We recognize that funding may not allow additional analysis, however, should funding be provided for the "downsized" 138 KV intertie alternatives, we would like to meet with APA and DFI to discuss our comments and coordinate the additional work.

Again, we appreciate the opportunity to comment and are available to assist as reasonably required. Please contact Myles Yerkes of our staff at 745-9267 if you have questions.

Sincerely,

James F. Palin
General Manager

MY:BB
302A.020789.146
cc: Ken Ritchey
Myles Yerkes, MEA

Appendix I

Value of Unserved Energy Saved by the Interties
Kenai-Anchorage Line Only
(M$/year)

Unserved Energy - Kenai:

191.8 - 39.3 (Seward) = 152.5 MWH/yr.

Reduction by Intertie:

Assumed:	Low = 46%	High = 62%
Correct:	Low = 80%	High = 80%

Customer Outage Costs:

Assumed = $\frac{\$427{,}000}{66\ \text{MWH}}$ = (.417)(2000) + (.59)(x) = \$6470/MWH

x = Average Comm/ind cost assumed

x = \$9552/MWH

Corrected for actual residential/ind.-comm. ratio for the Kenai Peninsula (Study page 4-4, Table 4-2)

Correct = .35 (2000) + .65 (9552) = \$6910/MWH

Final Value:

Assumed (LO) = 152.5 MWH/yr. x .46 x \$6470/MWH = \$.454 million/yr.
Assumed (HI) = 152.5 MWH/yr. x .62 x \$6470/MWH = \$.612 million/yr.
Correct = 152.5 MWH/yr. x .8 x \$6910/MWH = \$.843 million/yr.

Present Value (35 years @ 4.5% discount)

P/A (35, 4.5%) = 17.461

Assumed (Corrected) (LO) = (.454 + .187) (17.461) = \$11.2 M
Assumed (Corrected) (HI) = (.612 + .373) (17.461) = \$17.2 M
Corrected (LO) = (.843 + .187) (17.461) = \$18.0 M
Corrected (HI) = (.843 + .373) (17.461) = \$21.2 M

MY:BB
302A.051089.148

RESPONSES TO THE MATANUSKA ELECTRIC ASSOCIATION, INC. LETTER DATED MAY 12, 1989

M-1 Regarding the possibility of reduced benefit for the Kenai-Anchorage line due to stability limits on transfer capacity, see reply to letter from Chugach Electric Association, item C-5.

Regarding the possibility of additional benefits due to maintenance down time of the existing Kenai-Anchorage line, see reply to letter from Chugach Electric Association, item C-4.

The calculations presented in Appendix-I of the MEA letter suggest three changes to the calculations of the value of unserved energy presented in the Draft Final Report: An increase in the reduction in the Kenai outages due to the proposed new Kenai-Anchorage intertie, an adjustment to the calculation of the customer outage costs, and a correction to Tables 4-7, 4-8 and 4-9 of the Draft Final Report. Regarding the reduction in the Kenai outages, further studies to be conducted by PTI will shed additional light on this subject. Regarding the adjustment to the calculation of customer outage costs, the Kenai Peninsula residential to industrial-commercial ratio used in the Draft Final Report includes the Kenai load served by CEA; this load was not accounted for in the change suggested by MEA, and therefore no change is needed. Regarding Tables 4-7, 4-8 and 4-9, we agree with the suggested correction (of an arithmetic error in the calculation of Kenai unserved energy saved by interties, Table 4-7) which increases the reliability benefits of the Kenai-Anchorage intertie from $8.8 million to $11.2 million (low estimate) and from $14.0 million to $17.2 million (high estimate).

M-2 The Power Authority agrees that operation of Bradley Lake at its intended level of output raises stability issues that require corrective measures. The intent of the statement in the text was not to suggest disagreement on this point, but to credit utility representatives with initiating detailed consideration of the subject. The text has been revised to state this more clearly.

The Power Authority representative on the TCC concurs with the PTI conclusions. As stated in the report on page 3-5, additional studies (including SSR/SSO studies) are needed to proceed with the recommended solutions whether or not a new intertie is constructed. These additional studies have now been commissioned by the Power Authority as part of the Bradley Lake project, and will be conducted by PTI.

M-3 The analysis assumes that all economic transactions will take place and that no uneconomic transactions will take place. Because the CEA/Marathon/GVEA agreement does not require that any uneconomic transactions take place, the analysis should account for all anticipated transfers.

As stated in response M-1, further studies to be conducted by PTI will shed additional light on Kenai outages that would be reduced by Bradley Lake.

As stated on page 4-12 of the report, we agree that the Kenai Peninsula will generally experience an outage under import conditions when the connection with Anchorage is broken. The issue of power restoration will require more detailed analysis in the future. As noted in the comment, PTI has observed that restoration from Bradley Lake alone may be limited only to those feeders supplying roughly 2 MW or less, without reducing frequency below the utilities' desired threshold. Several issues merit attention: 1) How much of the Kenai Peninsula load is supplied by feeders supplying 2 MW or less at the time of outage? 2) Is there a possibility for relaxing the frequency constraints temporarily in order to restore power more quickly? If certain industrial customers are separated from the system during this part of the restoration period, and larger temporary drops in frequency are tolerated as a result, then feeders above 2 MW could be brought back with Bradley Lake alone. 3) There appears to be a way to bring back substantially more than 2 MW per feeder using Bradley Lake alone if it is worth wasting some water for several minutes. This would involve opening the needle valves and running in the deflector before bringing on a relatively large feeder. When the feeder is restored, the deflector responds quickly by pulling back rather than relying on the needle valves.

M-4 A more detailed unit commitment/economic dispatch analysis may reveal more benefit or less benefit than estimated in Appendix H of this report. An expanded analysis on this issue would be informative.

M-5 As stated in section 6.6.2, we agree that future capacity will not be added in fractional increments, but that other aspects of the estimation methodology tend to compensate for this. The methodology could be improved if we knew: 1) which facilities would be "life extended" or repowered rather than retired; 2) the cost of life extension or repowering; 3) how closely the "planned retirement dates" are likely to conform with actual plant retirements; and 4) the type and size of unit that would actually be installed to replace each retired unit.

We assumed that combined cycle capacity would be used for base load requirements. In general, new interties would provide increased access to capacity surplus in adjoining areas. This surplus consists of generating capacity that would otherwise be idle or underutilized, and which is therefore assumed to be the least efficient capacity available in the adjoining area. A new intertie may allow this surplus to be used to satisfy reserve requirements, or for peaking or intermediate load requirements. It is unlikely, however, that such surplus would be used to satisfy base load requirements. As a result, we concluded that increased access to such surplus would not allow the deferral of combined cycle capacity, but would allow deferral of combustion turbine capacity.

Regarding the impacts of increasing the capacity cost of a combustion turbine from $ 39 per kilowatt per year to $ 47 per kilowatt per year, please refer to the response to CEA's letter.

M-6 Regarding hour to hour dispatch benefits, please refer to item M-4 above.

On the issue of reserve scheduling, the comment appears to be based on the idea that the estimated 30 MW of spinning reserve imported from the Kenai Peninsula is calculated as the 60 MW transfer limit of the existing line minus an estimated 30 MW of average power flow due to thermal reshaping. If this were so, then the new line would allow additional spinning reserve to be scheduled from the Kenai Peninsula because of increased line transfer capacity. However, that is not how the 30 MW of spinning reserve was calculated.

As discussed briefly in section 7.2, the 30 MW of spinning reserve scheduled from the Kenai Peninsula is based on the total amount of spinning reserve required in Anchorage, examination of the units that typically provide the reserve, and the practice of distributing these reserves for improved reliability. In reviewing our analysis in this area we continue to believe that 30 MW is a reasonable average amount of spinning reserve desired in Anchorage from Kenai. We also agree that a more detailed analysis might identify benefits of greater line capacity because the 30 MW of available capacity that we estimated for the existing line results from averaging amounts both higher and lower than 30 MW.

On the other hand, as discussed in our reply to Chugach Electric (item C-5), the stability limit of the existing line is estimated by PTI at 90 MW input rather than 75 MW input (15 MW higher than assumed in our analysis). Although it may be desirable to limit routine transfers over the line to 75 MW (input), there appears to be no reason to forego the additional 15 MW capacity for purposes of spinning reserve. Further, the stability limit does not prevent transfers above 90 MW (input), but suggests that such transfers be of limited duration primarily for emergency purposes. The transfer limit of the existing line for estimating access to Kenai spinning reserve may therefore be substantially higher than 90 MW.

