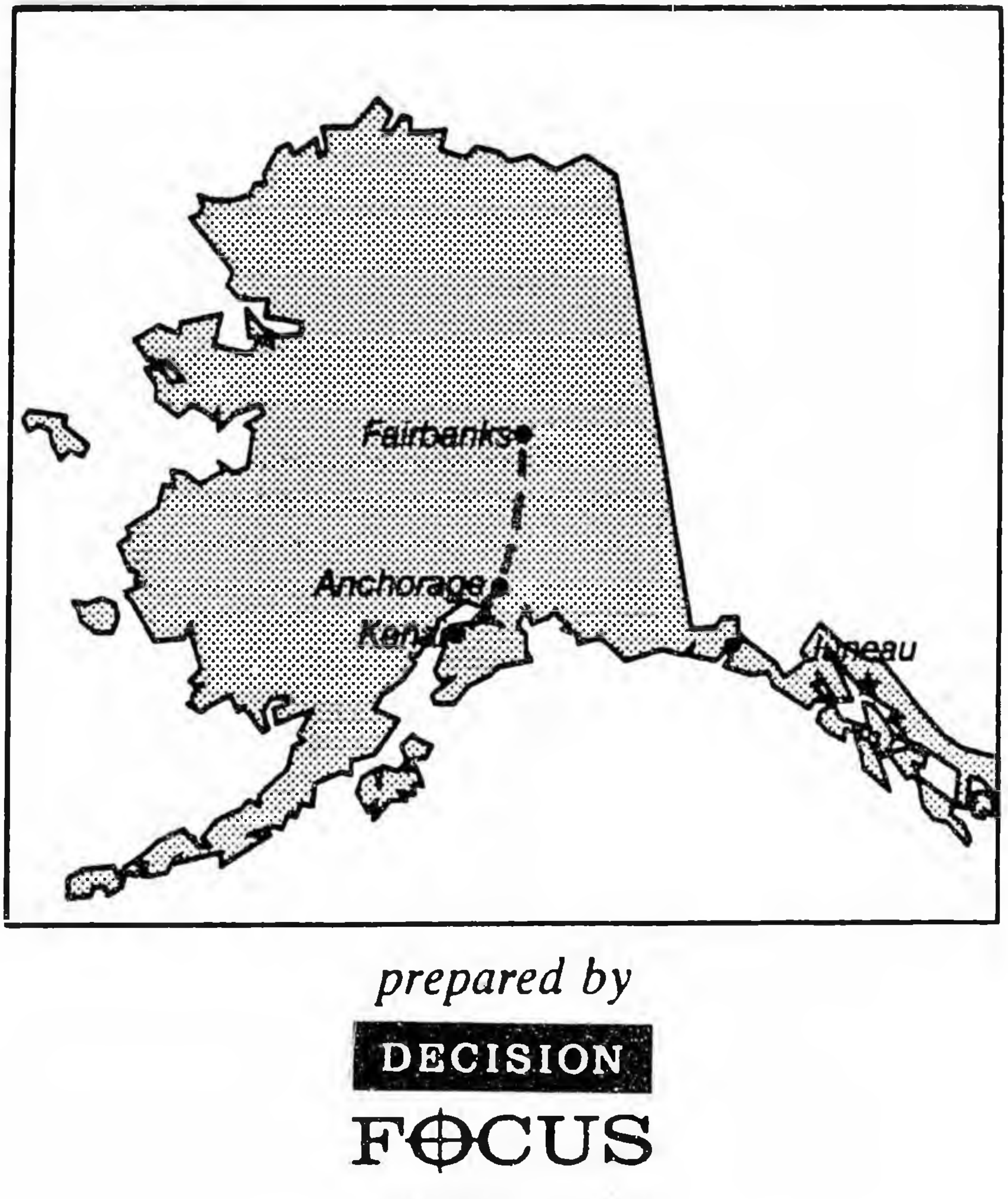
OVERVIEW - 138KV TRANSMISSION LINE

ECONOMIC FEASIBILITY
of the proposed
138 KV TRANSMISSION LINES IN THE RAILBELT

prepared for
Railbelt Electric Utilities



prepared by

DECISION FOCUS INCORPORATED

December 1989

ECONOMIC FEASIBILITY OF THE PROPOSED 138 KV TRANSMISSION LINES IN THE RAILBELT

Prepared for

Railbelt Electric Utilities

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December 21, 1989

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Section 1

INTRODUCTION

1.1 BACKGROUND

The Reconnaissance Study[1] prepared by Decision Focus Incorporated for the Alaska Power Authority (now Alaska Energy Authority) presented the costs and benefits of several intertie proposals suggested for the Railbelt. The study concluded that a new 230 KV line between Kenai and Anchorage, and a full upgrade of the Anchorage-Fairbanks line are not cost effective.

After the completion of the Reconnaissance Study, the Railbelt electric utilities proposed new downsized (138 KV) transmission lines between Kenai and Anchorage (southern line) and between Healy and Fairbanks (northern line). The northern line proposal would also include a limited upgrade of the Anchorage-Fairbanks line.

1.2 OBJECTIVE

The objective of this study is to assess the economic feasibility of the proposed Healy-Fairbanks 138 KV new intertie and the proposed Kenai-Anchorage 138 KV new intertie. The economic feasibility of the limited upgrade of the Anchorage-Fairbanks line is also evaluated. The purpose of this report is to present the results of the study.

1.3 REPORT ORGANIZATION

This report is organized similar to the Reconnaissance Study to facilitate the comparison between the costs and benefits of the proposed 138 KV interties presented in this study and the other alternatives (e.g., the 230 KV Kenai-Anchorage proposal and the full upgrade of the Anchorage-Fairbanks line) described in the Reconnaissance Study.

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[1] "Railbelt Intertie Reconnaissance Study, Benefits/Cost Analysis," prepared by Decision Focus Incorporated, for the Alaska Power Authority, June, 1989.

1.4 STUDY OVERVIEW

The assessment of the proposed transmission lines is focused on a comparison of their expected economic costs and benefits. Most inputs to this economic analysis such as fuel price and electric demand forecasts, were established by the Alaska Power Authority (now Alaska Energy Authority) and are reported in the Reconnaissance Study. New evidence and more detailed analysis of issues necessitated the update of several input assumptions. All changes and new estimates are documented in this report.

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

1. *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.

2. *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.

3. *Transmission Efficiency.* New, improved interties can produce savings to the extent that transmission losses are reduced. This is also presented in Section 5.

4. *State Revenue.* New, improved interties can lead to increased substitution of gas for oil and therefore to increased state revenues from increased gas royalty and severance taxes. 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.

1.5 SUMMARY OF FINDINGS

Table 1-1 shows the expected[2] costs and benefits for each of the three alternatives. Both the total and incremental (incremental over the limited upgrade of the Anchorage-Fairbanks line) costs and benefits of the Healy-Fairbanks intertie are presented.[3]

Table 1-1

RAILBELT ALTERNATIVES: COSTS AND BENEFITS

	Estimated Cost[a] ($1990 million)	Estimated Benefits[b] ($1990 million)	Benefit to Cost Ratio
New Kenai-Anchorage Intertie	74 to 86[c]	114 to 131	1.3 to 1.8
Limited Upgrade of Anchorage-Fairbanks Intertie	10	46	4.4
Healy-Fairbanks Northern Intertie			
• Total	64	106	1.6
• Incremental[d]	54	60	1.1

Notes:

a. Includes both capital and O&M costs
b. Present value of total benefits between 1994 and 2033 for the Kenai-Anchorage line and between 1994 and 2043 for the Anchorage-Fairbanks upgrade and Healy-Fairbanks line.
c. Includes replacement cost of submarine cable after 20 years of service.
d. Incremental over the limited upgrade of the Anchorage-Fairbanks line.

Figures 1-1 and 1-2 show the present values of net benefits and the benefit to cost ratios for the Kenai-Anchorage new intertie. Figures 1-3 and 1-4 show the present values of net benefits and the benefit to cost ratios for the limited upgrade of the Anchorage-Fairbanks new intertie. Figures 1-7 and 1-8 show the incremental present values of net benefits and the incremental benefit to cost ratios for the new Healy-Fairbanks intertie.

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[2] Unless otherwise noted, "expected" values are calculated for all scenarios assuming all scenarios have same probability.

[3] Unless otherwise noted, these and all other costs and benefits are presented in terms of 1990 dollars.

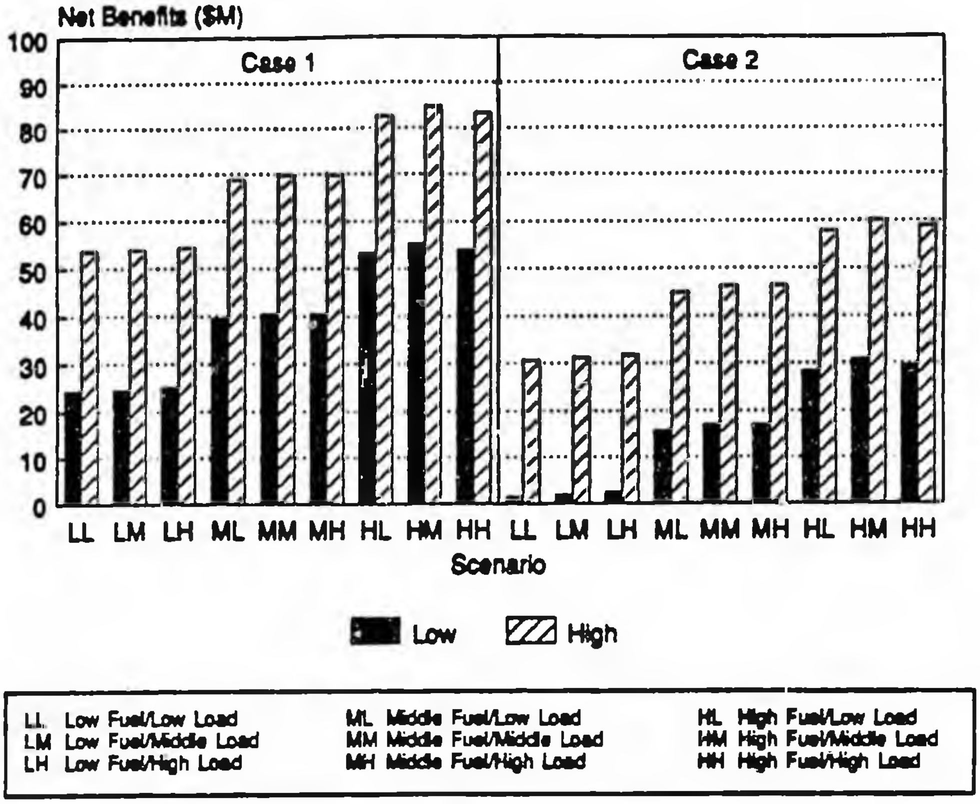

Figure 1-1. New Kenai-Anchorage Intertie: Net Benefits

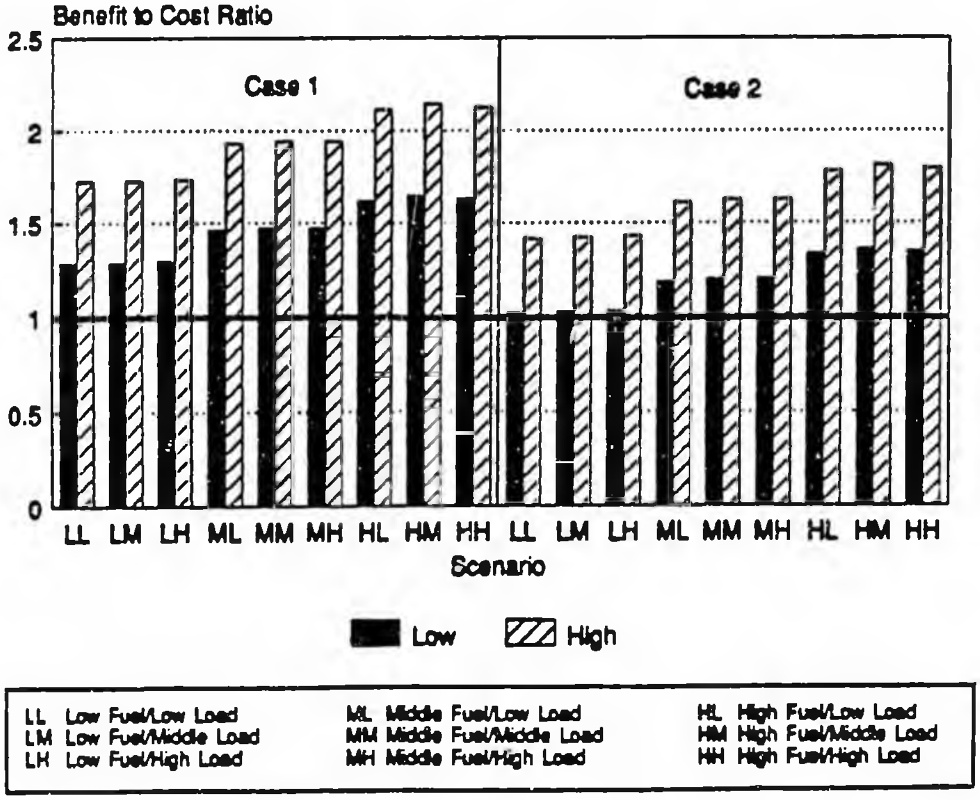

Figure 1-2. New Kenai-Anchorage Intertie: Benefit to Cost Ratios

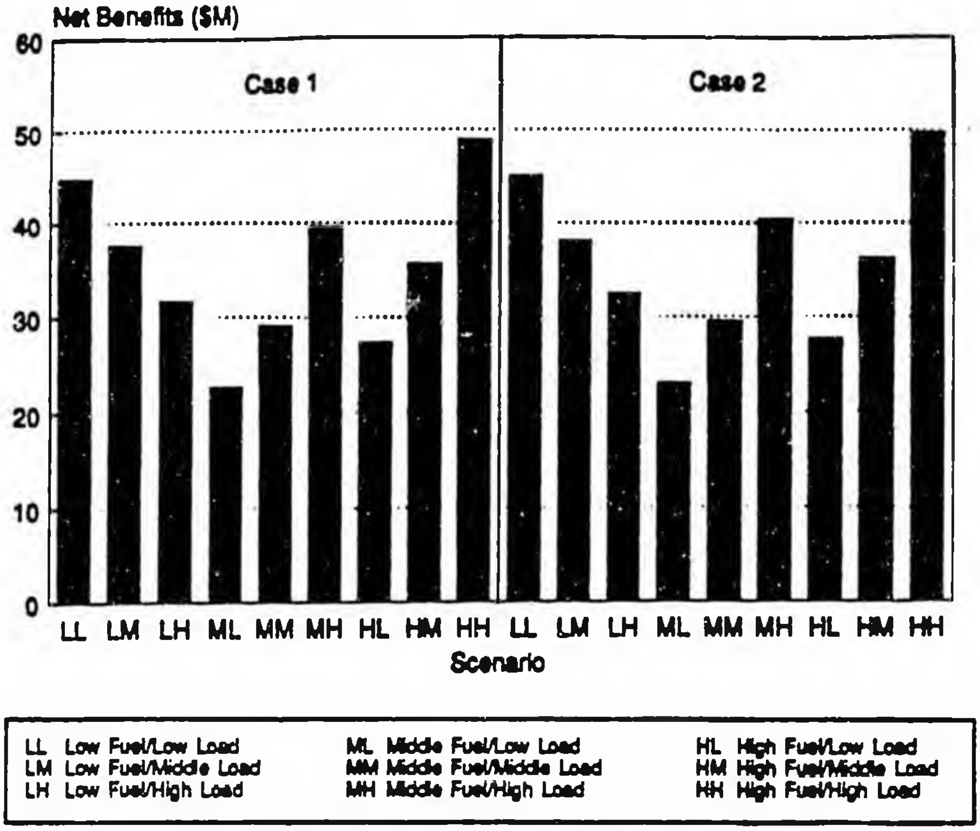

Figure 1-3. Anchorage-Fairbanks Upgrade to 100 MW: Net Benefits

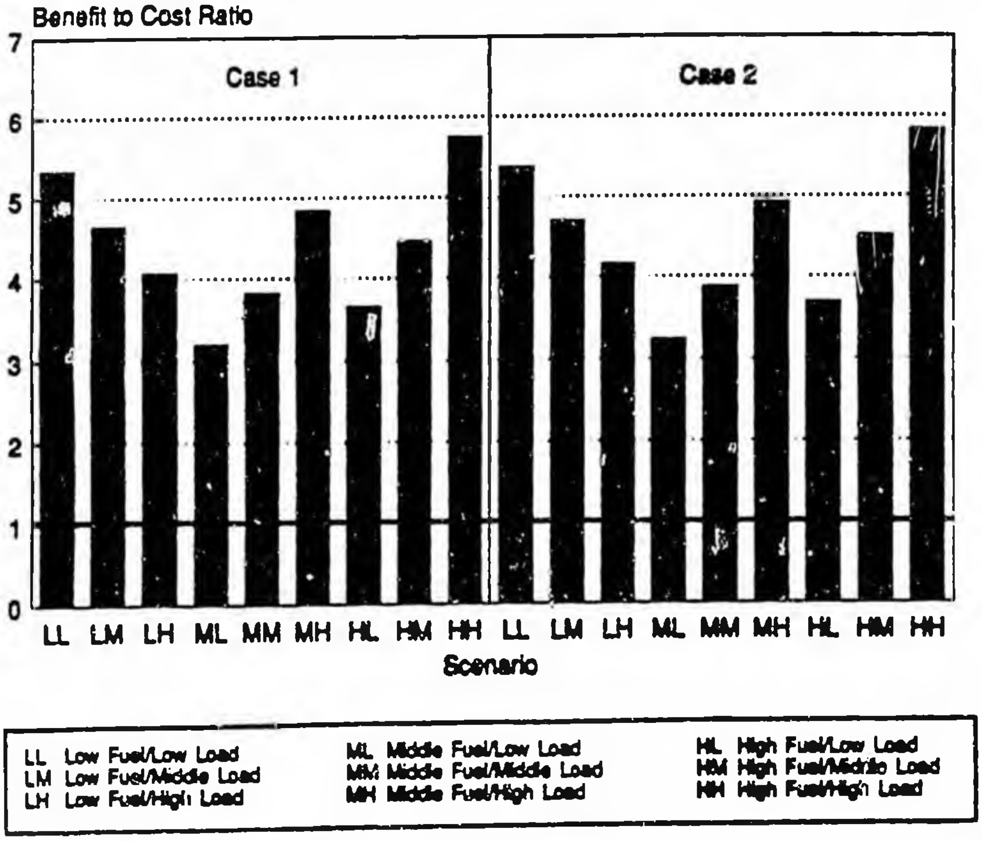

Figure 1-4. Anchorage-Fairbanks Upgrade to 100 MW: Benefit to Cost Ratios

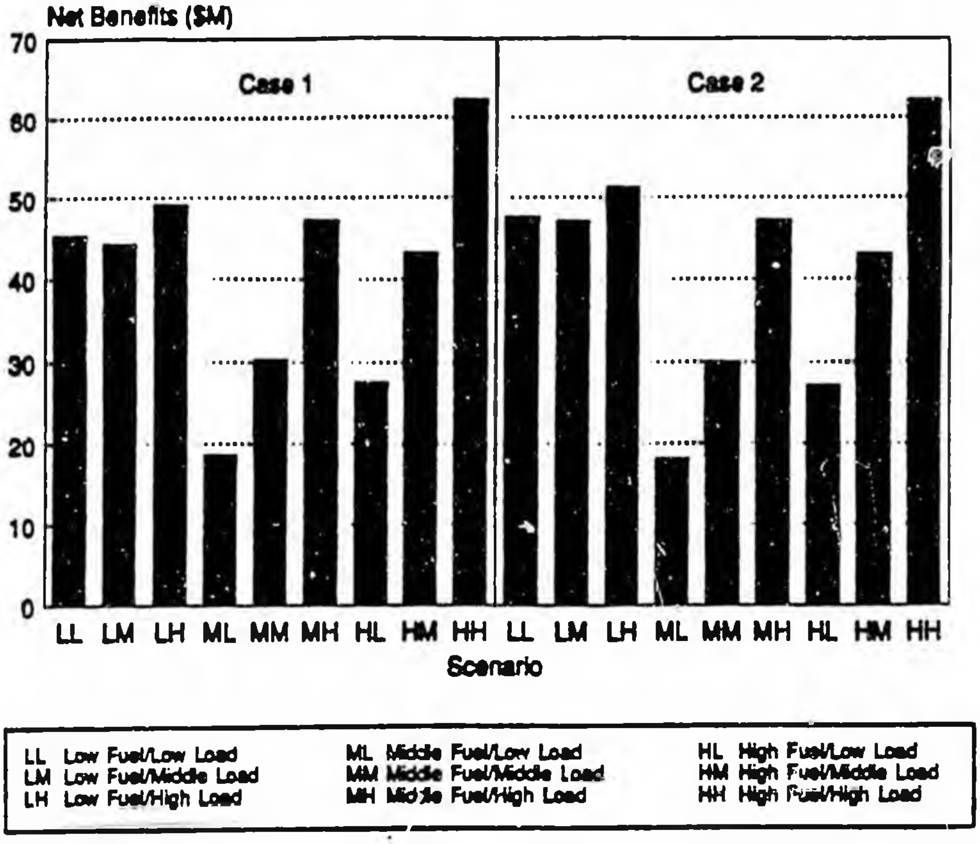

Figure 1-5. Healy-Fairbanks Northern Intertie: Net Benefits

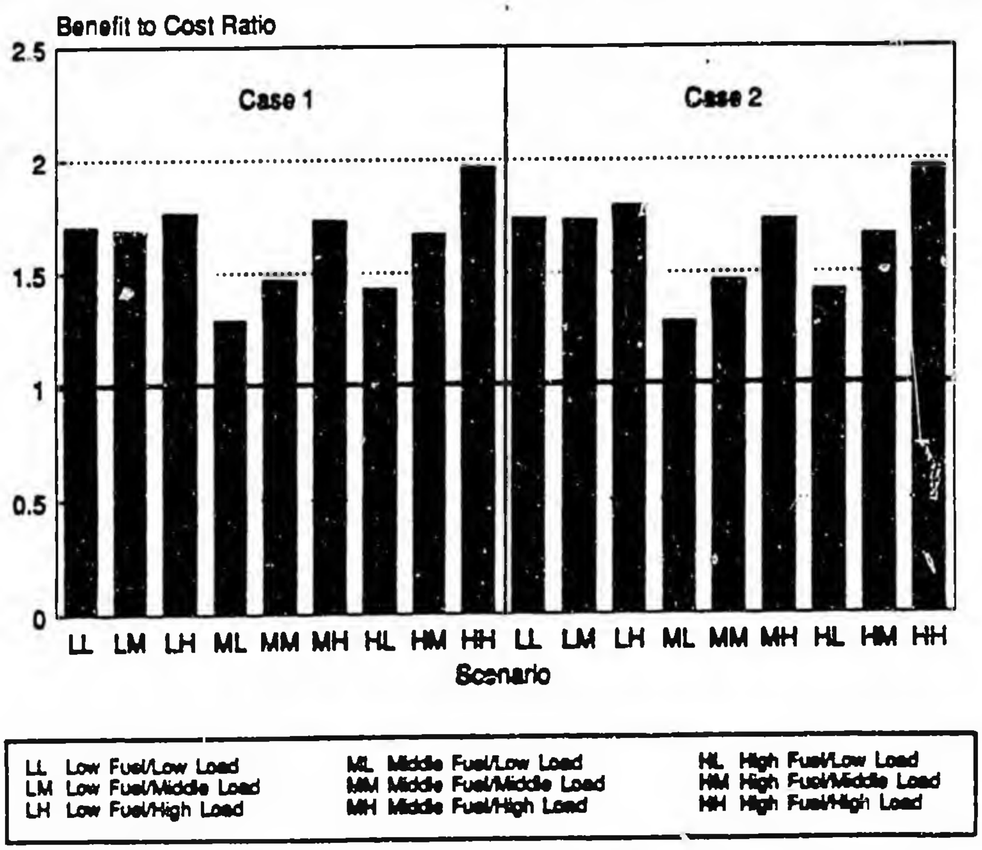

Figure 1-6. Healy-Fairbanks Northern Intertie: Benefit to Cost Ratios

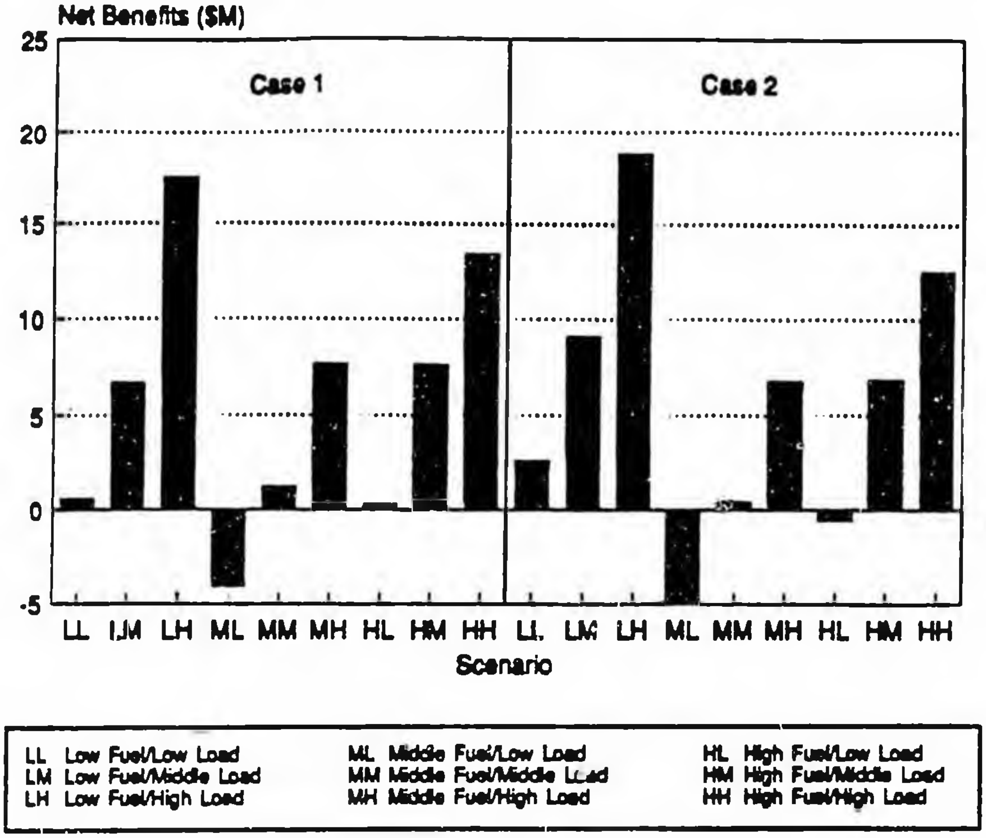

Figure 1-7. Healy-Fairbanks Northern Intertie: Net Benefits (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

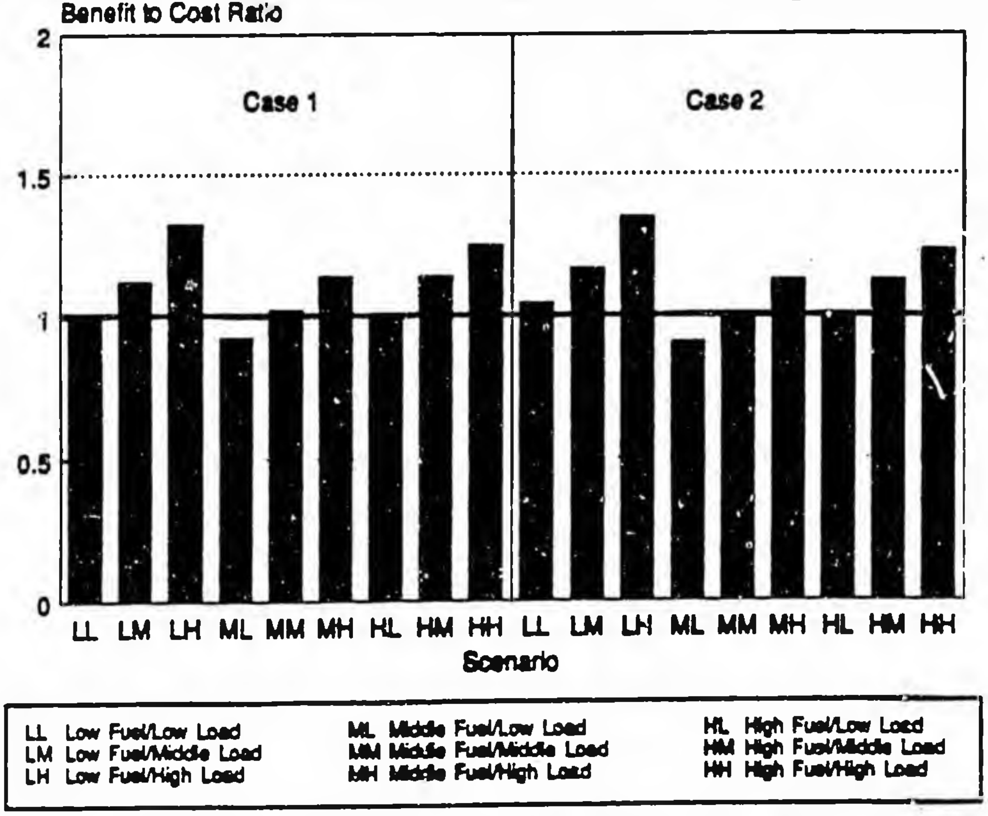

Figure 1-8. Healy-Fairbanks Northern Intertie: Benefit to Cost Ratios (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

1.5.1 New Kenai-Anchorage Intertie

This alternative consists of a new 138 KV transmission line between Anchorage and the Kenai Peninsula with a transfer capacity of 150 MW. The capital cost of the proposed Kenai-Anchorage intertie varies between $64.3 million (without replacement of the submarine cable) and $73.8 million (with replacement of the submarine cable). Operations and maintenance cost is estimated at $0.5 million per year. The present value of total costs is estimated at $74.1 million (without replacement of the submarine cable) and at $86.2 million (with the replacement of the submarine cable).

The expected value of benefits is estimated between $114.0 million and $131.3 million. This consists of the following benefits:

1. *Reliability*: The value of improved reliability due to the new intertie is estimated between $32.3 million and $49.6 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers between the Kenai Peninsula and Anchorage are estimated at $43.4 million adjusted for increased transmission losses and reduced gas royalty and severance taxes.[4]

3. *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 $24.4 million.

4. *Increased Spinning Reserve Sharing*: Improved access to Kenai Peninsula spinning reserves is estimated to produce a value of $8.9 million.

5. *Reduced Maintenance Costs*. A second line between Kenai and Anchorage would reduce the maintenance costs of the existing line by $5 million.

Figure 1-9 shows the relative contribution of each benefit category to the total expected benefits.

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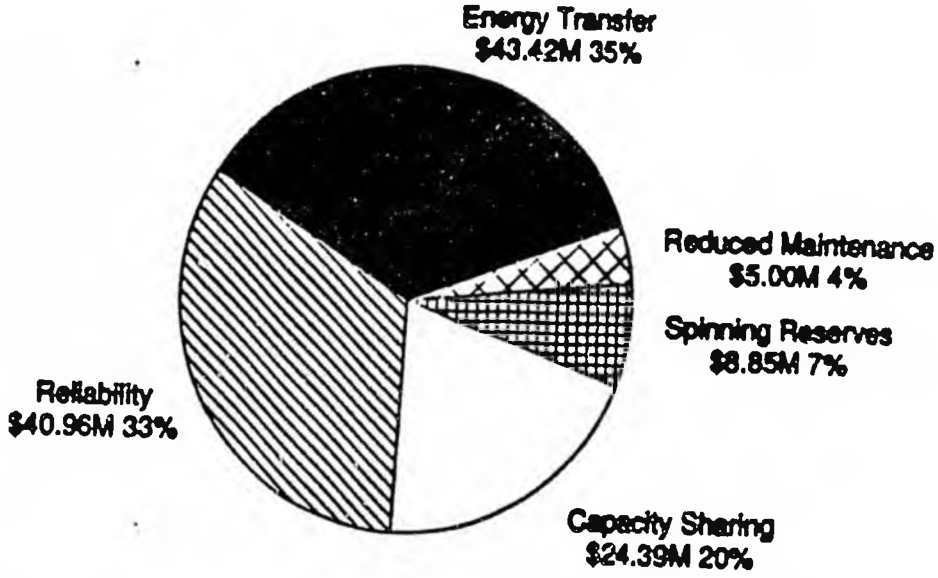
[4] Based on increased economy energy transfers of $51.0 million, increased transfer losses of $3.1 million and reduced gas royalty and severance taxes of $4.5 million.



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 1-9. New Kenai-Anchorage Intertie:
Breakdown of Expected Benefits

1.5.2 Limited Upgrade of Anchorage-Fairbanks Intertie to 100 MW

This alternative consists of electrical equipment to provide a limited increase of 30 MW input in the transfer capacity of the existing line. The estimated capital cost of this limited upgrade is $9.4 million (again, expressed in 1990 dollars). Operations and maintenance cost is estimated at $0.05 million per year. The present value of total costs is $10.3 million.

The expected value of benefits is estimated at $45.9 million in the following categories:

1. *Reliability*: The value of improved reliability is estimated at $5.0 million.
2. *Increased Economy Energy Transfer*: Savings due to increased transfers between Anchorage and Fairbanks, after adjusting for increased transmission losses and increased gas royalty and severance taxes are estimated at $31.8 million.[5]
3. *Increased Capacity Sharing Benefits*: 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 $9.0 million.

Figure 1-10 shows the relative contribution of each benefit category to the total expected benefits.

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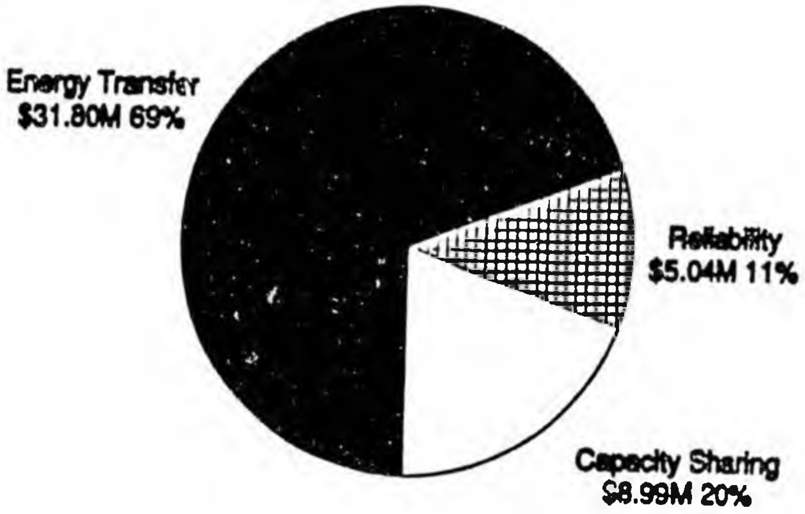
[5] Based on increased economy energy transfers of $42.7 million, increased transfer losses of $15.4 million and increased gas royalty and severance taxes of $4.5 million.



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 1-10. Anchorage-Fairbanks Upgrade to 100 MW:
Breakdown of Expected Benefits

1.5.3 New Healy-Fairbanks Intertie

This alternative consists of the limited upgrade of the Anchorage-Fairbanks line and a new transmission line between Healy and Fairbanks. Transfer capacity between Anchorage and Fairbanks would be increased to 120-140 MW and transfer losses would be reduced. The capital cost of this proposal is $58.7 million. The additional operations and maintenance cost is estimated at $0.3 million per year. The present value of total costs is estimated at $64.6 million.

The expected value of benefits is estimated at $105.8 million in the following categories:

1. *Reliability*: The value of improved reliability is estimated at $11.5 million.

2. *Increased Economy Energy Transfer*: Savings due to increased transfers between Anchorage and Fairbanks, after adjusting for increased transmission losses and increased gas royalty and severance taxes, are estimated at $76.9 million.[6]

3. *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 $17.3 million.

Figure 1-11 shows the relative contribution of each benefit category to the total expected benefits.

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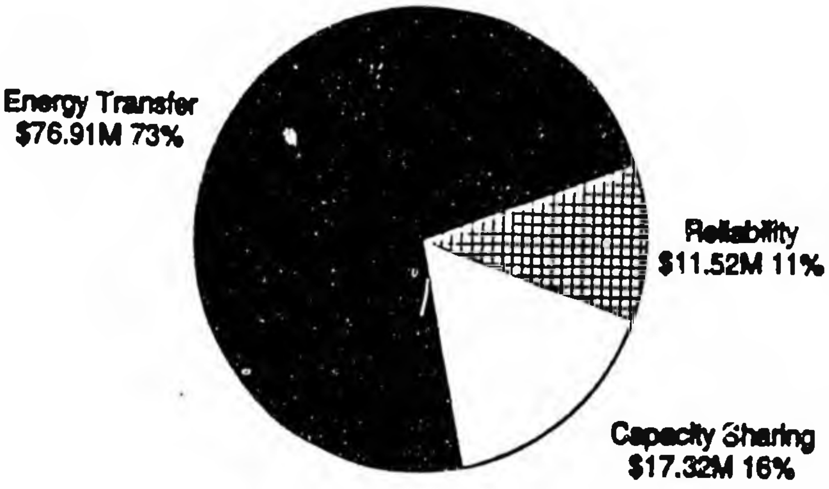
[6] Based on increased economy energy transfers of $76.2 million, increased transfer losses of $7.0 million and increased gas royalty and severance taxes of $7.7 million.