Also, this entire benefit category is based on the idea that spinning reserve from Bradley Lake can and will be substituted for spinning reserve from gas-fired units, an uncertain assumption because the gas-fired units are much faster in responding to load changes. A decision has not yet been made by the Railbelt utilities on whether or to what extent Bradley Lake will be designated to supply a portion of spinning reserve requirements.

Regarding the impact of a new intertie on the spinning reserve issue, the unresolved questions appear to be as follows:

1. Will Bradley Lake be used to supply some portion of spinning reserve that is currently supplied by gas-fired units? If so, the cost of spinning reserve could decline substantially, although reliability could also decline (i.e., average annual outages could increase) because of the slower response time.

2. What level of transfer capacity for the existing intertie should be assumed in determining access to Bradley Lake spinning reserve? This level may be above 75 MW (input), and may be above 90 MW.

3. To some extent, might Bradley Lake be designated to supply spinning reserve if a second intertie is built (despite Bradley Lake's slower response time), but not if the existing line remains the sole connection (regardless of the existing line's transfer capability)? During conditions of power import from Kenai to Anchorage and with the existing line only, Anchorage may wish to keep spinning reserve in gas-fired units at a level no lower than the amount of power import. The purpose of this approach would be to mitigate outages in Anchorage caused by failure of the existing line during Anchorage import conditions. With the addition of the new line, failures of the existing line would not cause Anchorage outages, and Anchorage may therefore be willing to keep more of its spinning reserve in Bradley Lake during Anchorage import conditions.

Municipality of Anchorage
Tom Fink, Mayor

Municipal Light & Power
1200 East First Avenue
Anchorage, Alaska 99501-1685
(907) 279-7671, Telecopiers: (907) 276-2961, 277-9272

June 9, 1989

RECEIVED
JUN 09 1989
ALASKA POWER AUTHORITY

Mr. Robert LeResche
Alaska Power Authority
701 E. Tudor Road
Anchorage, Alaska 99504

Subject: ML&P comments on the draft final report entitled "Railbelt Intertie Feasibility Study"

Dear Mr. LeResche:

ML&P has previously commented by various means about specific aspects of subject report. At this time we will confine our remarks to general methodological considerations.

MLP-1 We believe a great deal of excellent work went into preparing the various elements of this report and want to give credit to some of the very innovative solutions advanced to complex tieline stability and reliability problems. Unfortunately, when some of these solutions were integrated into the final model no recognition was given to the fact that the operational success of some of the solutions were problematical. Therefore, the Study results in some areas combining both facts and hopes. The consequence of this is that certain of the reports conclusions are suspect.

MLP-2 To a considerable degree this problem could have been prevented by appropriate peer review and assignment of probabilities of operational success of the various technological fixes proposed. Unfortunately, some of the problems and uncertainities come from weaknesses or possibly outright deficiencies in the Bradley design itself. To illustrate this please consider that at the time of this writing consideration is being given to relaxing a contractual stability criteria for the Bradley units governor because there is concern that the unit, as designed, cannot meet the requirement. To my knowledge every other operational railbelt generating unit could easily meet this same requirement. Whatever the outcome of this particular situation it demonstrates that we are still not able to accurately predict how this unit will perform or what is required to solve the stability and reliability problems.

Thank you for the opportunity to comment on this draft report.

Very truly yours,

Thomas R. Stahr

Thomas R. Stahr
General Manager

xc: B. Petrie
D. Emerman
M. Isaacs
D. Shira

Putting Energy Into Anchorage

RESPONSES TO ANCHORAGE MUNICIPAL LIGHT & POWER LETTER DATED JUNE 9, 1989

MLP-1 According to PTI, the only element of their stability recommendation that represents an innovation is use of a computer to control the operation of the braking resistors at the Bradley Lake project. Virtually all systems are unique in their specific configuration, but braking resistors, series capacitors, and SVS are neither unique nor unconventional.

MLP-2 PTI has been commissioned to perform additional studies. These will include simulations and tests that integrate the system stability aids with the actual governor design to confirm system response.

COPPER VALLEY ELECTRIC ASSOCIATION, INC.

P.O. BOX 45 GLENNALLEN, ALASKA 99588-0045

Glennallen	(907) 822-3211
Valdez	(907) 835-4301
Telefax #	(907) 822-5586

June 7, 1989

Mr. Dick Emmerman
Senior Economist
Alaska Power Authority
P.O. Box 190869
Anchorage, Alaska 99519-0869

Subject: Railbelt Intertie Feasibility Study - Draft Final Report

Dear Mr. Emmerman:

Thank you for the opportunity to submit comments for incorporation into the Railbelt Intertie Feasibility Study Final Report. The realization of this project holds great potential for the Copper Basin and a large portion of Interior Alaska.

The current cost of power continues to stifle growth in our area, and completion of the Northeast Intertie has the potential of lowering rates to a level where economic growth could occur. According to the study completed by Power Engineering, our electric rates projected to 2005 will be in excess of $.25/Kwh. The Northeast Intertie is one way to avoid these increases. We have included a copy of this analysis for your information.

In realizing the importance of the Northeast Intertie, several letters of support have been presented. Attached please find CVEA Resolution 88-33, ARECA Resolutions 88-3, 89-3-1 and a letter from the City of Valdez dated June 2, 1989. Each of these items indicates the importance of the Northeast Intertie to our area.

The final cost benefit ratios as presented in the draft report for the Northeast Intertie are less than favorable, yet our feelings are that the potential benefits have been understated and the costs have been overstated. The estimated cost includes $22 million of contingency alone. This is significant. Overstating costs as well as understating benefits may provide a conservative outlook for the project, while possibly crippling our chances for growth in our area attributed to low electric rates.

We must therefore go on record with our support for this project and with our concerns relating to the overstatement of costs and the understatement of benefits.

Sincerely,

R.D. (Doug) Bursey
General Manager

Enclosures

c:\wp50\me\89-33.me

RESPONSES TO COPPER VALLEY ELECTRIC ASSOCIATION, INC. LETTER DATED JUNE 7, 1989

Please note that a copy of the subject letter from Copper Valley Electric Association has been included in the Northeast Intertie design and cost estimate study along with the various supporting resolutions that were attached to the letter.

Contingency allowances are included in all of our construction cost estimates in recognition of the fact that planners can rarely anticipate every cost or problem that is likely to arise. If contingencies are appropriate in final construction budgets, they are even more appropriate in preliminary cost estimates such as those developed for this study. Further, the intensity of public concern regarding Northeast intertie routing issues suggests that the project would be subject to numerous revisions and adjustments to accommodate land use and environmental constraints, which means that a contingency allowance is particularly appropriate for this project.

A related comment regarding project costs was offered by Copper Valley in oral testimony provided to the Power Authority in early June. The comment was that annual O&M costs for the Northeast intertie were likely to be less than the level assumed in this analysis (i.e. 1.5 percent of the project construction cost). In support of this position, the Copper Valley representative noted that annual O&M costs for the existing line between Glennallen and Valdez were running well below 1.5 percent of the construction cost. What we wish to note here is that the 1.5 percent estimate includes not only routine O&M costs but also an allowance for major repairs and replacement of damaged or worn components. For example, in the case of the existing line from Glennallen to Valdez, it will cost about $1.7 million this year to repair avalanche damage incurred last winter. The 1.5 percent O&M cost estimate is intended to cover these costs as well as routine O&M costs.

USIBELLI COAL MINE, INC.
MARKETING
122 First Avenue
Suite 302
Fairbanks, Alaska 99701
(907) 452-2625
FAX 451-6543

May 8, 1989

Alaska Power Authority
P.O. Box 190869
Anchorage, Alaska 99519-0869

Attn: Richard Emerman, Project Manager

Re: Comments to Draft Final Report
Railbelt Intertie Feasibility Study

Dear Mr. Emerman:

In general, the report was difficult to follow, which was probably due to the complexity of the subject. Attempting to compare, on an equal footing, such a diverse group of alternatives is probably an exercise begging for confusion. Compounding the difficulty of making like comparisons between projects is the fact that varied starting points and project paths exist. Comments made herein are therefore based, to the degree possible, upon information contained in the report, to avoid introducing new variables into the picture.

Page 1-11, 50 mw coal fired power plant.

U-1 It is unclear whether or not the fuel cost is included in the computation of life cycle cost. The magnitude of the costs would seem to indicate not but the fact that it is explicitly stated in this section, but not for other alternatives, raises the question. If the cost of the coal fuel is used in the computation of life costs in the coal option then it should also be included in the other alternatives.