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 1-11. Healy-Fairbanks Northern Intertie:
Breakdown of Expected Benefits

Section 2

DESCRIPTION AND COSTS OF PROPOSED INTERTIES

2.1 DESCRIPTION AND CAPITAL COST OF INTERTIES

This section presents a description of each of the three proposals considered in this study, and summarizes the estimated capital costs for the proposals. Power Engineers Incorporated prepared the design and cost estimates for the Kenai-Anchorage intertie. Harza Engineering Company prepared the design and cost estimates for the Anchorage-Fairbanks intertie proposals. All costs presented in this section are in 1990 dollars.

2.1.1 New Intertie Between Anchorage and the Kenai Peninsula (KA138 Intertie)

The KA138 line is a 138 KV version of the 230 KV line between Kenai and Anchorage along the Enstar route. The line is comprised of three segment types: steel and wood pole overhead lines, underground cables, and a submarine cable through Turnagain Arm. An addition to the Huffman Substation and an addition to the International Substation have been considered as design options for the substation in Anchorage.

The capital cost of the KA138 proposal, with the Huffman Substation option and a 15 percent contingency, is estimated at $64.3 million[1] in 1990 dollars. The capital cost of the KA138 proposal, with the International Substation option and a 15 percent contingency, is estimated at $65.6 million[2] in 1990 dollars.

2.1.2 Limited Upgrade of the Anchorage-Fairbanks Intertie (AF100 Upgrade)

The AF100 upgrade is the same proposal for a limited upgrade of the intertie between Anchorage and Fairbanks previously considered in the Reconnaissance Study. The upgrade consists of new static VAR systems and series capacitors that will increase the capacity of the current line by 30 MW.

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[1] Report prepared by Power Engineers Incorporated for Chugach Electric Association, April, 1989.

[2] Ibid.

The capital cost of the AF100 upgrade, with a 15 percent contingency, is estimated at $9.4 million[3] in 1990 dollars.

2.1.3 New Intertie Between Healy and Fairbanks (AF138 Intertie)

The AF138 proposal is comprised of the limited upgrade of the Anchorage-Fairbanks intertie coupled with a new 138 KV line from Healy to Ft. Wainwright. The proposed 138 KV line between Healy and Ft. Wainwright is a steel-structure line that will significantly reduce the losses on the line between Healy and Fairbanks, and will increase the transfer between Anchorage and Fairbanks.

The capital cost of the 138 KV line and terminal substations, with a 15 percent contingency, is estimated at $49.3 million[4] in 1990 dollars. Including the capital cost of the limited upgrade ($9.4 million in 1990 dollars), the total capital cost of the proposal is, therefore, $58.7 million.

2.2 VARIABLE COSTS OF THE PROPOSED INTERTIES

The variable costs of an intertie are the annual operating and maintenance costs that are associated with the operation of the line. These costs are typically expressed as a percent of the capital cost of the line. In the Reconnaissance Study, the variable cost of each line is estimated as 1.5 percent of capital cost.[5] The Railbelt utilities have cited historical data as evidence that the variable costs for the existing Railbelt interties are less than 1.5 percent of capital cost. The lack of existing evidence supporting the variable cost of transmission lines prompted further investigation of the estimated variable costs of the proposed lines.

2.2.1 New Evidence of the Variable Cost of the AF138 Intertie

The annual operating and maintenance expenses for the existing Anchorage-Fairbanks intertie during the past three years averaged 1.0 percent of the capital cost of the line.[6] The estimated 1989 total expenses for the Anchorage-Fairbanks intertie are $1.4 million on a capital investment of $125 million. The proposed AF138 line

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[3] "Railbelt Intertie Reconnaissance Study, Benefits/Cost Analysis," prepared by Decision Focus Incorporated, for the Alaska Power Authority, June, 1989.

[4] Report prepared by Harza Engineering Company for Golden Valley Electric Association, April 5, 1989.

[5] Letter from Steven Haagenson, Golden Valley Electric Association, to Salim Jabbour, Decision Focus Incorporated, dated August 25, 1989.

[6] Letter from Myles Yerkes, Matanuska Electric Association, to Salim Jabbour, Decision Focus Incorporated, dated August 25, 1989.

would be a second line between Healy and Fairbanks; and some of the operating and maintenance functions would not require duplication.

For example, the AF138 line would not increase wheeling and dispatch costs. The administrative and general costs for a second intertie should be proportionally less than the current expenses to reflect an adjustment for wheeling and dispatch costs. The 1989 wheeling and dispatch costs are estimated at $0.6 million; and the administrative and general costs are $0.3 million. The adjusted administrative and general costs are $0.1 million ([(1.4 - 0.6 - 0.3)/(1.4 - 0.3)] * 0.3). With the adjustments for expenses that would not be duplicated, the estimated 1989 expenses would be $0.6 million (1.4 - 0.6 - .2), or 0.5 percent of the capital cost of the intertie.

Peter Donalek at Harza Engineering Company has confirmed the fact that 0.5 percent of capital cost is a reasonable estimate of the operating cost of a second intertie between Healy and Fairbanks.[7] He cited two pieces of evidence. First, the accepted industry standards for estimating the variable operating cost of a line are in the range of 0.5 to 1.5 percent. A steel-structure line in Alaska should require very low maintenance and should, therefore, be at the low end of the range. Second, the best estimate of the operating costs of a new line is the historical operating costs of similar lines in the region. Variable costs are extremely location-specific and industry averages are not particularly good estimates. This evidence was also confirmed by Barry Flynn of Flynn & Associates.[8]

We assume that the variable costs of the AF100 and AF138 lines are 0.5 percent of capital cost of the interties. Given these assumptions, the annual variable cost associated with the AF100 upgrade is $0.05 million per year in 1990 dollars. The annual variable cost associated with the AF138 intertie is estimated at $0.3 million per year in 1990 dollars.

2.2.2 New Evidence of the Variable Cost of the KA138 Line

The KA138 line is likely to have higher operating and maintenance costs than the proposed AF138 line. According to John McGrew at Power Engineers, a submarine cable has a considerably higher risk of damage from hazard than an overhead line. In addition to the risk of damage from boats in Alaska, there can be problems with ice gauging that can prematurely cut the life of a line short.[9] This information was

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[7] Phone conversation between Peter Donalek, Harza Engineering Company, and Carol Redfield, Decision Focus Incorporated, October 27, 1989.

[8] Letter from Barry Flynn, Flynn & Associates, to Salim Jabbour, Decision Focus Incorporated, dated November 1, 1989.

[9] Phone conversation between John McGrew, Power Engineers, and Carol Redfield, Decision Focus Incorporated, October 27, 1989.

confirmed for us by Ralph Samm, Manager of the Underground Transmission Program at EPRI.[10]

Problems from ice gauging and changing bottom contours have plagued the existing submarine cables in the Knik Arm of Cook Inlet. These lines are due for a complete replacement in 1990, approximately 15 years after they were originally built.

The submarine cables proposed for the KA138 line should not be subject to the same level of hazard as the current lines in Knik Arm. The KA138 submarine cable is designed to go through Turnagain Arm. The exposure to boat and ice hazards in Turnagain Arm should be less than in Knik Arm.

Given these facts, there is a probability that the new submarine cable will need to be replaced in the future. Assuming a complete replacement of the cable after twenty years, and a capital cost (with a 15-percent contingency) of $22.9 million in 1990 dollars, the present value of replacing the line in 20 years is $9.5 million.

We assume a variable operating and maintenance cost of 1.5 percent of the cost of capital for the submarine cable for an annual variable cost of $0.3 million. The remainder of the KA138 intertie is comprised of wood-pole and underground lines that should require minimal maintenance.[11] We assume that the variable cost of the intertie, excluding the submarine cable, will be 0.5 percent of the capital cost of the line.[12] Under these assumptions the annual variable cost of the line, excluding the submarine case, would be $0.2 million per year. The total variable operating and maintenance cost of the line is, therefore, $0.5 million per year in 1990 dollars.

2.3 ECONOMIC LIFE OF THE INTERTIES

The expected economic life of an intertie is used to determine the net present value of the annual variable costs of the line. The Reconnaissance Study assumes that the economic life of each of the proposed lines is 35 years. The Railbelt utilities indicated that the life of a line may be as long as 50 years. Further investigation indicated the following information.

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[10] Phone conversation between Ralph Samm, Manager of the Underground Transmission Program, Electric Power Research Institute, and Carol Redfield, Decision Focus Incorporated, October, 1989.

[11] Phone conversation between Harry Ng, Project Manager, Distribution Program, Electric Power Research Institute, and Carol Redfield, Decision Focus Incorporated, October, 1989.

[12] The capital cost of the line, excluding the submarine cable, is $41.4 million.

2.3.1 New Evidence of the Economic Life of the AF100 and AF138 Interties

The AF138 line is a steel-structure line. B.C. Hydro amortizes steel-pole lines over a 50-year horizon. B.C. Hydro currently has steel-pole lines in operation that were built in 1932 and, therefore, considers 50 years a "safe" assumption.[13] Bonneville Power currently amortizes lines over 44 years. However, Bonneville Power assumes that new technology should increase the expected life of new lines to 50 years.[14] In the design of the AF line, Commonwealth Associates assumes a 50-year life for the steel-pole lines.[15] According to Barry Flynn,[16] Pacific Gas and Electric's lattice-steel lines that were built in 1904 and 1906 continue to operate today in a reliable manner, as do wood-pole lines built in 1910 and 1922.

Harry Ng, a Transmission Engineer at EPRI, confirmed Bonneville Power's observation that most of the steel-pole lines that have been constructed to date are still in operation; and no one knows for sure how long they will last. He noted that most utilities assume a 40- to 50-year life for all lines.[17]

Based on this evidence we assume a 50-year life for the AF138 line.

2.3.2 New Evidence of the Economic Life of the KA138 Line

The KA138 line is primarily composed of wood-pole lines and a submarine cable. There is a broad range of estimates for the life of a wood-pole line. According to Paul Lyons of EPRI, a wood-pole line may last as little as 10 years in a humid climate, such as Florida, due to deterioration from fungus and pests.[18] In the Southwest, a wood-pole line may last well beyond 50 years. In the Alaska climate, wood-pole lines should have minimal problems with fungus and pests; and lines should last anywhere from 35 to 50 years.

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[13] Phone conversation between Bob Loose, BC Hydro, and Carol Redfield, Decision Focus Incorporated, October, 1989.

[14] See note 6.

[15] "Anchorage-Fairbanks Transmission Intertie Structure Study for Alaska Power Authority," prepared by Commonwealth Associates, Inc., Jackson, Michigan, August, 1981

[16] See note 8.

[17] See note 11.

[18] Phone conversation between Paul Lyons, Project Manager in the Overhead Transmission Lines Program, Electric Power Research Institute, and Carol Redfield, Decision Focus Incorporated. October, 1989.

Commonwealth Associates assumes a 35-year life for the wood-pole lines in the design proposal for the AF line.[19] Bonneville Power and B.C. Hydro[20] amortize wood-pole lines over 39- and 50-year horizons, respectively. Harza Engineering Company estimates that the lines should have a 40-year life.[21] We assume that the life of a wood-pole line in Alaska should be 40 years.

Without the occurrence of an unanticipated hazard, a submarine cable should last as long as any other line. However, any hazard has the risk of cutting short the life of the line. Ralph Samm, at EPRI, estimates the average life of a submarine cable to be 40 years—the "industry average for any type of line".[22] We consider the risk of a hazard that might cut short the life of the cable by evaluating the possibility of a complete replacement after 20 years of service (refer to Section 2.2.2).

Given this evidence, we assume a 40-year life for the entire KA138 line.

2.4 NET PRESENT VALUE OF THE COST OF THE PROPOSED INTERTIES

Assuming a 40-year life for the entire KA138 line and a discount rate of 4.5 percent, the net present value of the variable cost of the line is $9.7 million with the Huffman Substation option. The total cost of this proposal is $74.1 million with no replacement of the submarine cable.[23] Assuming a replacement of the cable after twenty years, the total cost of the KA138 proposal, with the Huffman station, is $86.2 million in 1990 dollars.

Assuming a 50-year life for the AF100 upgrade, the net present value of the variable costs associated with the upgrade is $0.9 million. The total cost of the AF100 proposal is $10.3 million, again in 1990 dollars.

Assuming a 50-year life for the AF138 intertie, the net present value of the variable costs associated with the intertie is $5.8 million. The total cost of the AF138 proposal is $64.6 million in 1990 dollars.

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[19] See note 14.

[20] See note 12.

[21] See note 7.

[22] See note 10.

[23] With the International Substation option, the net present value of the variable costs is $10.1 million and the total cost is $75.6 million, all in 1990 dollars.

Section 3

TRANSFER LOSSES OF EXISTING AND PROPOSED TRANSMISSION LINES

Transmission losses play an important role in the cost of power transfer between two distant areas. Since energy lost in transmission can be considered to have the same value as delivered power, an understanding of electrical losses is vital to evaluate the benefits of a transmission addition. Losses are considered for the limited upgrade of the Anchorage-Fairbanks line (AF100), the new intertie between Healy and Fairbanks (AF138), and the new intertie between Kenai and Anchorage (KA138).

3.1 ANCHORAGE-FAIRBANKS NEW/UPGRADED INTERTIES

Under the limited upgrade of the Anchorage-Fairbanks line (AF100), transmission losses are the same as the existing intertie; this is because the only change to the intertie is installation of stability equipment, which increases the transfer limit but does not impact losses. Therefore, additional loss calculations for the AF100 are required for the increased levels of transfer.

A major portion of the losses between Anchorage and Fairbanks for the existing and AF100 lines occur between Healy and Fairbanks. The following analysis shows that the proposed 138 KV line from Healy to Fairbanks (AF138) will significantly reduce losses by increasing transfer efficiency.

3.1.1 Calculation of Losses

Power Technologies Incorporated (PTI) provided a technical memorandum on losses and compensation requirements to the Golden Valley Electric Association in April, 1989.[1] This report detailed the technical power flow analysis necessary to assess the impact of the AF138 on transmission losses.

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1. Power Technologies Incorporated, "Healy—Ft. Wainwright Line: Losses and Compensation Requirements," submitted to Steve Haagenson, Golden Valley Electric Association, April 4, 1989.

Characteristics of the existing and proposed lines were used by PTI to evaluate losses for several levels of power flow on the lines. PTI calculated transmission losses for the AF100 and the AF138 for six levels of load in the Fairbanks area.[2] Table 3-1 shows losses for the first three cases, which involve loads of 50 percent, 75 percent, and 100 percent of 115 MW at Fairbanks. Table 3-2 shows losses for the second three cases, which involve loads of 50 percent, 75 percent, and 100 percent of 124.2 MW at Fairbanks. The choice of 124.2 MW at Fairbanks in the second set of cases is important. This load level corresponds to a flow into Healy of 105.6 MW for the AF138, which matches exactly the Healy flow for the AF100 and 115.0 MW at Anchorage (refer to Footnotes 3 and 5). The result is that the impact of the addition on losses can be directly evaluated, since the power input at Healy has been held constant (105.6 MW). Therefore, a good comparison could be made between the AF100 losses in Table 3-1 and the AF138 losses in Table 3-2.

Adapting the results from the PTI report, losses have been divided among the Anchorage area, transfer between Anchorage and Healy, and transfer between Healy and Fairbanks.

Table 3-1[3]

ANCHORAGE-FAIRBANKS TRANSFER LOSSES (MW)

	Fairbanks Load (100% = 115 MW)		
	100%	75%	50%
Anchorage Area[4]			
AF138	7.1	3.5	1.3
AF100	8.5	4.0	1.4
Anchorage to Fairbanks			
AF138	10.4	5.3	2.2
AF100	21.8	10.4	4.1

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[2] In all cases there is no generation in the Fairbanks area.

[3] Power flows into Healy for the AF138 are 95.4, 64.4, and 34.0 MW at 100, 75, and 50 percent load levels. Power flows into Healy for the AF100 are 105.6, 69.1, and 35.9 MW at 100, 75, and 50 percent load levels.

[4] Losses shown are the total losses in the Anchorage minus those losses which are not due to transfers to Fairbanks (estimated at 12 MW, based on consultation with PTI). These "variable losses" increase with the power transferred from Anchorage to Fairbanks.

Table 3-2[5]

ANCHORAGE-FAIRBANKS TRANSFER LOSSES (MW)

	Fairbanks Load (100% = 124.2 MW) 100%	75%	50%
Anchorage Area[6]			
AF138	8.6	4.2	1.6
AF100	10.9	4.8	1.7
Anchorage to Fairbanks			
AF138	12.6	6.4	2.5
AF100	28.2	12.5	4.9

Data from Tables 3-1 and 3-2 was incorporated into Tables 3-3 and 3-4, which show loss calculations for the AF100 intertie upgrade and AF138 new intertie for different input levels at Anchorage.

Table 3-3

AF100 NEW INTERTIE BREAKDOWN OF TRANSFER LOSSES

MW at FBX	MW at Healy			AF Losses			Anch Loss	MW at Anch	Total Losses		
	Anch	Healy	Total	HF	AH	Total			MW	%input	Incr
124.2	119.2	25.0	144.2	20.0	8.2	28.2	10.9	138.3	39.1	28.3	48.9
115.0	105.6	25.0	130.6	15.6	6.2	21.8	8.5	120.3	30.3	25.2	37.3
93.2	77.4	25.0	102.4	9.3	3.3	12.5	4.8	85.5	17.3	20.2	29.6
86.3	69.1	25.0	94.1	7.8	2.6	10.4	4.0	75.7	14.4	19.0	24.4
62.1	41.1	25.0	66.1	4.0	0.9	4.9	1.7	43.7	6.6	15.1	19.3
57.5	35.9	25.0	60.9	3.4	0.7	4.1	1.4	38.0	5.5	14.5	14.5
Col. 1	2	3	4	5	6	7	8	9	10	11	12

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[5] Power flows into Healy for the AF138 are 105.6, 71.8, and 38.8 MW for 100, 75, and 50 percent load levels. Power flows into Healy for the AF100 are 119.2, 77.4, and 41.1 MW for 100, 75, and 50 percent load levels.

[6] See Footnote 4.

Table 3-4

AF138 INTERTIE UPGRADE
BREAKDOWN OF TRANSFER LOSSES

MW at FBX	MW at Healy			AF Losses			Anch Loss	MW at Anch	Total Losses		
	Anch	Healy	Total	HF	AH	Total			MW	%input	Incr
124.2	105.6	25.0	130.6	6.4	6.2	12.6	20.6	120.4	21.2	17.6	28.7
115.0	95.4	25.0	120.4	5.4	5.0	10.4	19.1	107.5	17.5	16.3	24.0
93.2	71.8	25.0	96.8	3.6	2.8	6.4	16.2	78.8	10.6	13.5	20.7
86.3	64.4	25.0	89.4	3.2	2.1	5.3	15.5	70.1	8.8	12.6	16.3
62.1	38.8	25.0	63.8	1.7	0.8	2.5	13.6	41.2	4.1	10.0	11.5
57.5	34.0	25.0	59.0	1.5	0.7	2.2	13.3	36.0	3.5	9.7	9.7

For each table, the power in MW at each node is identified, as well as the losses incurred between the nodes. For example, consider the first row of Table 3-3, which takes data from the 100% load column of Table 3-2.

In Table 3-3 Column 1 (124.2 MW), the load at Fairbanks; Column 2 (119.2 MW), the flow into Healy from Anchorage; and Column 7 (28.2 MW), the total losses, are all taken from Table 3-2. The local generation in Healy (25.0 MW), shown in Column 3, is added to the Anchorage portion (119.2 MW) to arrive at the total power at Healy (144.2 MW) in Column 4. Column 5 is the loss from Healy to Fairbanks (20.0 MW), and is calculated as the difference between the total power at Fairbanks (Column 1) and the total power at Healy (Column 4). Column 6 is the loss from Anchorage to Healy (8.2 MW), and is calculated as the difference between total losses (Column 7) and the losses from Healy to Fairbanks (Column 5).

Column 8, the losses in Anchorage (10.9 MW), is taken from Table 3-2. The power at Anchorage (138.3 MW) is calculated by adding the losses from Anchorage to Healy (8.2 MW) to the Anchorage portion of the power at Healy (119.2 MW). Columns 7 and 8 are added to find the total losses from Anchorage to Fairbanks (39.1 MW) in Column 10. Column 11 calculates total losses as a percent of the input power at Anchorage (39.1/138.3 = 28.3%). Incremental loss percentage is calculated in Column 12 ([39.1-30.3]/[138.3-120.3] = 48.9%)

3.1.2 Generalization of Losses

With Tables 3-3 and 3-4, loss calculations can be made at other transfer levels by interpolation. Whenever intermediate loss computations are necessary, loss is assumed to follow a squared relation to the power transferred. This is a basic result of power transfer, where power loss is equal to the square of the current times the impedance, and the current is in direct proportion to the power transferred. For example, if transmission loss (L_R) between two nodes is known at some reference transfer level (T_R), then the transmission loss L at transfer level T can be estimated as:

$$L = L_R (T/T_R)^2$$

All such calculations are referenced to the closest data input given in PTI's analysis. Transmission losses of Healy generation contributes to total losses, but the generated power is not included in the base amount of generation to which the percent loss is referred. This allows Over/Under to model Healy as part of the Fairbanks area, recognizing losses from Healy to Fairbanks, but only as a percentage of power input at Anchorage.

Historically, 62 MW has been the limit of power delivered to Fairbanks on the Anchorage-Fairbanks intertie. It was reported and used in the Reconnaissance Study that the power input to achieve 62 MW at Fairbanks is 70 MW at Anchorage.[7] The 70 MW input, however, only considered losses north of Anchorage; if losses in the Anchorage area were included (as they are for this analysis), an input greater than 70 MW would be needed to deliver 62 MW at Fairbanks. The second row of Table 3-5 shows that for an input of 70 MW at Anchorage, losses would equal 12.6 MW, making the delivered power to Fairbanks equal to 57.4 MW.

Table 3-5

TRANSMISSION LOSSES FOR THE EXISTING
ANCHORAGE-FAIRBANKS INTERTIE

Anchorage Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
40.0	5.8	14.5	14.5
70.0	12.6	18.0	22.8
77.0	14.8	19.3	32.1

The transfer limit of the AF100 would be either 84 MW (Case 1) or 87 MW (Case 2), delivered to Fairbanks. In order to deliver 84 MW to Fairbanks, roughly 110 MW is needed as input at Anchorage. Several increments of transfer levels up to

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[7] Railbelt Intertie Reconnaissance Study, Section 2, page 2-3.

110 MW have been chosen to provide intermediate detail for use of the loss calculations in the Over/Under simulations. Table 3-6 outlines AF100 losses, relating the level of power generated at Anchorage and total transmission losses from Anchorage to Fairbanks. Losses are shown in terms of MW input at Anchorage, as percent of input power, and as percentage incremental losses.

Table 3-6

TRANSMISSION LOSSES FOR THE AF100 INTERTIE UPGRADE

Anchorage Input MW	Total Loss (MW)	(%)	Incremental Loss (%)
40.0	5.8	14.5	14.5
70.0	12.6	18.0	22.8
100.0	22.3	22.3	32.1
110.0	26.9	24.5	46.8

Table 3-7 shows losses for the AF138 new intertie, again breaking transfer levels into several increments to provide representative detail for the Over/Under simulations. The highest level of transfer in Table 3-7 corresponds to an input of 140 MW at Anchorage, resulting in a delivery of 112 MW in Fairbanks, which is the limit expected for the AF138 in Case 2.

Table 3-7

TRANSMISSION LOSSES FOR THE AF138 NEW INTERTIE

Anchorage Input MW	Total Loss (MW)	(%)	Incremental Loss (%)
40.0	3.8	9.5	9.5
70.0	8.8	12.6	16.7
100.0	15.6	15.6	22.6
120.0	21.3	17.8	28.6
140.0	28.1	20.1	34.1

3.2 KENAI-ANCHORAGE NEW INTERTIE (KA138)

Transfer between the Kenai-Anchorage has been taken from the Reconnaissance Study.[8] Table 3-8 shows the losses for several levels of transfer on the existing 115 KV intertie between Kenai and Anchorage. Case 1 assumes a transfer limit of 70 MW input at Kenai and 61 MW output at Anchorage. Case 2 assumes a transfer limit of 90 MW input at Kenai and 75 MW output at Anchorage.

Table 3-9 shows the losses for several levels of transfer for the case of a second intertie (138 KV) between Kenai and Anchorage.

Table 3-8

TRANSMISSION LOSSES FOR THE EXISTING KENAI-ANCHORAGE INTERTIE

Kenai Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
40.0	3.6	8.9	8.9
60.0	6.9	11.5	16.6
70.0	8.8	12.6	19.2
90.0	14.5	15.6	28.7

Table 3-9

TRANSMISSION LOSSES FOR THE NEW KENAI-ANCHORAGE INTERTIE (KA138)

Kenai Input MW	Total Loss (MW)	Total Loss (%)	Incremental Loss (%)
60.0	2.5	4.2	4.2
90.0	5.6	6.2	10.2
100.0	6.9	6.9	13.2
120.0	9.9	8.3	15.2
150.0	15.4	10.3	18.6

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[8] Losses at transfer levels not reported in the Reconnaissance Study were calculated using the approach outlined in Section 3.1.2.

Section 4

RELIABILITY BENEFITS OF PROPOSED 138 KV INTERTIES

This section analyzes the effects that the proposed interties would have on service reliability. Reliability is important because the value of electric power exceeds the cost of producing the power. The cost to a utility of an outage may be small, while the cost of that same outage to an industrial or commercial customer may be very large. The proposed upgraded or new interties will improve service reliability by reducing both the frequency and duration of customer outages.

The assessment of the value of improved system reliability requires an estimate of the outages that an intertie will avoid and the cost to customers of the outages that are avoided. We estimate the impact of the interties on customer outages by analyzing the historical outages in the Railbelt area and the changes that the interties should bring about.

For the costs of customer outages, we have relied on research compiled by the Electric Power Research Institute (EPRI) on the value of service reliability [1]. Since the completion of the Reconnaissance Study, a new EPRI study on service reliability was released. The new study presents substantial evidence that the costs of customer outages are significantly higher than previously estimated. The new evidence is presented in the analysis that follows.

This section is divided into four parts. First, we review the historical levels of customer unserved energy. Second, we estimate the impact that the proposed interties will have on customer unserved energy. Third, we review the new evidence of the costs of customer outages presented in the 1989 EPRI report. Fourth, we apply the costs of outages to the estimate of the impact that the interties will have on customer outages to assign a dollar value to the reliability benefits of the interties.

4.1 IMPACT OF PROPOSED INTERTIES ON CUSTOMER UNSERVED ENERGY

In the event of an outage, customer unserved energy is the electrical energy that would have been demanded by customers if the outage had not occurred. The impact of the interties on customer unserved energy is the change in customer outages that the interties are expected to bring about.

4.1.1 Historical Customer Unserved Energy

For the Reconnaissance Study, data on historical customer outages in the Railbelt region was collected from each of the Railbelt utilities.[1] The customer unserved energy in the Railbelt averaged 955 MWh/year for 1986/1987. Residential customers experienced 44 percent of the unserved energy. A majority of the outages were in Anchorage with an average 655 MWh of unserved energy, or 69 percent of all Railbelt outages. Kenai averaged 192 MWh of outages and Fairbanks averaged 104 MWh of unserved energy.

4.1.2 Impact of the KA138 Intertie on Customer Unserved Energy

The KA138 line is proposed for the same route as the KA line analyzed in the Reconnaissance Study. Similar to the KA line, it would be a second line between Kenai and Anchorage, and, presumably, would be constructed to the same reliability standards as the KA line. Because of this, we assume that it should have the same impact on customer unserved energy as the KA line. We summarize below the expected impact of a new KA intertie on customer unserved energy based on the analysis presented in the Reconnaissance Study.[2]

The KA line is expected to save between 20 and 80 percent of Kenai customer unserved energy when Kenai is exporting power, and 50 percent of unserved energy when Kenai is importing power. The exception to this are Seward outages which will not be avoided by the new interties. Kenai is expected to be an exporter of power 40 percent of the time and an importer 60 percent of the time. We analyze a low case of 46 percent of outages avoided (40 percent of outages avoided 40 percent of the time, and 50 percent of the outages avoided 60 percent of the time) and a high case of 62 percent of outages avoided (80 percent of outages avoided 40 percent of the time, and 50 percent of outages avoided 60 percent of the time).

The KA line would avoid outages in Anchorage when Anchorage is importing power from Kenai (40 percent of the time). It should, therefore, avoid 1.2 outages per year (40 percent of an average 3 outages per year). We analyze a low case of one avoided outage per year of one hour in duration, and a high case of two avoided outages per year of one hour duration. Each outage is limited to 30 MW due to the availability of spinning reserves in Anchorage.

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[1] Refer to "Railbelt Intertie Reconnaissance Study," Appendix A, Prepared by Decision Focus Incorporated for Alaska Energy Authority, June 1989.

[2] Refer to "Railbelt Intertie Reconnaissance Study," Section 4, Prepared by Decision Focus Incorporated for Alaska Energy Authority, June 1989.

4.1.3 Impact of the AF100 Intertie on Customer Unserved Energy

As determined in the Reconnaissance Study, the AF100 upgrade should save 10 percent of MEA outages due to reduced outage duration in the area.

4.1.4 Impact of the AF138 Intertie on Customer Unserved Energy

The AF138 line is comprised of the AF100 upgrade coupled with a new 138 KV line between Healy and Fairbanks. In addition to avoiding 10 percent of MEA outages due to the AF100 upgrade, the AF138 proposal will achieve reliability benefits due to the construction of a second intertie between Healy and Fairbanks.

The AF138 line provides an alternate route between Healy and Fairbanks. Because Fairbanks is typically an importer of power from Anchorage, the second line would avoid some outages in the Fairbanks area. The Northeast intertie analyzed in the Reconnaissance Study was estimated to save 40 percent of Fairbanks outages by providing an alternate route between the two areas. Since the distance from Healy to Fairbanks is approximately one-third of the distance from Anchorage to Fairbanks, we estimate that the AF138 intertie would avoid 12 percent of Fairbanks outages (one-third of the 40 percent of the Fairbanks outages that the Northeast intertie would avoid).

Table 4-1 summarizes the expected impacts of the proposed 138 KV interties on customer unserved energy.

Table 4-1

SUMMARY OF UNSERVED ENERGY FOR THE 138 KV INTERTIES

Area	KA138 Low Case	KA138 High Case	AF100 Intertie	AF138 Intertie
Kenai	46% of Kenai unserved energy saved	62% of Kenai unserved energy saved	0	0
Anchorage	30 MWh of unserved energy saved	60 MWh of unserved energy saved	10% MEA unserved energy saved	10% MEA unserved energy saved
Fairbanks	0	0	0	12% Fairbanks unserved energy saved

4.2 COSTS OF CUSTOMER OUTAGES

The cost of a customer outage is the value to a customer of unserved energy. There are several ways to estimate the cost of an outage resulting in a wide range of cost estimates. The most widely accepted estimation methods in recent years are survey techniques that ask customers to assess the value of the losses suffered during an outage.[3]

The Reconnaissance Study relied on outage cost data from a 1986 EPRI report on service reliability. From that study, the results of the Ontario Hydro surveys of outage costs for industrial and commercial customers, as presented by Scott, were selected as the most applicable to the Railbelt [2]. Since the completion of the Reconnaissance Study, EPRI has released a new study of service reliability that presents updated evidence on the value of service reliability [3].

The new data provided in the 1989 study impacts the analysis of the benefits of the proposed interties in two ways:

1. The study indicates that the cost of residential outages may be considerably higher than previously estimated.

2. The study reveals new information about the Ontario Hydro survey results that was not evident from the Scott summary in the 1986 Study.

The new evidence on the cost of outages results in significantly higher estimates of outage costs for both residential and commercial/industrial customers. The reliability benefits in this analysis are, therefore, significantly higher than the benefits estimated in the Reconnaissance Study.

4.2.1 New Evidence on the Costs of Residential Outages

The Reconnaissance Study uses estimates of residential outage costs from a study completed by Sangvhi in 1983 [4]. Sangvhi estimates that the unit cost of a residential outage is in the range of $0.07/KWh to $2.07/KWh (in 1987 dollars). More recent surveys have yielded considerably higher estimates of the costs of residential customer outages.

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[3] Refer to "Customer Demand for Service Reliability," Section 2, Prepared for Electric Power Research Institute by Laurits R. Christensen Associates, Inc., Madison, Wisconsin, May 1989.

The preferred methods for customer surveys in recent studies are the *Direct Cost* and the *Willingness-to-Pay* survey approaches.[4] The *Direct Cost* approach asks customers to assess the total loss that would occur in the event of an outage. The *Willingness-to-Pay* approach asks customers to assess what they would be willing to pay to avoid an outage. The range of outage costs resulting from these survey techniques is broad. The variation is partly explained by the wide variety of the survey techniques. It is also due to differences in the customers experience with outages. Customers who have not experienced many outages may give very different responses than customers who experience frequent outages.

The range of survey results from the 1989 EPRI study is presented in Table 4-2. The costs range from $0.21/KWh to $9.91/KWh. For this analysis we assume a unit cost of $5.00/KWh for residential outages. This value is approximately the midpoint of the range of survey results.

Table 4-2

RESIDENTIAL OUTAGE COSTS
(1990 $)

Source	Condition	Method	$/KW
Sangvhi (1983)	---	Proxi	2.07
Ontario Hydro (1980)	---	WTP	0.21
Billington, et al. (1982)	---	Direct	1.76
Doane, et al. (1989)	Annual average*	Direct	10.17
Doane, et al. (1989)	Annual average*	Direct	9.39
Goett, et al. (1989)	Winter	WTP	2.18
Meta Systems, et al (1986)	Annual average*	WTP	3.45

WTP = Willingness to Pay

Source: "Customer Demand for Service Reliability," EPRI, EA-4494, May 1986.

*For surveys that estimated separate winter and summer estimates of outage costs, we calculated an annual average outage cost assuming 50 percent summer and 50 percent winter.

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[4] Refer to "Customer Demand for Service Reliability," Section 2, Electric Power Research Institute, May 1989.

4.2.2 New Evidence on the Costs of Commercial/Industrial Outages

The unit cost of a commercial or industrial outage can vary greatly with the duration of the outage. The cost per kilowatt hour of a five-minute outage is usually higher than the cost per kilowatt hour of a one-hour outage. However, the total cost of a one-hour outage exceeds the total cost of a five-minute outage.

The Ontario Hydro surveys asked customers to assess the total cost of an outage for a number of different outage durations. At the time of the survey, no attempt was made to assess the customer usage during an outage. The results of the Ontario Hydro surveys have been converted to an assessment of the cost per kilowatt hour of an outage by making an assumption about the usage at the time of an outage. The assumption that is made about usage can result in widely varying assumptions about the cost per kilowatt hour of an outage.

In his 1983 article [5], Len Scott uses the results of the Ontario Hydro surveys to calculate an estimate of the dollar per kilowatt hour cost of an outage. To convert the survey results, given in dollars per outage to dollars per kilowatt hour, Scott's results assume that the usage in Ontario was equal to 75 percent of the annual peak demand at the time of an outage. Scott's results are presented for different outage durations and different customer types in Table 4-3.

Table 4-3

CUSTOMER OUTAGE COSTS ASSUMING USAGE IS 75 PERCENT OF PEAK DEMAND

	UNIT OUTAGE COST ($/KWH, 1980 $)					COMMERCIAL/IND	
Outage	Lg Ind	Sm Ind	Building	Retail	Inst	$1980/MWh	$1980/MW
1 min	61.80	69.00	195.00	23.40	1.80	58781	980
5 min	15.97	18.68	47.77	8.57	0.92	15923	1327
10 min	10.24	12.38	29.35	6.71	0.80	10563	1761
15 min	8.33	10.28	23.21	6.09	0.77	8772	2193
20 min	7.38	9.24	20.16	5.79	0.75	7887	2629
1 hour	3.97	6.31	14.33	7.32	1.01	6987	6987
2 hours	3.12	5.34	13.02	8.33	1.06	7056	14112
4 hours	2.26	4.37	11.71	9.33	1.11	7120	28480
8 hours	1.66	4.03	10.14	12.28	2.2	8273	66184
10 hours	1.34	3.1	8.57	15.23	2.2	9198	91980

In the 1989 EPRI reliability report, Christensen Associates presented the results of the same Ontario Hydro surveys shown in the Scott report. Rather than assuming that the customer usage at the time of an outage was equal to 75 percent of the annual peak demand, Christensen Associates presented a range of possible costs per kilowatt hour for an outage based on a range of assumptions about the customer usage at the time of an outage. At one end of the range, they assumed that customer usage is 75 percent of annual peak demand. At the other end of the range, they assume that customer usage is equal to the average annual demand for each customer type surveyed.[5]

The results for the unit cost of an outage assuming annual average demand, as shown in the 1989 EPRI report, are presented in Table 4-4. Clearly, neither table is right or wrong, they are simply different interpretations of the same surveys. Using Table 4-3 and assuming that customer usage at the time of an outage is 75 percent of annual peak demand would lead to the same outage cost (in dollars per outage) calculated by using Table 4-4 and assuming that customer usage at the time of an outage is equal to the average annual demand.

Table 4-4

CUSTOMER OUTAGE COSTS ASSUMING USAGE IS ANNUAL AVERAGE DEMAND

	UNIT OUTAGE COSTS ($/KWH, 1980 $)					COMMERCIAL/IND	
Outage	Lg Ind	Sm Ind	Building	Retail	Inst	$1980/MWh	$1980/MW
1 min	224.00	162.11	480.99	38.30	3.18	143119	2385
5 min	57.88	43.89	117.83	14.03	1.62	37795	3148
10 min	37.12	29.09	72.40	10.98	1.41	24612	4100
15 min	30.19	24.15	57.25	9.97	1.36	20221	5055
20 min	26.75	21.71	49.73	9.48	1.32	18044	6009
1 hour	14.39	14.82	35.35	11.98	1.78	14830	14829
2 hours	11.31	12.55	32.12	13.64	1.87	14525	29050
4 hours	8.19	10.27	28.88	15.27	1.96	14209	56836
8 hours	6.02	9.47	25.01	20.10	3.89	15734	125867
10 hours	4.86	7.28	21.14	24.93	3.89	16895	168951

In our analysis, the total cost of a customer outage in the Railbelt area is calculated by multiplying the annual average customer usage by the estimated cost per kilowatt hour of an outage and by the duration of an outage. To be consistent with this calculation of total outage costs we, therefore, have used the unit outage costs calculated assuming customer usage equal to annual average demand as presented in Table 4-4.

The Reconnaissance Study was completed before the 1989 reliability report was made available, which clarified the different assumptions about customer usage that have been used to interpret the Ontario Hydro survey results. The reliability benefits in that study were calculated with the outage costs as interpreted by Scott and presented in Table 4-4. As a result, the reliability benefits in that study were

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[5] Phone conversation with David Glyes at Laurits Christensen Associates, October, 1989.

calculated with a significantly lower estimate of the cost of an outage than implied by the Ontario Hydro surveys. This analysis makes the appropriate correction. Hence, the reliability benefits in the Reconnaissance Study are less than the benefits from this analysis.

The total cost of a customer outage is calculated as the customer unserved energy times the unit cost of an outage. Table 4-5 shows for each customer type and outage duration the annual average cost of customer outages for 1986/1987 for the utilities in the Railbelt region. Also shown in the table is the division in outage costs between residential and non-residential customers.

Table 4-5

COSTS OF CUSTOMER OUTAGES IN THE RAILBELT REGION

	(M$/yr)			(%)		
Utility	Residt'l	Ind/Comm	Total	Residt'l	Ind/Comm	Total
AMLP	0.24	4.57	4.80	4.92	95.08	100.00
MEA	0.68	1.87	2.55	26.72	73.28	100.00
HEA	0.17	1.69	1.86	9.03	90.97	100.00
SES	0.07	0.81	0.88	7.92	92.08	100.00
FMUS	0.03	0.78	0.81	3.28	96.72	100.00
GVEA	0.15	1.93	2.08	7.41	92.59	100.00
CVEA	0.01	0.17	0.18	3.38	96.62	100.00
CEA	0.75	3.60	4.35	17.18	82.82	100.00
Total	2.09	15.42	17.50	11.95	88.05	100.00

Note: The costs shown are calculated using the average historical outages in 1986/1987.

4.3 VALUE OF IMPROVED SYSTEM RELIABILITY

In Table 4-6 we summarize the unserved energy that the proposed 138 KV interties are expected to save. In Table 4-7 we have applied the unit costs of outages to the unserved energy to estimate the value of the unserved energy that would be saved.

Table 4-6

UNSERVED ENERGY SAVED
(MWh/year)

	KA138 LOW	KA138 HIGH	AF100	AF138
KENAI	70.15	94.56	0.00	0.00
ANCHORAGE	30.00	60.00	20.88	20.88
FAIRBANKS	0.00	0.00	0.00	12.14
TOTAL	100.15	154.56	20.88	33.02

Table 4-7

VALUE OF SAVED UNSERVED ENERGY
(millions 1990 $/year)

	KA138 LOW	KA138 HIGH	AF100	AF138
KENAI	1.26	1.69	0.00	0.00
ANCHORAGE	0.50	1.00	0.26	0.26
FAIRBANKS	0.00	0.00	0.00	0.33
TOTAL VALUE	1.76	2.69	0.26	0.58

To calculate the net present value of the saved unserved energy for the KA138 intertie, we assume a 40-year life for the intertie (see Section 2 of this report) and a discount rate of 4.5 percent. The net present value of the saved unserved energy for the KA138 low case is $32.3 million and for the KA138 high case is $49.6 million (in 1990 dollars).

To calculate the new present value of saved unserved energy for the Anchorage-Fairbanks proposals, we assume a 50-year life for the intertie (see Section 2 of this report) and a discount rate of 4.5 percent. The net present value of the saved unserved energy for the AF100 upgrade is $5.0 million. The net present value for the saved unserved energy for the AF138 intertie is $11.5 million.

The value of improved system reliability is the value of the avoided cost of unserved energy unless the same level of reliability can be achieved for less cost. For the Railbelt, an alternative means of achieving the same reliability as the proposed interties is to maintain a higher level of spinning reserves. If the cost of increasing spinning reserves to achieve the same level of reliability as the interties is less than the value assigned to the saved unserved energy, then the value of the level of reliability is the cost of the equivalent spinning reserves.

In the Reconnaissance Study we estimated the cost of maintaining one additional megawatt of spinning reserves to be on the order of $80,000 (1000 KW/MW x 8760 hours/year x 0.005 MBtu/KWh x 1.8 $/MBtu). Our revised analysis of spinning costs in the Railbelt (see Section 7) indicates that the cost of maintaining one megawatt of spinning reserves to be on the order of $112,000 (1000 KW/MW x 8760 hours/year x 0.007 MBtu/KWh x 1.8 $/MBtu). At this cost, it is unlikely that the spinning reserve approach would produce a lower estimate of the value of improved service reliability.

Table 4-8 summarizes the present value of the reliability benefits for each of the intertie proposals.

Table 4-8

PRESENT VALUE OF RELIABILITY BENEFITS

	$1990 Millions
KA138 Intertie (Low Case)	32.33
KA138 Intertie (High Case)	49.58
AF100 Upgrade	5.04
AF138 Intertie	11.52

4.4 REFERENCES

[1] "Value of Service Reliability to Customers," EPRI Report EA-4494, prepared for EPRI by Criterion, Incorporated, San Diego, CA, May 1986.

[2] L. V. Scott, "Ontario Hydro Surveys on Power Systems Reliability: Summary of Customer Viewpoints," compiled in *The Value of Service Reliability to Consumers*, EPRI Report #EA-4494, May 1986.

[3] "Customer Demand for Service Reliability: Existing and Potential Sources of Information," prepared for EPRI by Laurits Christensen Associates, Madison, Wisconsin, May 1989.

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

[5] Scott op. cit.

Section 5

ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS OF THE INTERTIE ALTERNATIVES

5.1 OVERVIEW

This section describes the benefits that the AF100, AF138, and KA138 intertie options provide in terms of increased economy energy savings and decreased transmission losses. We cover these benefits together in this section since they are closely related. The economy energy and transmission loss savings were simultaneously analyzed using the Over/Under production simulation model.[1] A number of adjustments were subsequently made to the Over/Under results as follows:

1. For the AF100 and AF138 options, an adjustment was made to account for the North Pole operating constraint (refer to Section 5.2).
2. For the KA138 intertie, 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 (refer to Section 5.2).
3. For all intertie options, an adjustment was made for the benefits from the collection of gas royalty and severance taxes (refer to Section 5.2).

The results of this analysis show that the benefits to be gained within these categories for all three options are substantial. The benefits between Anchorage and Fairbanks are primarily due to the large 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. The benefits of both the AF138 and the AF100 options are due, for the most part, to alleviating the capacity constraint of the existing line. The benefits of the new Kenai-Anchorage line are almost entirely due to increased hydro-thermal coordination.

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[1] 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.

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.[2]

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 capacity, 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 the Anchorage-Fairbanks intertie alternatives 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

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[2] 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.

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 in order 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 Benefits from Increased Gas Royalty

The new Anchorage-Fairbanks intertie would allow increased gas substitution for oil and, therefore, would increase the State's royalty and severance tax. This benefit is not accounted for in the Over/Under simulation. To calculate the benefits from the gas royalty, we assume a royalty of 18 percent of the well-head gas price. The gas royalty benefit is calculated as a straight percentage of the increase in gas use attributed to the interties. We adjust for reduced benefits in later years when the gas supply is depleted.

5.2.6 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. The initial modeling year was set at 1994 since most of the alternatives could not be brought on-line before then. The Kenai-Anchorage intertie was subjected to the same set of inputs for the 40-year period from 1994 to 2033. The Anchorage-Fairbanks intertie alternatives were subjected to the same set of alternatives for the 50-year period from 1994 to 2038.[3]

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[3] For more details on the economic life of a line refer to Section 2.

Electricity demand and fuel prices are assumed constant between 2010 and 2038 due to the heightened uncertainty associated with distant time frames. Total system costs under each set of assumptions were computed in 1990 dollars for each year and discounted back to 1994. Significant modeling assumptions are presented in Appendix B of this report. For more details on the methodology used for multi-area production simulation and the calculation of adjustments associated with the North Pole operating constraint, refer to the Reconnaissance Study, Appendix E.[4] The adjustment of Kenai-Anchorage transfers based on improved hydro-thermal coordination is described in Appendix A of this study.

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

1. A new Kenai-Anchorage 138 KV line with input transfer capacity equal to 150 MW (labelled "KA138").
2. A limited upgrade of the Anchorage-Fairbanks line to an input transfer capacity of 110 MW (labelled "AF100").
3. A limited upgrade of the Anchorage-Fairbanks line with a new 138 KV line from Healy to Ft. Wainwright with an input transfer capacity between 120 MW and 140 MW.[5]

5.3 ALTERNATIVE CASE SCENARIOS

5.3.1 Fuel and Load Forecast Scenarios

A set of base case scenarios were developed for the combination of three fuel-price and three load-forecast assumptions. These forecasts are the same forecasts used in the Reconnaissance Study.[6] In this study, no attempt has been made to weight the different fuel and load forecast scenarios. Where average values are calculated, each scenario is treated as equally likely.

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[4] Refer to "Railbelt Intertie Reconnnaissance Study: Benefits/Cost Analysis," prepared by Decision Focus Incorporated for Alaska Power Authority, May 1989.

[5] See Section 5.3.

[6] The fuel price forecasts are discussed in Appendix B, and the load forecasts are discussed in Appendix C of the Reconnaissance Study.

5.3.2 Intertie Capacity Scenarios

Two cases of the economy energy and transmission loss benefits were evaluated. Case 1 assumes the following transfer limits:

	Input (MW)	Output (MW)
Kenai-Anchorage		
• Existing 115 KV Line	70	61
• With Second 138 KV Line (KA138)	150	110
Anchorage-Fairbanks		
• Existing Line	77	62
• With Limited Upgrade (AF100)	110	84
• With Second 138 KV Line (AF138)	120	99

Case 2 assumes the following transfer limits:

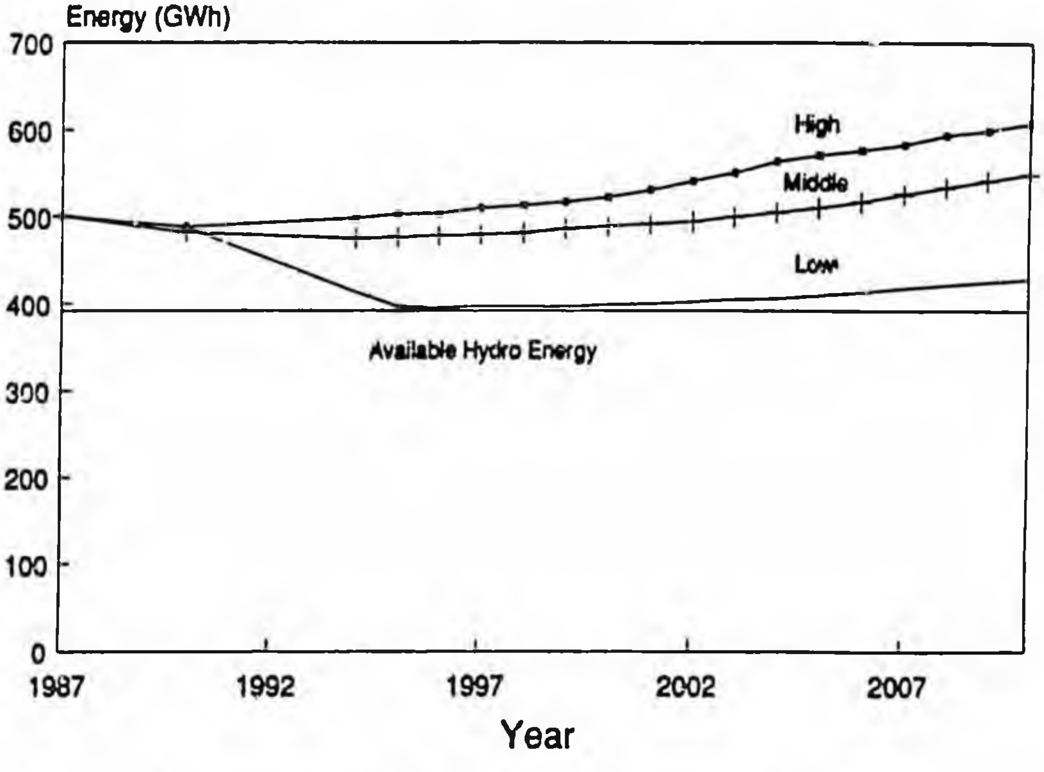
	Input (MW)	Output (MW)
Kenai-Anchorage		
• Existing 115 KV Line	90	75
• With Second 138 KV Line (KA138)	150	110
Anchorage-Fairbanks		
• Existing Line	77	62
• With Limited Upgrade (AF100)	110	84
• With Second 138 KV Line (AF138)	140	112

Both cases were evaluated for each of the fuel and load forecast scenarios.

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 Anchorage and Kenai have gas-fired generating units, but 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.



Insert Harvard line graph from Recon. Study here.

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 A.

Anticipated transfers between the two areas without the new intertie are shown in Table 5-1 for Case 1 and Case 2. Including the cost-effective transfers estimated to limit part-load operation of thermal units in Anchorage, transfer levels from Kenai to Anchorage in 1994 average 102 GWh per year for Case 1.[7] Transfers from Kenai to Anchorage decline slightly by 2010. Transfers from Anchorage to Kenai in 1994 average 147 GWh per year in the expected case, growing to 217 GWh per year by 2010 due to anticipated load growth on the Kenai Peninsula. As shown, the results for Case 2 do not differ significantly from Case 1.[8] For each case, the transmission losses associated with these transfer levels are also shown.

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[7] For Case 1, the existing Kenai-Anchorage line has a transfer limit of 613 GWh per year (based on 70 MW x 8760 hours per year).

[8] For Case 2, the existing Kenai-Anchorage line has a transfer limit of 788 GWh per year (based on 90 MW x 8760 hours per year).

Table 5-1

KENAI-ANCHORAGE TRANSFERS WITH EXISTING LINE

BASK

	Assumptions		Economy Energy Transfer (GWh/yr) South ----> North			Economy Energy Transfer (GWh/yr) North ----> South			Transmission Loss (GWh/yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	123.8	118.1	110.2	142.3	135.0	172.3	29.3	28.1	30.7
		Middle	105.7	82.4	81.7	144.1	126.0	267.6	27.8	24.2	36.7
		High	93.5	85.3	82.8	131.6	123.1	287.4	25.6	24.2	38.6
	Middle	Low	115.6	118.0	110.1	142.3	156.0	172.3	28.6	30.0	30.7
		Middle	98.6	82.2	81.3	144.1	139.2	225.2	27.2	25.3	32.9
		High	81.6	84.6	82.4	132.5	133.8	215.8	24.7	25.0	32.2
	High	Low	115.6	117.7	110.0	160.7	156.0	172.3	30.2	30.0	30.7
		Middle	98.6	81.4	81.2	172.8	139.1	225.2	29.8	25.2	32.9
		High	81.6	82.0	82.1	151.1	133.8	216.6	26.3	24.8	32.2
Case 2	Low	Low	128.7	123.0	115.1	148.4	141.1	178.4	31.3	30.1	32.7
		Middle	110.6	87.3	86.6	150.2	132.1	273.7	29.8	26.2	38.7
		High	98.4	90.2	87.7	137.7	129.2	293.5	27.6	26.2	40.6
	Middle	Low	120.5	122.9	115.0	148.4	162.1	178.4	30.6	32.0	32.7
		Middle	103.5	87.1	86.2	150.2	145.3	231.3	29.2	27.3	34.9
		High	86.5	89.5	87.3	138.6	139.9	221.9	26.7	27.0	34.2
	High	Low	120.5	122.6	114.9	166.8	162.1	178.4	32.2	32.0	32.7
		Middle	103.5	86.3	86.1	178.9	145.2	231.3	31.8	27.2	34.9
		High	86.5	86.9	87.0	157.2	139.9	222.7	28.3	26.8	34.2

Table includes hydrothermal coordination adjustment.

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, on average, transfer levels in 1994 from Kenai to Anchorage increase by about 113 GWh per year due to the new line. Transfers from Anchorage to Kenai in 1994 increase on average by about 147 GWh per year. Transfer losses decrease slightly with the new line.

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. The annual average net savings vary between $2.0 and $2.9 million per year between 1994 and 2010. Over 90 percent of the benefits can be attributed to increased hydro-thermal coordination. There are small negative benefits associated with the change in transfer losses and a decrease in the gas royalty, however, the economy transfer benefits strongly outweigh the small losses.

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 present value of these benefit categories average $43.4 million. As shown, the results for Case 1 and Case 2 do not differ significantly.

Table 5-2

CHANGE IN KENAI-ANCHORAGE TRANSFERS DUE TO THE NEW LINE

			Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
	Assumptions		South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	117.0	115.2	113.8	125.1	128.0	106.2	-2.4	-1.8	-4.1
		Middle	113.7	110.6	109.8	153.6	201.3	101.5	-0.6	3.2	-7.7
		High	111.3	111.9	109.7	142.9	226.8	143.6	-0.0	4.3	-6.9
	Middle	Low	114.9	115.3	114.1	125.1	107.0	106.2	-2.2	-3.6	-4.1
		Middle	112.6	110.8	111.6	167.5	188.1	143.8	0.2	2.0	-3.8
		High	110.4	112.6	114.8	191.9	230.5	214.6	2.5	4.0	-0.3
	High	Low	114.9	115.2	114.0	106.7	107.0	106.2	-3.8	-3.6	-4.1
		Middle	112.6	110.8	110.8	138.8	188.2	143.8	-2.3	2.1	-3.8
		High	110.4	112.7	112.6	173.3	230.5	213.8	0.9	4.2	-0.4
Case #2	Low	Low	112.1	110.3	108.9	119.0	121.9	100.1	-4.4	-3.8	-6.1
		Middle	108.8	105.7	104.9	147.5	195.2	95.4	-2.6	1.2	-9.7
		High	106.4	107.0	104.8	136.8	220.7	136.9	-2.0	2.3	-8.9
	Middle	Low	110.0	110.4	109.2	119.0	100.9	100.1	-4.2	-5.6	-6.1
		Middle	107.7	105.9	106.7	161.4	182.0	137.7	-1.8	0.0	-5.8
		High	105.5	107.7	109.9	185.8	224.4	208.5	0.5	2.0	-2.3
	High	Low	110.0	110.3	109.1	100.6	100.9	100.1	-5.8	-5.6	-6.1
		Middle	107.7	105.9	105.9	132.7	182.1	137.7	-4.3	0.1	-5.8
		High	105.5	107.8	107.7	167.2	224.4	207.7	-1.1	2.2	-2.4

Table includes hydrothermal coordination adjustemnt.

Table 5-3

ANNUAL TRANSFER BENEFITS DUE TO THE NEW KENAI-ANCHORAGE LINE

Assumptions			Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	1.6	1.8	1.9	0.0	0.0	0.1	1.6	1.8	1.9
		Middle	1.6	1.8	1.9	0.0	-0.1	0.2	1.6	1.8	2.1
		High	1.5	1.8	2.0	0.0	-0.1	0.1	1.5	1.8	2.2
	Middle	Low	2.0	2.3	2.7	0.0	0.1	0.1	2.0	2.4	2.8
		Middle	2.1	2.5	2.9	-0.0	-0.0	0.1	2.1	2.5	3.0
		High	2.1	2.5	3.0	-0.1	-0.1	-0.0	2.0	2.4	3.0
	High	Low	2.2	2.8	3.6	0.1	0.1	0.1	2.3	2.9	3.7
		Middle	2.4	3.1	3.8	0.0	-0.1	0.1	2.4	3.0	3.9
		High	2.4	3.1	3.9	-0.0	-0.1	0.0	2.4	2.9	3.9
Case #2	Low	Low	1.5	1.8	1.8	0.0	0.0	0.1	1.6	1.8	1.9
		Middle	1.6	1.8	1.9	0.0	-0.0	0.2	1.6	1.8	2.1
		High	1.5	1.8	2.0	0.0	-0.1	0.2	1.5	1.7	2.2
	Middle	Low	2.0	2.3	2.7	0.1	0.1	0.1	2.0	2.4	2.8
		Middle	2.1	2.4	2.8	0.0	-0.0	0.2	2.1	2.4	3.0
		High	2.0	2.5	3.0	-0.0	-0.1	0.0	2.0	2.4	3.0
	High	Low	2.2	2.8	3.5	0.1	0.1	0.2	2.3	2.9	3.6
		Middle	2.3	3.0	3.7	0.1	-0.0	0.2	2.4	3.0	3.9
		High	2.3	3.0	3.8	0.0	-0.1	0.1	2.4	2.9	3.9

1. All values are in 1990 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer
   \+ Reduced Transmission Loss
4. Table includes hydrothermal coordination adjustemnt.

Table 5-4

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

	Assumptions					
Scenario	Fuel	Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Net Transfer Benefits
Case #1	Low	Low	35.0	-2.1	-3.1	29.8
		Middle	35.7	-1.1	-3.4	31.2
		High	36.9	-1.3	-3.2	32.5
	Middle	Low	48.9	-2.9	-4.0	42.0
		Middle	51.7	-2.9	-4.6	44.3
		High	53.9	-4.5	-4.5	44.9
	High	Low	61.8	-3.6	-5.3	52.9
		Middle	65.4	-3.5	-5.7	56.3
		High	68.0	-5.5	-6.9	55.6
Case #2	Low	Low	35.2	-2.1	-3.1	30.0
		Middle	35.9	-1.1	-3.4	31.5
		High	37.2	-1.3	-3.2	32.7
	Middle	Low	49.3	-2.9	-4.1	42.3
		Middle	52.1	-3.0	-4.6	44.6
		High	54.3	-4.5	-4.5	45.2
	High	Low	62.3	-3.7	-5.3	53.3
		Middle	65.9	-3.6	-5.7	56.7
		High	68.5	-5.6	-6.9	56.0

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2033 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include hydrothermal coordination adjustment.

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 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 $33.47 per MWh is computed for the North Pole units compared with $18.05 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 $1.36, $1.95, and $2.26 per MBtu for the low, middle, and high fuel forecasts respectively (i.e., it is higher for the higher-priced scenarios). In addition, as time goes on, the differential within each forecast also increases to $2.09, $3.02, and $3.97 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.[9] In the expected case in 1994, transfers from Anchorage to Fairbanks are estimated at about 471 GWh per year,[10] declining to about 418 GWh by 2010. Transmission losses associated with these transfers range from 74 to 57 GWh per year, averaging around 15 percent of transfers.

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[9] 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.

[10] The existing Anchorage-Fairbanks line has a transfer limit of 675 GWh per year (based on 77 MW x 8760 hours per year).

Table 5-5

ANCHORAGE-FAIRBANKS TRANSFERS WITH EXISTING LINE

BASE

Assumptions			Economy Energy Transfer (GWh/yr)						Transmission Loss (GWh/yr)		
			South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	502.3	428.0	374.7	0.0	0.0	0.0	75.5	54.2	42.5
		Middle	509.5	406.4	421.7	0.0	0.0	0.0	77.9	50.7	55.7
		High	510.1	416.7	493.3	0.0	0.0	0.0	78.2	52.5	75.6
	Middle	Low	451.3	477.5	469.1	0.0	0.0	0.0	71.5	78.6	72.8
		Middle	443.6	475.8	444.3	0.0	0.0	0.0	69.6	76.9	63.7
		High	475.3	505.6	467.7	0.0	0.0	0.0	77.2	82.9	68.2
	High	Low	442.0	445.5	354.3	0.0	0.0	0.0	70.1	70.9	45.3
		Middle	433.1	394.8	343.4	0.0	0.0	0.0	68.1	57.9	39.8
		High	471.1	416.8	392.1	0.0	0.0	0.0	76.6	61.6	50.1
Case 2	Low	Low	502.3	428.0	374.7	0.0	0.0	0.0	75.5	54.2	42.5
		Middle	509.5	406.4	421.7	0.0	0.0	0.0	77.9	50.7	55.7
		High	510.1	416.7	493.3	0.0	0.0	0.0	78.2	52.5	75.6
	Middle	Low	451.3	477.5	469.1	0.0	0.0	0.0	71.5	78.6	72.8
		Middle	443.6	475.8	444.3	0.0	0.0	0.0	69.6	76.9	63.7
		High	475.3	505.6	467.7	0.0	0.0	0.0	77.2	82.9	68.2
	High	Low	442.0	445.5	354.3	0.0	0.0	0.0	70.1	70.9	45.3
		Middle	433.1	394.8	343.4	0.0	0.0	0.0	68.1	57.9	39.8
		High	471.1	416.7	392.1	0.0	0.0	0.0	76.6	61.6	50.1

Table includes North Pole adjustment.

5.7 AF100 LIMITED UPGRADE OF ANCHORAGE-FAIRBANKS LINE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS.

As described in Section 2, the AF100 limited upgrade 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 77 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 110 MW to be input at the Anchorage end with approximately 84 MW received on the Fairbanks end.

5.7.1 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 5-6. On average, transfers from Anchorage to Fairbanks due to the AF100 are projected to increase by about 67 GWh per year in 1994 and by 106 GWh per year in 2010. Although the upgrade permits a higher level of transfers, it also results in higher transfer losses; transfer losses increase by about 22 GWh per year in 1994 and by 35 GWh per year in 2010.

5.7.2 Benefits of Increased Anchorage-Fairbanks Transfers

As shown in Table 5-7, the value of the increased Anchorage-Fairbanks transfers ranges from an average of nearly $1.0 million per year in 1994 to $2.8 million per year in 2010. The negative benefits associated with "reduced transmission 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 5-8. The benefit of the change in transmission losses is a loss of $15.4 million, which is strongly outweighed by the benefits of increased economy energy transfers (an average benefit of $42.7 million), primarily due to the removal of the North Pole constraint. The present value of the average net benefits in these categories is $31.8 million.

Table 5-6

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

			Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
	Assumptions		South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	160.9	144.9	163.1	0.0	0.0	0.0	52.3	46.4	57.8
		Middle	146.8	137.8	106.1	0.0	0.0	0.0	47.7	44.1	34.7
		High	146.4	167.3	93.9	0.0	0.0	0.0	46.9	54.1	31.0
	Middle	Low	23.0	18.7	73.7	0.0	0.0	0.0	7.4	6.1	24.0
		Middle	23.9	35.0	94.8	0.0	0.0	0.0	7.7	11.2	30.7
		High	25.4	56.9	151.8	0.0	0.0	0.0	8.2	18.3	49.1
	High	Low	23.0	15.3	62.3	0.0	0.0	0.0	7.4	4.9	20.3
		Middle	23.9	28.8	83.9	0.0	0.0	0.0	7.7	9.2	27.2
		High	25.4	45.8	127.0	0.0	0.0	0.0	8.2	15.0	41.1
Case #2	Low	Low	160.9	144.9	163.1	0.0	0.0	0.0	52.3	46.4	57.8
		Middle	146.8	137.8	106.1	0.0	0.0	0.0	47.7	44.1	34.7
		High	146.4	167.3	93.9	0.0	0.0	0.0	46.9	54.1	31.0
	Middle	Low	23.0	18.7	73.7	0.0	0.0	0.0	7.4	6.1	24.0
		Middle	23.9	35.0	94.8	0.0	0.0	0.0	7.7	11.2	30.7
		High	25.4	56.9	151.8	0.0	0.0	0.0	8.2	18.3	49.1
	High	Low	23.0	15.3	62.3	0.0	0.0	0.0	7.4	4.9	20.3
		Middle	23.9	28.8	83.9	0.0	0.0	0.0	7.7	9.2	27.2
		High	25.4	45.8	127.0	0.0	0.0	0.0	8.2	15.0	41.1

Table includes North Pole adjustment.

Table 5-7

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

Assumptions			Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	2.1	2.6	3.0	-0.8	-0.9	-1.2	1.2	1.8	1.9
		Middle	1.9	2.5	2.0	-0.8	-0.8	-0.7	1.1	1.7	1.2
		High	1.9	2.8	1.4	-0.7	-1.0	-0.7	1.1	1.8	0.8
	Middle	Low	0.4	0.4	2.0	-0.2	-0.2	-0.7	0.3	0.2	1.3
		Middle	0.5	0.8	2.6	-0.2	-0.3	-0.9	0.3	0.5	1.7
		High	0.5	1.2	3.9	-0.2	-0.5	-1.5	0.3	0.7	2.5
	High	Low	0.5	0.4	2.4	-0.2	-0.2	-0.8	0.3	0.3	1.6
		Middle	0.5	0.9	3.3	-0.2	-0.3	-1.1	0.3	0.6	2.2
		High	0.5	1.4	4.9	-0.2	-0.5	-1.7	0.3	0.9	3.2
Case #2	Low	Low	2.1	2.6	3.0	-0.8	-0.9	-1.2	1.2	1.8	1.9
		Middle	1.9	2.5	2.0	-0.8	-0.8	-0.7	1.1	1.7	1.2
		High	1.9	2.8	1.4	-0.7	-1.0	-0.7	1.1	1.8	0.8
	Middle	Low	0.4	0.4	2.0	-0.2	-0.2	-0.7	0.3	0.2	1.3
		Middle	0.5	0.8	2.6	-0.2	-0.3	-0.9	0.3	0.5	1.7
		High	0.5	1.2	3.9	-0.2	-0.5	-1.5	0.3	0.7	2.5
	High	Low	0.5	0.4	2.4	-0.2	-0.2	-0.8	0.3	0.3	1.6
		Middle	0.5	0.9	3.3	-0.2	-0.3	-1.1	0.3	0.6	2.2
		High	0.5	1.4	4.9	-0.2	-0.5	-1.7	0.3	0.9	3.2

1. All values are in 1990 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer
   \+ Reduced Transmission Loss
4. Table includes North Pole adjustment.

Table 5-8

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

	Assumptions		Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Net Transfer Benefits
Scenario	Fuel	Load				
Case #1	Low	Low	55.0	-20.2	6.1	40.9
		Middle	44.6	-16.4	5.3	33.5
		High	40.5	-16.8	5.6	29.3
	Middle	Low	25.4	-9.1	2.5	18.8
		Middle	33.6	-12.0	3.3	25.0
		High	51.1	-19.1	5.2	37.2
	High	Low	30.9	-10.3	2.9	23.4
		Middle	41.6	-14.0	3.9	31.5
		High	61.8	-21.1	5.9	46.6
Case #2	Low	Low	55.0	-20.2	6.1	40.9
		Middle	44.6	-16.4	5.3	33.5
		High	40.5	-16.8	5.6	29.3
	Middle	Low	25.4	-9.1	2.5	18.8
		Middle	33.6	-12.0	3.3	25.0
		High	51.1	-19.1	5.2	37.2
	High	Low	30.9	-10.3	2.9	23.4
		Middle	41.6	-14.0	3.9	31.5
		High	61.8	-21.1	5.9	46.6

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

5.8 AF138 INTERTIE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS

As described in Section 2, the AF138 option consists of the limited upgrade of the Anchorage-Fairbanks line to 100 MW and a new 138 KV intertie from Healy to Ft. Wainwright. With the existing line, 77 MW can be input in Anchorage and 62 MW received in Fairbanks. With the AF138 option, 120 MW can be input in Anchorage and 99 MW received in Fairbanks.

5.8.1 Increased Anchorage-Fairbanks Transfers

The change in transfer levels due to the new Anchorage-Faribanks 138 KV line is shown in Table 5-9. The average increase in transfer levels from Anchorage to Fairbanks due to the new intertie is on average 122 GWh per year in 1994 and 186 GWh per year in 2010. The transfer losses increase by an average 2 GWh in 1994 and by 23 GWh in 2010. These increases are a direct result of the increase in transfers across the lines.

5.8.2 Benefits of Increased Anchorage-Fairbanks Transfers

The annual savings associated with the increased Anchorage-Fairbanks transfers and reduced transmission losses are shown in Table 5-10. The expected annual net savings (adjusted for transfer losses) rise from $2.0 million in 1994 to $4.3 million in 2010.

The present value of these savings discounted to 1994 at 4.5 percent is shown in Table 5-11. The present value of the average net benefits is $76.9 million. The benefits due to economy energy savings are $76.2 million; and the benefits due to increased gas royalty are $7.7 million. These benefits are offset by a loss of $7.0 million from increased transmission losses.

Approximately half of the total benefits can be traced to the removal of the North Pole constraint. In other words, the analysis indicates that the inability to provide small economical increments of power in Fairbanks, when needed at times of full intertie loading, is very costly.

Table 5-9

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO A SECOND HEALY-FAIRBANKS 138 KV LINE

			Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
Assumptions			South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	222.3	229.5	259.7	0.0	0.0	0.0	26.6	33.1	39.7
		Middle	206.5	199.7	228.9	0.0	0.0	0.0	22.3	27.1	30.2
		High	238.0	232.5	218.0	0.0	0.0	0.0	29.3	37.2	24.2
	Middle	Low	137.6	20.5	102.4	0.0	0.0	0.0	1.0	-21.1	1.5
		Middle	124.9	39.1	146.9	0.0	0.0	0.0	-0.6	-17.0	11.6
		High	79.1	102.6	218.5	0.0	0.0	0.0	-11.3	-1.1	26.8
	High	Low	32.1	37.3	156.0	0.0	0.0	0.0	-16.1	-17.1	13.2
		Middle	32.0	90.3	176.3	0.0	0.0	0.0	-15.6	-4.0	20.7
		High	25.8	111.7	170.9	0.0	0.0	0.0	-20.0	0.2	19.5
Case #2	Low	Low	222.3	229.5	277.9	0.0	0.0	0.0	26.6	33.1	45.5
		Middle	206.5	199.7	245.1	0.0	0.0	0.0	22.3	27.1	35.4
		High	238.0	250.0	227.6	0.0	0.0	0.0	29.3	42.8	27.3
	Middle	Low	137.8	20.6	103.1	0.0	0.0	0.0	1.0	-21.7	1.7
		Middle	124.9	39.2	148.0	0.0	0.0	0.0	-0.6	-17.0	12.0
		High	79.2	103.3	218.8	0.0	0.0	0.0	-11.2	-0.9	26.9
	High	Low	32.1	37.3	156.7	0.0	0.0	0.0	-16.1	-17.1	13.4
		Middle	32.0	90.3	177.4	0.0	0.0	0.0	-15.6	-4.0	21.1
		High	25.8	112.4	171.2	0.0	0.0	0.0	-19.9	0.5	19.6

Table includes North Pole adjustment.

Table 5-10

ANNUAL TRANSFER BENEFITS DUE TO A SECOND HEALY-FAIRBANKS 138 KV LINE

Assumptions			Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	3.3	3.8	4.6	-0.5	-0.6	-0.8	2.8	3.2	3.8
		Middle	3.0	3.6	4.3	-0.4	-0.5	-0.7	2.6	3.1	3.7
		High	3.1	4.3	4.6	-0.5	-0.7	-0.5	2.6	3.6	4.1
	Middle	Low	1.6	1.1	3.3	-0.0	0.5	-0.1	1.6	1.6	3.2
		Middle	1.6	1.6	4.4	0.0	0.4	-0.4	1.6	1.9	4.0
		High	1.4	2.5	6.0	0.2	-0.0	-0.9	1.6	2.5	5.1
	High	Low	1.3	1.4	4.2	0.3	0.4	-0.6	1.6	1.8	3.6
		Middle	1.3	2.1	5.7	0.3	0.0	-0.9	1.6	2.1	4.8
		High	1.3	2.8	7.1	0.4	-0.1	-0.9	1.7	2.7	6.2
Case #2	Low	Low	3.3	3.9	5.0	-0.5	-0.6	-1.0	2.8	3.2	4.1
		Middle	3.0	3.6	4.7	-0.4	-0.5	-0.8	2.6	3.1	3.9
		High	3.1	4.6	4.8	-0.5	-0.8	-0.6	2.6	3.8	4.2
	Middle	Low	1.6	1.1	3.3	-0.0	0.5	-0.1	1.6	1.6	3.2
		Middle	1.6	1.6	4.5	0.0	0.4	-0.5	1.6	1.9	4.0
		High	1.4	2.5	6.0	0.2	-0.0	-0.9	1.6	2.5	5.1
	High	Low	1.3	1.4	4.2	0.3	0.4	-0.6	1.6	1.8	3.6
		Middle	1.3	2.1	5.7	0.3	0.0	-0.9	1.6	2.1	4.8
		High	1.3	2.8	7.1	0.4	-0.1	-0.9	1.7	2.7	6.2

1. All values are in 1990 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer
   \+ Reduced Transmission Loss
4. Table includes North Pole adjustment.