U-2 The figure used in the interim report of $0.99 per MBTU is more likely than the $0.85 number used in this report (reference comments submitted on the interim report).

U-3 The fixed O&M cost of $5.6 million equates to a cost of about $112.00 per kilowatt. Table G-2 on page G-7 states the fixed O&M at $58.16 per kilowatt. Why the increase?

There are several benefits to the coal plant which are missing or understated:

U-4 The text of the report seems to indicate that lower fuel cost benefits are derived from substitution of gas as the primary fuel. The Healy plant would improve overall system performance and thus the total transmission capability to Fairbanks would be increased. The Healy plant would therefore permit avoidance of oil fired electricity generation.

U-5 No benefit is computed for increased employment as a result of the coal plant, which I believe would be greater relative to the rest of the alternatives.

U-6 Once the cost of the coal plant is sunk, consumption of power from the plant would primarily be governed by variable costs and fuel. It is therefore likely that the Healy plant would be operated entirely as a base loaded unit transmitting power both north and south and the benefits would be tied to the plants output and not to the Fairbanks area demand. If power is being transmitted both directions from Healy then transmission losses in the system would be reduced even further.

Page 1-12 Gas pipeline between Cook Inlet and Fairbanks

U-7 Inclusion of benefits outside of the electric power sector places the gas pipeline option in a scenario that is not comparable to the other alternatives. Although it makes sense to install a gas distribution system if the pipeline is built, the same could be said for other programs. For instance expansion of the electricity distribution system in Fairbanks would yield benefits through increased sharing of fixed generating costs. Investment in modern coal burning equipment at commercial and residential installations would also yield substantial benefits. In general, the computation of benefits should be limited to the electric power sector.

There are at least two costs associated with the gas pipeline options which are not addressed;

U-8 Retirement of existing oil and coal industries. Existing distribution, production and utilization facilities would need to be retired prior to their planned retirement date. Reduced consumption of coal and oil would increase the cost of those commodities and force switching to gas prior to the end of the equipment´s useful life. Salvage value of used coal and oil equipment in a market swamped with the same would be negligible.

U-9 Loss of income to the Alaska Railroad. The average freight price for coal shipped north on the Alaska Railroad is about $8.40 per ton for about 600,000 tons per year. The loss of income would therefore be about $5 million per year, much of which could not be recovered from other sources.

U-10 Loss of employment in the Fairbanks area. Employment in the production, transportation and power generation sectors in the Fairbanks area would be substantial and not likely be offset entirely by increases in other parts of the railbelt.

U-11 The above discussion of the gas and coal options underscores the difficulty of comparing such diverse alternatives. While the gas pipeline's benefits are limited to the railbelt, demonstration of new coal combustion technology at Healy could lead the way for use of that technology in other regions of Alaska, where benefits would be more pronounced than in the energy rich railbelt. Assessment of benefits outside of the railbelt is probably beyond the scope of this study.

Page 8-3 first paragraph.

U-12 As stated earlier, the coal plant would not back out the full 50 megawatts of gas generated capacity due to increases in capacity of the existing system.

Page 8-7 Table 8-3

U-13 The fixed O&M cost of $5.58 million per year equates to $111.60 per kilowatt. Page G-7 states the fixed O&M at $58.16 per kilowatt. ?

Page 8-8 Table 8-4

U-14 What was the assumed value of electricity for this table and what assumptions does the expected value relate to? What this table seems to say is that if the coal plant cost was zero then coal would still be a loser at the currently favored "low" gas price forecast. This appears to be in conflict with the benefit which is computed in the report for reductions in variable O&M and fuel costs.

Page 8-9 capital cost increment for steam to coal dryer

U-15 Installation of a coal dryer results in an equivalent power loss (heat and electricity) of about 8 megawatts, about 5 of which is attributable to heat loss. This equates to an equivalent "cost" of the steam generating system of about $3700 per kilowatt, more than the high case cost estimate. Since the steam generating system amounts to about one quarter of the plant cost, (see Stone & Webster report "Estimated Costs and Environmental Impacts of Coal-Fired Power Plants in the Alaska Railbelt Region", Table 7-10) an equivalent cost of about $1000 per kilowatt (or less) would seem more reasonable, or an incremental cost of about $5 million.

Page 10-5 Section 10.4

U-16 Does the assertion that system reliability would be improved include provisions for several weeks of gas storage capacity in Fairbanks? This condition currently exists in the form of coal stockpiles and should be figured in the gas option cost, if it is not already. Otherwise, Fairbanks could be faced with a supply disaster should an accident put the pipeline out of commission.

Page B-1 & 2 Crude oil price forecast.

U-17 Given the current price of crude oil, it would seem that at least the mid price forecast should be regarded as the most likely scenario.

Page B-9 Table B-11

U-18 If one assumes that the Mid price forecast is the most likely then gas may be flowing north only until the year 2015. Benefits of the gas line would therefore be felt for only about half of the study period. At the high cost of gas predicted beyond 2015, it is likely that coal would be a cheaper option for Anchorage area electricity and benefits of gas flowing south would be minimal, since a lower demand on Cook Inlet reserves would likely hold those prices down.

Page B-12 & 13

U-19 It is stated that the pipeline cost is avoidable and thus is deducted as a lump sum. From what?

If one makes the assumption that gas is being delivered to the Fairbanks consumer then the pipeline is already built and the cost is not avoidable. At a minimum, the fixed O&M costs of the pipeline should be figured in the delivered price. I question the validity that mine mouth coal costs and rail transportation costs are fully avoidable. The market for used railroad trackage, locomotives, stripping draglines, haul roads, sediment ponds, reclamation commitments, heavy equipment shops, coal tipples, etc. are extremely limited and not likely to yield enough value to cover the cost of demolition and transportation. If the wellhead price of gas is to be used in the benefit analysis then the cost of liquidating the assets of the alternatives should be added to the cost of the gas line.

Page C-2, second paragraph.

U-20 Doesn´t the middle case predict the price of oil at $18/brl?

Page I-2, first paragraph.

U-21 The statement that other promising options are not addressed in the study underscores the need to remove the benefits outside of the electric power sector from the gas line analysis.

Page I-5, last paragraph.

U-22 The statement that utilities would convert to gas in 1994 because the price of gas would be significantly lower than coal must assume that the present gas reserves are adequate to commit to long term supply agreements with the Fairbanks utilities. More likely, it would seem that the Fairbanks price would reflect the anticipated cost of new reserves, which escalates to well over the coal price by about the year 2005. The utilities' euphoria would be rather short lived.

Page I-18, first paragraph.

U-23 If political pressure is preventing conversion to gas by the military installations today, it does not seem likely that pressure will be less in 1999. As with the previous comment, the price advantage of natural gas will most likely have vanished by 1999.

Page I-29, Table I-2.

U-24 The use of a ceiling price for gas delivered to Fairbanks residential consumers of $1.56 per MMBTU seems much too low. It does not seem reasonable to predict that Fairbanks consumers will receive gas at utility rates which are about half of what Anchorage residential consumers are paying. This price is also half of what the marginal cost of new reserves is predicted to be in 2010 (Table B-5).

Thank you for this opportunity to comment on the draft report. If there are any questions or additional information needs regarding these comments, please feel free to contact me at the phone number on the letterhead.

Sincerely yours,

Steve W. Denton

Usibelli Coal Mine, Inc.
by Steve W. Denton
Engineering Consultant

RESPONSES TO THE USIBELLI COAL MINE, INC. LETTER DATED MAY 8, 1989

U-1 Only capital costs and fixed operations and maintenance (O&M) costs are accounted for in the "cost" column. The production simulation model calculates fuel costs and variable O&M costs for each scenario. Thus, for a given set of assumptions, the total fuel and variable O&M costs are calculated over the planning period for a generation system that includes the proposed coal plant and for a system that does not include the coal plant. The difference between these two scenarios in fuel and variable O&M costs is accounted for in the benefits column.

U-2 Comment noted. The $.85 figure was suggested by UCM in discussion on 3/1/89. The interim report comment was received a week later, and should have taken precedence.

U-3 Fixed O&M costs are taken from Table 7-11 of the Stone & Webster report dated November 1988 entitled "Estimated Costs and Environmental Impacts of Coal-Fired Power Plants in the Alaska Railbelt Region," reduced by 4 percent to convert from 1988 dollars to 1987 dollars. The $58.16 per kilowatt shown in Table G-2 is based on a 150 megawatt power plant. This is the most economic size on a unit cost basis, and formed the basis of the estimates used in the screening analysis described in Appendix G. The $5.6 million per year (roughly $112 per kilowatt) is also taken directly from Table 7-11, but is based on a 50 megawatt plant, the size selected for the detailed economic analysis.