Table 5-11

PRESENT VALUE OF TRANSFER BENEFITS DUE TO A SECOND HEALY-FAIRBANKS 138 KV LINE

	Assumptions		Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Net Transfer Benefits
Scenario	Fuel	Load				
Case #1	Low	Low	84.9	-14.5	10.0	80.3
		Middle	82.7	-13.5	9.9	79.1
		High	87.8	-11.9	9.9	85.8
	Middle	Low	47.6	2.5	3.7	53.7
		Middle	61.7	-1.9	5.3	65.1
		High	83.8	-7.7	7.8	83.8
	High	Low	57.7	-1.2	6.3	62.7
		Middle	76.1	-5.6	7.7	78.1
		High	97.1	-6.7	8.6	99.0
Case #2	Low	Low	88.9	-15.8	10.3	83.4
		Middle	87.1	-15.0	10.4	82.5
		High	90.7	-13.0	10.2	88.0
	Middle	Low	47.7	2.4	3.7	53.8
		Middle	61.9	-2.0	5.3	65.2
		High	84.0	-7.8	7.8	83.9
	High	Low	57.8	-1.3	6.3	62.8
		Middle	76.4	-5.8	7.7	78.3
		High	97.2	-6.8	8.6	99.0

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

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, future investment in generation capacity could be deferred or avoided. This section describes the benefits of increased capacity sharing due to the proposed Kenai-Anchorage new intertie (KA138), the limited upgrade of the Anchorage-Fairbanks intertie (AF100), and the new Healy-Fairbanks intertie (AF138).

We start by presenting background concepts and graphical aids to introduce capacity-sharing benefits. This is followed by presentation of 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, dividing the reductions in shortage into deferral and avoidance categories. The total benefits of reduced Railbelt capacity shortage (i.e., benefits of capacity sharing) vary between $13.4 and $35.7 million for the KA138, $7.6 and $9.9 million for the AF100, and $16.3 and $18.2 million for the AF138.

6.2 CAPACITY SHARING BENEFITS

Two types of capacity-sharing benefits due to new/upgraded interties are discussed in detail in this section: capacity deferral and capacity avoidance. Although there may be other possible benefits (see Section 6.10), these two types appear to be the most important and the most readily quantified.

A new or upgraded intertie between two areas provides a vehicle for the sharing of energy resources, such that a deficiency in one area might be overcome through use of another area's resources. As is discussed in the following sections, the Railbelt will have a situation in the next decade where two areas (Kenai and Fairbanks) will have capacity surpluses, while another (Anchorage) will have a capacity shortage. Capacity deferral benefits are possible through increased transmission between the surplus and shortage areas.

Figure 6-1 shows how new interties would help defer needed capacity additions in Anchorage. The thick solid line reflects decreasing Anchorage available capacity for the period of 1994-2030, including retirements and excluding any new capacity. The thin solid line shows increasing capacity requirements, defined as load plus reserves, for the same period. Once capacity requirements become greater than available capacity, Anchorage would need to add capacity equaling that difference. The dashed line shows the capacity surplus available in Kenai and Fairbanks that is available to Anchorage through a new/upgraded intertie. The surplus in those areas is decreasing through time, and is reduced to zero before the end of the planning horizon; the impact of this temporary surplus is to delay, or *defer*, capacity additions in Anchorage. The shaded area shows benefits possible from the deferral of capacity additions, showing that deferral is only applicable when Anchorage has a capacity shortage.

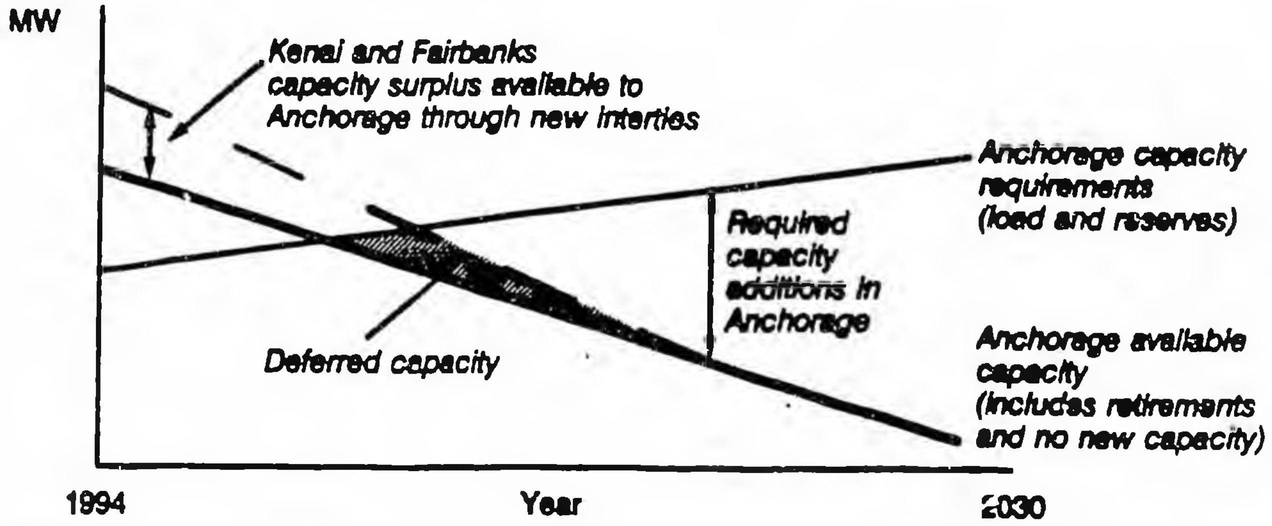


Figure 6-1. Capacity Deferral Benefits

The second type of capacity-sharing benefit possible from greater interconnection is capacity avoidance. This benefit is derived from the increase in reliability that the new or upgraded intertie provides to each area. The Railbelt utilities, like all utilities, set certain targets of reserve capacity margin to ensure sufficient delivery of power and energy. Such targets are generally a percentage of installed system capacity or load. A new/upgraded intertie provides another resource that a given area can rely on in the event of outages, unexpected loads, or other occurrences.

Figure 6-2 shows how one or more intertie could reduce capacity requirements. The solid line represents the capacity requirements of a given area. Including the intertie(s) will result in an additional resource that is available through the life of the intertie(s). The impact of the additional resource is a constant reduction in the capacity requirements of the area. If a shortage exists in this area (e.g. Anchorage) then this reduction contributes to an equivalent amount of *avoided* capacity additions.

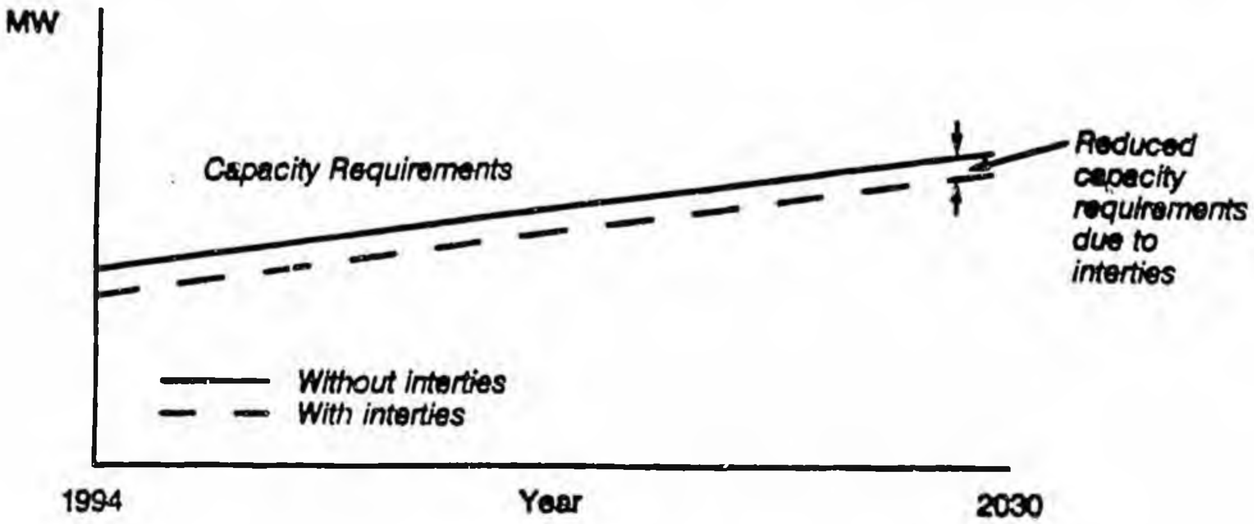


Figure 6-2. Reduced Capacity Requirements

Figure 6-3 builds on Figure 6-1, displaying the avoided capacity benefit for Anchorage, which reduces required capacity starting in the first year of shortage in the Anchorage area. The shaded benefits of the new/upgraded interties in Figure 6-3 are derived from deferred and avoided capacity additions *in the Anchorage area only.*

Figure 6-4 shows how increased interconnection between Kenai and Anchorage, and Fairbanks and Anchorage could impact the surplus areas, which could then be translated to a benefit for the capacity short area. As shown in Figure 6-1, Kenai and Fairbanks have surpluses available to Anchorage through the interties, corresponding to the difference between the thick solid line and the dashed line in Figure 6-4. Lower capacity requirements in Kenai and Fairbanks due to increased reliability, shown in Figure 6-2, further increases the surplus which will exist in Kenai and Fairbanks. This additional capacity surplus made available by Kenai and Fairbanks to Anchorage is the shaded portion of Figure 6-4. The result in Anchorage could be additional deferred capacity.

Figure 6-5 combines the two capacity-sharing benefits due to the proposed interties: avoided capacity and deferred capacity in Anchorage and additional surpluses in Kenai and Fairbanks, translating into additional deferred capacity in Anchorage (or alternatively, avoided new capacity in Fairbanks and Kenai).

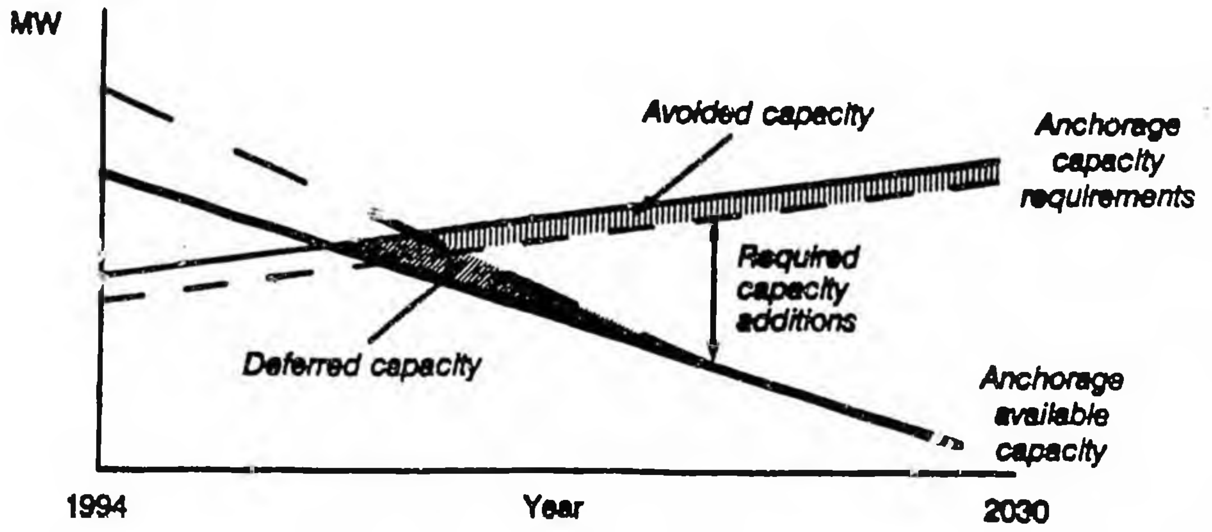
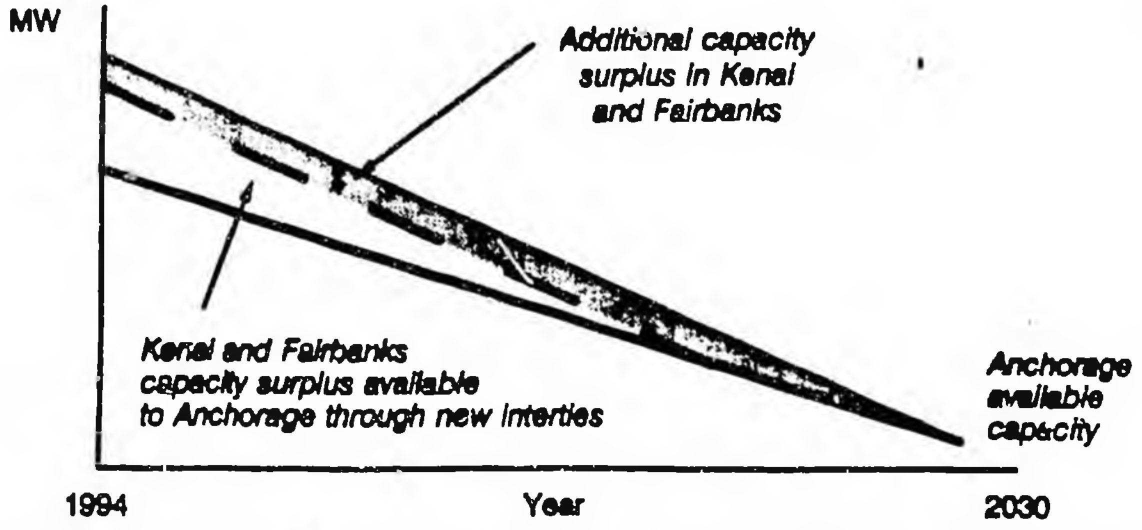


Figure 6-3. Avoided and Deferred Capacity Benefits



Lower capacity requirements in Kenai and Fairbanks would result in increased capacity surplus that can be shared with Anchorage

Figure 6-4. Increased Capacity Surplus From Lower Capacity Requirements

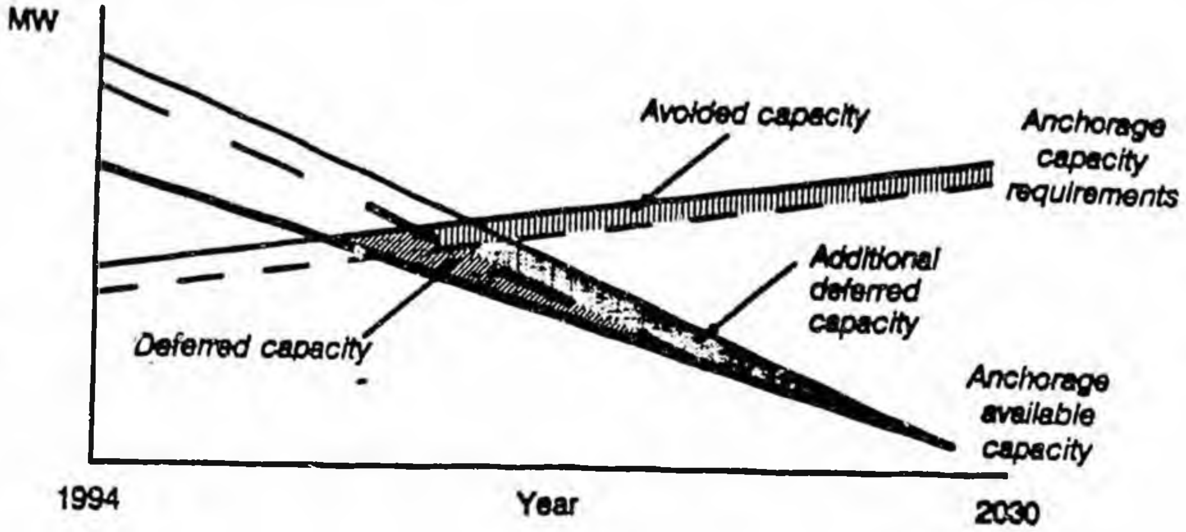


Figure 6-5. Total Capacity-Sharing Benefits

Capacity-sharing benefits due to the new/upgraded interties are integrated into a flow chart in Figure 6-6. Note that capacity-sharing benefits are not limited to capacity-short areas, since a surplus in one area can be used to alleviate shortages in other areas.

The following sections incorporate the concepts and benefits described in this section into a more detailed analysis of the capacity-sharing benefits of the proposed interties for the Railbelt.

6.3 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

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[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.

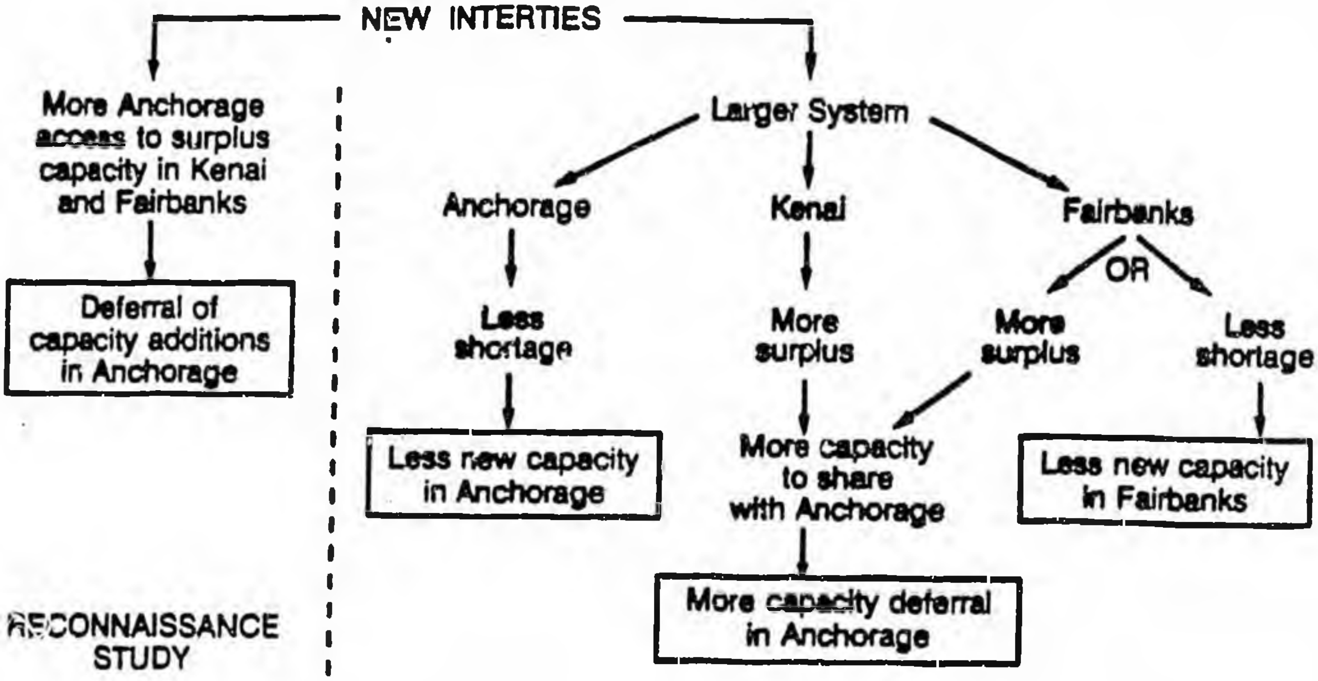

Figure 6-6. Capacity-Sharing Benefits for the Railbelt

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 37 years.[2] Table 6-1 summarizes the Kenai capacity surplus for three 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 10 to 15 years depending on load growth. The current capacity surplus in Fairbanks is around 100 MW. Table 6-2 summarizes the Fairbanks capacity surplus for the period 1994-2028 for all three load forecasts.

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[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 little impact on the capacity deferral benefits calculated in the following sections, since 2009 was the last year for which there was a capacity sharing benefit (refer to Sections 6.5 and 6.6).

Table [illegible]-1

KENAI CAPACITY SURPLUS (MW)*

	Load Growth		
Year	Low	Medium	High
1994	138	124	120
1995	139	121	116
1996	139	121	115
1997	139	120	114
1998	139	120	113
1999	139	119	113
2000	138	118	111
2001	138	118	1[illegible]0
2002	137	117	107
2003	137	116	105
2004	136	115	103
2005	131	109	96
2006	130	107	95
2007	111	87	76
2008	110	86	73
2009	109	84	72
2010	68	43	30
2011	66	40	28
2012	65	39	27
2013	63	38	25
2014	62	36	24
2015	61	35	23
2016	60	34	22
2017	58	33	20
2018	57	31	19
2019	56	30	18
2020	54	29	16
2021	53	27	15
2022	52	26	14
2023	50	25	12
2024	49	23	11
2025	48	22	10
2026	47	21	9
2027	45	20	7
2028	44	18	6

*Based on a 30 percent planning reserve margin. Calculations assume that no Kenai capacity is moved to Anchorage.

Table 6-2

FAIRBANKS CAPACITY SURPLUS*

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

*Based on a 30 percent planning reserve margin.

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.

6.4 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.

6.4.1 Kenai Capacity Shortage

Kenai is expected to have a capacity surplus until at least 2028. Table 6-3 illustrates the expected local capacity in Kenai between 1994 and 2028 and the corresponding capacity shortage, which is zero for all three load forecasts through the entire study period.

6.4.2 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 2002 and 2005. Table 6-4 illustrates the expected local capacity in Fairbanks between 1994 and 2028 and the corresponding capacity shortage for all three load forecasts.

Table 6-3

KENAI CAPACITY SHORTAGE

Year	Local Capacity (MW)	Load Growth : Low Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : Medium Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : High Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	223	65	85	0	76	99	0	80	103	0
1995	220	62	81	0	76	99	0	80	104	0
1996	220	62	81	0	76	99	0	80	105	0
1997	220	62	81	0	77	100	0	82	106	0
1998	220	63	81	0	77	100	0	82	107	0
1999	220	63	81	0	78	101	0	83	107	0
2000	220	63	82	0	78	102	0	84	109	0
2001	220	63	82	0	79	102	0	85	110	0
2002	220	64	83	0	79	103	0	87	113	0
2003	220	64	83	0	80	104	0	88	115	0
2004	220	64	84	0	81	105	0	90	117	0
2005	215	65	84	0	82	106	0	91	119	0
2006	215	66	85	0	83	108	0	92	120	0
2007	197	66	86	0	84	110	0	93	121	0
2008	197	67	87	0	85	111	0	95	124	0
2009	197	68	88	0	87	113	0	96	125	0
2010	157	68	89	0	88	114	0	97	127	0
2011	156	69	90	0	89	116	0	98	128	0
2012	156	70	91	0	90	117	0	99	129	0
2013	156	71	93	0	91	118	0	100	131	0
2014	156	72	94	0	92	120	0	101	132	0
2015	156	73	95	0	93	121	0	102	133	0
2016	156	74	96	0	94	122	0	103	134	0
2017	156	75	98		95	123	0	104	136	0
2018	156	76	99	0	96	125	0	105	137	0
2019	156	77	100	0	97	126	0	106	138	0
2020	156	78	102	0	98	127	0	107	140	0
2021	156	79	103	0	99	129	0	108	141	0
2022	156	80	104	0	100	130	0	109	142	0
2023	156	81	106	0	101	131	0	110	144	0
2024	156	82	107	0	102	133	0	111	145	0
2025	156	83	108	0	103	134	0	112	146	0
2026	156	84	109	0	104	135	0	113	147	0
2027	156	85	111	0	105	136	0	114	149	0
2028	156	86	112	0	106	138	0	115	150	0

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 : Medium			Load Growth : High		
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)
1994	245	119	155	0	118	153	0	125	162	0
1995	243	119	155	0	119	154	0	127	165	0
19[illegible]	236	119	155	0	119	155	0	128	166	0
1[illegible]	233	120	156	0	120	156	0	130	169	0
19[illegible]	233	121	157	0	121	157	0	132	171	0
1999	233	121	157	0	122	159	0	133	173	0
2000	226	121	158	0	123	160	0	136	177	0
2001	208	122	159	0	125	162	0	136	177	0
2002	165	124	161	0	126	163	0	141	183	18
2003	165	125	162	0	127	165	0	143	185	20
2004	165	126	163	0	129	167	2	146	190	25
2005	145	127	165	20	131	170	25	152	197	52
2006	61	128	167	106	133	173	112	157	205	144
2007	0	130	169	169	136	177	177	157	204	204
2008	0	132	172	172	139	180	180	158	206	206
2009	0	133	173	173	141	183	183	160	208	208
2010	0	135	176	176	143	187	187	163	212	212
2011	0	136	177	177	145	189	189	166	216	216
2012	0	137	179	179	147	192	192	169	220	220
2013	0	138	180	180	149	194	194	172	224	224
2014	0	139	181	181	151	197	197	175	228	228
2015	0	140	183	183	153	200	200	178	232	232
2016	0	141	184	184	155	202	202	181	236	236
2017	0	142	185	185	157	205	205	184	240	240
2018	0	143	186	186	159	207	207	187	244	244
2019	0	144	188	188	161	210	210	190	248	248
2020	0	145	189	189	163	213	213	193	251	251
2021	0	146	190	190	165	215	215	196	255	255
2022	0	147	192	192	167	218	218	199	259	259
2023	0	148	193	193	169	220	220	202	263	263
2024	0	149	194	194	171	223	223	205	267	267
2025	0	150	196	196	173	226	226	208	271	271
2026	0	151	197	197	175	228	228	211	275	275
2027	0	152	198	198	177	231	231	214	279	279
2028	0	153	199	199	179	233	233	217	283	283

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

6.4.3 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. Two estimates of the current transfer limit on the Kenai-Anchorage line have been used to calculate the capacity shortage in Anchorage (and later to calculate benefits from the KA138). Case 1 assumes a 60 MW existing transfer limit, based on Anchorage delivery, while Case 2 uses 88 MW as the existing limit.

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 the three load forecasts.

6.5 CAPACITY DEFERRAL DUE TO NEW/UPGRADED INTERTIES

This section outlines the reductions in capacity shortages due to the proposed interties, accounting for the advantages of deferring capacity additions in one area through utilization of currently forecasted surpluses in other areas. Section 6.7 describes shortage reductions through capacity avoidance.

Due to some variability reported for the transfer limits of the existing and proposed interties, two cases corresponding to different transfer scenarios have been used to bound capacity deferral benefits of the new/upgraded interties.

Table 6-5

ANCHORAGE CAPACITY SHORTAGE—CASE 1

		Load Growth : Low			Load Growth : Medium			Load Growth : High		
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)
1994	633	383	498	0	386	502	0	404	525	0
1995	499	382	497	0	390	507	0	407	529	0
1996	379	381	495	0	392	510	9	411	534	33
1997	347	381	495	26	393	510	41	417	543	74
1998	328	380	494	44	396	515	65	423	550	101
1999	117	380	494	255	401	522	283	430	559	322
2000	117	380	494	255	405	527	288	438	569	343
2001	117	382	497	271	411	534	311	447	581	373
2002	117	385	501	320	416	540	361	455	592	415
2003	117	389	506	326	422	549	372	465	604	427
2004	117	393	511	332	430	559	382	475	618	441
2005	117	397	515	338	438	570	393	483	628	451
2006	117	401	522	345	448	583	406	494	642	465
2007	117	406	528	351	460	598	421	504	655	478
2008	117	411	534	357	471	612	435	513	666	489
2009	30	416	541	451	482	627	537	520	676	586
2010	5	422	549	484	494	642	594	532	691	656
2011	5	427	555	490	504	655	609	542	704	671
2012	5	432	562	497	514	668	624	552	717	685
2013	5	437	568	503	524	681	638	562	730	700
2014	5	442	575	510	534	694	652	572	743	714
2015	5	447	581	516	544	707	667	582	756	728
2016	5	452	588	523	554	720	681	592	769	743
2017	5	457	594	531	564	733	695	602	782	757
2018	5	462	601	539	574	746	710	612	795	771
2019	5	467	607	547	584	759	724	622	808	786
2020	5	472	614	554	594	772	738	632	821	800
2021	5	477	620	562	604	785	752	642	834	814
2022	5	482	627	570	614	798	767	652	847	828
2023	5	487	633	578	624	811	781	662	860	843
2024	5	492	640	586	634	824	795	672	873	857
2025	5	497	646	593	644	837	810	682	886	871
2026	5	502	653	601	654	850	824	692	899	886
2027	5	507	659	609	664	863	838	702	912	900
2028	5	512	666	617	674	876	853	712	925	914

Capacity requirements are based on a 30 percent capacity reserve margin.

Capacity shortage, if any, for Anchorage = Anchorage Capacity Requirements
— Anchorage Local Capacity
— Surplus in Kenai and Fairbanks Accessible via Transmission Lines

Table 6-5

ANCHORAGE CAPACITY SHORTAGE—CASE 2

Year	Local Capacity (MW)	Load Growth : Low			Load Growth : Medium			Load Growth : High		
		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	633	383	498	0	386	502	0	404	525	0
1995	499	382	497	0	390	507	0	407	529	0
1996	379	381	495	0	392	510	0	411	534	5
1997	347	381	495	0	393	510	13	417	543	46
1998	328	380	494	16	396	515	37	423	550	73
1999	117	380	494	227	401	522	255	430	559	294
2000	117	380	494	227	405	527	260	438	569	315
2001	117	382	497	243	411	534	283	447	581	345
2002	117	385	501	292	416	540	333	455	592	387
2003	117	389	506	298	422	549	344	465	604	399
2004	117	393	511	304	430	559	354	475	618	413
2005	117	397	515	310	438	570	365	483	628	423
2006	117	401	522	317	448	583	378	494	642	437
2007	117	406	528	323	460	598	393	504	655	463
2008	117	411	534	329	471	612	409	513	666	476
2009	30	416	541	423	482	627	513	520	676	574
2010	5	422	549	475	494	642	594	532	691	656
2011	5	427	555	484	504	655	609	542	704	671
2012	5	432	562	492	514	668	624	552	717	685
2013	5	437	568	500	524	681	638	562	730	700
2014	5	442	575	508	534	694	652	572	743	714
2015	5	447	581	515	544	707	667	582	756	728
2016	5	452	588	523	554	720	681	592	769	743
2017	5	457	594	531	564	733	695	602	782	757
2018	5	462	601	539	574	746	710	612	795	771
2019	5	467	607	547	584	759	724	622	808	786
2020	5	472	614	554	594	772	738	632	821	800
2021	5	477	620	562	604	785	752	642	834	814
2022	5	482	627	570	614	798	767	652	847	828
2023	5	487	633	578	624	811	781	662	860	843
2024	5	492	640	586	634	824	795	672	873	857
2025	5	497	646	593	644	837	810	682	886	871
2026	5	502	653	601	654	850	824	692	899	886
2027	5	507	659	609	664	863	838	702	912	900
2028	5	512	666	617	674	876	853	712	925	914

Capacity requirements are based on a 30 percent capacity reserve margin.

Capacity shortage, if any, for Anchorage = Anchorage Capacity Requirements
— Anchorage Local Capacity
— Surplus in Kenai and Fairbanks Accessible via Transmission Lines

6.5.1 Kenai-Anchorage New Intertie (KA138)

The new Kenai-Anchorage intertie would allow Anchorage to use the capacity surplus in Kenai without the 60 to 88 MW transfer limit that exists today.[4] The combined Kenai-Anchorage area would include the capacity resources of the two areas to meet the capacity requirements of the combined area, recognizing that the intertie might constrain some sharing of resources. 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 KA138 line would therefore allow Anchorage to use the capacity surplus in Kenai up to the transfer limit of the line, and correspondingly reduce capacity shortages in Anchorage. Table 6-6 illustrates the capacity shortages in the Kenai/Anchorage combined area for all three 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, consider the situation in Anchorage for Case 1, where the existing transfer limit between Anchorage and Kenai is 60 MW. In Table 6-5 (Case 1), there is a 65 MW capacity shortage in Anchorage for the middle load growth forecast in 1998[5] and a 15 MW capacity shortage in the Anchorage/Kenai combined area (Table 6-6). Therefore, the new Kenai-Anchorage intertie would reduce the capacity shortage in 1998 by 50 MW (65 MW - 15 MW) for the middle load forecast. This reduced capacity shortage is due to the fact that the new intertie would allow Anchorage to use 110 MW of the 120 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 KA138. Note that the reductions never exceed the increase in the transfer limit (50 MW for Case 1, 22 MW for Case 2).

According to Table 6-7, the Kenai/Anchorage capacity shortages are reduced between 1996 and 2015; no capacity shortage reductions are identified after 2015. Therefore, these reduced shortages represent *deferred capacity additions* rather than *avoided capacity additions*. Avoided capacity additions could be accomplished since the KA138 could reduce the capacity reserve margin of the Kenai/Anchorage area; these reductions are outlined in Sections 6.7 and 6.8.

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[4] The transfer limit for the new intertie would be 110 MW adjusted for transmission losses. The existing limit has been reported as both 60 MW and 88 MW, which constitute Case 1 and Case 2, respectively.

[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 Growth : Medium			Load Growth : High		
		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	856	448	582	0	462	601	0	484	629	0
1995	719	445	578	0	466	606	0	487	633	0
1996	599	443	576	0	468	609	0	491	639	0
1997	567	443	576	0	469	610	0	499	648	24
1998	548	442	575	0	473	615	15	505	657	51
1999	337	443	575	205	479	623	233	513	666	272
2000	337	443	576	205	484	629	238	521	678	293
2001	337	445	579	221	489	636	261	532	691	323
2002	337	449	584	270	495	643	311	542	705	368
2003	337	453	589	276	502	653	322	553	719	382
2004	337	457	594	282	511	664	332	566	735	398
2005	332	461	600	288	520	676	344	575	747	415
2006	332	467	607	295	531	691	359	586	762	430
2007	314	472	614	301	544	707	393	597	777	463
2008	314	478	621	307	556	723	409	608	790	476
2009	227	484	629	402	569	740	513	616	801	574
2010	162	490	637	475	582	756	594	629	818	656
2011	161	496	645	484	593	770	609	640	832	671
2012	161	502	653	492	604	785	624	651	846	685
2013	161	508	661	500	615	799	638	662	861	700
2014	161	514	669	508	626	813	652	673	875	714
2015	161	520	676	515	637	828	667	684	689	728
2016	161	526	684	523	648	842	681	695	904	743
2017	161	532	692	531	659	856	695	706	918	757
2018	161	538	700	539	670	871	710	717	932	771
2019	161	544	708	547	681	885	724	728	947	786
2020	161	550	715	554	692	899	738	739	961	800
2021	161	556	723	562	703	913	752	750	975	814
2022	161	562	731	570	714	928	767	761	989	828
2023	161	568	739	578	725	942	781	772	1004	843
2024	161	574	747	586	736	956	795	783	1018	857
2025	161	580	754	593	747	971	810	794	1032	871
2026	161	586	762	601	758	985	824	805	1047	886
2027	161	592	770	609	769	999	838	816	1061	900
2028	161	598	778	617	780	1014	853	827	1075	914

The Kenai/Anchorage Capacity (Second column) is the sum of the two area's capacities which, due to transmission limits, may not serve an equal amount of load.

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Kenai/Anchorage area = Kenai/Anchorage Capacity Requirements
— Kenai/Anchorage Capacity
— Surplus in Fairbanks Accessible via Existing Anchorage/Fairbanks Lines

Table 6-7

REDUCED KENAI/ANCHORAGE CAPACITY SHORTAGE DUE TO KENAI-ANCHORAGE NEW INTERTIE (MW)

CASE 1				CASE 2			
	Load Growth				Load Growth		
Year	Low	Medium	High	Year	Low	Medium	High
1994	0	0	0	1994	0	0	0
1995	0	0	0	1995	0	0	0
1996	0	9	33	1996	0	0	5
1997	26	41	50	1997	0	13	22
1998	44	50	50	1998	16	22	22
1999	50	50	50	1999	22	22	22
2000	50	50	50	2000	22	22	22
2001	50	50	50	2001	22	22	22
2002	50	50	47	2002	22	22	19
2003	50	50	45	2003	22	22	17
2004	50	50	43	2004	22	22	15
2005	50	49	36	2005	22	21	8
2006	50	47	35	2006	22	19	7
2007	50	27	16	2007	22	0	0
2008	50	26	13	2008	22	0	0
2009	49	24	12	2009	21	0	0
2010	8	0	0	2010	0	0	0
2011	6	0	0	2011	0	0	0
2012	5	0	0	2012	0	0	0
2013	3	0	0	2013	0	0	0
2014	2	0	0	2014	0	0	0
2015	1	0	0	2015	0	0	0
2016	0	0	0	2016	0	0	0
2017	0	0	0	2017	0	0	0
2018	0	0	0	2018	0	0	0
2019	0	0	0	2019	0	0	0
2020	0	0	0	2020	0	0	0
2021	0	0	0	2021	0	0	0
2022	0	0	0	2022	0	0	0
2023	0	0	0	2023	0	0	0
2024	0	0	0	2024	0	0	0
2025	0	0	0	2025	0	0	0
2026	0	0	0	2026	0	0	0
2027	0	0	0	2027	0	0	0
2028	0	0	0	2028	0	0	0

6.5.2 Anchorage-Fairbanks Intertie Upgrade (AF100)

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 for Case 1 and 88 MW for Case 2, based on Anchorage delivery). The AF100 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 three load forecasts.[7]

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 the upgrade). For example, there is a 41 MW capacity shortage in Anchorage for the middle load growth forecast in 1997[8] and a 26 MW capacity shortage in the Anchorage/Fairbanks combined area. Therefore, the AF100 upgrade would reduce the capacity shortage in 1997 by 15 MW (41 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 77 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 AF100 upgrade for the two cases of AF100 transfer limits.

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 since the Anchorage-Fairbanks AF100 upgrade could reduce the capacity reserve margin of the Anchorage/Fairbanks area; these reductions are outlined in Sections 6.7 and 6.8.

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[6] The transfer limit of the upgraded intertie would be 84 to 87 MW adjusted for transmission losses. These two limits are used as Cases 1 and 2.

[7] The Case 1 transfer limit of 60 MW for the existing KA line is assumed.

[8] 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 (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : Medium Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : High Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	878	502	653	0	504	655	0	529	688	0
1995	742	502	652	0	509	661	0	533	694	0
1996	615	500	650	0	511	665	0	539	700	25
1997	580	501	651	11	513	666	26	547	711	71
1998	561	500	650	29	517	672	51	555	722	101
1999	350	501	651	241	523	680	270	563	732	322
2000	343	502	652	249	529	687	284	574	746	343
2001	325	505	656	271	535	696	311	583	758	373
2002	282	509	662	320	541	703	361	596	775	433
2003	282	514	668	326	549	714	372	607	789	447
2004	282	518	674	332	558	726	384	621	808	466
2005	262	524	681	359	569	740	418	635	825	503
2006	178	530	689	451	581	756	518	651	846	608
2007	117	536	697	520	596	774	597	661	859	682
2008	117	543	706	529	610	793	616	671	872	695
2009	30	550	714	624	624	811	721	680	884	794
2010	5	558	725	660	637	828	781	695	904	868
2011	5	564	733	668	649	844	799	708	921	887
2012	5	570	740	675	661	860	815	721	937	906
2013	5	576	748	683	673	875	832	734	954	924
2014	5	582	756	691	685	891	849	747	971	942
2015	5	588	764	699	697	906	866	760	988	960
2016	5	594	772	707	709	922	883	773	1005	978
2017	5	600	779	716	721	938	900	786	1022	997
2018	5	606	787	725	733	953	917	799	1039	1015
2019	5	612	795	734	745	969	934	812	1056	1033
2020	5	618	803	744	757	984	951	825	1073	1051
2021	5	624	811	753	769	1000	968	838	1090	1069
2022	5	630	818	762	781	1016	984	851	1106	1088
2023	5	636	826	771	793	1031	1001	864	1123	1106
2024	5	642	834	780	805	1047	1018	877	1140	1124
2025	5	648	842	789	817	1062	1035	890	1157	1142
2026	5	654	850	798	329	1078	1052	903	1174	1160
2027	5	660	857	807	841	1094	1069	916	1191	1179
2028	5	666	865	816	853	1109	1086	929	1208	1197

The Anchorage/Fairbanks Capacity (Second Column) is the sum of the two areas capacities which, due to transmission limits, may not serve an equal amount of load.

Capacity requirements are based on a 30 percent capacity reserve margin.

Capacity shortage, if any, for Anchorage/Fairbanks Area = Anchorage/Fairbanks Capacity Requirements
— Anchorage/Fairbanks Capacity
— Surplus in Kenai Accessible via Existing Kenai/Anchorage Lines

Table 6-9

REDUCED ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE DUE TO ANCHORAGE/FAIRBANKS INTERTIE UPGRADE (MW)

	CASE 1				CASE 2		
	Load Growth				Load Growth		
Year	Low	Medium	High	Year	Low	Medium	High
1994	0	0	0	1994	0	0	0
1995	0	0	0	1995	0	0	0
1996	0	9	8	1996	0	0	5
1997	15	15	2	1997	0	13	2
1998	14	14	0	1998	14	14	0
1999	14	12	0	1999	14	12	0
2000	6	4	0	2000	6	4	0
2001	0	0	0	2001	0	0	0
2002	0	0	0	2002	0	0	0
2003	0	0	0	2003	0	0	0
2004	0	0	0	2004	0	0	0
2005	0	0	0	2005	0	0	0
2006	0	0	0	2006	0	0	0
2007	0	0	0	2007	0	0	0
2008	0	0	0	2008	0	0	0
2009	0	0	0	2009	0	0	0
2010	0	0	0	2010	0	0	0
2011	0	0	0	2011	0	0	0
2012	0	0	0	2012	0	0	0
2013	0	0	0	2013	0	0	0
2014	0	0	0	2014	0	0	0
2015	0	0	0	2015	0	0	0
2016	0	0	0	2016	0	0	0
2017	0	0	0	2017	0	0	0
2018	0	0	0	2018	0	0	0
2019	0	0	0	2019	0	0	0
2020	0	0	0	2020	0	0	0
2021	0	0	0	2021	0	0	0
2022	0	0	0	2022	0	0	0
2023	0	0	0	2023	0	0	0
2024	0	0	0	2024	0	0	0
2025	0	0	0	2025	0	0	0
2026	0	0	0	2026	0	0	0
2027	0	0	0	2027	0	0	0
2028	0	0	0	2028	0	0	0

6.5.3 Healy-Fairbanks New Intertie (AF138)

The AF138 intertie would allow Anchorage and Fairbanks to reduce their capacity requirements by the same amount calculated for the Anchorage-Fairbanks AF100 upgrade; since the AF100 provides all the transfer capability needed to take advantage of capacity sharing between Anchorage to Fairbanks. Table 6-9 shows the reduced shortage for the Anchorage/Fairbanks area is always less than the increased transfer levels for the AF proposals. The increase in transfer limits for the AF138 provides no additional capacity deferral benefits beyond those calculated for the AF100.

6.6 BENEFITS OF CAPACITY DEFERRAL DUE TO NEW/UPGRADED INTERTIES

When capacity is needed, the Railbelt utilities would acquire additional capacity by repowering existing power plants, extending the life of existing power plants, or 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 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 6.5.1 and 6.5.2), the resulting savings are cost deferrals rather than cost avoidances. 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 $51 per kilowatt per year.[9]

6.6.1 Kenai-Anchorage New Intertie (KA138)

Using the calculated reduced Kenai/Anchorage capacity shortages (Table 6-7) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings due to capacity deferral attributed to the KA138 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 deferral due to the KA138 intertie vary between $18.91 million and $20.90 million for Case 1 and $6.67 million and $8.30 million for Case 2.

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[9] Based on the levelized capital cost of a combustion turbine of $490 per kilowatt, and a fixed O&M of $13 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 (million dollars)

CASE 1

	Load Growth		
Year	Low	Medium	High
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.43	1.69
1997	1.31	2.12	2.55
1998	2.24	2.55	2.55
1999	2.55	2.55	2.55
2000	2.55	2.55	2.55
2001	2.55	2.55	2.53
2002	2.55	2.55	2.42
2003	2.55	2.55	2.31
2004	2.55	2.55	2.17
2005	2.55	2.48	1.83
2006	2.55	2.41	1.78
2007	2.55	1.40	0.79
2008	2.55	1.32	0.67
2009	2.51	1.24	0.62
2010	0.42	0.00	0.00
2011	0.30	0.00	0.00
2012	0.24	0.00	0.00
2013	0.17	0.00	0.00
2014	0.11	0.00	0.00
2015	0.04	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
NPV 3.0%	24.18	23.31	21.21
NPV 4.5%	20.90	19.63	18.91

CASE 2

	Load Growth		
Year	Low	Medium	High
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.00	0.26
1997	0.00	0.68	1.12
1998	0.80	1.12	1.12
1999	1.12	1.12	1.12
2000	1.12	1.12	1.12
2001	1.12	1.12	1.11
2002	1.12	1.12	0.99
2003	1.12	1.12	0.89
2004	1.12	1.12	0.75
2005	1.12	0.97	0.41
2006	1.12	0.91	0.36
2007	1.12	0.00	0.00
2008	1.12	0.00	0.00
2009	1.07	0.00	0.00
2010	0.00	0.00	0.00
2011	0.00	0.00	0.00
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
NPV 3.0%	9.62	8.23	7.41
NPV 4.5%	8.30	7.29	6.67

6.6.2 Anchorage-Fairbanks Intertie Upgrade (AF100)

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Table 6-9) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings due to capacity deferral attributed to the AF100. Table 6-11 summarizes the results. At a discount rate of 4.5 percent per year, the benefits of capacity deferral due to the AF100 upgrade vary between $0.43 million and $2.20 million for Case 1 and $0.33 million and $1.75 million for Case 2.

6.6.3 Healy-Fairbanks New Intertie (AF138)

Because the AF100 upgrade and the AF138 intertie would lead to the same capacity shortage reductions, these calculations produce the same capacity deferral benefits. Those benefits are between $0.43 million and $2.20 million for Case 1 and $0.33 million and $1.75 million for Case 2.

6.7 CAPACITY AVOIDANCE DUE TO NEW/UPGRADED INTERTIES

The proposed interties make two significant contributions relevant for capacity-sharing benefits: access to another area's capacity and increased reliability.

The previous section presented reductions in capacity shortage in Anchorage due to the proposed interties by *accessing* surplus capacity in Kenai and Fairbanks (surplus areas) to defer capacity additions in Anchorage (shortage area). Capacity deferral benefits derive from capacity in surplus areas contributing to a target reserve margin for a shortage area.

The reserve margin of an electric power system is a function of desired system reliability, sizes of power plants, availability of power plants, and system size. A system reserve margin decreases with lower desired system reliability, smaller plants size, higher plants availability, and larger system size.

A new intertie leads to larger system sizes for interconnected areas and therefore would allow both areas to establish lower reserve margins, and/or add larger size units while keeping desired reliability unchanged. Lowering reserve margins leads to reduced capacity additions, i.e., capacity avoidance benefits.

Table 6-11

BENEFITS OF REDUCED ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE
(million dollars)

CASE 1

	Load Growth		
Year	Low	Medium	High
1994	0.00	0.00	0.0
1995	0.00	0.00	0.00
1996	0.00	0.43	0.39
1997	0.74	0.77	0.11
1998	0.73	0.69	0.00
1999	0.72	0.63	0.00
2000	0.31	0.18	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00
2011	0.00	0.00	0.00
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
NPV 3.0%	2.14	2.37	0.46
NPV 4.5%	1.99	2.20	0.43

CASE 2

	Load Growth		
Year	Low	Medium	High
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.00	0.26
1997	0.00	0.68	0.11
1998	0.73	0.69	0.00
1999	0.72	0.63	0.00
2000	0.31	0.18	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00
2011	0.00	0.00	0.00
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
NPV 3.0%	1.49	1.89	0.34
NPV 4.5%	1.37	1.75	0.33

This section calculates the reductions in capacity reserve margin that could be made with the proposed interties and the associated avoidance of some capacity additions.[10] No estimate of economies of scale benefits is provided in this analysis,[11] due to lack of good data on economies of scale.

6.7.1 Equivalent Reliability Index

Many different measures of the reliability of a power system have been developed and used; they vary depending on the particular needs of the measurement. Loss of Load Probability (LOLP) has gained considerable use in the industry as a reasonably well-defined index of system reliability [2]. An Equivalent Reliability Index (ERI), based on the same concepts of LOLP, is defined and used here for evaluation of the new/upgraded interties.

Experience has shown that the mean and variance (the square of the standard deviation) of capacity availability represent, reasonably well, the distribution of availability for reliability purposes, and that the distribution can be approximated by the Normal or Gaussian distribution [2]. In reference [3], LOLP is calculated by evaluating the area under the capacity availability distribution from zero to a given load. This evaluation requires standardizing the variable and using a standard Normal table to evaluate the probability.

For example, the LOLP at a load of L, for a capacity availability mean M and standard deviation S, could be found from calculating the standard variable:

$$Z = (L - M)/S$$

and

LOLP = 0.5 – Area Under the Standard Normal Evaluated Between 0 and Z

The implication of the calculation for the following discussion is that a change in the capacity of the system results in changes to the mean and variance of the availability distribution. A system addition would result in a different level of load that could be served (or lost) for the same LOLP target.

Following the same rational, and assuming the capacity on outage to be normally distributed, the Equivalent Reliability Index (ERI) is a measure of the adequacy of the reserve margin to meet the level of outages.

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[10] The section on reliability (Section 4) covered the benefits of the new/upgraded interties gained from the reduction in outages; impacts on capacity planning were not included in that analysis.

[11] The inclusion of economies of scale benefits could only increase the benefits of capacity sharing.

$$ERI = (RM - m)/s,$$

where RM = Reserve Capacity Margin (MW)
m = Mean of Capacity on Outage (MW)
s = Standard Deviation of Capacity on Outage (MW)

A change in available capacity affects the mean and standard deviation of the capacity on outage. A new intertie, for instance, leads to a decrease in the standard deviation of the capacity on outages. This implies that the reserve margin could be adjusted downward for the decrease in the standard deviation of the capacity on outage, while holding the ERI constant.

6.7.2 Calculation of Avoided Capacity

The ERI is used as a measure of capacity adequacy, taking as input reserve margin and the distribution of capacity outages. Holding the ERI constant for evaluation of the cases with and without the interties, we calculate reductions in needed reserve margins due to the new/upgraded interties. New/upgraded interties result in reductions in reserve margins, since the impact of reliable additions is to decrease the standard deviation of the outage distribution (while slightly increasing the mean). Reductions in reserve margins lead to a fixed level of capacity avoidance for the area of interest.

A simulation of the capacity avoidance due to the new/upgraded interties used capacity and outage data for each generating unit in the Railbelt. A reserve load margin[12] of 30 percent, which is equivalent to a system reserve margin[13] of 23.08 percent, is assumed. Available generating resources for each area consist of those units most important for evaluation purposes; i.e., if a unit is to be retired in 1992, the unit is not included. The simulation assumes that the relationship between loads and resources remains constant through the study period so that the percent reserve margin stays constant.

The ERI is calculated, as described above, from the capacity on outage data. For each proposal, the amount of avoided capacity is calculated as the MW reduction in reserve margin, such that the ERI is held constant with the addition of the new intertie. Benefits of the avoided additions to capacity are then calculated by applying the same capacity value ($51/kW) as in the deferral analysis.

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[12] Reserve load margin is the amount of available generating resources that exceeds forecasted load, calculated as a percent of the load.

[13] System reserve margin is the amount of available generating resources that exceeds forecasted load, calculated as a percentage of the total available generating resources.

6.7.3 Kenai-Anchorage New Intertie (KA138)

The amount of avoided capacity additions in the Kenai/Anchorage area due to the KA138 ranges from 9.4 MW to 20.7 MW for each year in which shortages occur, which is the case after 1999. The low estimate is based on an existing transfer limit of 88 MW between Kenai and Anchorage, while the high estimate is based on an existing transfer limit of 60 MW.

6.7.4 Anchorage-Fairbanks Intertie Upgrade (AF100)

The amount of avoided capacity additions in the combined Anchorage/Fairbanks area, due to the AF100 line, ranges from 9.6 MW to 10.9 MW for each year in which shortages occur. The low estimate is based on a transfer limit of 84 MW for the AF100, while the high estimate corresponds to a transfer limit of 87 MW.

6.7.5 Healy-Fairbanks New Intertie (AF138)

The amount of avoided capacity additions in the combined Anchorage/Fairbanks area, due to the AF138 line, is 21.3 MW for each year of shortage conditions. This estimate is based on a transfer limit of 112 MW, after losses, for the AF138 between Anchorage and Fairbanks.

6.8 BENEFITS OF CAPACITY AVOIDANCE DUE TO NEW/UPGRADED INTERTIES

6.8.1 Kenai-Anchorage New Intertie (KA138)

Using the calculated reduced Kenai/Anchorage capacity shortages (Section 6.7.3) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings from capacity avoidance due to the KA138.[14]

The benefits are calculated for 1994-2033 at a discount rate of 4.5 percent per year; no benefits accrue for the years 1994-1998 since there are no forecasted capacity for this period in the Railbelt. The benefits of capacity avoidance due to the KA138 intertie vary between $14.8 million for Case 1 and $6.74 million for Case 2.

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[14] A 40-year lifetime has been estimated for the KA138.

6.8.2 Anchorage-Fairbanks Intertie Upgrade (AF100)

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Section 6.7.4) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings from capacity avoidance due to the AF100.

The benefits are calculated for 1994-2043[15] at a discount rate of 4.5 percent per year; no benefits accrue for 1994-1998 since there are no forecasted capacity shortages for this period in the Railbelt.

The benefits of capacity avoidance due to the AF100 upgrade are between $7.16 million for Case 1 and $8.13 million for Case 2.

6.8.3 Healy-Fairbanks New Intertie (AF138)

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Section 6.7.5) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings from capacity due to the AF138.

The benefits are calculated for 1994-2043[16] at a discount rate of 4.5 percent per year; no benefits accrue for 1994-1998 since there are no forecasted capacity shortages for this period in the Railbelt. The benefits of capacity avoidance due to the AF138 intertie are $15.97 million.

6.9 TOTAL CAPACITY-SHARING BENEFITS DUE TO NEW/UPGRADED INTERTIES

Total benefits of the new/upgraded interties are the sum of capacity deferral benefits (Section 6.6, Tables 6-10, 6-11) and capacity avoidance benefits (Sections 6.8.1, 6.8.2, 6.8.3). The total benefits for each new or upgraded intertie are shown in Table 6-12.

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[15] A 50-year lifetime has been estimated for the steel tower construction proposed for the AF100.

[16] A 50-year lifetime has been estimated for the steel tower construction proposed for the AF138.

Table 6-12

TOTAL CAPACITY-SHARING BENEFITS
(million dollars, 1990 dollars)

	Case 1			Case 2		
	Load			Load		
	Low	Mid	High	Low	Mid	High
KA138	35.7	34.4	33.7	15.0	14.0	13.4
AF100	9.2	9.4	7.6	9.5	9.9	8.5
AF138	18.0	18.2	16.4	17.3	17.7	16.3

6.10 REFERENCES

[1] Alaska Intertie Agreement, December 1985.

[2] R. Billinton, "Bibliography on the Application of Probability Methods in Power System Reliability," *IEEE Transactions*, vol. PAS-91, pp. 649-660, 1972.

[3] J. Stremel, "The Cumulant Method of Calculating LOLP," IEEE PES Summer Meeting, Paper A 79 506-7, 1979.

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 four factors:

1. The operating reserve requirements in Anchorage.
2. The cost of providing operating reserves from thermal plants in Anchorage.
3. The transmission capacity between Anchorage and Kenai.
4. The generating capability in Kenai.

All four factors are discussed in more detail in the following subsections. The addition of a new Kenai-Anchorage intertie would increase the savings due to operating reserve sharing by about $5.2 to $13.5 million.

Appendix A 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.

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[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 the practice of distributing these reserves such that they are not all lost with a single event.

With a second Kenai-Anchorage line, it would be feasible to transfer more than 30 MW of operating reserve from Kenai to Anchorage. The existence of two lines would provide a backup link between Kenai and Anchorage in the event of a line failure so that operating reserves are not all lost. Based on our discussions with system dispatchers,[2] we estimate that a second line would allow the transfer of up to 50 MW of operating reserve from Kenai to Anchorage. The 50 MW results from allowing for 15 MW of operating reserves to be provided by thermal power plants in Anchorage; these 15 MW are necessary to provide load following in the Railbelt.

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 A provides more specific information about gas turbine part-load operating costs. 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,[3] 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 Table A-2). Therefore, the cost of spinning reserves provided by Beluga #5 is estimated at 5000 Btu/kWh.

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[2] Meetings between Salim J. Jabbour and system dispatchers at Golden Valley Electric Association, Chugach Electric Association, Alaska Municipal Light & Power on August 8, 9 and 10, 1989.

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

A detailed examination of the operating records of CEA, GVEA, and AMLP for 1988 indicates that the cost of providing spinning reserves is between 7,000 and 11,000 Btu/KWh.[4] In this study, we estimate the cost of spinning reserves at 7,000 Btu/KWh.

7.4 KENAI-ANCHORAGE TRANSMISSION CAPACITY

The new intertie will be capable of transferring 150 MW from Kenai to Anchorage (110 MW delivered). Based on the analysis described in Appendix A, transmission capacity will not be a constraint on the transfer of 50 MW of operating reserve.

The existing line can transfer 60 MW (delivered) from Kenai to Anchorage in Case 1, and 88 MW (delivered under emergency conditions) in Case 2. Based on the analysis described in Appendix A, it is expected that there will be 26 MW of capacity available for the transfer of operating reserves in Case 1 and 29 MW in Case 2. Because this increment of capacity has very high losses (approximately 20 percent), it will be seldom utilized for economy transactions. Transferring operating reserve is ideal because it does not incur losses. Therefore the transmission capacity between Kenai and Anchorage will be a constraint on the transfer of operating reserves under the single line scenario.

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 provide useful operating reserve has been studied recently.[5] These findings indicate that while Bradley Lake's response rate is not fast enough to provide spinning reserves, Bradley Lake would allow the Railbelt utilities to get increased spinning reserves out of the thermal units at minimal or no additional cost. Following is an excerpt from a PTI report that explains this concept:

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[4] Value of Bradley Lake Spinning Reserves, prepared by Decision Focus Incorporated, October 6, 1989.

[5] Power Technologies Incorporated and Stone and Webster Engineering Corporation have been working on this issue for the Alaska Energy Authority.

> Combustion turbines are typically rated based on a maximum allowable turbine exhaust gas temperature. CT ratings are usually established for a standard set of environmental operating conditions known as ISO conditions. ISO conditions refer to an ambient temperature of 59 degrees Fahrenheit, at normal sea-level atmospheric pressure and at a certain relative humidity. For ISO conditions, CT will typically have two ratings based on some defined value of turbine exhaust gas temperatures:
>
> 1) Base Rating
> 2) Peak Rating
>
> The turbine exhaust gas temperature is a significant indicator of the amount of life expenditure that occurs in a CT due to erosion and fatigue of the internal turbine parts.
>
> The base rating is the power rating at which a CT can operate for sustained periods of time and stay within what is considered to be a normal maintenance schedule and without severe or unusual degradation to the internal parts of the turbine. The peak rating is a power rating greater than the base rating at which a CT can operate for some limited period of time (hours), but which will cause greater than normal degradation of the internal parts of the turbine and will increase the frequency and necessity of maintenance.
>
> Although not specified as a rating, CT have an emergency capability which is above the peak rating. This emergency capability may correspond to the maximum, physical fuel consumption capability of the turbine as allowed by the fuel control system. A CT can operate at this emergency capability for only a very limited period of time, and operation at such levels (for more than a few seconds consecutively) will result in severe degradation of the internal parts of the turbine and will require significant maintenance activity...
>
> ...Various operating strategies can be developed to obtain increased response capability from a CT. One could normally operate a CT at no more than its base rating level and, during below-normal frequency conditions, take advantage of the few seconds of temporary "above rated power" output which might occur before the controls reduce the output of the CT back to its base rating level. Conversely, one could normally strive to operate a CT at no more than its base rating level, but configure the controls of the CT to allow it to operate, on a sustained basis, up to its peak rating level. Thus, in response to a below-normal frequency condition, the governor could boost the output of the CT to the emergency capability (maximum fuel consumption) until the exhaust temperature controls bring the output back to the peak rating level. The CT could then be allowed to operate at the peak rating level until other generation was brought on-line or until the output of slower responding hydro or steam units could be increased. Thus, the latter strategy would provide more sustained reserve capability from a given combustion turbine than the first operating strategy. Further, provided that a CT was not allowed to remain at its peak rating level for inordinate amounts of time, severe degradation of the internal parts of the turbine could be minimized and excessive maintenance activity avoided.

By using the "peak rating strategy," utilities can get increased spinning reserves from operating combustion turbines. The increase in spinning reserves is the difference between the peak and base ratings of the turbines. While the "peak rating strategy" could be used without Bradley Lake, the strategy would provide spinning reserves only if combustion turbines are operated at peak loading during emergency situations, for several minutes, until a unit is brought on-line. According to the PTI report, this would reduce the economic life of the turbines. The impact of Bradley Lake would be to reduce the time during which the turbines would be operated at peak loading to less than 1 minute.

Therefore, we assume that Bradley Lake would allow the use of the "peak rating strategy" and provide additional spinning reserves. Assuming a 10 percent difference between the peak and base ratings[6] of thermal units, we estimate that Bradley would provide an additional 30 MW of spinning reserves in the summer and 50 MW in the winter.[7]

7.6 SAVINGS IN OPERATING RESERVE COSTS

The benefits of increased operating reserve sharing due to a second line between Kenai and Anchorage derive from increased intertie availability,[8] increased reliance on Kenai's spinning reserves in the winter,[9] and increased intertie transfer capability.[10] We estimate the annual benefits of increased operating reserve sharing between $400,000 and $1,200,000. The net present value of increased operating reserve sharing is between $5.2 million and $13.5 million[11] (see Table 7-1).

Table 7-1

NET PERCENT VALUE OF SAVINGS DUE TO INCREASED OPERATING RESERVE SHARING (million dollars, 1990 dollars)

Scenario	Fuel	Increased Intertie Availability	Increased Reliance On Kenai Reserves In Winter	Increased Intertie Transfer Capability	Total
Case 1	Low	3.70	0.62	3.35	7.67
	Mid	5.11	0.87	4.71	10.69
	High	6.37	1.10	6.00	13.47
Case 2	Low	3.70	0.62	0.84	5.16
	Mid	5.10	0.87	1.18	7.15
	High	6.38	1.10	1.50	8.98

---

[6] Based on discussions with PTI and representatives of the Railbelt electric utilities.

[7] Based on Railbelt loads.

[8] Refer to discussion on scheduled maintenance of the 115 KV line in Section 2.

[9] Refer to Section 7.5.

[10] Refer to Section 7.4.

[11] Savings are adjusted for reduced gas royalty.

Section 8

SUMMARY AND CONCLUSIONS

8.1 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. In accordance with the practice followed throughout this analysis, all costs and benefits are expressed in terms of 1990 dollars.

The costs and benefits of the following intertie proposals are summarized in this section:

1. A new Kenai-Anchorage 138 KV intertie
2. A limited upgrade of the Anchorage-Fairbanks line
3. A new Healy-Fairbanks 138 KV intertie

The following benefit categories are described:

1. Reliability
2. Economy Energy Transfer
3. Transmission Efficiency
4. State Revenue
5. Capacity Sharing
6. Operating Reserve Sharing

8.2 NEW KENAI-ANCHORAGE 138 KV INTERTIE

Table 8-1 shows the present value of costs and benefits for the new Kenai-Anchorage line in each of the categories identified in this analysis. Positive benefits are indicated for each scenario examined. The expected value of net economic benefits is between $27.8 million and $57.1 million. The expected benefit to cost ratio is between 1.32 and 1.77. The difference between the low and high estimates of benefit reflects both the difference between the high and low reliability benefit and the difference between the low and high capital costs. The high estimate of total costs includes a replacement cost of $9.5 million (net present value of a replacement cost of $22.9 million after 20 years of service) for the submarine cable.

Figure 8-1 displays net benefits for each scenario. Figure 8-2 shows the relative contribution of each benefit category to the total expected benefits.

Table 8-1

NEW KENAI-ANCHORAGE INTERTIE: SUMMARY OF COSTS AND BENEFITS

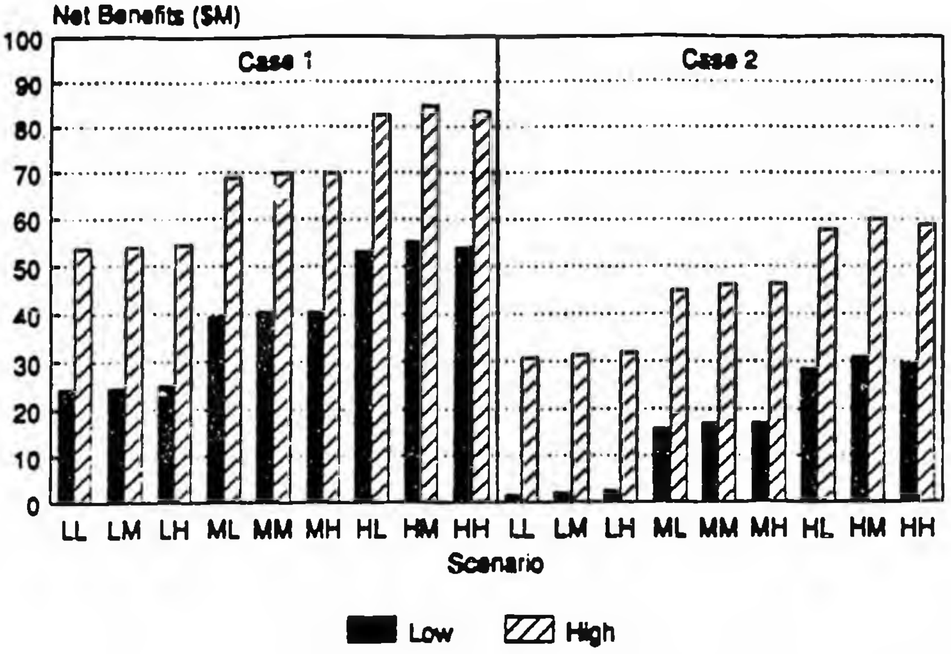
	Assumptions		Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Increased Spinning Reserves Sharing Benefits	Total Benefits		Total Costs		Net Benefits		Benefit to Cost Ratio	
Scenario	Fuel	Load						Low	High	Low	High	Low	High	Low	High
Case #1	Low	Low	33.0	-2.1	-3.1	35.7	7.7	110.5	127.8	74.1	86.2	24.3	53.7	1.28	1.72
		Middle	33.7	-1.1	-3.6	34.4	7.7	110.7	127.9	74.1	86.2	24.5	53.8	1.28	1.73
		High	34.9	-1.3	-3.2	33.7	7.7	111.2	128.4	74.1	86.2	25.0	54.3	1.29	1.73
	Middle	Low	48.9	-2.9	-4.0	35.7	10.7	125.7	142.9	74.1	86.2	39.5	68.8	1.46	1.93
		Middle	51.7	-2.9	-4.6	34.4	10.7	126.7	143.9	74.1	86.2	40.5	69.8	1.47	1.94
		High	53.9	-4.5	-4.5	33.7	10.7	126.8	143.9	74.1	86.2	40.6	69.8	1.47	1.94
	High	Low	61.8	-3.6	-5.3	35.7	13.5	139.4	156.7	74.1	86.2	53.2	82.5	1.62	2.11
		Middle	65.4	-3.5	-5.7	34.4	13.5	141.5	158.7	74.1	86.3	55.3	84.6	1.64	2.14
		High	68.0	-3.9	-6.9	33.7	13.5	140.1	157.6	74.1	86.2	53.9	83.5	1.63	2.13
Case #2	Low	Low	33.2	-2.1	-3.1	15.0	5.2	87.6	104.8	74.1	86.2	1.4	30.7	1.02	1.41
		Middle	35.9	-1.1	-3.4	14.0	5.2	88.0	105.3	74.1	86.2	1.8	31.1	1.02	1.42
		High	37.2	-1.3	-3.2	13.4	5.2	88.6	105.9	74.1	86.2	2.4	31.7	1.03	1.43
	Middle	Low	49.3	-2.9	-4.1	15.0	7.2	101.8	119.1	74.1	86.2	15.6	44.9	1.18	1.61
		Middle	52.1	-3.0	-4.6	14.0	7.2	103.1	120.4	74.1	86.2	16.9	46.2	1.20	1.62
		High	54.3	-4.5	-4.5	13.4	7.2	103.2	120.4	74.1	86.2	17.0	46.3	1.20	1.62
	High	Low	62.3	-2.7	-5.3	15.0	9.0	114.6	131.9	74.1	86.2	28.4	57.7	1.33	1.78
		Middle	65.9	-3.6	-5.7	14.0	9.0	117.0	134.2	74.1	86.2	30.8	60.1	1.36	1.81
		High	68.3	-5.6	-6.9	13.4	9.0	115.7	133.0	74.1	86.2	29.5	58.9	1.34	1.79

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2033 discounted at 4.3%/yr)
2. Total benefits include:

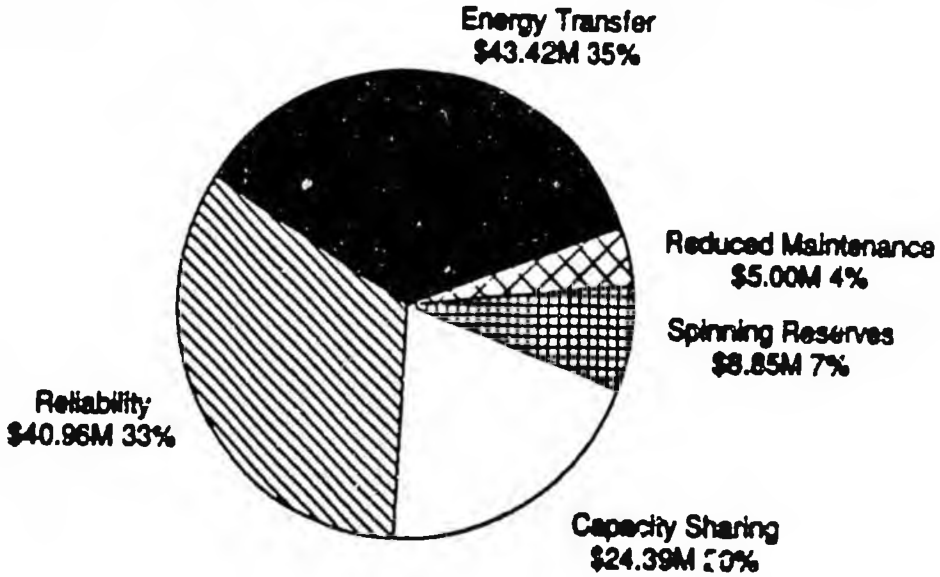
Benefit	Low	High
Reliability benefits	32.33	49.38
Reduced maintenance costs of 115 KV line	5.00	5.00

3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes hydrothermal coordination adjustment.



LL	Low Fuel/Low Load	ML	Middle Fuel/Low Load	HL	High Fuel/Low Load
LM	Low Fuel/Middle Load	MM	Middle Fuel/Middle Load	HM	High Fuel/Middle Load
LH	Low Fuel/High Load	MH	Middle Fuel/High Load	HH	High Fuel/High Load

Figure 8-1. New Kenai-Anchorage Intertie: Net Benefits



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 8-2. New Kenai-Anchorage Intertie: Breakdown of Expected Benefits

8.3 LIMITED UPGRADE OF THE ANCHORAGE-FAIRBANKS INTERTIE TO 100 MW

Table 8-2 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 $35.5 million. The expected benefit to cost ratio is 4.45.

Figure 8-3 displays the net benefits estimated for each scenario. Figure 8-4 shows the relative contribution of each benefit category to the total expected benefits.