U-4 As described on page 8-3, transmission losses would be reduced if energy were imported to Fairbanks from Healy rather than from Anchorage. The value of this reduction in transmission losses is accounted for in the analysis. In the absence of an intertie upgrade, the maximum import of energy into Fairbanks is dictated by system stability limits, which we assume are not changed by construction of the proposed coal plant.

U-5 For economic analysis of power projects, it has been the policy of the Power Authority not to attempt to characterize the impact of alternative power systems on regional employment, or to attach a particular value to any perceived difference in employment impact.

The impact of power supply alternatives on employment levels can be very confusing. For example, it may appear that the most expensive power supply option results in the greatest increase in employment while the most efficient option results in the least. The implication that is sometimes drawn from this is that the economy benefits the most from the most expensive power supply alternative. The indirect employment benefits that result from lower cost power are more difficult to quantify.

Further, the value of an identified difference in employment impact is equal to the amount that people (in this case, ratepayers and taxpayers) would be willing to pay for it. In other words, how much of an increase in electric bills or tax bills would Alaskans be willing to pay in order that an additional job be created within the economy? Without an answer to this question, we cannot compute a value for increased employment.

U-6 The proposed Healy plant was modeled with the capability of providing power both to Fairbanks and Anchorage, and its estimated output was therefore not constrained by Fairbanks demand. The estimate of transmission loss reduction is reasonable within the limits attainable through use of a long-run, multi-area simulation model.

U-7 The purpose of the analysis was to assess the economic feasibility of various proposals, not simply to compare them within a single dimension. The economic feasibility of a gas pipeline system cannot possibly be judged without assessing its impact on the residential and commercial heating markets.

U-8 As described on pages B-11 though B-13, it was assumed that the full delivered costs of coal and oil can be avoided to the extent that sales are reduced, although it is recognized that fixed cost components exist in the production and delivery of these fuels. As stated on page B-13, adjusting for these fixed cost components would reduce the benefits identified for projects such as the gas pipeline, assuming that the estimated value of gas remained unchanged. However, an argument could also be made that the value of gas should be set at its production cost or, perhaps, at its opportunity value in other markets. Either of these would probably be lower than the negotiated value of gas assumed in the analysis.

U-9 Again, as discussed on page B-13, coal transportation costs are assumed to be variable, consisting primarily of labor, fuel, and railroad cars which (if unused) can be leased or sold. All costs represent income to someone: still they are considered costs if they represent the consumption of economic resources. In this case, lost income to the Railroad represents a cost savings that is accounted for in the analysis as a benefit.

U-10 See response to item U-5.

U-11 We have not seen evidence that new coal combustion technology would be more appropriate than conventional technology outside the Railbelt.

U-12 See response to item U-4.

U-13 See response to item U-3.

U-14 There is no assumed value of electricity underlying the table. For a given set of fuel price and load forecast assumptions, the table shows (in part) what the capital cost of the 50 MW coal plant would have to be in order for the present value of total system costs to be equal for scenarios with and without the coal plant. For example, in the Low fuel price/Low load scenario, the table indicates that the capital cost of the coal plant would have to be minus $14.2 million for the economics to reach breakeven with the scenario that excludes the new coal plant. For the High fuel/High load scenario, the capital cost would have to be $79.7 million.

The explanation for the apparent conflict of these results with reduced fuel and variable O&M costs is found in the high fixed O&M costs of the coal plant. Although the fuel and variable costs of coal-fired generation are expected to be less than fuel and variable O&M for gas-fired generation, the fixed O&M of coal plants is higher than the combined fixed O&M and capital costs of gas plants. If the breakeven capital cost of the coal plant is zero, it means that the fuel cost, variable O&M cost, and fixed O&M cost of the coal plant is equal to the fuel cost, variable O&M, fixed O&M, and capital cost of the comparably sized gas plant.

The "Base Case Expected Value" is the probability weighted average of outcomes among the nine initial sets of assumptions (ranging from Low fuel/Low load with a joint probability of .30, to High fuel/High load with a joint probability of .08). See pages 5-4 and 5-5.

U-15 See attached reply prepared by Stone & Webster.

U-16 The estimate of improved electric system reliability does not depend on gas storage facilities, and no such facilities are assumed. Transmission failures that produce outages occur, on average, several times per year. In contrast, we assume that there would be very few, if any, accidents that would result in significant gas supply disruptions in Fairbanks over the useful life of the proposed pipeline. This difference in the assumed frequency of events supports the estimate of improved electric system reliability.

One or more such accidents could occur, however, even if their frequency is much lower than would be expected for electrical transmission failures. Remaining electrical supply would be available over the existing Anchorage-Fairbanks intertie, and also from any local generating facilities that continue to burn coal (e.g. the existing 25 MW Healy coal-fired power plant), or that are designed to burn either natural gas or fuel oil. In addition, existing diesel-fired reserve facilities may be maintained.

Contingency plans to respond to possible gas supply disruption outside the electric power sector have not been considered in this study, but may warrant attention should the gas pipeline project proceed.

U-17 The economic feasibility of all projects is reported for each fuel price scenario, should any reader prefer a focus other than the Power Authority's "expected value."

Note that the crude oil price forecasts are given in 1987 dollars. Under the Low scenario, the price of West Texas Intermediate (WTI) is estimated at about $17.00 per barrel in 1990 when expressed in nominal (1990) dollars. Under the Mid scenario, the WTI price in 1990 is estimated at about $21.50 per barrel in 1990 when expressed in nominal dollars. At this writing, the nominal WTI price is about $20.00 per barrel. In any event, these near term prices are of limited value in establishing long term price assumptions between 1994 and 2028, the planning period for this analysis.

U-18 As discussed on page B-5, fuel prices were held constant (in real terms) for most of the cases examined beyond the year 2010 "due to the low level of confidence attached to such distant forecasts." Because of this uncertainty surrounding fuel prices, the report covers a broad range of fuel price assumptions and also covers certain sensitivity cases, including two in which the price of gas is projected to escalate sharply after 2010 based on assumed increases in gas production costs.

If the gas production costs were to increase after 2010 as shown in the sensitivity cases, then the economics of coal-fired power generation would certainly improve during that time frame. However, as shown on pages I-6 and I-7, gas would continue to undercut delivered fuel oil prices in Fairbanks well beyond 2010, and therefore is estimated to produce continued benefit in Fairbanks outside the electric power sector.

U-19 The full capital and O&M costs of the proposed gas pipeline system are reflected in the "cost" column of the benefit/cost analysis. These costs are deducted from total benefits in order to calculate "net benefits."

The appropriate way to treat the fixed capital and O&M costs of the gas pipeline is in the form of a lump sum, i.e. these costs are incurred in full whether gas delivery through the proposed pipeline is high or low. To then add some or all of these costs into the assumed price of gas used for the system modeling would constitute double counting . The full costs of providing gas to Fairbanks consumers are accounted for in the analysis.

It is true, however, that the delivered price of gas that would be faced by Fairbanks consumers would probably include the O&M costs and a portion of the capital costs of the pipeline system, which has implications for the estimated rates of conversion to natural gas. This issue is discussed in some detail on page I-12.

Regarding the issue of "avoidable" costs for coal, oil, and gas, see answer to U-8.

U-20 The middle oil price scenario does reflect $18 per barrel in 1990. However, the middle case for the population forecast represents the approximate mid-point of a probability distribution constructed from a lengthy series of population projections. There are a number of distinct cases that cluster around the mid- point, some that are based in part on the "Low" oil price scenario and others that are based in part on the "Mid" oil price scenario. The case that was selected to typify a 50th percentile projection incorporated the "Low" oil price. This is fully described in "Economic and Demographic Projections for the Alaska Railbelt: 1988-2010" by the Institute of Social and Economic Research, August 10, 1988.

U-21 See response to U-7. Weatherization of buildings in the Fairbanks area was identified for evaluation within the scope of work, but such evaluation was not accomplished due to time and budget constraints. Further investigation would be appropriate.

U-22 The analysis does assume that gas reserves will be consistent with the price outlook for each scenario (e.g., it is assumed under the Low price scenario that gas reserves will be consistent with the Low price outlook). The maximum annual Fairbanks area gas demand assumed in the analysis is less than one-tenth the current annual consumption of Cook Inlet gas. It is assumed that this additional demand would not be enough to appreciably affect wellhead gas prices.