Table 8-2

ANCHORAGE-FAIRBANKS UPGRADE TO 100 MW: SUMMARY OF COSTS AND BENEFITS

Scenario	Assumptions Fuel	Assumptions Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Case #1	Low	Low	55.0	-20.2	6.1	9.2	55.0	10.3	44.7	5.34
		Middle	44.6	-16.4	5.3	9.4	47.9	10.3	37.6	4.65
		High	40.5	-16.8	5.6	7.6	41.9	10.3	31.6	4.07
	Middle	Low	25.4	-9.1	2.5	9.2	33.0	10.3	22.7	3.20
		Middle	33.6	-12.0	3.3	9.4	39.4	10.3	29.0	3.82
		High	51.1	-19.1	5.2	7.6	49.9	10.3	39.5	4.84
	High	Low	30.9	-10.3	2.9	9.2	37.6	10.3	27.3	3.65
		Middle	41.6	-14.0	3.9	9.4	45.9	10.3	35.6	4.46
		High	61.8	-21.1	5.9	7.6	59.2	10.3	48.9	5.74
Case #2	Low	Low	55.0	-20.2	6.1	9.5	55.4	10.3	45.1	5.37
		Middle	44.6	-16.4	5.3	9.9	48.4	10.3	38.1	4.70
		High	40.5	-16.8	5.6	8.5	42.8	10.3	32.5	4.15
	Middle	Low	25.4	-9.1	2.5	9.5	33.3	10.3	23.0	3.23
		Middle	33.6	-12.0	3.3	9.9	39.9	10.3	29.6	3.87
		High	51.1	-19.1	5.2	8.5	50.7	10.3	40.4	4.92
	High	Low	30.9	-10.3	2.9	9.5	38.0	10.3	27.7	3.68
		Middle	41.6	-14.0	3.9	9.9	46.5	10.3	36.2	4.51
		High	61.8	-21.1	5.9	8.5	60.1	10.3	49.8	5.83

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of 5.04 million dollars.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

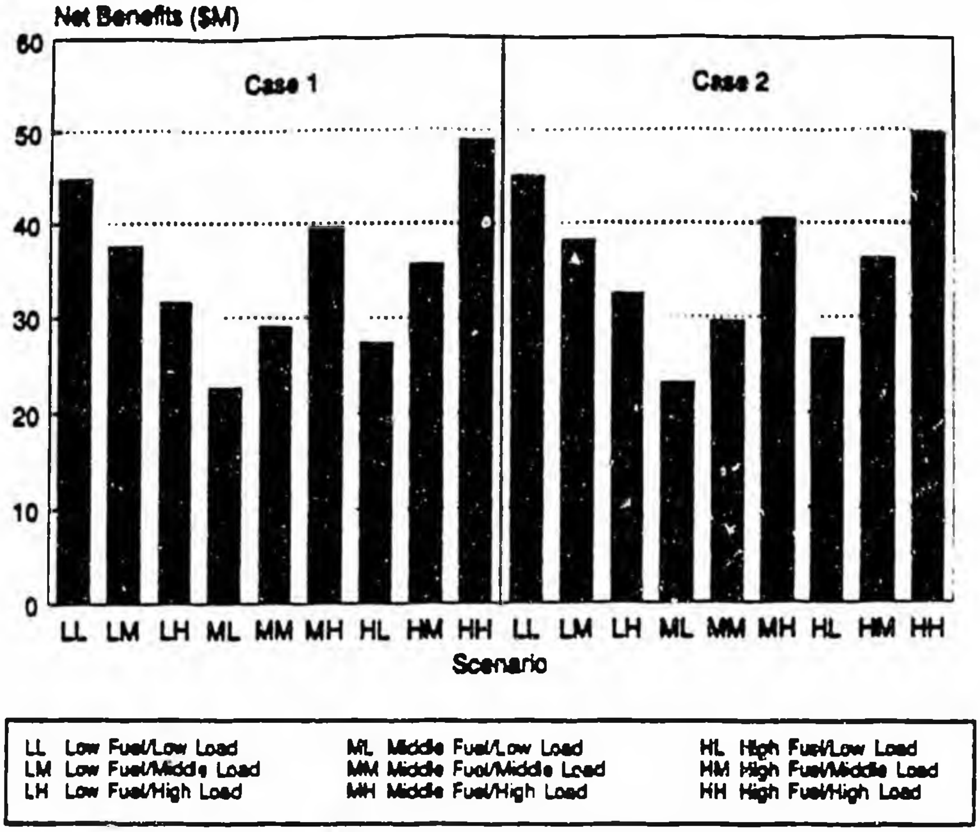
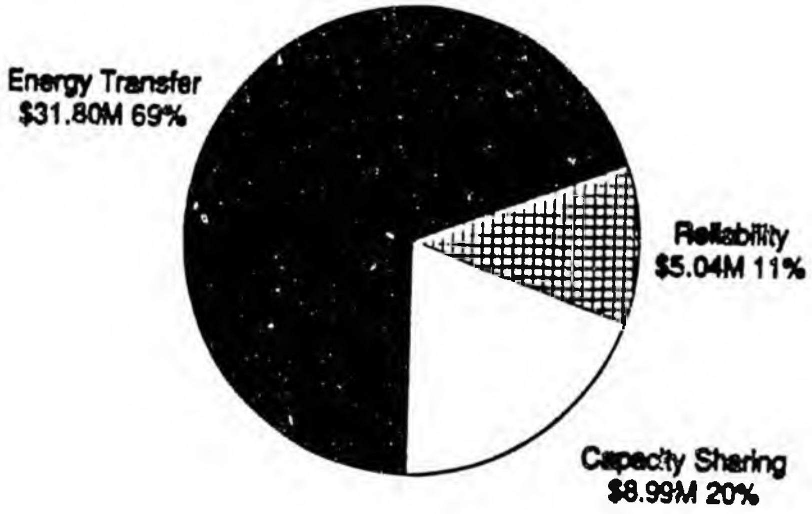


Figure 8-3. Anchorage-Fairbanks Upgrade to 100 MW: Net Benefits



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 8-4. Anchorage-Fairbanks Upgrade to 100 MW:
Breakdown of Expected Benefits

8.4 HEALY-FAIRBANKS INTERTIE

Table 8-3 shows the present value of costs and benefits for the Healy-Fairbanks Northern intertie. Positive benefits are indicated for each scenario examined. The expected value of economic benefit is $41.2 million. The expected benefit to cost ratio is 1.64.

Figure 8-5 displays the net benefits estimated for each scenario. Figure 8-6 shows the relative contribution of each benefit category to the total expected benefits.

Table 8-3

HEALY-FAIRBANKS NORTHERN INTERTIE: SUMMARY OF COSTS AND BENEFITS

Scenario	Assumptions Fuel	 Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Case #1	Low	Low	84.9	-14.5	10.0	18.0	109.8	64.6	45.3	1.70
		Middle	82.7	-13.5	9.9	18.2	108.8	64.6	44.3	1.69
		High	87.8	-11.9	9.9	16.4	113.7	64.6	49.1	1.76
	Middle	Low	47.6	2.5	3.7	18.0	83.2	64.6	18.6	1.29
		Middle	61.7	-1.9	5.3	18.2	94.8	64.6	30.2	1.47
		High	83.8	-7.7	7.8	16.4	111.8	64.6	47.2	1.73
	High	Low	57.7	-1.2	6.3	18.0	92.2	64.6	27.6	1.43
		Middle	76.1	-5.6	7.7	18.2	107.8	64.6	43.2	1.67
		High	97.1	-6.7	8.6	16.4	126.9	64.6	62.3	1.97
Case #2	Low	Low	88.9	-15.8	10.3	17.3	112.2	64.6	47.7	1.74
		Middle	87.1	-15.0	10.4	17.7	111.7	64.6	47.2	1.73
		High	90.7	-13.0	10.2	16.3	115.8	64.6	51.3	1.79
	Middle	Low	47.7	2.4	3.7	17.3	82.6	64.6	18.1	1.28
		Middle	61.9	-2.0	5.3	17.7	94.5	64.6	29.9	1.46
		High	84.0	-7.8	7.8	16.3	111.7	64.6	47.2	1.73
	High	Low	57.8	-1.3	6.3	17.3	91.7	64.6	27.1	1.42
		Middle	76.4	-5.8	7.7	17.7	107.5	64.6	43.0	1.67
		High	97.2	-6.8	8.6	16.3	126.8	64.6	62.3	1.96

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of 11.52 million dollars.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

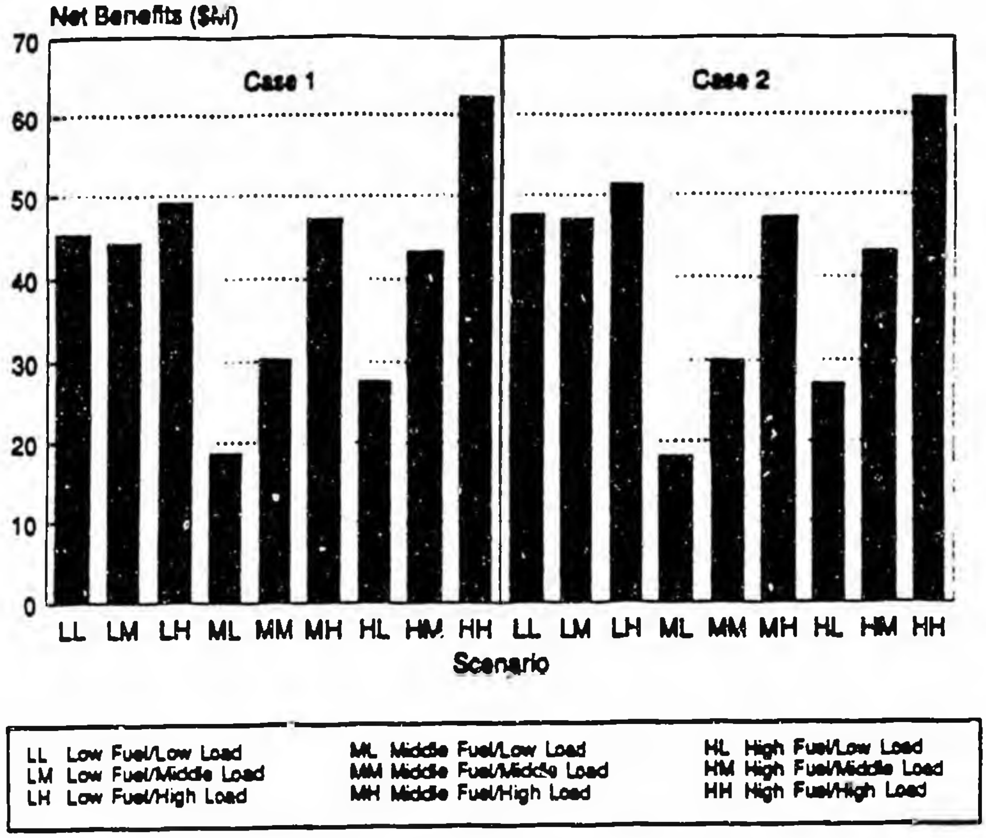
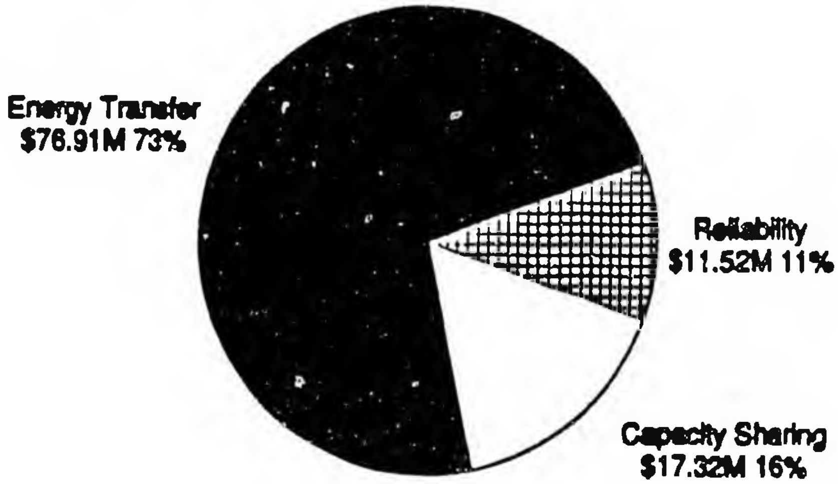


Figure 8-5. Healy-Fairbanks Northern Intertie: Net Benefits



Energy transfer includes transfer loss and gas royalty.
Average of all scenarios.

Figure 8-6. Healy-Fairbanks Northern Intertie: Breakdown of Expected Benefits

Table 8-4 shows the present value of the incremental costs and benefits for the Healy-Fairbanks northern intertie. All costs and benefits presented in Table 8-4 are incremental over corresponding costs and benefits of the limited upgrade of the Anchorage-Fairbanks line. The expected value of incremental net economic benefits is $5.7 million. The expected incremental benefit to cost ratio is 1.1. Most of the examined scenarios show positive incremental net benefits; only three scenarios (all with low load forecasts) show small negative incremental net benefits.

Figure 8-7 displays the incremental net benefits estimated for each scenario. Figure 8-8 shows the relative contribution of each benefit category to the total expected incremental benefits.

Table 8-4

HEALY-FAIRBANKS NORTHERN INTERTIE: SUMMARY OF COSTS AND BENEFITS (INCREMENTAL OVER THE LIMITED UPGRADE OF THE ANCHORAGE-FAIRBANKS LINE)

Paste Table 8-4, reduced, here.

Scenario	Assumptions Fuel	 Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Case 1	Low	Low	29.9	5.7	3.9	8.8	54.8	54.2	0.5	1.01
		Middle	38.1	2.9	4.7	8.8	60.9	54.2	6.7	1.12
		High	47.3	4.9	4.3	8.8	71.8	54.2	17.5	1.32
	Middle	Low	22.1	11.6	1.2	8.8	50.2	54.2	-4.0	0.93
		Middle	28.1	10.1	2.0	8.8	55.4	54.2	1.2	1.02
		High	32.7	11.4	2.6	8.8	61.9	54.2	7.7	1.14
	High	Low	26.8	9.0	3.4	8.8	54.5	54.2	0.3	1.01
		Middle	34.4	8.3	3.8	8.8	61.8	54.2	7.6	1.14
		High	35.3	14.4	2.7	8.8	67.7	54.2	13.4	1.25
Case 2	Low	Low	33.9	4.4	4.2	7.8	56.8	54.2	2.6	1.05
		Middle	42.5	1.5	5.1	7.8	63.3	54.2	9.1	1.17
		High	50.2	3.8	4.6	7.8	73.0	54.2	18.8	1.35
	Middle	Low	22.3	11.5	1.2	7.8	49.3	54.2	-4.9	0.91
		Middle	28.3	10.0	2.0	7.8	54.6	54.2	0.4	1.01
		High	32.8	11.3	2.6	7.8	61.0	54.2	6.8	1.12
	High	Low	27.0	8.9	3.4	7.8	53.7	54.2	-0.6	0.99
		Middle	34.8	8.2	3.8	7.8	61.1	54.2	6.8	1.13
		High	35.4	14.3	2.7	7.8	66.7	54.2	12.5	1.23

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of 5.48 million dollars.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

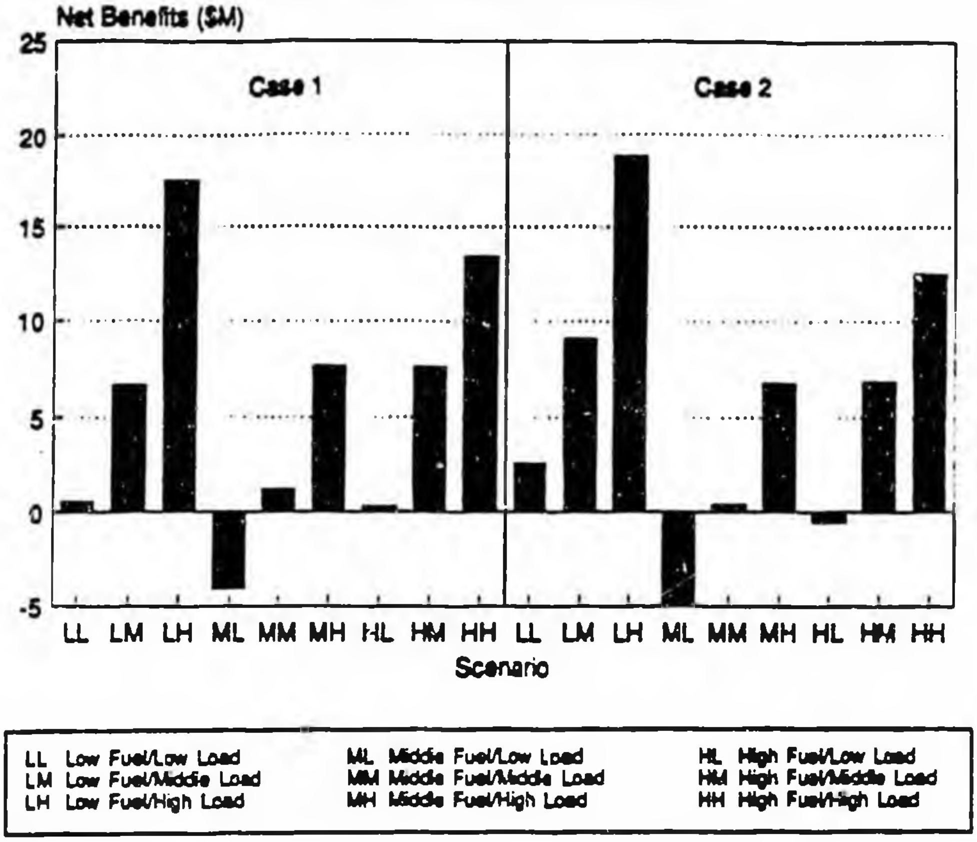
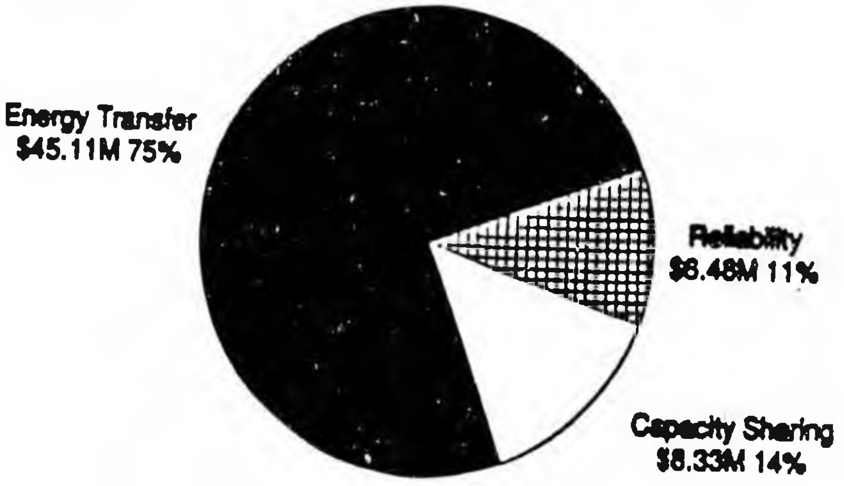


Figure 8-7. Healy-Fairbanks Northern Intertie: Net Benefits (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)



Energy transfer includes transfer loss
and gas royalty.
Average of all scenarios.

Figure 8-8. Healy-Fairbanks Northern Intertie: Breakdown of Expected Benefits (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

Appendix A

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, 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, low-cost generating capability in Kenai.

All of these are discussed in more detail in the following subsections. Approximately \$1.4 million to \$3.4 million (in 1990 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.

A.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 A-1 lists performance data for the Beluga CT #5.

Table A-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 and 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 A-1 illustrates the process.

During this cycle, the cost of thermal generation would be significantly reduced. For example, from Table A-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 (i.e. thermal generation shifted through time) basis, this amounts to 4,098 Btu/kWh (i.e., 1,623 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:

Total heat rate at 50% loading	15,012 Btu/kWh
Incremental heat rate between 50% and 100% loadings	10,914[2] Btu/kWh
Difference	4,098 Btu/kWh

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[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.

[2] Using the values in Table A-1: (885.6 - 495.4)MBtu/(66 - 33)MW = 10.914 MBtu/MWh or 10,914 Btu/kWh.

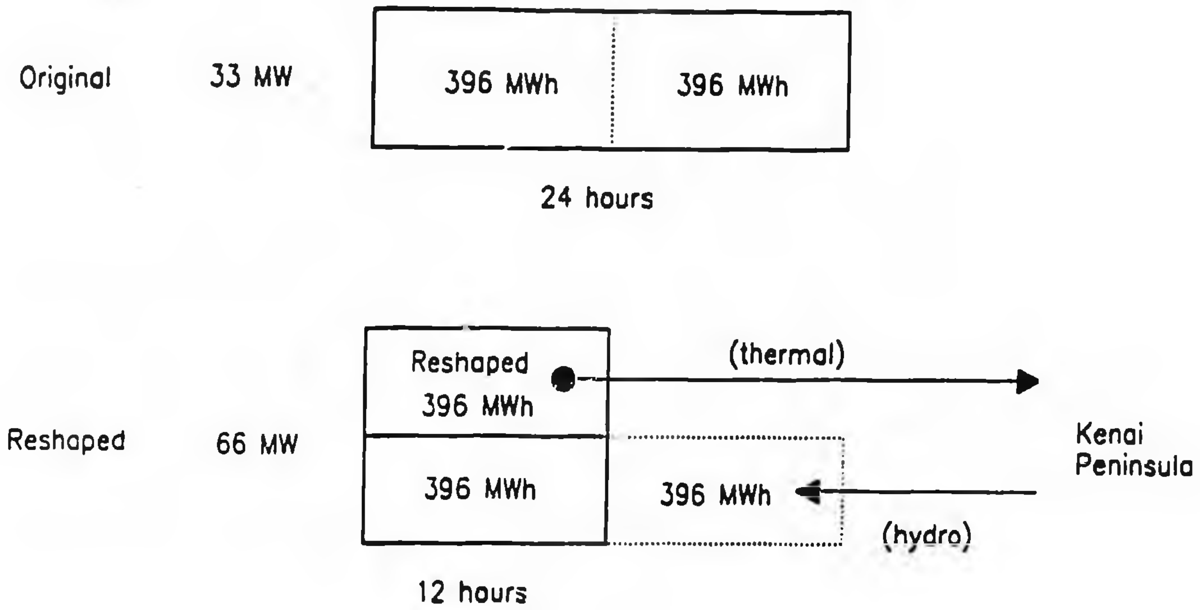

Figure A-1. Reshaping Thermal Energy Generation

The most expensive or marginal generating units in operation are the likely candidates for thermal energy generation reshaping. Table A-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. Therefore, the magnitude of savings illustrated in the previous example would generally carry over to results based on the complete set of representative units enumerated in Table A-2.

Reshaping thermal energy production will be applied to the marginal unit or the unit loaded last. We estimate the marginal units relative likelihood based on the unit's technology. The production simulation results indicate that combined cycles (CC) technology will be the marginal operating technology in Anchorage approximately 75 percent of the time; and gas turbine or combustion turbine (CT) technology will be marginal the remaining 25 percent of the time. We also distinguish between two "classes" of CC units: a 50 MW class (represented by AMLP #56 CC) and a 100 MW class (represented by Beluga CC #8).

Table A-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]

Based on our examination of the production simulation results, we estimate that when the combined cycle is the marginal technology, about half the time the 50 MW class would be marginal; during the other half the larger 100 MW class combined cycle would be marginal. If gas turbine technology is marginal, we assessed the relative probability of the various units being marginal based primarily on their relative sizes.

Table A-3 lists the technology, representative units, and probability that a representative unit is the marginal unit in Anchorage before applying the hydro-thermal coordination.

Table A-3

MARGINAL UNIT IN ANCHORAGE BEFORE APPLYING HYDRO-THERMAL COORDINATION

Technology	Fraction of Time	Representative Unit	Fraction of Time
Combined Cycle	75%	Beluga #8 (100 MW class)	37.5%
		AMLP #56 (50 MW class)	37.5%
Gas Turbine	25%	Beluga #3	5%
		AMLP #8	9%
		Beluga #5	8%
		AMLP #4	3%

The amount of thermal demand which must be reshaped in order to affect hydro-thermal coordination benefits depends on which thermal unit in Anchorage is marginal before applying hydro-thermal coordination, and what the loading on that unit would otherwise be. Take, for example, a 100 MW class combined cycle unit. Given that such a unit is marginal, we conclude that the demand placed on this unit is uniformly distributed between its minimum and maximum loadings.[3] We reached the conclusion of uniform distribution because, given that a unit is the marginally committed unit, its loading above minimum will vary randomly based on temperature and other random events that affect electric demand. Figure A-2 illustrates a cumulative probability distribution of this assessment. This figure illustrates that given that the unit is marginal, there is a 100 percent probability that the loading is less than 100 MW and 0 percent probability that the loading is less than 25 MW. This figure also illustrates other likelihoods, for example the probability of a loading between 50 MW and 75 MW is 33 percent. This characteristic is important in determining how often sufficient transfer capability exists in the Kenai-Anchorage intertie to realize hydro thermal coordination. We return to this issue after defining the transmission capabilities.

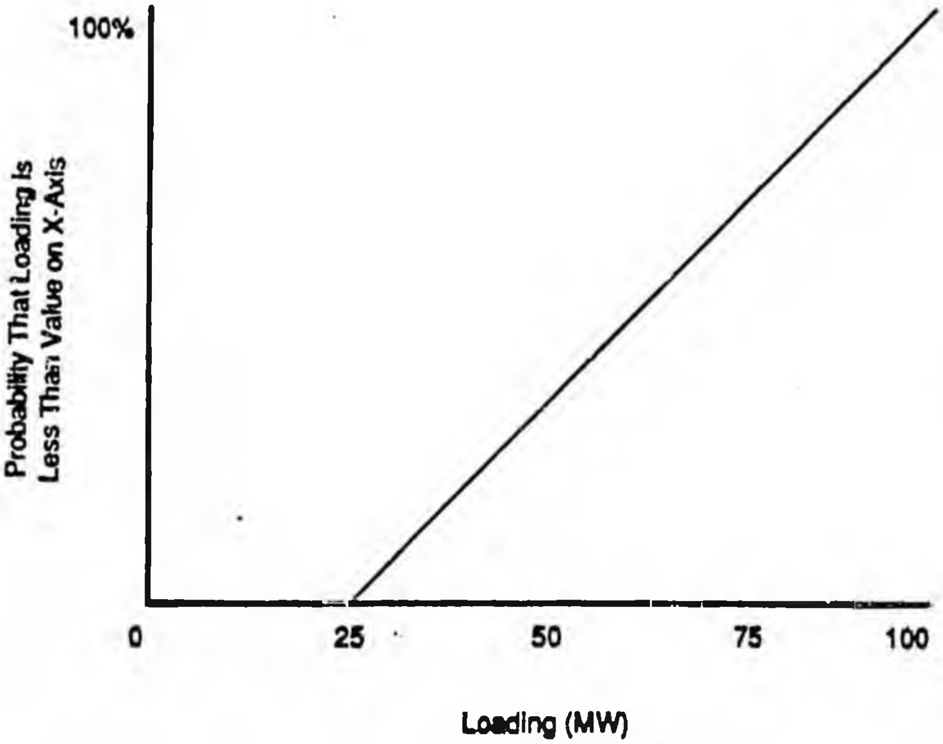

Figure A-2. Loading of a Marginal 100 MW Class Combined Cycle

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[3] For the 100 MW class combined cycle, we assume a 25 MW minimum load.

A.2 KENAI-ANCHORAGE TRANSMISSION LOSSES AND CAPACITY

Transmission losses and transfer capacity interact to affect the savings of reshaping. First, we review the impact of losses. Second, we discuss the impact of capacity constraints. Then we review the 100 MW combined-cycle class in detail.

Transmission losses reduce the benefits of reshaping thermal generation because they increase the required amount of input energy transfer and limit the potential for economic energy transfer between areas. The performance of the proposed 138 KV line and the existing 115 KV[4] line is listed in Table A-4. For the existing line, transmission losses are 8.9 percent for the first 40 MW and an incremental 16.6 percent for the second 20 MW, with still greater losses for higher loadings. We will use 8.9 percent losses as an example now. In order to have 1.0 MWh for reshaping in Anchorage, 1.098 MWh (1.0 MWh/(100% - 8.9%)) must be generated in Kenai. Furthermore, to return this 1.087 MWh to Kenai,[5] 1.2049 MWh (1.098 MWh/(100% - 8.9%)) must be generated in Anchorage. The right-most column in Table A-4 lists the reshaping energy requirement, i.e., the energy required to be generated in Anchorage to allow the reshaping of 1 MWh in Anchorage. It is possible that the losses can be so great as to prevent economical reshaping.

Table A-4

KENAI-ANCHORAGE TRANSMISSION LINE PERFORMANCE

	Input Range (MW)	Incremental Losses[a] (%)	Average Losses[a] (%)	Output Range (MW)	Reshaping Energy Requirement (MWh/MWh)
With a second 138 KV line	0-60	4.2	4.2	0-57	1.09
	60-90	10.2	6.2	57-84	1.14
	90-100	13.2	6.9	84-93	1.15
	100-120	15.2	3.3	93-110	1.19
	120-155	18.6	10.6	110-139	1.25
Existing 115 KV line	0-40	8.9	8.9	0-36	1.20
	40-60	16.6	11.5	36-53	1.28
	60-70	19.2	12.6	53-61	1.31
	70-90	28.7	16.2	61-75	1.42

a. Refer to Section 3.

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[4] The performance of the 115 KV line is shown up to 90 MW input; however, there is uncertainty concerning the ability of the line to accept more than 70 MW input.

[5] Figure A-1 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 or with additional thermal generation in Kenai. Much of the time it is most economical to generate this thermal energy in Anchorage and transmit it to Kenai.

Reshaping thermal energy in Anchorage may also be limited by the total line transfer capability. If 100 MW combined cycle is marginal, it may be loaded between 25 MW and 100 MW as illustrated in Figure A-2. With the 138 KV line, any such loading can be accommodated; the existing 115 KV line alone has sufficient capability to reshape this unit only if its output is less than 61 MW or 75 MW depending on the transfer capacity of the 115 KV line.

We next explain how the transmission losses and transfer limits interact to determine what savings are possible given that a specific unit is marginal. Table A-5 lists the results for 100 MW class combined cycles. In the first full column from the left, this table shows the different performance ranges described in the previous table. The next column to the right lists the probability that reshaping falls within a specified range of transmission performance. These probabilities are calculated using the information illustrated in Figure A-2. This listing confirms that the 138 KV line can serve all reshaping demands while the 115 KV line cannot serve reshaping demands for this type of generating unit 32.7 percent of the time (i.e., above 75 MW). The next column to the right describes the savings obtained by reshaping. These values are calculated by substracting from 10,981 Btu/kWh, 7,801 Btu/kWh times the energy ratio shown in the right-most column in Table A-4. As one goes down this column for a transmission alternative, the savings decrease per kilowatthour reshaped because of increased losses. Note that while it may be possible to transfer up 75 MW output with the existing 115 KV line it is uneconomical to reshape above 61 MW. The next column to the right indicates the average loading one would expect given the transmission system is operating within that performance range. Therefore, the savings would be that loading (converted to kilowatts) times the savings in column to the left.[6]

The average range loading of the line for reshaping listed in Table A-5 is also useful in the calculation of unused line transfer capacity which could be used for spinning reserve transfers. The line capacity available to transfer spinning reserve is listed in the right-most column. Spinning reserve transfers are also limited by generation considerations. When the 100 MW class combined cycle unit is the reshaped unit, the calculations show that the 138 KV line always has enough unused capability to transfer 30 MW of spinning reserve and can transfer 50 MW of spinning reserve 90.8 percent of the time. The remaining 9.2 percent of the time it is limited to 42 MW.

The calculations summarized here for the 100 MW class combined cycle were repeated for all the generating units listed in Table A-1. The results for each specific unit were weighted by their respective probability of being the marginal unit. With the second 138 KV line, there would be enough capacity to transfer 49.7 MW (on average) of spinning reserves. On the other hand, the 115 KV line desiring to transfer 30 MW

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[6] For example, for the first row in this table, the savings would be 2,481 Btu/kWh times an average loading of 41,000 kw or 101 million Btus/hour. The results for the complete unit would be obtained weighting these savings by the probabilities that the loading is within that range.

of spinning reserve only has enough unused line capacity to transfer 28.7 MW (on average) if the output rating of the line is 75 MW and 23 MW (on average) if the output rating is 61 MW. Table A-6 summarizes the savings from hydrothermal coordination averaged across all unit loadings and all units.

Table A-5

PARAMETERS FOR 100 MW CLASS COMBINED CYCLE AS THE RESHAPED THERMAL UNIT

	Line Output Range (MW)	Probability of Loading in Range	Reshaping Savings (Btu/kWh)	Average Range Loading (MW)	Average Line Capacity and Output Available for Spinning Reserve (MW)	
With a second 138 KV line	0-57	43.3%	2481	41	98	
	57-84	35.9%	2115	71	68	
	84-93	11.6%	1981	89	50	
	93-110	9.2%	1707	97	42	
		100.0%				
Existing 115 KV line					75 max	61 max
	0-36	15.3%	1581	31	44	30
	36-53	22.2%	1028	45	30	16
	53-61	10.8%	775	57	18	4
	61-75	19.0%	0		75	61
	unit loading too big for line	32.7%	0		75	61
		100.0%				

Table A-6

HOURLY AVERAGE HYDRO-THERMAL COORDINATION SAVINGS

	Fuel Savings (million Btu per hour of reshaping)	Average Line Capacity Remaining for Spinning Reserve Use (MW)[7]
New 138KV line	356	50
Existing 115KV line		
Limited to 75 MW input	125	29
Limited to 90 MW input	128	26

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[7] Calculation assumes that maximum spinning reserves are limited to 50 MW (actually 49.7 MW) for the 138 KV line and to 30 MW for the 115 KV line.

A.3 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 to Soldotna will increase from 17 MW to 133 MW.[8] Since Kenai's load rarely exceeds 70 MW,[9] Kenai generating capability will seldom limit transactions on the existing 60 MW interconnection to Anchorage.

The new intertie's capacity is higher and as a result more capability in Kenai will sometimes be required. 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 reshaping or spinning reserve demand would not be served.[10] We have analyzed these circumstances and concluded that the vast majority of the time in which greater generation is required in Kenai, the efficient gas turbines in Kenai will be sufficient and economic in meeting these increased generating requirements. Note that some of the most efficient gas turbines in the Railbelt are located on the Kenai Peninsula.

A.4 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. As a result, reshaping occurs approximately 4,000 kilowatthours per year.[11]

With only the existing Kenai-Anchorage transmission line, other uses may preclude these reshaping transactions. We estimate that other uses will block reshaping on the existing line another 500 hours per year. This is principally a consequence of the need to substantially rebuild the existing line as described in Appendix B.

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[8] Based on 114 MW of Bradley Lake energy delivered to Soldotna.

[9] 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.

[10] Hydro-thermal coordination is an economy-type transaction and as such unserved demand does not affect reliability. Instead unserved demand refers to unavailable economic savings.

[11] To reshape a thermal generating unit in Anchorage requires approximately two hours of transfer between Kenai and Anchorage (see Figure A-1). The 4,000 annual hours results from (90%) * (8764 hours per year) / (2 hours use of transmission per hour of reshaping) = 3943.8 hours reshaped per year.

A.5 BENEFITS OF NEW KENAI-ANCHORAGE LINE

Table A-7 shows that, with the existing line, the thermal energy transfers between Kenai and Anchorage would be around 91 to 98 GWh per year. Table A-8 shows that these transfers would increase by 104 to 110 GWh per year with the new line. The net benefits of these increased transfers are around 1.4 to 3.4 million dollars per year and are listed in Table A-9.

Table A-7

KENAI-ANCHORAGE TRANSFERS DUE TO HYDRO-THERMAL COORDINATION WITH EXISTING INTERTIE

			Thermal Energy Reshaping Transfers (GWh/yr)						Associated Transmission Loss (GWh/yr)		
			South	---->	North	North	---->	South			
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	81	81	81	92	92	92	21	21	21
		Middle	81	81	81	92	92	92	21	21	21
		High	81	81	81	92	92	92	21	21	21
	Middle	Low	81	81	81	92	92	92	21	21	21
		Middle	81	81	81	92	92	92	21	21	21
		High	81	81	81	92	92	92	21	21	21
	High	Low	81	81	81	92	92	92	21	21	21
		Middle	81	81	81	92	92	92	21	21	21
		High	81	81	81	92	92	92	21	21	21
Case 2	Low	Low	86	86	86	98	98	98	23	23	23
		Middle	86	86	86	98	98	98	23	23	23
		High	86	86	86	98	98	98	23	23	23
	Middle	Low	86	86	86	98	98	98	23	23	23
		Middle	86	86	86	98	98	98	23	23	23
		High	86	86	86	98	98	98	23	23	23
	High	Low	86	86	86	98	98	98	23	23	23
		Middle	86	86	86	98	98	98	23	23	23
		High	86	86	86	98	98	98	23	23	23

Table A-8

NET INCREASE (DECREASE) IN KENAI-ANCHORAGE HYDRO-THERMAL COORDINATION TRANSFERS DUE TO THE NEW 138KV INTERTIE

			Increase in Thermal Energy Reshaping Transfers (GWh/yr)						Change in Transmission Associated Loss (GWh/yr)		
			South	---->	North	North	---->	South			
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	110	110	110	110	110	110	1	1	1
		Middle	110	110	110	110	110	110	1	1	1
		High	110	110	110	110	110	110	1	1	1
	Middle	Low	110	110	110	110	110	110	1	1	1
		Middle	110	110	110	110	110	110	1	1	1
		High	110	110	110	110	110	110	1	1	1
	High	Low	110	110	110	110	110	110	1	1	1
		Middle	110	110	110	110	110	110	1	1	1
		High	110	110	110	110	110	110	1	1	1
Case 2	Low	Low	105	105	105	104	104	104	-1	-1	-1
		Middle	105	105	105	104	104	104	-1	-1	-1
		High	105	105	105	104	104	104	-1	-1	-1
	Middle	Low	105	105	105	104	104	104	-1	-1	-1
		Middle	105	105	105	104	104	104	-1	-1	-1
		High	105	105	105	104	104	104	-1	-1	-1
	High	Low	105	105	105	104	104	104	-1	-1	-1
		Middle	105	105	105	104	104	104	-1	-1	-1
		High	105	105	105	104	104	104	-1	-1	-1

Table A-9

NET BENEFITS OF INCREASED HYDRO-THERMAL COORDINATION DUE TO THE NEW KENAI-ANCHORAGE INTERTIE

(million dollars, 1990 dollars)

			Increased Transfer Benefits (M$/yr)			Reduced Transmission Loss (M$/yr)			Net Benefits (M$/yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	1.43	1.60	1.79	-0.01	-0.01	-0.02	1.42	1.59	1.78
		Middle	1.43	1.60	1.79	-0.01	-0.01	-0.02	1.42	1.59	1.78
		High	1.43	1.60	1.79	-0.01	-0.01	-0.02	1.42	1.59	1.78
	Middle	Low	1.81	2.17	2.60	-0.02	-0.02	-0.02	1.79	2.15	2.57
		Middle	1.81	2.17	2.60	-0.02	-0.02	-0.02	1.79	2.15	2.57
		High	1.81	2.17	2.60	-0.02	-0.02	-0.02	1.79	2.15	2.57
	High	Low	2.08	2.65	3.39	-0.02	-0.02	-0.03	2.06	2.63	3.36
		Middle	2.08	2.65	3.39	-0.02	-0.02	-0.03	2.06	2.63	3.36
		High	2.08	2.65	3.39	-0.02	-0.02	-0.03	2.06	2.63	3.36
Case 2	Low	Low	1.39	1.56	1.75	0.01	0.02	0.02	1.41	1.58	1.76
		Middle	1.39	1.56	1.75	0.01	0.02	0.02	1.41	1.58	1.76
		High	1.39	1.56	1.75	0.01	0.02	0.02	1.41	1.58	1.76
	Middle	Low	1.76	2.11	2.53	0.02	0.02	0.02	1.77	2.13	2.55
		Middle	1.76	2.11	2.53	0.02	0.02	0.02	1.77	2.13	2.55
		High	1.76	2.11	2.53	0.02	0.02	0.02	1.77	2.13	2.55
	High	Low	2.02	2.58	3.30	0.02	0.03	0.03	2.04	2.61	3.33
		Middle	2.02	2.58	3.30	0.02	0.03	0.03	2.04	2.61	3.33
		High	2.02	2.58	3.30	0.02	0.03	0.03	2.04	2.61	3.33

A.7 REFERENCE

[1] Alaska Power Authority, Railbelt Intertie Proposal Preliminary Economic Assessment, March 1987, p. 8.2.11.

Appendix B

MODELING ASSUMPTIONS

This appendix summarizes the significant modeling assumptions used in the evaluation of the economy energy and transmission loss benefits of the three alternative intertie proposals. Unless otherwise noted in this Appendix or in this report, all assumptions used in the Reconnaissance Study are used in this analysis.

B.1 COSTS AND BENEFITS

All fixed and variable costs, fuel prices, and benefits are reported in 1990 dollars. The price inflators used to convert the 1987 prices in the Reconnaissance Study to 1990 dollars are based on the GNP price inflator as reported in the *Survey of Current Business*, July 1989.[1] Table B-1 shows the price inflators assumed for the years 1987 to 1990.

For the evaluation of the present value of future costs and benefits, we assume a discount rate of 4.5 percent, as established by APA.

Table B-1

PRICE INFLATORS

Year	GNP Inflator
1987-1988	3%
1988-1989	3%
1989-1990	4.5%

B.2 FUEL PRICE FORECASTS

The fuel price forecasts used in this analysis are the same forecasts used in the Reconnaissance Study. In this analysis, however, well-head gas prices are assumed everywhere, and all transportation charges have been removed.[2]

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[1] "Survey of Current Business," U.S. Department of Commerce: Bureau of Economic Analysis, Volume 69, Number 6, July 1989, p. 89.

[2] Refer to Appendix B of the Reconnaissance Study.

B.3 LOAD FORECASTS

The load forecasts are the same forecasts used in the Reconnaissance Study with no changes.[3]

B.4 BERNICE LAKE UNIT

We assume that the Bernice Lake unit will stay in Kenai.

B.5 SOLDOTNA

The Soldotna plant is assumed to have the same operating and maintenance costs as Bernice Lake.

B.6 RECONSTRUCTION OF THE EXISTING KENAI-ANCHORAGE 115 KV LINE

The existing Kenai-Anchorage line is scheduled for incremental line replacement between the years 1994 and 2007.[4] In modeling the transfers across the existing line, we have adjusted the intertie availability to account for this scheduled maintenance. Table B-2 shows the estimated number of days of scheduled maintenance and the corresponding availability assumed for the existing line. We assume four months of winter and eight months of summer.

The KA138 proposal allows for a second line between Kenai and Anchorage that would make the deferral of some of the scheduled maintenance possible. The deferred replacement of the existing line is estimated to result in a reduction of lifetime maintenance costs of $5 million.

Table B-2

RECONSTRUCTION PLAN OF THE EXISTING KENAI-ANCHORAGE 115 KV LINE

	Maintenance Days		Line Availability	
Years	Summer	Winter	Summer	Winter
1994-2007	85	14	65	88
2008-2033	14	14	95	88

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[3] Refer to Appendix C of the Reconnaissance Study.

[4] Letter from Gerald Mackey, Planning Engineer, Chugach Electric Association, to Salim Jabbour, Decision Focus Incorporated, dated September 5, 1989.

Alaska State Legislature
HOUSE RESOURCES COMMITTEE
P.O. Box V
State Capitol
Juneau, Alaska 99811
(907) 465-3715

HOUSE RESOURCES COMMITTEE
OVERVIEW: PROPOSED 138 KV TRANSMISSION LINE

February 22, 1990
3:30 - 5:00

Salim Jabbour, Vice President, Decision Focus Inc.

Mike Kelly, General Manager, Golden Valley Electric Ass.

Ginny Fay, Analyst, Legislative Research Agency

Alan Mitchell, Analysis North

Bob LeResche, Executive Director, Alaska Energy Authority

Alaska State Legislature

Legislative Research Agency

P.O. Box Y
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Fax: (907) 463-3351

February 19, 1990

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny Fay GFay
Legislative Analyst

RE: Review of the Economic Feasibility Study of the Railbelt Utilities' Proposed 138 Kilovolt Electrical Interties
Research Request 90.165

You requested this agency to review the *Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt* report which was recently prepared for the Railbelt electric utilities[1] by Decision Focus Incorporated (DFI). This same firm prepared the *Railbelt Intertie Reconnaissance Study: Benefit/Cost Analysis* for the Alaska Energy Authority (this study is referred to as the AEA study in this memorandum). The AEA study (completed June 1989) was conducted to determine the economic feasibility of 230 kilovolt (KV) electrical interties between Anchorage and the Kenai Peninsula, and Anchorage and Fairbanks, and their alternatives as required by state statute (AS 44.83.177). Because the 230 KV lines were not found to be economically feasible (i.e., they have benefit/cost ratios less than one), the Railbelt utilities proposed lower capacity transmission lines and hired DFI to analyze their economic feasibility.[2] The downsized 138 KV interties would be constructed between Kenai and Anchorage (southern line) and between Healy and Fairbanks (northern line). The northern line proposal also includes a limited upgrade of the existing Anchorage-Fairbanks line (limited AF100).

This memorandum reviews the major economic benefit categories of the 138 KV study--reliability, economy energy transfer, capacity sharing, and spinning reserve sharing. As a result of time constraints, however, this should not be considered a comprehensive review.

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[1] The Railbelt electric utilities include Anchorage Municipal Light & Power (AML&P), Chugach Electric Association (CEA), Fairbanks Municipal Utility System (FMUS), Golden Valley Electric Association (GVEA), Homer Electric Association (HEA), and Matanuska Electric Association (MEA).

[2] Without AEA board action, however, the 138 KV intertie study does not constitute a statutorily required feasibility study because it was not conducted on the behalf of the state.

SUMMARY

Description and Costs of the Proposed Interties

The proposed new intertie between Anchorage and the Kenai Peninsula (KA138) is a 138 KV version of the 230 KV line between Kenai and Anchorage along the Enstar route. This route was the less expensive alternative of the two routes analyzed in the AEA study. The capital cost of the KA138 proposal is estimated at $64.1 - $65.6 million (Table 1). The limited Anchorage-Fairbanks 100 KV upgrade (AF100) is the same proposal for a limited upgrade of the intertie between Anchorage and Fairbanks previously considered in the AEA study. The upgrade consists of new static VAR systems and series capacitors that will increase the capacity of the current line by 30 MW. The capital cost of the AF100 upgrade is estimated at $9.4 million in 1990 dollars (Table 1). The AF138 proposal is comprised of the limited upgrade of the Anchorage-Fairbanks intertie coupled with a new 138 KV line from Healy to Ft. Wainwright. The total capital cost of the proposal is $58.7 million (Table 1). This memorandum does not review the projects' cost estimates which should also receive independent review or review by AEA engineers.

Benefits of the Anchorage-Kenai Peninsula 138 KV Intertie

Decision Focus identifies five major categories of benefits for the southern intertie--reliability; economy energy transfer, which includes hydroelectric and thermal unit coordination; capacity sharing; spinning reserve sharing; and reduced maintenance costs on Chugach Electric Association's existing intertie. The total estimated benefit value for these categories is $123 million, which is approximately $72 million more than the benefit value estimated for the Anchorage-Kenai 230 KV line in the AEA study (Table 2).

Review of the DFI KA138 KV study, however, indicates that the benefits are overstated. Four major errors were made in calculating benefits of the southern line:

- The value of reliability benefits increased from $15.7 million to $41.0 million for the southern line as a result of the use of different estimates for the value of unserved residential, and commercial and industrial energy. The increase in the value of commercial and industrial unserved energy resulted from a misapplication of survey data which overestimated these benefits by approximately $20 million in present value. The calculation method and results of the AEA 230 KV study are more accurate (pp. 10-12).

- A computation error was found in the calculation of the benefits of hydro-thermal coordination benefits of the new intertie. Hydro-thermal coordination allows partly loaded, less efficient thermal generating capacity in Anchorage to be turned off and replaced with

Bradley Lake hydroelectric generation capacity on the Kenai Peninsula. Decision Focus, Inc. has recognized this computation error, which overstates economy energy transfer benefits of the new intertie by $25 million in present value (pp. 12-14).

- A second calculation error in the hydro-thermal benefit calculation results from using a constant rather than varying gas turbine heat rate across turbine loading levels for calculating fuel savings. This oversimplification results in an additional $4 million in benefits of the new Anchorage-Kenai line (p. 13).

- Operating or spinning reserves are the operating capacity that is not used to serve the existing load, but instead is available to respond quickly to changes in load or electrical demand. The operating reserve benefit of upgrading the Anchorage-Kenai intertie results from the substitution of operating reserve from the Bradley Lake hydroelectric project for gas-fired spinning reserves in Anchorage, because Bradley Lake spin is free while gas consumption makes thermal spin costly. Decision Focus estimates the value of this benefit category at $5.2 to $13.5 million, but a correction in the formula used to calculate these benefits reduces the value of operating reserve sharing to $2.1 to $5.4 million (p. 28).

In addition to these quantified corrections to the benefit calculation, the net benefits of the southern line were substantially increased in the utility study as a result of changes in assumptions regarding 1) operating and maintenance costs of the new line (p. 9); 2) economic life of the new intertie (pp. 9-10); and 3) reduced maintenance costs of the existing CEA line (pp. 28-29). Assumptions about electrical system optimal dispatch (pp. 13-14) and capacity sharing and retirement schedules (pp. 18-27) also result in the overestimate of benefits in the analysis. The DFI 138 KV study does not provide adequate justification for these changes in assumptions. Given our time constraints, we have not made corrections to these benefit categories have not been quantified. To do so would further reduce the estimated benefits.

Benefits of the Limited Anchorage-Fairbanks 100 KV Upgrade and Full 138 KV Line

In its analysis, DFI identifies three benefit categories for the northern intertie upgrade and a new 138 KV line between Healy and Fairbanks--reliability, economy energy transfer, and capacity sharing. Benefits to the limited AF100 upgrade changed relatively little between the AEA 230 KV study and the utility 138 KV study (Table 3). However, the incremental benefits of the new 138 KV line are overestimated as a result of three major assumptions:

- Reliability benefits are overestimated for the northern line as a result of the same misapplication of the value of commercial and industrial unserved energy described for the southern line (pp. 10-12).

- The North Pole operating constraint accounts for the majority of northern intertie economy energy benefits but assumptions regarding generating unit dispatch overestimate these benefits by $3 million. In addition, economy energy benefits are overestimated as a result of dropping fuel price differential and military load sensitivity analyses in the utility 138 KV study that were conducted in the AEA study (pp. 14-18).

- In addition to these quantified corrections to benefit calculations, benefits are overestimated as a result of assumptions regarding capacity sharing and retirement schedules (pp. 18-22).

If the construction of the Healy clean coal demonstration project is funded, benefits of the interties should be recalculated. A recent letter by DFI (Attachment A) indicates that while the Healy facility would not significantly affect the benefits of the northern line, it would reduce the reliability and capacity sharing benefits of southern intertie (p. 29).

In conclusion, based on this limited review, there appear to be significant errors in computations and unjustified changes in assumptions in the recently completed Decision Focus 138 KV study. While the limited AF100 upgrade appears to continue to have a benefit/cost ratio above one, the construction of either a new southern or northern line does not appear to be economically justifiable when the errors are corrected. For the Anchorage-Kenai Peninsula 138 KV intertie, our review of benefits indicates that maximum benefits are approximately $68 million. In contrast, DFI calculated benefits of $122.7 million (Table 2). For the Anchorage-Fairbanks fully upgraded 138 KV line, we calculated maximum incremental benefits over the limited upgrade of $45.4 million while DFI estimated these benefits at $59.9 million (Table 3). It is clear that had the 138 KV lines been analyzed under the same assumptions as those used in the AEA 230 KV study, the 138 KV lines would not have been found economically feasible. A decision to proceed with these 138 KV intertie projects would be based on the political rather than economic merits of the projects.

TABLE 1
ESTIMATED COSTS AND BENEFITS OF THE PROPOSED 138 KV ELECTRICAL INTERTIES FROM THE DFI 138KV INTERTIE STUDY
(millions $ 1990)

	Estimated Cost(a)	Estimated Benefits(b)	Benefit to Cost Ratio
New Anchorage-Kenai Intertie	74 to 86 (c)	114 to 131	1.3 to 1.8
Limited Upgrade Anchorage-Fairbanks Intertie	10	46	4.4
Healy-Fairbanks Intertie			
Total	64	106	1.6
Incremental(d)	54	60	1.1

Notes:

a: Includes both capital and operation and maintenance (O&M) costs; assumes lower cost Enstar route, not Tesoro route.

b: Present value of total benefits between 1994 and 2033 for the Kenai-Anchorage line and between 1994 and 2043 for the Anchorage-Fairbanks upgrade and Healy-Fairbanks line.

c: Includes replacement of submarine cable after 20 years of service.

d: Incremental over the limited upgrade of the Anchorage-Fairbanks line.

Source: Decision Focus Inc., "Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt," December 1989; Anchorage-Kenai cost estimates were prepared by Powers Engineers for the Chugach Electric Association; and Anchorage-Fairbanks cost estimate was prepared by Harza Engineering Company for the Golden Valley Electric Association.

Prepared by the Legislative Research Agency, February 1990 (90-165a).

TABLE 2

COMPARISON OF BENEFITS AND ASSUMPTIONS OF THE ALASKA ENERGY AUTHORITY 230 KV INTERTIE AND THE PROPOSED UTILITY 138 KV INTERTIES STUDIES--ANCHORAGE-KENAI PENINSULA INTERTIE

(millions $ 1990)

BENEFIT CATEGORY	BENEFIT VALUE(a)		DIFFERENCE	PARTIALLY CORRECTED BENEFIT VALUE*	ASSUMPTIONS CHANGED
	AEA/230 KV	138 KV			
FUEL PRICES					
Fuel & Load Forecast Probabilities Changed					Weighted probabilities: 60/30/10 for high/medium/low fuel and load growth forecast in reconnaissance study changed to even weighted probabilities in 138 KV study.
Royalties Netted Out					Assumes that the price of gas will increase less than inflation and the discount rate, i.e., better off to have royalties now than in the future.
Fuel Price Differential Extended thru Year 40					Ignores ICF study for AEA which indicates that gas production costs and prices are likely to escalate after year 17 of the analysis. This implies convergence of oil and gas prices after 2010.
RELIABILITY	15.7	41.0	25.3	20.0	Increased value of commercial and industrial unserved energy- different interpretation of data.
INCREASED ENERGY TRANSFER					Contains a $25 million mathematical error; hydro-thermal coordination accounts for 90 percent ($40 million) of benefits; assumes an optimally dispatched system; in contrast, currently $3-6 million annual benefit potential from improved system dispatch (without a new intertie) and unutilized hydro-thermal coordination with the Eklutna Dam.
Hydro-Thermal Coordination(c)	22.5	37.5	15.0	9.1	
Other Economy Energy	0.0	5.9	5.9	5.9	
INCREASED CAPACITY SHARING*	12.0	24.4	12.4	24.4	Based on book-life retirement and capacity shortage in the mid-1990s; recent avoided cost dockets and utility data indicate life extension plans to 2000-2015.
INCREASED SPINNING RESERVE SHARING	0.8	8.9	8.1	3.6	Improved access to Kenai excess capacity for reserves; assumes gas generation in use on Kenai and no life extension of Anchorage gas units.
REDUCED MAINTENANCE COSTS*	0.0	5.0	5.0	5.0	Reduced costs for Chugach Electric's existing intertie.
TOTAL	51.0	122.7	71.7	68.0	
BENEFIT:COST RATIO(b)	0.5	1.6		0.9	

Notes: *Corrected benefit values are adjusted primarily for mathematical errors and do not include all quantifiable adjustments such as those for capacity sharing, reduced maintenance costs, and changes in fuel price assumptions. The corrected benefit total should be viewed as a maximum.

(a) based on average benefit values

(b) based on average benefit and cost value

(c) For the 230KV study, this category includes increased stability and energy transfer, and reduced transmission.

Source: Decision Focus Inc., "Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt," December 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165b).

TABLE 3
COMPARISON OF BENEFITS AND ASSUMPTIONS OF THE ALASKA ENERGY AUTHORITY 230 KV INTERTIE AND THE PROPOSED UTILITY 138 KV INTERTIES STUDIES--ANCHORAGE-FAIRBANKS INTERTIE
(millions $ 1990)

	BENEFIT VALUE(a)			PARTIALLY CORRECTED	
BENEFIT CATEGORY	AEA/230 KV	138 KV	DIFFERENCE	BENEFIT VALUE*	ASSUMPTIONS CHANGED
LIMITED 100 KV UPGRADE					
FUEL PRICES					
Fuel & Load Forecast Probabilities Changed					Weighted probabilities: 60/30/10 for high/medium/low fuel and load growth forecast in AEA study changed to even weighted probabilities in 138 KV study. No military load sensitivity analysis.
Royalties Netted Out					Assumes that the price of gas will increase less than inflation and the discount rate, i.e., better off to have royalties now than in the future.
Fuel Price Differential Extended thru Year 50					Ignores ICF study for AEA which indicates that gas production costs and prices are likely to escalate after year 17 of the analysis. This implies convergence of oil and gas prices after 2010.
RELIABILITY	0.0	5.0	5.0		Used higher numbers for the cost and amount of unserved energy during outages.
ECONOMY ENERGY TRANSFER & REDUCED TRANSMISSION LOSSES	43.0	31.8	(11.2)		Price of coal is assumed constant over the extended 50-year period of analysis Fairbanks coal generation displaces a portion of gas-fired economy energy sales over the intertie from Anchorage.
CAPACITY SHARING	1.2	9.0	7.8		Based on book-life retirement and capacity shortage in the mid-1990s; recent avoided cost dockets and utility data indicate life extension plans to 2000-2015.
TOTAL	44.2	45.8	1.6		
BENEFIT:COST RATIO(b)	3.9	4.4			
FULL INTERTIE UPGRADE					Same assumption changes as limited upgrade.
FUEL PRICES					
Fuel & Load Forecast Probabilities Changed					
Royalties Netted Out					
Fuel Price Differential Extended thru Year 50					
RELIABILITY		6.5		4.0	
ECONOMY ENERGY TRANSFER & REDUCED TRANSMISSION LOSSES		45.1		33.1	This benefit category is reduced $12 million to correct for the fuel price differential assumption and the North Pole operating constraint.
CAPACITY SHARING		8.3		8.3	
TOTAL		59.9		45.4	
BENEFIT:COST RATIO(b)		---			
INCREMENTAL B:C RATIO(b)		1.1		0.8	

Notes: *Corrected benefit values are adjusted primarily for some input assumptions and do not include all quantifiable adjustments such as those for capacity sharing, reduced maintenance costs, and changes in fuel price assumptions. Benefits of the AF138 are incremental above the AF100. The corrected benefit total should be viewed as a maximum.
(a) based on average benefit values.
(b) based on average benefit and cost value

Source: Decision Focus Inc., "Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt," December 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165c).

DESCRIPTIONS AND COSTS OF THE PROPOSED INTERTIES

New Intertie between Anchorage and the Kenai Peninsula (KA138 Intertie)

The KA138 line is a 138 KV version of the 230 KV line between Kenai and Anchorage along the Enstar route. This route was the less expensive alternative of the two routes analyzed in the AEA study. The line is comprised of three segment types: steel and wood pole overhead lines, underground cables, and a submarine cable through Turnagain Arm. Additions to the Huffman and International Substations have been considered as design options for the substation in Anchorage.

The capital cost of the KA138 proposal, with the Huffman Substation option and a 15 percent contingency, is estimated at $64.1 million in 1990 dollars. The capital cost of the proposal, with the International Substation option and a 15 percent contingency, is estimated at $65.6 million in 1990 dollars (Table 1).[3]

Limited Upgrade of the Anchorage-Fairbanks Intertie (AF100 Upgrade)

The AF100 upgrade is the same proposal for a limited upgrade of the intertie between Anchorage and Fairbanks previously considered in the AEA study. The upgrade consists of new static VAR systems and series capacitors that will increase the capacity of the current line by 30 MW. The capital cost of the AF100 upgrade, with a 15 percent contingency, is estimated at $9.4 million in 1990 dollars (Table 1).[4]

New Intertie Between Healy and Fairbanks (AF138 Intertie)

The AF138 proposal is comprised of the limited upgrade of the Anchorage-Fairbanks intertie coupled with a new 138 KV line from Healy to Ft. Wainwright. The proposed 138 KV line between Healy and Fort Wainwright is a steel-structure line that will reduce the transmission losses on the line between Healy and Fairbanks, and will increase the transfer capability between Anchorage and Fairbanks.

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[3] Both of these cost estimates were prepared by Power Engineers Incorporated for CEA in April, 1989.

[4] Decision Focus Incorporated, *Railbelt Intertie Reconnaissance Study, Benefit/Cost Analysis*, prepared for the Alaska Power Authority, June 1989.

The capital cost of the 138 KV line and terminal substations, with a 15 percent contingency, is estimated to be $49.3 million in 1990 dollars.[5] Including the capital cost of the limited upgrade ($9.4 million in 1990 dollars), the total capital cost of the proposal is $58.7 million (Table 1).

This memorandum does not review the projects' cost estimates which should also receive independent review or review by AEA engineers.

Operating and Maintenance Cost of the Proposed Interties

The variable costs of an intertie are the annual operating and maintenance costs that are associated with the operation of the line. These costs are typically expressed as a percentage of the capital cost of the line. In the AEA 230 KV study, as well as the previous intertie upgrade analysis[6] and the analyses for the construction of the existing Anchorage-Healy intertie, the variable cost of each line was estimated as 1.5 percent of capital cost. The accepted industry standards for calculating these costs are 0.5 to 1.5 percent. Because of Alaska's harsh climate and higher cost of living, the 1.5 percent estimate has previously been used in Alaska. In the 138 KV study, the variable costs of the Anchorage-Fairbanks and the Anchorage-Kenai lines were reduced to 0.5 and 1.0 percent, respectively, based on Railbelt utility input and that of engineering consultants.[7] The effect of this change is to reduce costs and thus, increase the benefit/cost ratio.

Economic Life of the Interties

The planning horizon of the study is set equal to the expected economic life of each intertie. The AEA 230 KV study assumes that the economic life of each of the proposed lines is 35 years. The Railbelt utilities indicated that the life of a line could be as long as 50 years. Based on DFI personal communications, the life of the 138 KV lines were changed to 50 and 40 years for the Anchorage-Fairbanks and Anchorage-Kenai lines, respectively.[8] While this change increases the net present value of the variable cost of the lines,

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[5] The estimate was prepared by Harza Engineering Company for GVEA, April 5, 1989.

[6] Lotus Consulting Group, *Railbelt Intertie Proposal: Preliminary Economic Assessment*, prepared for the Alaska Power Authority, March 1987.

[7] Harza Engineering Company; Flynn & Associates; and Power Engineers--see page 2-3 of the 138 KV study for more details.

[8] See Decision Focus Incorporated, December 1989, p. 2-5 for more detailed information on assumptions regarding the economic life of interties.

it is more than offset by the increase in the net present value of benefits that result from extending the life of the lines. Thus, the net effect is to increase the benefit/cost ratio of the lines.

RELIABILITY BENEFITS

The reliability of an electrical system is important because the value of electric power exceeds the cost of producing the power. While the cost to a utility of an outage may be relatively small, the value to an industrial or commercial customer may be quite large. The proposed upgraded or new interties are expected to improve service reliability by reducing both the frequency and duration of customer outages.

The assessment of the value of improved system reliability requires an estimate of the outages that an intertie would avoid and the cost to customers of these avoided outages. Decision Focus estimated the impact of the interties on customer outages or unserved energy by analyzing the historical outages in the Railbelt area and the reduction in outages that could be attributed to new interties. For the cost of customer outages, DFI relied on research prepared for the Electric Power Research Institute.[9]

Decision Focus used similar methodology to calculate the reliability benefits for the AEA 230 KV study and the Railbelt utilities' 138 KV study. Benefits, however, increased from $14.0 million to $41.0 million for the Anchorage-Kenai line and from $1.4 million to $11.5 million for the Anchorage-Fairbanks lines as a result of the use of different estimates for the cost and amount of unserved energy. The increased value used to calculate the cost of unserved commercial and industrial sector unserved energy accounts for the majority of this increase.

In the AEA 230 KV study, DFI values unserved residential energy at $2.07/kilowatt hour (KWh) based on a study completed by Sangvhi in 1983. More recent surveys, reported in the 1989 EPRI study cited above, estimate residential outage costs ranging from $0.21/KWh to $9.91/KWh. Based on this more recent information, DFI assumed a cost of $5.00/KWh for residential

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[9] *The Value of Service Reliability to Customers*, EPRI Report EA-4494, prepared for EPRI by Criterion, Incorporated, San Diego, Ca. May 1986; L.V. Scott, "Ontario Hydro Surveys on Power Systems Reliability: Summary of Customer Viewpoints," compiled in *The Value of Service Reliability to Customers*, EPRI Report EA-4494, May 1986; *Customer Demand for Service Reliability: Existing and Potential Sources of Information*, prepared for EPRI By Laurits Christensen Associates, Madison, Wisconsin, May 1989; and A.P. Sanghvi, "Economic Costs of Electricity Supply Interruptions: U.S. and Foreign Experience," in *The Value of Service Reliability to Customers*, EPRI Report EA-4494, May 1986.

outages which is the midpoint of the range of results. This change more than doubles the residential sector's reliability benefits of the 138 KV line.

Similarly, the benefits of improved industrial and commercial reliability increased by a magnitude of two as a result of a different interpretation of results from surveys conducted by Ontario Hydro. Based on these surveys, Len Scott estimated the dollar per kilowatt hour cost of an outage assuming the electrical usage at the time of the outage was 75 percent of annual peak demand at the time of the outage, i.e., that the facilities were open and operating at the time of the outage.[10] This is an accurate interpretation of the survey data because the survey question asked for "the cost of an outage that occurs at 10 a.m. on a Friday morning in January."[11] In the original AEA 230 KV intertie analysis, DFI used Scott's data to calculate the cost of industrial and commercial sector unserved energy that could be avoided from the construction and/or upgrade of new interties.

In the 1989 EPRI reliability report, Christensen Associates present the results of the same Ontario Hydro surveys shown in the Scott report. In this 1989 report, Christensen Associates explicitly urge caution when using dollars per peak kilowatt hour of usage or dollars per average annual usage because their inappropriate application can lead to inaccurate results.[12] Based on a conversation with one of the Christensen analysts and without information regarding the actual survey question, DFI changed the formula for calculating the cost of unserved energy to reflect average annual demand rather than peak demand which is inconsistent with the survey question and thus the calculated cost of unserved energy. This change dramatically increased the value of industrial and commercial reliability benefits.[13] In light of information on the actual survey question, Decision Focus investigators acknowledged that the formula was misapplied in the utility 138 KV intertie study.[14] This results

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[10] L.V. Scott, May 1986.

[11] Dick Emerman, senior economist, Alaska Energy Authority, personal communication, January 10, 1990, based on his conversation with David Glyer, Laurits Christensen Associates, January 1990; Ginny Fay, personal communication with David Glyer, February 16, 1990.

[12] Laurits R. Christensen Associates, 1989, p. 2-14.

[13] The average annual or peak demand figure is in the denominator of the formula which is why dividing by average annual (a smaller number), gives a higher cost of unserved energy.

[14] Meeting with Decision Focus Incorporated principal investigators Salim Jabbour and Richard Fancher, Anchorage, January 30, 1990. The analysts, however, maintain that despite the misapplication of the formula, the result is correct.

in an overestimate of intertie benefits of the southern line by approximately $15 million and the northern line by approximately $5 million.

ECONOMY ENERGY TRANSFER AND HYDRO-THERMAL COORDINATION BENEFITS

Economy energy benefits are realized when an intertie allows energy to be 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 the opportunity for additional economy energy savings. According to Decision Focus's analysis, benefits between Anchorage and Fairbanks are primarily a result of disparities in power production costs in the two areas. Partially as a result of their conclusions regarding the optimal dispatch of Fairbanks power generating units (i.e., limited operation of the FMUS coal facility), peak demand in Fairbanks exceeds the transfer capacity of the current intertie. Therefore, the benefits of both the AF100 and AF138 are attributable to alleviating the capacity constraint of the current line. In contrast, the benefits of the new Kenai-Anchorage line are almost entirely the result of increased coordination of hydroelectric and thermal generating units.

In their study, DFI simultaneously analyzed economy energy and transmission loss savings using the Over/Under production simulation model.[15] A number of adjustments were subsequently made to the Over/Under results as follows:

- for the AF100 and AF138 options, an adjustment was made to account for the "North Pole operating constraint (explained below),"
- for the KA138 intertie, an adjustment was made to account for the increased transfer levels to replace the less efficient performance of partly loaded gas-fired turbines with Bradley Lake hydroelectric power, i.e., hydro-thermal coordination;
- and for all intertie options, an adjustment was made for the benefits from the collection of gas royalty and severance taxes.

These adjustments account for a substantial portion of the economy energy transfer benefits of the intertie and are discussed in the remainder of this section.

Economy Energy Transfers Between the Kenai Peninsula and Anchorage

While both Anchorage and the Kenai Peninsula have gas-fired generating units, Anchorage's units are more efficient. As a result, little or no economy energy

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[15] The Over/Under model is a long-term capacity expansion/production simulation model that was developed by DFI for the EPRI.

benefit can be gained from operating the gas units on the Kenai Peninsula. In addition, after the completion of the Bradley Lake hydroelectric project, the Kenai Peninsula will have substantial hydroelectric resources. The available hydroelectric resources over the course of the average year, however, will be less than the anticipated energy requirements on the Kenai Peninsula. Therefore, Kenai continues to be a net importer of energy from Anchorage.

The main component of expected transfers between Anchorage and the Kenai Peninsula is based on the optimal pattern of dispatch of energy from Bradley Lake. Bradley Lake has sufficient water storage capability to allow hydro energy production during the winter months in excess of Kenai Peninsula demand requirements. In addition, the Bradley and Cooper Lake facilities provide more power than needed to meet Kenai peak demand. Therefore, some of this excess capacity can be used to allow the turning off of less efficient, only partly loaded gas-fired turbines operating in the Anchorage area.

However, there are two major errors in DFI's analysis of hydro-thermal coordination benefits. The first is a calculation error which results in a $25 million overestimate of benefits. The error involves a fuel savings estimate in millions of Btu per hour of hydro-thermal reshaping located in Table A-6 on page A-8 of the utility 138 KV report. In the first column of Table A-6, the figure "356" should read "132" and the figure "125" should read "55."[16]

The second miscalculation results from using a constant rather than varying gas turbine heat rate across loading levels for calculating fuel savings for hydro-thermal coordination. Gas turbines operating at full load have their most optimal, efficient heat rates. As turbine loading is reduced, the heat rate increases (in Btu's per KWh). To accurately calculate fuel savings from turning off turbines in Anchorage, this varying heat rate efficiency needs to be taken into account. Use of a constant, 50 percent loaded, turbine heat rate overestimates the savings potential of the new intertie. This oversimplification results in an additional $4 million overestimate in benefits of the new Anchorage-Kenai intertie.[17]

A third problem with the hydro-thermal coordination benefits calculation is that it assumes that after the Bradley Lake project is completed and a new Anchorage-Kenai intertie is constructed, the electrical system will be optimally dispatched in order to capture the *potential* benefits of the system. If optimal dispatch does not occur, these benefits will be realized. Salim Jabbour, principal investigator, DFI, estimated that $3-$6 million in annual savings are currently available in the Railbelt if the system were optimally dispatched. In calculating potential benefits of a new intertie, DFI attempted

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[16] Richard Fancher of DFI confirmed this calculation error in Anchorage on January 30, 1990.

[17] Ibid.

to compare optimal systems with and without a new intertie. It is not clear, however, whether the effects of the currently suboptimal system are fully removed because data from actual utility dispatch patterns is used to determine which gas-fired unit would be shut off under hydro-thermal coordination, i.e., a 100 MW unit. The size of this unit, in turn, results in the capacity of the existing intertie being insufficient to turn off the unit. If, however, all of the units in Anchorage were optimally dispatched by one control center, it is likely that the unit identified to be the "marginal" unit to be shut off (from the historical utility data) would be smaller than 100 MW. If so, the current intertie capacity may be sufficient to shut off the unit.

The most significant problem with the hydro-thermal benefit category, however, is the assumption that these potential benefits would be realized through optimal utility dispatch in the Railbelt given the significant utility and ratepayer savings that are currently available but unrealized. There will be even less market incentive for the utilities to capture the potential new intertie benefits because the intertie will be financed by a state grant. Decision Focus investigators suggested that to increase the likelihood of capturing hydro-thermal coordination benefits, a condition of a state grant should be the development of a single utility dispatch control center in Anchorage for the southern Railbelt and one control center in Fairbanks for the northern Railbelt (the latter is currently the case).[18]

Economy Energy Transfers Between Anchorage and Fairbanks

In the system simulation conducted by DFI, nearly all transfers of power between Anchorage and Fairbanks flow from south to north because Anchorage gas-fired generation costs less than Fairbanks oil-fired power. Fairbanks first relies upon its existing coal-fired capacity. In the absence of an intertie, Fairbanks would next rely upon existing oil-fired generation capacity. An intertie allows the displacement of higher cost Fairbanks oil-fired generation with lower cost Anchorage gas-fired generation. Increased transmission line capacity allows Fairbanks to take advantage of increased economy energy transfers as Fairbanks electrical demand grows. Most (73 percent) of the benefits of the AF100 upgrade and the construction of a new Healy-Fairbanks 138 KV line result from increased economy energy transfers. However, these benefits are driven by three significant assumptions.

North Pole Operating Constraint. The first key assumption is the so-called "North Pole operating constraint." The North Pole operating constraint occurs because of the poor part-load performance of the Golden Valley Electric Association (GVEA) two 61 MW oil-fired combustion turbines located at North Pole. To be economically most efficient, the units must be operated above a

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[18] Meeting with Salim Jabbour and Richard Fancher, DFI, Anchorage, January 30, 1990.

minimum load level. When demand in Fairbanks for energy over the intertie exceeds the intertie capacity, one of the North Pole units must be started. Because the minimum economic level of operation of these units is relatively high, intertie purchases are reduced whenever a North pole unit is started, even if Fairbanks demand only minimally exceeds intertie capacity. The AF100 and AF138 projects would reduce or eliminate this North Pole constraint by allowing a higher level of energy transfer into Fairbanks from Anchorage. As a result, there would be fewer occasions for the North Pole units to be started.

There are three problems with the calculation of benefits from eliminating the North Pole operating constraints. The first is that the DFI North Pole calculation assumes that the Fairbanks Municipal Utility System (FMUS) 20 MW coal-fired Chena #5 unit is not operated before the North Pole units until after the intertie reaches its full capacity. This occurs most often under the lower fuel price scenarios when full-load heat rates of Fairbanks generating units are compared. In contrast, DFI's Over/Under simulation model shows the Chena #5 unit operating after the year 2002. In actuality, part-load heat rates indicate that the FMUS Chena #5 coal-fired unit should be dispatched before any part loading of North Pole units. In fact, FMUS baseloads the Chena #5 unit. This correction reduces the incremental benefits of the AF138 over the AF100 by approximately $3 million.

The second problem with the North Pole constraint analysis is that the Fairbanks load forecast used by DFI assumes that the Fairbanks utilities supply power to the military. In the Railbelt electrical demand forecast conducted for the AEA by the University of Alaska, Institute of Social and Economic Research (ISER), Scott Goldsmith indicated that the extent to which Fairbanks utilities will supply military power in the future is uncertain. As a result, the military load should be subjected to a sensitivity analysis--this was done in the AEA study. Because no sensitivity analysis was done in the utility 138 KV study to determine the impact of this assumption, economy energy benefits are overestimated. The frequency of the North Pole operating constraint would be reduced without the military demand.

The third problem with the benefits attributed to the North Pole constraint is that it does not take into consideration the current negotiations between GVEA and FMUS regarding the sale of FMUS' 20 MW oil-fired Chena #6 unit.[19] Currently, this unit is not operating because its location on the Chena River causes water quality problems from fuel storage and leakage. The cost estimate for moving the unit to GVEA's North Pole facility is approximately $2 million. Given the significant level of intertie benefits attributable to the North Pole

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[19] Information on this purchase was not considered in the utility 138 KV study because this information was not provided to DFI. The information was contained in North American Electric Reliability Council (NERC) filings submitted to the AEA by FMUS and GVEA.

operating constraint, moving a generator appears more cost effective than the construction of the new AF138. If each of the transactions were to be privately financed, it is doubtful that GVEA would construct a new power line rather than move an idle generator.

Fuel Price Differentials. As part of the Railbelt alternatives study, the AEA contracted with ICF, Inc. to analyze fuel costs in the Railbelt.[20] Based on the ICF analysis, the AEA developed fuel price forecasts and estimates of price differentials between major fuel types in the Railbelt--natural gas, fuel oil, and coal. Economy energy sales over electrical transmission lines are motivated by fuel price differentials because lower cost power is transmitted to regions with higher cost power.