We assume that if the cost of producing new reserves were to increase in the manner suggested in the ICF analysis, that all Cook Inlet wellhead prices would increase in the amount necessary to cover those costs (although the average wellhead price may lag behind the marginal production cost for several years). This would occur regardless of the ultimate destination of the gas. However, for all of the base case scenarios, the cost of producing new reserves is not assumed to increase in the manner suggested by ICF.

U-23 The assumption is that the economic logic of conversion would ultimately lead to that decision, although the decision process might require several years. The economics of conversion would continue to be favorable in 1999 under the Low price scenario.

U-24 See responses to U-19 and U-22.

STONE & WEBSTER ENGINEERING CORPORATION

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ENGLEWOOD, COLORADO 80111

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May 25, 1989
J.O. No. 17898.01

Mr. Richard Emerman, Senior Economist
Alaska Power Authority
701 East Tudor Road
Anchorage, Alaska 99519

COMMENT RESPONSE
ALASKA RAILBELT COAL
PLANT COSTS AND IMPACTS STUDY

Stone & Webster Engineering Corporation (Stone & Webster) has reviewed the telecopy you sent us, dated May 11, 1989, which included the comment by Usibelli Coal Mine, Inc. (UCM).

Stone & Webster interprets the comment as follows:

The first part of the comment identifies that 5 MW of equivalent electrical power is required by the coal drying process in the form of heat. Based on an incremental capital cost of $18.4 million, this results in $3,700 per kilowatt.

Stone & Webster's response to the first part of the comment is that 84.5 MBtu per hour of heat in the form of high quality steam to the coal drying process could result in anywhere from 7-10 MW of equivalent electrical power. This would result in a dollar per kilowatt value significantly lower than the $3,700 per kilowatt presented by the comment.

The second part of the comment attempts to arrive at an incremental capital cost from another perspective. The comment assumes that the entire impact on costs is in the steam generating equipment only. Since steam generating equipment costs account for approximately 25% of the total construction costs per Stone & Webster's report, Table 7-10, the incremental cost should be $1,000 per kilowatt and not $3,700 per kilowatt.

In response to the second part of the comment, the incremental capital cost for the cogeneration facility was estimated to be $18.4 million. Reference page 8-9 of the Railbelt Intertie Feasibility Study. Only half of this is the cost for steam generator related equipment. The other half is plant equipment such as air/gas draft systems, fuel handling, ash handling, and balance of plant systems/facilities. Therefore, the argument that only the steam generating portion is impacted is not valid.

Other issues which would impact the cogeneration plant incremental costs include:

- If the low power plant cost estimate was used rather than the high cost estimate, the incremental capital costs would have been proportionately less.
- The assumption of the use of superheated steam for coal drying drives the cogeneration plant costs up. If waste heat is utilized for coal drying, the plant capital costs would be significantly lower.
- A reduced energy demand by the process, possibly due to the coal drying processes' ability to generate heat internal to the process, would reduce the capital and O&M costs.

Please advise if we can be of further assistance.

SMRosendahl

S. M. Rosendahl
Project Engineer

SMR/TRO

Alaska State Legislature

Senate Advisory Council

P.O. Box V
State Capitol
Juneau, Alaska 99811
Phone: (907) 465-3114

May 5, 1989

Bob LeResche, Executive Director
Alaska Power Authority
P.O. Box AM
Juneau, AK 99811

RE: Railbelt Alternatives Draft Study

Dear ~~Mr. LeResche:~~ Bob

Based on a review of the recently published Railbelt Intertie Feasibility Study, Draft Final Report dated April 1989 and my previous involvement with this issue, I would like to offer the following comments.

D-1 To begin with the procedural matters first, I believe that a certain amount of confusion has been created by the use of the generic term "feasibility" whereas the statutory project approval process uses the same term in a much more precise and constricted way. All ambiguity as to what was to be accomplished should have been eliminated with the legislative language in Ch.42 SLA 1986 amending the original tasking. Since there is no audit trail showing that the requirements of AS 44.83.177 and 179 (Reconnaissance study and OMB review) have been complied with before, or that an exemption/waiver was obtained, and based on what is addressed by the draft study, the only possible conclusion is that the document in fact represents the reconnaissance study envisioned by AS 44.83.177. What remains after the completion of the final reconnaissance study is APA Board action and OMB review for compliance with the requirements of AS 44.83.177 (b) and (c).

In accordance with 44.83.181, unless the OMB disapproves the reconnaissance study within 30 days the authority shall complete a feasibility study and a plan of finance assuming that it has the resources to do same. Most likely this would require legislative appropriations since in the past studies of this type have been accomplished through professional service contracts.

With regards to the substance of the draft report I would like to commend the APA for preparing one of the best reports of this type that I have seen, **and there have been a few!** Nevertheless, there are some areas of concern.

D-2 The first of these deals with the load forecasts. I continue to believe that these forecasts are too low and in fact some of the Railbelt utilities already report significantly higher actual growth in 1988. From the sensitivity analysis in the draft report it is obvious that the load forecast has a major impact on the results. I would therefore recommend that the final report contain an expanded sensitivity analysis utilizing higher load forecasts that are more reflective of our historical data. Tables and graphs dealing with loads should be expanded to include at least 10 years of historical data and in order to provide some perspective to the forecasts.

D-3 The second area of concern deals with the scenario on which the Anchorage - Kenai intertie analysis is based. Essentially, the new line is considered for construction in addition to the existing line. This scenario would probably produce less benefits than if a new intertie was built to replace the existing line. It seems to me that as a minimum this question should be explored in greater depth during the feasibility study phase of the process.

D-4 The third area of concern deals with the gas pipeline alternative. Specifically, I believe that the assumed conversion rates from oil to gas are overly optimistic. Many studies to date indicate that consumers have a much higher discount rates than analysts and that payback periods greater than one to two years result in substantially lower penetration rates. This would be especially true as the cost of the conversion moves into the $2000 range. I believe that the high conversion rates assumed in the draft report can only be achieved with large subsidies from the state or from the utility companies - a not very likely scenario given the budget deficits or the consumers desire to keep rate increases to absolute minimum.

D-5 The fourth area concerns the "technical" fixes to the existing lines. AS 44.83.187 (d) exempts additions or modifications needed to complete a project. If it is the decision of the APA that technical fixes are the appropriate solution to the problems then I would recommend that the exemption be clearly spelled in the findings.

In conclusion, let me add that your cover memo to the recipients of the draft study was very apropos.

With best regards,

Kurt S. Dzinich

RESPONSES TO MR. KURT S. DZINICH, SENATE ADVISORY COUNCIL LETTER DATED MAY 5, 1989

D-1 We have substituted the word "reconnaissance" for the word "feasibility" in the title of the document.

D-2 Appropriate graphs in the load forecast report by ISER, which constitutes one volume of the reconnaissance study, have been revised to include Railbelt energy requirements back to 1980. The table below is included here to provide further historical context:

RAILBELT UTILITY ELECTRIC ENERGY GENERATION*
(GWh)

Year	Southcentral Area	Fairbanks Area	Total Railbelt
1965	367	120	487
1970	700	222	922
1975	1353	452	1805
1980	2112	440	2552
1985	2939	509	3448

* From "Railbelt Intertie Proposal: Preliminary Economic Assessment," Alaska Power Authority, March 1987.

Note that the forecast of "energy requirements" presented in the ISER load forecast report does not include transmission losses, although such losses are included in the "energy generation" figures shown above.

The impact of higher load forecasts is evident from the sensitivity analyses reported in the text. For example, the net benefits of the proposed new Kenai-Anchorage line are inversely proportional to the load forecast largely because of

R1776b

the decline in capacity sharing benefits that accompanies the higher forecasts. On the other hand, the net benefits of the proposed "full upgrade" of the Anchorage-Fairbanks intertie are directly proportional to the load forecast.

We have attempted to base the population, employment, and electric load forecasts on explicit sets of planning assumptions approved to the extent possible by the Power Authority Board, rather than on extrapolation of historical growth. Load forecasts that are significantly outside the range examined in the draft report would not be accepted by the Power Authority at this time as a basis for planning and project recommendation.

D-3 Chugach Electric Association (CEA) is the owner of the existing line. We were informed early in the study process by CEA that their expectation is to maintain the existing line in sound operating condition for the indefinite future whether or not a new line is constructed that runs beneath Turnagain Arm. There are CEA retail customers along the route of the existing line, and they could not be served from the proposed new line.

One proposal has been suggested by another utility that would involve abandoning, and presumably dismantling, portions of the existing line, serving some customers with installation of remote diesel generators, and downgrading remaining sections of the existing line from 115 KV to a lower standard, perhaps 69 KV. The idea would be to take this action in the event that the new line were built. This type of action is conceivable though it would conflict with the general objective among utility engineers to seek redundancy within their systems and to upgrade, not downgrade, transmission links where possible. We would consider examining that assumption in any future studies only if CEA revised its position and expressed intent to take that action.

D-4 The issue of the conversion rate is discussed in the latter half of section I.2.4. The sensitivity analysis showed that assuming a 20 percent oil-to-gas residential conversion rate instead of a 40 percent rate lowers residential benefits by 9 percent. However, the effect on the total expected benefits of the proposed pipeline (including electric power system benefits) in the base case scenario is only 3.5 percent.

Should a conversion incentive program be necessary to achieve a significant conversion rate. The present value of the budgetary cost is estimated at $10 million. While this is a substantial sum, it amounts to approximately 5 percent of the estimated construction cost.

D-5 The stability recommendations discussed in Section 3 will be implemented as part of the Bradley Lake project. The Bradley Lake budget has been amended to include the costs presented in Table 3-1.

PETRO STAR INC.

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P.O. Box 56239
North Pole, Alaska 99705
Walt Schlotfeldt
President

June 7, 1989

Mr. Richard Emerman
Alaska Power Authority
P.O. Box 190869
Anchorage, Alaska 99519-0869

Dear Mr. Emerman:

I recently reviewed the "Railbelt Intertie Feasibility Study" (Draft Final Report, April 1989) and have outlined below several major issues of concern which I feel need to be addressed.

1. There are several faults with the CONCEPT of the pipeline. Assumptions were used but not explained.

P-1 (A) Why must the line be large enough to serve the current needs of Anchorage?

P-2 (B) Who will pay for cost overruns which are likely?

(C) Who will pay the O&M costs of the pipeline?

2. There are several potential problems with gas that are not adequately addressed.

P-3 (A) Will buried gas lines be dangerous in the shifting of permafrost?

P-4 (B) Will ice fog conditions worsen with the moisture which will be released from the gas?

P-5 (C) Should there be a failure of the line will <u>all</u> of the community be without heat and lights? During the winter months, what time frame should be allowed for "down time"? Is it safe for the entire community to be on one source of energy for heat and lights?

3. The report does not address the NEGATIVES in its cost/benefit analysis.

P-6 (A) What negative economic effects will be felt in the community and how do these measure against the benefits?

P-7 (B) Other industries may not be willing to invest here if the State is ready to go into competition with them.

P-8 (C) The cost of removing all of the tanks currently in use needs to be calculated.

P-9 (D) The report states that only 47% of the residential market will be served. What additional costs will be borne by the other 53%?

P-10 (E) What additional costs will consumers pay for refined product which is used as gasoline or diesel fuel?

4. There are some serious FAULTS with the conclusions.

P-11 (A) Comparing wellhead natural gas with a delivered fuel price is like comparing apples and oranges. <u>This makes the whole report SUSPECT</u>.

P-12 (B) The study only addresses Enstar's wellhead gas purchase price. If a smaller supplier is granted this distribution by APUC, then there probably would be a higher wellhead price because of the lower volume.

P-13 (C) The report includes no value for the negative economic consequences to existing industry. This further casts shadows on the report.

P-14 (D) The economic benefits are probably overstated. I find it highly unlikely that the benefits to electrical distribution, residential and commercial heat, the military and FMUS will all occur.

Electric	$119 million
Residential	225 million
Commercial	96 million
Military	68 million
FMUS	19 million
	$527 million

P-15 (E) No mention is made of the cost of using Enstar's pipeline or how this would be arranged.

P-16 (F) No analysis is done on the suggestion to set up a mini Permanent Fund to rebate to <u>all</u> energy users some of their energy costs from the <u>earnings</u> from a $230 million fund.

In conclusion, the gas line proposal is an ill-conceived idea with serious negative consequences to our community, most of which are not addressed by the APA. Gas availabiilty is a potential threat to the safety and security of our homes and businesses. The APA study does not do a fair job of evaluating all of the consequences of the proposed pipeline. The fairness of the State funding this pipeline to compete with industries which have made their investments in the community has not been addressed. It is unreasonable for the State to support this proposal.

I look forward to hearing from you and will be happy to discuss these issues with you at your convenience.

Sincerely,

Walt Schlotfeldt

Walt Schlotfeldt
President

WPS:pm:W.90607-1

RESPONSES TO THE PETRO STAR, INC.
LETTER DATED JUNE 7, 1989

P-1 The pipeline defined for the analysis was sized to accommodate the maximum expected daily requirement for natural gas in Fairbanks over the next 30 years. This is described in detail in section 4.0 of the study entitled "Estimated Costs and Environmental Impacts of a Natural Gas Pipeline System Linking Fairbanks with the Cook Inlet Area," by Stone & Webster Engineering Corp., January 1989. The economic study points out that this size would also be large enough to supply most of the present commercial and residential gas demand in the Anchorage area should the direction of flow ever be reversed. This observation was relevant to consideration of North Slope gas and its impact on the Anchorage-Fairbanks pipeline proposal.

P-2 The economic analysis compares the total estimated benefits of the pipeline with the total estimated costs, and makes no attempt to allocate those costs to different parties.

P-3 Please refer to the Stone & Webster report cited in P-1 above, pages 5-7 and 6-9. While permafrost requires special construction techniques, there is no evidence in the Stone & Webster report of any danger to properly installed pipelines.

P-4 Please refer to the Stone & Webster report cited in P-1 above, page 9-17 and also Appendix D, reply to comment by Fairbanks North Star Borough. It is expected that combustion of natural gas would produce additional ice fog in the Fairbanks area, but that its broad distribution over the area would not likely increase the severity of the ice fog situation along any highway or any specific area.

P-5 Failure of the line was not addressed in these studies. As stated on pages I-10 and I-11 of this report, it was assumed that 58 percent of residential households would ultimately have access to the gas distribution system, and that 95 percent of commercial floorstock outside the district heating system would also have access to gas. Whether these potential customers would be without heat would depend on the magnitude of the failure, the supply of gas that might still be deliverable on the Fairbanks side of the failure, and the existence of any back-up heating systems. Electricity can be supplied from Anchorage and from Healy over the Anchorage-Fairbanks intertie. No "down time" for the pipeline, i.e. no service interruptions for customers, would be expected. The issue of safety would require additional review in any further studies of the pipeline option. It may be noted that Anchorage was solely dependent on the Kenai gas pipeline for many years for its gas supply, until the new Beluga pipeline was completed a few years ago.

P-6 If switching from oil to gas results in a lower cost of energy, then the amount of that cost reduction would constitute a benefit to the consumer and to society. Switching also creates distributional effects as money is redirected from the oil business to the gas business. The fact that the oil business would lose income and employment in this scenario, and that the gas business would gain, does not affect the magnitude of cost savings in the provision of energy. However, these distributional effects are certainly real, and government may be in a position to decide that the economic benefit is not worth the disruption of existing businesses. This appears to be an issue for political determination.

P-7 State involvement may discourage some industries and encourage others. The extent of State participation in the economy again appears to be an issue for political determination.

P-8 The issue of tank removal was not considered in the analysis. We have been told that most people in the MatSu region who have recently converted from oil to gas have drained their oil tanks and left them in the ground. In response to this comment, however, we also determined that a legal requirement exists under the Uniform Fire Code that tanks must be removed if they have not been used for 12 months. The cost to remove a residential tank is apparently in the range of $350-400.

There are two reasons, however, why the net cost of tank removal may be considered less than this: 1) At some point, the consumer would have had to replace the tank anyway. If the tank were nearing replacement age, then the cost to remove it would have been incurred soon in any event. If the tank were new, however, the cost of removal would not otherwise be incurred for many more years. 2) To the extent that tank removal prevents leakage that would otherwise occur, environmental benefits would be realized. Part or all of the cost of tank removal may be compensated by the environmental benefit of preventing tank leakage.

P-9 No additional costs are assumed to be borne by those who do not convert, since the cost of delivered fuel oil is assumed to be primarily variable in the long run. Please refer to discussion on pages B-12,13.

P-10 As described above, no additional costs are estimated for these consumers since the cost of delivered fuel oil is assumed to be primarily variable in the long run.

P-11 As discussed in Appendix I, the costs of delivery were handled differently for the two fuels. For natural gas, the cost of delivery consists of the fixed capital cost and fixed O&M cost of the pipeline delivery system. These fixed costs are assessed against the gas alternative in the benefit/cost analysis. Delivery costs for fuel oil, however, are not fixed. As discussed on page B-13 of the report, these costs consist primarily of trucks and labor, costs that can be adjusted up or down in the long run in proportion to delivery volume. Consequently, the delivery cost of fuel oil is reflected in the fuel oil price, meaning that delivery costs increase and decrease in direct proportion to delivery volume.

P-12 The Enstar contracts are used as the best available guideline to establish the wellhead value of Cook Inlet gas over the analysis period. It is assumed that other purchasers of wellhead gas would face comparable prices. The base price recently negotiated by Chugach Electric with Marathon is lower than the Enstar acquisition price used in the gas pipeline analysis.

P-13 See reply to P-6 above.

P-14 Comment is noted.

P-15 There is no additional cost incurred in using the excess capacity that exists in Enstar's pipeline, i.e. no resources are expended for additional construction, maintenance, or operation in order to carry the additional gas. This is not to say that Enstar would not levy a charge for use of its pipeline, but this again would constitute a transfer (i.e. a redistribution) rather than an economic cost. In a regulated business, such a charge might reduce payments incurred by other Enstar customers.

P-16 The economic test for the pipeline as well as the other alternatives under review was to demonstrate a real internal rate of return in excess of 4.5 percent. Demonstrating a benefit/cost ratio above 1.0 at a 4.5 percent real discount rate is equivalent to demonstrating a real rate of return above 4.5 percent. The analysis therefore suggests that the gas pipeline would generate higher benefit than would a "mini Permanent Fund" investment approach assuming the real earnings rate for that fund was in the 4.5 percent range. The distribution of benefits under the two approaches would, of course, be much different, as would the level of uncertainty in the estimated return.

Chevron

Saupe Enterprises, Inc.
Jobber, Chevron U.S.A. Inc. **Products**
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June 9, 1989

Mr. Richard Emerman
Alaska Power Authority
P.O. Box 190869
Anchorage, AK 99519-0869

Dear Mr. Emerman:

Since I had to miss the first part of your hearing in Fairbanks last week, I appreciate the opportunity to provide written testimony on the A.P.A report. I will be brief.

I am very concerned because:

a) there are many unsubstantiated assumptions made.

b) some of the data apparently was provided by a firm most likely to receive the benefits of a huge State subsidy.

c) the negative impacts on existing infra-structures and businesses have not been considered.

d) the use of public money to compete against private investment will be a serious blow to existing and future private risk capital.

e) there is no analysis of the indirect "social" or "quality-of-life" costs associated with natural gas.

The failure of the A.P.A. report to address these areas has already resulted in barrage of wild promotional "hype" from certain quarters who want to see only one side of the issue.

We believe there are more questions raised than answered by this report, and would suggest that a complete, balanced, and thorough study be done before allowing conclusions to be drawn. It would certainly be imprudent for the State to commit to such a huge investment without consideration of <u>all</u> factors involved, and we suggest that a much more comprehensive study is necessary.

I'd be happy to discuss the above points in more detail if you wish.

Sincerely,

B.~~H.~~ Saupe'

RESPONSES TO SAUPE ENTERPRISES, INC. LETTER DATED JUNE 9, 1989

Comment on assumptions and data is noted, but contains no specifics to which we could reply. Please see response to letter from Petro Star, Inc. regarding other issues. We agree that an investment of the magnitude contemplated for the proposed gas line would warrant further review, though the analysis conducted in this study clearly suggests that the project has economic potential.

May 5, 198!

Alaska Pow‹uthority
P.O. Box 1!9
Anchorage,!ska 99519-0869

To Whom It' Concern:

This leг constitutes public comment from the Nelchina/deltna Community Corporation on the proposed Northeast ertie, the "Railbelt Intertie Feasibility Study" prepared fAPA by Decision Focus of Los Altos, California, and the "Alas?ower Authority Northeast Transmission Intertie Feasibili?esign and Cost Estimate Study Draft Report," prepared bwer Engineers, Inc., of Hailey, Idaho.

The NMC rsents the residents and interests of an area from the northern boundary of the Mat-Su borough east to the Lake Louise Ro‹ We are not "anti" or "pro" development, but we desire thll projects affecting our area be planned and implementeth care and attention to potential impacts. After examining above materials and "suggested route" of the Northeast ertie, we have to stand opposed to the project as planned.

We have bσeneral and specific concerns with the project.

The firsteral concern is that the project is being pushed through wdisregard for resident input and some apparently deliberatceptions. No meetings have been held north of the borough bary prior to the closing of this public comment period, augh legislators Leman, Larson, Menard, Shultz and Szymanskiıre told by APA in a April 13 letter that APA "attendedtings with concerned residents along the Glenn Highway".

We found about the project, the studies, and the closing of the commeıriod from a neighbor inside the borough. We had to request tocuments from APA and have had barely sufficient time to ene their contents. The common wisdom about the project rays it as something there was no need to be concernedıt because there would be no money to complete it. APA has bı willful participant in promoting such an attitude and discoıng comment on the intertie by their lack of public notice, pıularly in the Glennallen area.

Another cn is that the "Feasibility Study" for the entire intertie m, published in April, assumes 13 million dollars of benefithe CVEA/NE Intertie from selling power to the USAF Backscattoject. Basin residents were informed by CVEA and the USAF winter that the Backscatter would NOT be using power froA. There is no excuse for this 13 million dollar assumption to appear in the April report. The 29 million dollar cost over benefit figure already given for the line thus looks more like 42 million in the hole. Is there adequate justification for such an expenditure? The cost over benefit analysis also assumes the construction of a new oil refinery at Valdez, which the same APA study also calls "unlikely." Is APA giving us any kind of real estimate about the cost of this 273 mile long project?

The January study (Power Engineers) cites "improved service and rates" for CVEA members as one of the benefits of the proposed line. How is this to be accomplished in the face of the apparent debt load?

The studies themselves, while hefty and expensive, seem poorly written and based on faulty information. The April study calls all land use and environmental impacts "negligible" or "low", yet we see major conflicts with the route suggested. What are they comparing our impacts to? A city block in Los Angeles?

The January study which is concerned solely with the NE Intertie repeatedly quotes the 1986 USAF study for a Military Operation Area here. This study was essentially thrown out of consideration in 1987 because it contained such erroneous land use estimates and misrepresented environmental concerns.

A representative of DNR Fish and Game which NMC contacted in preparing these comments could not believe that APA would use such a document as the USAF study in any serious feasibility study.

Both studies state that the NE Intertie with its 230KVA lines on 100' towers will avoid habitations, recreation areas and specifically runways, yet the "suggested route" passes directly through the State Nelchina Recreation Area and passes within one quarter mile of three airstrips and within one half mile of three others. Three of these are commercial air taxi operations and another is the State owned Tazlina air strip. This is just along the 25 miles of the Glenn Highway that falls inside NMC boundaries.

Fish and Game has concern about a remote route for the intertie, so we are not proposing that you pursue such a route. Most of us depend in one way or another upon the preservation of habitat, so the concerns of Fish and Game are our concerns as well.

What we want APA to do is their homework. If we can be shown that this Intertie should be built, we would ask the thing to be routed so that it does not abrogate our livelihoods, our recreation, our natural resources or the future development of our community. The January study states that the "suggested route" presents "no impacts which cannot be migitated" (section VII-1), yet we see very severe impacts that cannot be migitated unless the route is altered, i.e. airstrips and float plane operations, proximity to residents.

There is very little said in either of the reports we examined about health hazards associated with these power lines. How close to habitations should a 230KVA line be placed?

We would also like to see a very carefully prepared EIS, using real data, approved by the state agencies who are the authorities in natural resource management, not a questionable military study. When impacts are stated as "negligible," "low," or whatever, we would like to know what the comparison is based on.

When the NE Intertie study (January 1989) refers to "Mile 105", they are referring to mile 105 of the proposed intertie, not yet in existence. This should be cross referenced in all future documents with highway mileposts, geographical or legal description so the public or other agencies (from who comments are supposedly being solicited) can more easily tell what area is under discussion.

It seems only fair that APA also publish their schedule for studies, public comment periods, and the specific timetable and procedure which is being followed for this project. What requirements have to legally be fulfilled before the NE Intertie is considered "approved"? Shouldn't public comment have been solicited before a 2.25 million dollar "Feasibility Study" was completed?

Will a lack of present funding start the approval process over, or will the project sit as written and be built if and when funds are available? We deserve answers to these concerns.

Sincerely,

Kahren Rudbeck

Kahren Rudbeck, President
Nelchina/Mendeltna Community Corporation
HCO 3 Box 8700
Palmer, Alaska 99645

KR/meo

cc: Sen. Jack Coghill
Rep. Dick Shultz
Rep. Bette Cato
Rep. Loren Leman
Rep. Ron Larson
Rep. Curt Menard
Sen. Jalmar Kertulla
Sen. Mike Szymanski
Bob Tobey, AK Fish and Game
Copper River Country Journal
Anchorage Daily News
Tolsona Community Corporation
Copper Valley Electric Association

Alaska State Legislature

SENATE

RECEIVED 5/1?/89

Official Business

P.O. Box V
State Capitol
Juneau, Alaska 99811

May 12, 1989

Mr. Bob LaResche
Executive Director
Alaska Power Authority
P. O. Box AM
Juneau, Alaska 99811

Dear Bob: & Suzanne,

I am enclosing a copy of a letter from Kahren Rudbeck relating to public comment on the Northeast Intertie project. I, too, was under the impression that public input had been solicited from all the residents along the Glenn Highway who would be impacted by the project.

I would appreciate it if you would reply directly to Ms. Rudbeck's concerns and copy me with your response.

Thank you for your attention to this matter.

Sincerely

J Kerttula

Senator Jay Kerttula

JK:pt
cc: Kahren Rudbeck
HCO 3, Box 8700
Palmer, Alaska 99645

Alaska Power Authority

State of Alaska

May 23, 1989

Ms. Kahren Rudbeck
President
Nelchina/Mendeltna Community Corporation
HCO 3 Box 8700
Palmer, Alaska 99645

Dear Ms. Rudbeck:

Thank you for your letter of May 5, 1989 regarding the Railbelt intertie studies. Your comment will be included in the set of final reports to be published this summer entitled "Railbelt Intertie Reconnaissance Study." In addition, I would like to reply to some of the points you have raised.

1. The Alaska Power Authority was asked by members of the Northeast Intertie Concerned Residents (NEICR) to meet with them, and the evening of April 11, 1989 was selected as a mutually agreeable time. As a result, Power Authority staff attended two meetings with Glenn Highway residents on that date; one at the Sheep Mountain Lodge with the Chickaloon Community Council and a second with the NEICR group at the Glacier View school. These meetings were arranged by the two local resident groups.

   Our study schedule anticipated that public meetings regarding all of the study elements would take place after the issuance of the draft report and prior to completion of the final report. The enclosed public meeting notice was sent to you earlier, and notes that a public meeting will be held in Glennallen on June 2, 1989, and in Palmer on June 5. It is our intention at these two meetings to focus on the routing alternatives for the proposed Northeast intertie.

   The Power Authority added the Northeast intertie proposal to our scope of work at the request of the utilities, and concluded in our draft report that its costs exceed its benefits. We are not trying to push the project through.

2. Regarding the electrical load forecast used in our analysis for the Copper Valley area, the complete text of that forecast supplied to us by the Institute of Social and Economic

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☒ P.O. Box 190869 701 East Tudor Road Anchorage, Alaska 99519-0869 (907) 561-7877

5856/968(1)

Research (ISER) at the University of Alaska is enclosed for your review. The issue with regard to the backscatter project is whether any of the power will be supplied from the utility grid. Even though Copper Valley Electric Association (CVEA) has withdrawn its bid, it is possible that some power would be purchased from the local utility by the winning bidder whether or not the Northeast intertie is built.

As described in the economic study and in the enclosed material from ISER, the project was analyzed using three alternative load forecasts, one of which reflected 100% on-site generation at the radar site (i.e. zero purchases from the utility grid). Because the probability of supplying power partially from the grid declined when CVEA withdrew its bid, we calculated what the "expected value" of benefits would be for the Northeast intertie if 100% on-site generation were assumed for all three alternative load forecasts rather than just one. This is the $13 million benefit reduction noted in the text. You are correct that, assuming the winning bidder would not purchase any power from the utility grid, the expected value of "costs over benefits" would decline further, from $29 million net cost to $42 million net cost.

The three load forecasts are labeled Low, Mid, and High. No additional load is included for the proposed Valdez refinery in either the Low or the Mid forecast. For the High forecast, it is assumed that the refinery is built but that the refinery supplies 100% of its own power requirements. However, the population impact of the refinery is also estimated for the High forecast, and an increment of residential and commercial load due to this population impact is estimated and included.

3. Discussion of rates in the January study was premature. On that subject, however, it would be expected that CVEA rates would go down if the State built the Northeast intertie with grants from the General Fund, since there would be no debt service in that case yet CVEA could reduce costs by supplanting diesel power with gas-fired power from Anchorage. On the other hand, our analysis indicates that overall savings would not be sufficient to compensate for project costs. Consequently, if the project were financed with market debt, rates overall would be expected to go up.

4. Your comments on environmental impacts, land use, and health hazards have been forwarded to Hart Crowser/Power Engineers (contractors for the Northeast intertie cost, route, and preliminary design study) for their information and review. The contractor will make a presentation and be available for discussion at the June 2 public meeting in Glennallen and at

the June 5 public meeting in Palmer. If the Northeast intertie project were to proceed to further stages of planning or ultimate construction, the Power Authority would be committed to thorough evaluation of these issues within a public process necessary to achieve any possible consensus. Although additional review is presently taking place regarding route alternatives and health issues, we do not anticipate additional funding in the foreseeable future to pursue these questions much further. This is based on my own assessment that the Northeast intertie proposal is unlikely to be pursued further anytime soon.

5. Regarding legal requirements needed for approval of the Northeast intertie, the first set of requirements is the State project approval process set out in AS 44.83.177 through 44.83.187. Briefly, this involves preparation of "reconnaissance" and "feasibility" studies by the Power Authority and approval of these studies by the State Office of Management and Budget and, finally, approval of the project by the Legislature. Presently, we have completed a draft reconnaissance study, which we anticipate issuing in final form this summer. Enclosed is a letter (including attachments) from myself to James Colver of NEICR regarding the project approval process.

   Should the Legislature ultimately approve construction of the Northeast intertie project, and if satisfactory project financing could be arranged, the next step would be to acquire right-of-way from State, federal, and local governments and from private landowners along the route. The federal government must perform an environmental assessment in conjunction with the right-of-way decision. If the federal environmental assessment concludes that there would be significant environmental impact, then a full Environmental Impact Statement (EIS) would be required. State and local government have their own procedures for approving or denying right-of-way applications, which include providing notice to affected residents and holding public hearings in the event of significant controversy. In addition, there would be numerous construction permits that would have to be obtained in conjunction with stream crossings, road building, and similar matters.

   Public comment is being solicited prior to completion of the reconnaissance study as required in the State project approval process.

   The negative economic findings of the reconnaissance study do not support advancing the process to the feasibility stage.

If the project were to proceed sometime in the future, the first step would be to revise the reconnaissance study that is now at issue.

I hope these remarks are helpful to you.

Sincerely,

Robert E. LeResche /snp

Robert E. LeResche
Executive Director

RE:REL:it

Enclosures as stated

cc: The Honorable Jay Kerttula, w/o attachments, Alaska State Senator

Alaska Power Authority

PUBLIC MEETING NOTICE

Alaska Power Authority
Railbelt Intertie Studies

Public comment is invited on the draft report of the Railbelt Intertie Studies undertaken at Legislative request by the Alaska Power Authority. The primary purpose of the studies is to assess the economic merit of various Railbelt Intertie proposals as well as alternative proposals including coal-fired power plants, a natural gas pipeline between Anchorage and Fairbanks and electric end-use conservation programs.

Public meetings to present the draft findings and take public comment will be held in the following locations:

5/30/89	Anchorage	Z.J. Loussac Library Public Conference Room
5/31/89	Fairbanks	Noel Wien Library Conference Room
6/1/89	Soldotna	Borough Administration Bldg. Conference Room B
6/2/89	Glennallen	Glennallen School Student Commons
6/5/89	Palmer	Cottonwood Elementary School

At each meeting a presentation of study results will be conducted from 7:00 p.m. to 7:30 p.m. Public comment will be taken from 7:30 p.m. to 9:00 p.m. Written comments can be submitted until June 9, 1989 and should be directed to:

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Copies of the draft report are available at the Legislative Information offices in Anchorage, Fairbanks, Soldotna, Glennallen and Wasilla or by contacting the Alaska Power Authority at the above address.