In their utility 138 KV analysis, DFI made two significant departures from fuel price assumptions used in the earlier AEA 230 KV study. The first is changing the probability weighting of the fuel price forecasts. In the AEA study, the low, middle, and high fuel forecasts were given a 60, 30, and 10 percent probability weighting for calculating the potential benefits of the upgraded/new interties. In the utility 138 KV study, the fuel forecasts were given equally weighted probabilities (i.e., 33.3 percent each). The effect of this change in weighting is to increase the forecasted fuel prices and the benefits of economy energy sales to the southern line. As a result of the relative coal price differential, changing the fuel forecast probabilities lowered the economy energy benefits of the northern line (i.e., Fairbanks produced coal power replaces natural gas economy energy sales because of the higher price of natural gas). There was no justification given for changing the forecast probabilities.

The second change made in the utility 138 KV study was to remove the sensitivity analysis for fuel price differentials after the year 2010. In the ICF analysis, fuel prices were forecasted through the year 2010. The life of the intertie projects, however, extends beyond that time horizon. Therefore, assumptions about fuel price differentials must be made after the year 2010. One of the sensitivity analyses conducted was to collapse the price differential between Cook Inlet natural gas and Fairbanks fuel oil based on the sharply rising marginal cost of Cook Inlet gas reserves as gas is depleted.[21]

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[20] ICF Incorporated, *Fuel Price Outlooks: Crude Oil, Natural Gas, and Fuel Oil, Railbelt Intertie Reconnaissance Study*, Volume 4, prepared for the Alaska Power Authority, August 1988.

[21] Fuel price differentials and this sensitivity analysis is discussed at length in Appendix B of the DFI report prepared for the AEA. See especially pages B-4 and B-5.

The effect of this Cook Inlet natural gas price increase is to remove the price differential between Cook Inlet natural gas and Fairbanks fuel oil after the year 2015, which would significantly erode the calculated benefits of economy energy transfers from Anchorage to Fairbanks. This is especially true in the utility 138 KV study because the life of the new Healy-Fairbanks intertie was increased from 35 to 50 years. Given the uncertainty of this distant time horizon and the level of known reserves of Cool Inlet natural gas, a fuel price differential sensitivity analysis should be conducted; no justification was given for removing the analysis from the utility report.[22] Maintaining a fuel price differential between 2020 and 2043 overstates the net present value of the incremental benefits of the AF138 over the AF100 by about $10 million.

Gas Royalty Benefits. A benefit category that was not included in the AEA 230 KV study but was added to the utility 138 KV study is the benefits from increased gas royalties.[23] This category was added on the premise that the new Anchorage-Fairbanks intertie would [illegible] increased gas substitution for oil, and therefore, would increase Alaska's royalty and severance taxes. This benefit calculation assumes that the price of natural gas will increase less than inflation plus the discount rate. To the extent that this assumption is incorrect, the benefit calculation overestimates actual benefits.

According to DFI, the royalty benefit calculation is adjusted "in the later years when the gas supply is depleted." However, it appears that there is no adjustment made for increased gas prices as Cook Inlet gas is depleted. The increase in gas prices could more than offset any increase in the present value of gas royalties and severance taxes that results from moving these payments forward in time. In addition, if gas resources are depleted in the next 50 years as DFI indicates--based on ICF's analysis--then maintaining a constant fuel price differential between natural gas and fuel oil to calculate the benefits of economy energy sales is inconsistent.

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[22] Maintaining a constant fuel price differential also contradicts the statement made on page 5-3 of the utility 138 KV report regarding benefits from increased gas royalties. In this section, DFI states that "benefits from increased gas royalties are reduced in later years when the gas supply is depleted." Economic logic dictates that as Cook Inlet gas is depleted, its price will increase. This will, in turn, reduce or eliminate the price differential between Cook Inlet natural gas and Fairbanks fuel oil and thus, the benefits of increased economy energy sales over the intertie.

[23] Gas royalty and severance tax benefits were not included in the feasibility analysis for the existing state-owned and constructed Anchorage-Fairbanks intertie. Nor were foregone natural gas royalties and severance taxes calculated as a cost in the Bradley Lake hydroelectric project analysis. If they had been, even with the sunk costs and higher gas prices assumed in 1987, the project may not have been found economically feasible.

CAPACITY SHARING BENEFITS

Electric power system interconnections through transmission lines allow one or more areas to share generation capacity and/or reduce required generation reserve margins without compromising system reliability. New or upgraded interties can reduce future investment costs by deferring or avoiding the need for generation capacity. During the period of analysis, the Railbelt will have two areas (Kenai and Fairbanks) with capacity surpluses, while one area (Anchorage) will eventually have a capacity shortage. Capacity deferral benefits are possible through increased power transmission between the surplus and shortage areas. Decision Focus analyzed the potential benefits of both capacity deferral and avoidance. This section primarily reviews the benefits attributable to capacity deferment.

Decision Focus calculated capacity deferment benefits based on generation capacity retirement schedules and a 20-year life of new gas turbines as provided by the Railbelt utilities. According to a recent AML&P study,[24] they intend to retire two units in 1992 after 30 and 28 years of life, which makes the 20-year lifespan a questionable assumption. The use of the conservative 20-year life span results in an increase in capacity deferral benefits.

The new KA138 intertie results in capacity deferment benefits because it has a higher transfer capacity than the existing intertie. To calculate capacity deferment benefits, DFI models two transfer capacity cases for the existing intertie. In Case 1, the existing intertie transfers 75 MW of input and 60 MW of output (the difference is customer usage along the line and line transfer losses). In Case 2, the existing line transfers 90 MW of input and provides 75 MW of output. In their analysis, however, DFI erroneously modelled 88 MW of output for Case 2 which understated the benefits of the new intertie.

This understatement, however, is more than compensated by the considerable disagreement over the actual transfer capacity of the Anchorage-Kenai line. Two transfer capacities were modelled primarily because of this disagreement. The engineering consultant for the Alaska Energy Authority, PTI, indicates that the existing intertie can routinely transfer 90 MW input and 75 MW output.[25] However, this would be the upper transfer capability of the existing line in the absence of "technical fixes;" the line's transfer capacity continues to be the topic of considerable debate. To the extent that the existing line's transfer capacity can be increased, the capacity benefits of a new line are significantly eroded.

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[24] Anchorage Municipal Light & Power, "Explanation and Support for Avoided Cost Tariff Proposed by ML&P," October 25, 1989, p. 8.

[25] PTI, "Kenai Export Limits With and Without a New Line With and Without Additional Compensation," PTI Report Number R106-89, November 30, 1989.

Another significant problem with the estimate of capacity deferment benefits results from the inconsistency between generation capacity retirement schedules used for the intertie analyses, and those provided to the AEA for a North American Electric Reliability Council (NERC) study, and for calculating utility avoided costs. Information on current Railbelt standing capacity and retirement of that capacity is presented in Tables 4 - 6 for the subregions of Anchorage, the Kenai Peninsula, and Fairbanks. These tables are based on utility system modelling used by DFI (Appendix F, AEA study). The same system modelling was used for both the AEA and utility studies (see Attachment B).

In this memorandum, the DFI information has been adjusted to account for the extension of the operating life of existing equipment. This life extension is based on utility information for 1) avoided cost hearings[26] and 2) the NERC survey identified above. Thus, the primary difference between DFI's capacity and retirement schedules and those in Tables 4 - 6 is that DFI assumes no capacity life extension, while according to the information presented for calculating avoided costs and provided to NERC, a considerable amount of life extension is anticipated. The generating units to be overhauled or rebuilt are identified as such in the tables. These tables assume one major rebuild that increases the life of the unit by 15 years. In addition, according to CEA's NERC report, the Bernice Lake #4 natural gas turbine is being moved to Anchorage in 1994 and, therefore, is reflected as such in these tables. Movement of this unit further reduces the capacity constraint of the existing Anchorage-Kenai intertie.

Figures 1 - 4 illustrate total installed capacity, capacity retirement, and forecasted low, middle, and high electrical power demand in the Railbelt and its subregions from 1994 through 2025. Information on installed capacity and retirement dates is from Tables 4 - 6. The energy demand forecasts are from the University of Alaska, Institute of Social and Economic Research analysis for the Railbelt intertie study.[27] The demand forecasts are peak demand and include a 30 percent reserve margin. According to Figure 1, under the high forecast the Railbelt will need no additional generating capacity until the year 2007; under the low demand forecast, no additional capacity will be needed

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[26] Under the Public Utilities Regulatory Policies Act of 1978 (PURPA), utilities must purchase power from independent qualifying facilities at their avoided energy costs which is defined as the cost of the next increment of power they would produce. There is inconsistency, however, between AML&P's avoided cost and NERC information. For AML&P retirements in the 1990s, NERC survey information was used.

[27] University of Alaska Anchorage, Institute of Social and Economic Research in collaboration with Adams, Morgenthaler, & Company, Inc.; Regional Economic Research, Inc.; and James E. McMahon; *Forecast of Electricity Demand in the Alaska Railbelt Region: 1988-2010;* prepared for the Alaska Power Authority, April 30, 1989.

until 2009. Anchorage will be short of capacity sometime between 2007 and 2009. This, however, does not take into consideration potential power sales from the Kenai Peninsula that will have ample capacity throughout the period of analysis.

Determining the value of capacity deferment first requires the calculation of the amount of capacity deferred through the retirement schedules described above. The second part of the calculation is the estimate of the cost of the capacity that is deferred. In their analysis, DFI estimates that the cost of deferred capacity is $51/KW/year. However, prior to 2007 when additional capacity is required in the Railbelt, the replacement cost of gas turbines overestimates the potential capacity sharing benefits because the cost of life extension is less than $51/KW/year. In their avoided cost proposal, AML&P suggests that gas turbines can be life extended for only the cost of fixed operation and maintenance, $13/KW/year, 74 percent less the $51/KW/year in the DFI study. While AML&P's cost estimate seems extremely low, it indicates that capacity can be acquired at considerably less than DFI's estimates. In the utility report, DFI acknowledges (p. 6-5) that the extent to which capacity is life-extended rather than replaced will reduce capacity sharing benefits.

TABLE 4
POWER PRODUCTION CAPACITY AND RETIREMENT IN ANCHORAGE

Unit name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
Eklutna	APAd	Hydro	30.0	----
AMLPCT#1	AMLP	NG	16	2015(a)
AMLPCT#2	AMLP	NG	16	2015(a)
AMLPCT#3	AMLP	NG	19	2015(a)
AMLPCT#4	AMLP	NG	33	2015(a)
AMLPCC#56	AMLP	NG	47	2015(b)
AMLPCC#76	AMLP	NG	109	2014(b)
AMLPCT#8	AMLP	NG	87	----
BEL CT#1	CEA	NG	17	2002
BEL CT#2	CEA	NG	17	2006
BEL CT#3	CEA	NG	55	2003
BEL CT#4	CEA	NG	9	1994
BEL CT#5	CEA	NG	66	2006
BEL CC#68	CEA	NG	101	2008
BEL CC#78	CEA	NG	101	2008
INT CT#1	CEA	NG	16	1996
INT CT#2	CEA	NG	16	1997
INT CT#3	CEA	NG	19	1997
INT CT#5	CEA	NG	25	----(c)

Notes:
(a) Units are repowered to 13,500 btu/kwh and life extended.
(b) Retrofitted and remains constant throughout the study period.
(c) This unit is moved in 1994 from the Kenai Peninsula to Anchorage.

Legend:
APAd= Alaska Power Administration
AMLP= Anchorage Municipal Light and Power
CEA= Chugach Electric Association
CT= Combustion Turbine
NG= Natural Gas

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989; Railbelt utility data submitted for North American Electric Reliabilty Council study, December 1989; and Anchorage Municipal Light & Power, "Explanation and Support for Avoided Cost Tariff Proposed by ML&P," October 25, 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165d).

TABLE 5
POWER PRODUCTION CAPACITY AND RETIREMENT ON THE KENAI PENINSULA

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
BERNCT#1	CEA	NG	8	1994
BERNCT#2	CEA	NG	18	2006
BERNCT#3	CEA	NG	25	2019(a)
BERNCT#4	CEA	NG	25	2004(b)
COOPER LAKE	CEA	Hydro	17	----
SOLDOTCT#1	AEG&T	NG	39	----(a)
SELDIC#1-4	HEA	OIL	2.1	2015(a)
SESIC#1-3	SES	OIL	10.5	2010(a)
BRADLEY LAKE	AEA	Hydro	119	----

Legend:

CEA= Chugach Electric Association
AEG&T= Alaska Electric Generation and Transmission Cooperative
HEA= Homer Electric Association
SES= Seward Electric System
CT= Combustion Turbine
NG= Natural Gas
IC= Internal Combustion

Notes:
(a) Units are life extended and remain constant throughout analysis.
(b) This unit is moved to Anchorage in 1994.

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989; Railbelt utility data submitted for North American Electric Reliabilty Council study, December 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165E).

TABLE 6
POWER PRODUCTION CAPACITY AND RETIREMENT IN FAIRBANKS

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
CHENST#1	FMUS	Coal	5	2001
CHENST#2	FMUS	Coal	2	2000
CHENST#3	FMUS	Coal	1.5	1995
CHENCT#4	FMUS	Oil	6	1987
CHENST#5	FMUS	Coal	20	2010
CHENCT#6	FMUS	Oil	26	2006
FMUSIC#1	FMUS	Oil	2.8	1992
FMUSIC#2	FMUS	Oil	2.8	1992
FMUSIC#3	FMUS	Oil	2.8	1995
HEALST#1	GVEA	Coal	25	2017(a)
HEALIC#2	GVEA	Oil	2.8	1997
NOPOCT#1	GVEA	Oil	61	2021(a)
NOPOCT#2	GVEA	Oil	61	2022(a)
ZENCT#1	GVEA	Oil	18	2016(a)
ZENCT#2	GVEA	Oil	18	2002
DSLIC#1-8	GVEA	Oil	14.7	2011

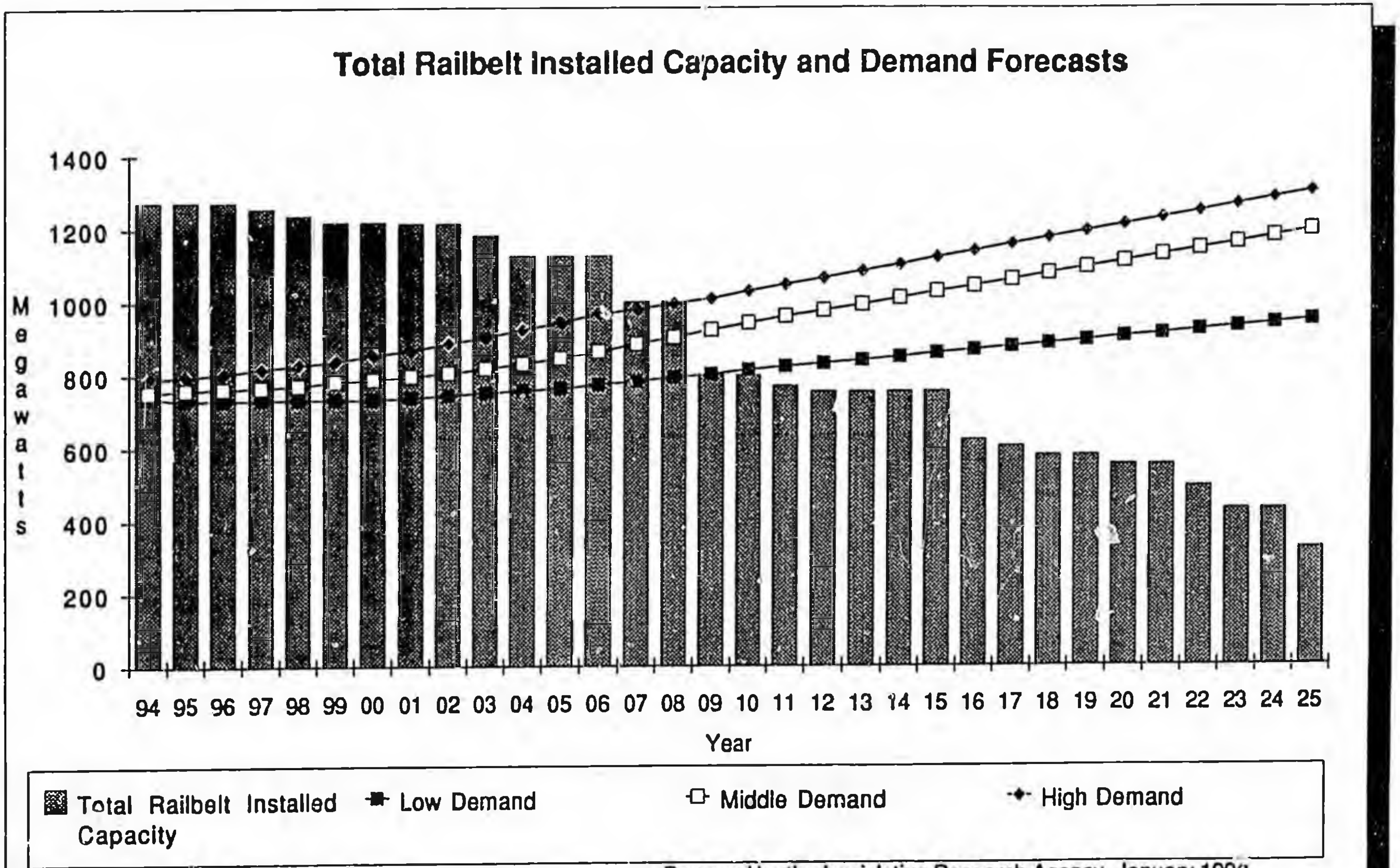
Legend:
FMUS= Fairbanks Municipal Electric Association
GVEA= Golden Valley Electric Association
ST= Steam Turbine
CT= Combustion Turbine
IC= Internal Comustion

Notes:
(a) Units are life extended and remain constant throughout the analysis.
*Chena Unit #4 Not Currently Operating; #6 possible sale to GVEA.

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989; Railbelt utility data submitted for North American Electric Reliabilty Council study, December 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165F).

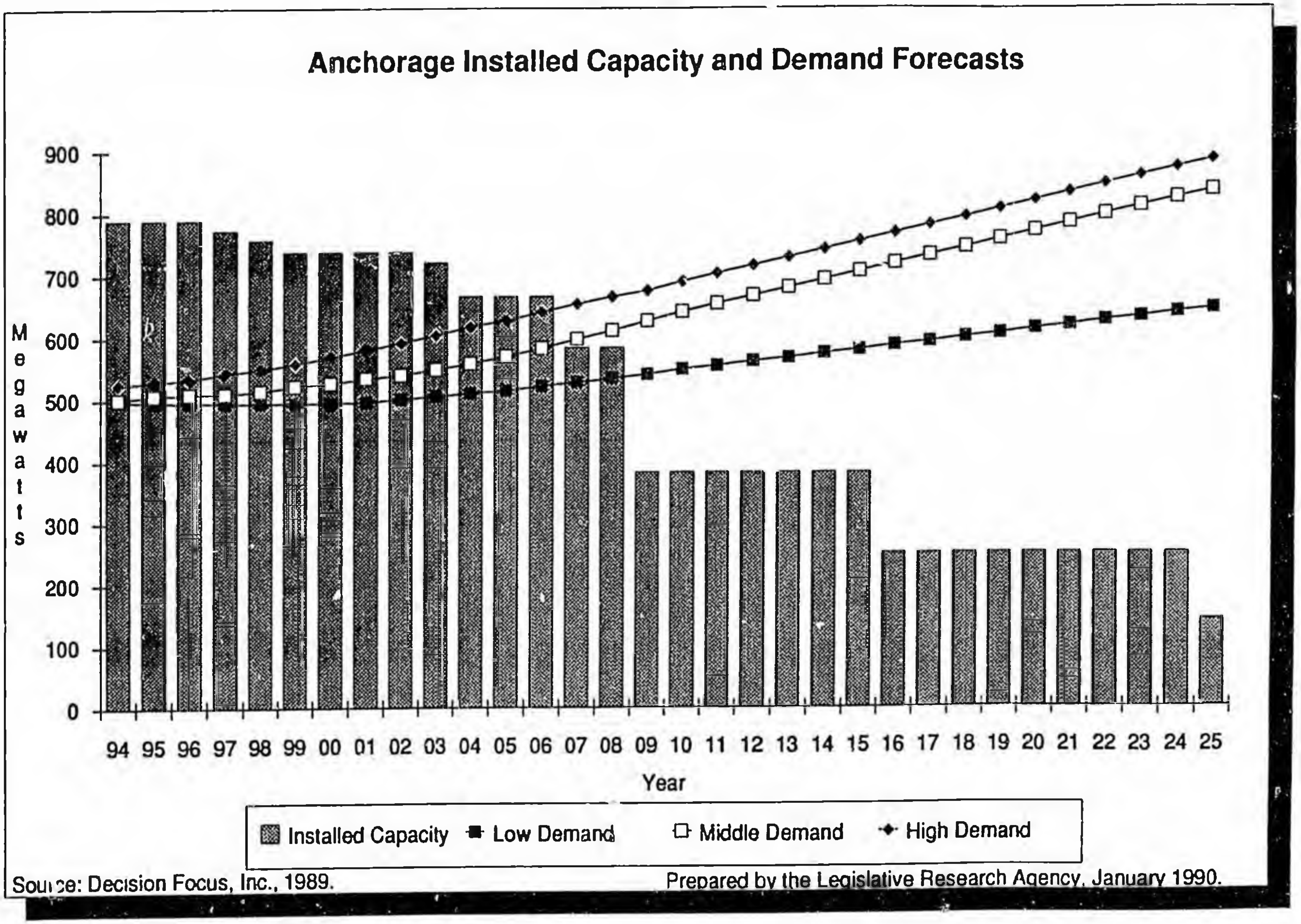
FIGURE 1



Source: Decision Focus Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

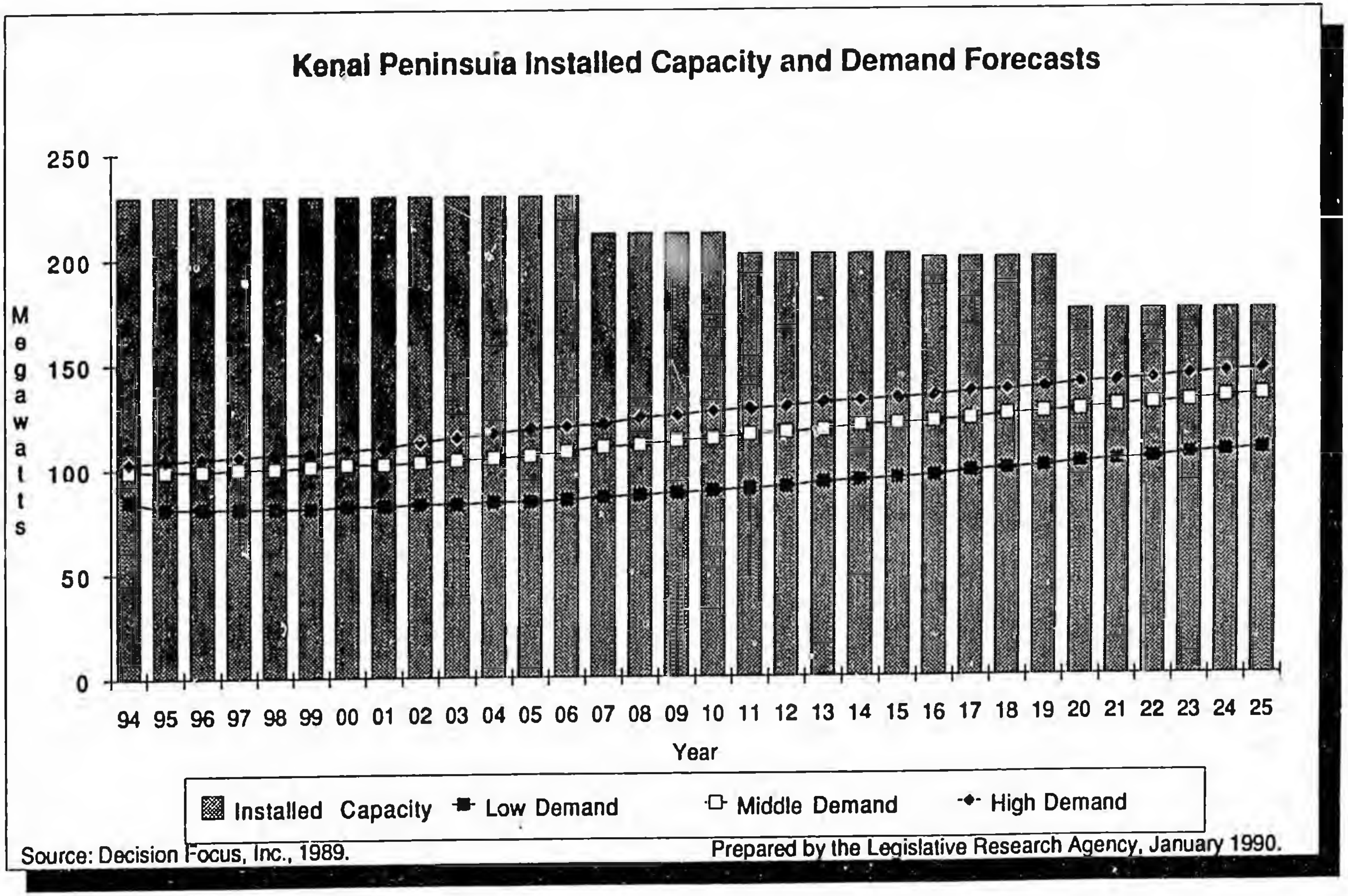
FIGURE 2



Source: Decision Focus, Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

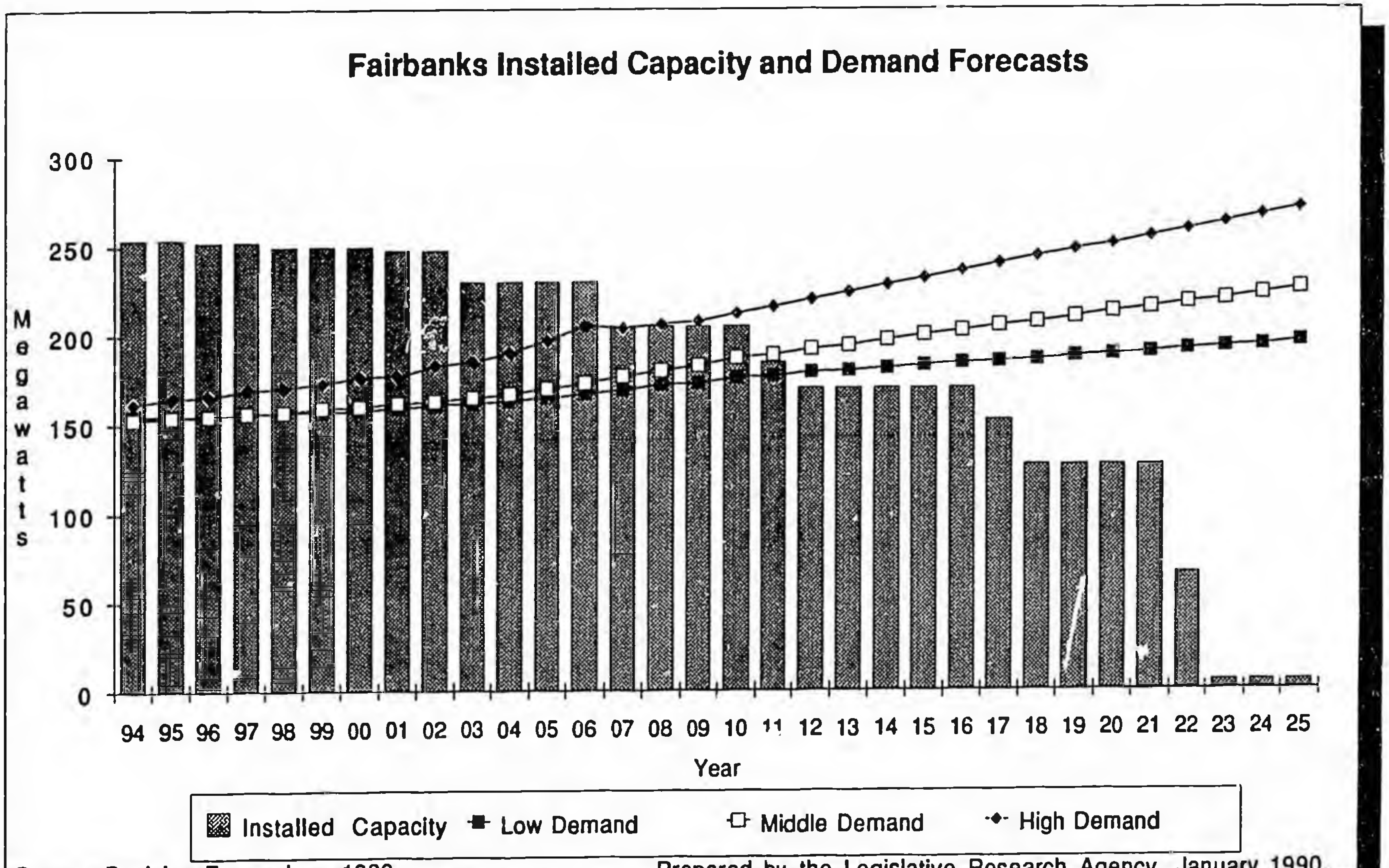
FIGURE 3



Source: Decision Focus, Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

FIGURE 4



Source: Decision Focus, Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

OPERATING OR SPINNING RESERVE SHARING

Operating or spinning reserves are the operating capacity that is not being used to serve the existing load. Instead, it is available to respond to a change in load. For example, a 40 MW unit that is serving a 20 MW load is providing 20 MW of load and 20 MW of spinning reserves. Operating or spinning reserves are used to respond to changes in customer demand and failures in the electric generation and/or transmission system. In this manner, operating reserves improve system reliability, but they also add to system costs. The operating reserve benefit of upgrading the Anchorage-Kenai intertie results from the substitution of operating reserve from the Bradley Lake hydroelectric project for gas-fired spin in Anchorage because Bradley Lake spin is free while gas consumption makes thermal spin costly.

In their analysis, DFI estimates that the new 138 KV Anchorage-Kenai line would increase operating reserves sharing and result in $5.2 to $13.5 million in benefits. This is based on DFI examination of operating records of CEA, GVEA, and AML&P for 1988 which indicated that the cost of providing spinning reserves is between 7,000 and 11,000 Btu/KWh. Based on this review, DFI estimates the cost of spinning reserve to be 7,000 Btu/KWh. This cost of spinning reserves on a Btu per kilowatt hour basis was then applied to the gas turbine part-load operating cost data to calculate the total benefits attributable to a reduction in Anchorage gas-fired spinning reserves.

In two extensive meetings with Salim Jabbour, principal investigator, we asked DFI to verify the formula used to calculate the cost of spinning reserves because the formula used in a DFI report failed to produce accurate results.[28] While DFI was not able to substantiate their formula, they did acknowledge that Alan Mitchell's formula to calculate the cost of spinning reserves is correct.[29] Using Mr. Mitchell's formula, the cost of spinning reserves is 2,800 Btu/KWh. This correction reduces the benefits of spinning reserve sharing to $2.1 to $5.4 million or an average of $3.6 million. This contrasts with DFI's estimated benefits of $5.2 to $13.5 million or an average of $9.4 million. Details of these calculations are provided in Attachment C.

REDUCED MAINTENANCE COSTS

A new benefit category in the DFI utility study, which was not in the AEA study, is reduced maintenance costs of the existing Anchorage-Kenai intertie as a result of the construction of the new KA138 line. The present value of

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[28] Decision Focus, Inc., "Value of Bradley Lake Spinning Reserves," prepared for the Railbelt Utilities, October 6, 1989, p. 6.

[29] Alan Mitchell of Analysis North is the utility consumer advocate under contract to the state of Alaska.

reduced maintenance attributed to the new intertie is $5 million. The justification for these benefits is not described in the report and is based on information provided by the Chugach Electric Association to DFI. Given that CEA stands to benefit considerably from the state construction of the intertie, this reduced maintenance cost estimate should be reviewed by an independent party or AEA engineers in the course of their review of intertie construction cost estimates.

IMPACT OF THE HEALY CLEAN COAL DEMONSTRATION PROJECT ON INTERTIE BENEFITS

If the construction of the Healy clean coal demonstration project is funded, benefits of the interties should be recalculated. In a recent letter by DFI (Attachment A), Salim Jabbour indicates that while the Healy facility would not significantly affect the benefits of the northern line, it would further reduce the reliability and capacity sharing benefits of the southern intertie.

* * *

In conclusion, based on this limited review, there appear to be significant errors in computations and unjustified changes in assumptions in the recently completed Decision Focus 138 KV study. While the limited AF100 upgrade appears to continue to have a benefit/cost ratio above one, the construction of either a new southern or northern line does not appear to be economically justifiable at this time. It is clear that had the 138 KV lines been analyzed under the same assumptions as those used in the AEA 230 KV study, the 138 KV lines would not have been found economically feasible. A decision to proceed with these 138 KV intertie projects would be based on the political rather than economic merits of the projects.

I hope this information answers your questions. If you have additional questions, please do not hesitate to call.

Attachments

ATTACHMENT A

Letter from Salim Jabbour, DFI, to
Mike Kelly, GVEA regarding the
Impact of the Healy Clean Coal Project
on the 138KV Intertie Study

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January 15, 1990

Mr. Michael P. Kelly
General Manager
Golden Valley Electric Association
P.O. Box 71249
Fairbanks, AK 99707

Dear Mike:

In response to your request, I am writing to provide you with my best professional judgement on how the Healy Coal Project (HCP) would affect the economic feasibility of the proposed 138 KV lines. The following discussion is based on four hours of work; no quantitative analysis was performed.

Impact of The HCP on The Economic Feasibility of The Southern Line

The HCP would affect the economic benefits of the proposed southern line through at least two of the categories identified in the December 1989 report.

> *Capacity Sharing.* The HCP would increase the capacity surplus in Fairbanks (assuming no power plants in the Fairbanks area are retired or mothballed because of the HCP). Capacity surplus in Fairbanks could be used by Anchorage (even without any new lines) to meet future capacity shortages in the Anchorage area. This would reduce Anchorage needs for capacity additions in the future and therefore reduce capacity sharing benefits due to the southern line.
>
> *Reliability.* The HCP could provide Anchorage with a source of energy in case of emergencies; therefore it could reduce outage durations and outage costs in Anchorage. The extent to which this is feasible depends on Fairbanks needs for power during an emergency in Anchorage and whether or not surplus capacity in the north is available for export to the Anchorage area. Therefore, it is possible that the HCP could reduce the reliability benefits of the proposed southern line.

Overall, the HCP is expected to reduce the benefits of the proposed southern line. It is estimated that the expected benefit to cost ratio would remain larger than one, i.e. the proposed southern line would remain cost effective. This assumes, of course, that all other assumptions remain unchanged.

Impact of The HCP on The Economic Feasibility of The Northern Line

The HCP would affect the economic benefits of the northern line primarily through its impact on energy transfers between Anchorage and Fairbanks. The benefits of the proposed northern line derive primarily from the Anchorage-Fairbanks energy transfers through the reduction in the transfer losses between the two areas, and the elimination of the constraint on the transfer capacity.

The HCP would reduce Fairbanks needs for imports from Anchorage, but would not significantly impact energy transfers over the Healy-Fairbanks corridor. Since most of the losses occur between Healy and Fairbanks, the HCP is expected to slightly reduce the transfer loss benefits of the proposed northern line.

However, since the combined capacity of the new HCP and GVEA's Healy plant exceeds the transfer capacity of the Healy-Fairbanks existing line, one could argue that the proposed northern line would allow increased economy transfers by eliminating this constraint (this argument assumes that transfers from HCP to Fairbanks are more optimal than transfers to Anchorage because Fairbanks has higher generation costs).

Overall, it is estimated that the HCP would not have a significant impact on the benefits of the northern line.

In conclusion, it seems that the HCP would not significantly impact the benefit to cost ratios of the proposed 138 KV interties. Based on this conclusion, I would not recommend a detailed re-evaluation of the interties.

Sincerely,

Salim Jabbour

Salim J. Jabbour
Vice President

ATTACHMENT B

DFI System Modelling Data (Appendix F) AML&P Avoided Cost Information and NERC Study Information

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).

EXPLANATION AND SUPPORT FOR AVOIDED COST TARIFF PROPOSED BY ML&P

The purpose of this document is to support the Avoided Cost tariff (No. later) submitted by the Municipality of Anchorage, doing business as Municipal Light and Power (ML&P). This document outlines the avoided cost methodology and Qualifying Facility (QF) rate formulas, that are included in the ML&P "Cogeneration avoided cost rate tariff" that ML&P intends to use with future Public Utility Regulatory Policies Act (PURPA) (16 USC 824a-3) resources or QFs greater than 100 kW. The methodology will be used to develop avoided costs for QFs on a case-by-case basis within this size range based on specific size and operating characteristics of proposed QFs. ML&P did not have a tariff or approved methodology on file with the Alaska Public Utilities Commission (APUC) for avoided costs of facilities greater than 100 kW when it was subject to APUC regulation.

The avoided cost methodology and QF rate formulas provide a generic method that can be used to determine rates for a variety of QFs. The rates satisfy the requirements of PURPA. The methodology will be used to develop a contract rate that is responsive to changes in ML&P's fuel costs and the rate of inflation throughout the term of a QF contract.

To calculate the avoided costs of ML&P a computer simulation was performed of the ML&P generation system. A set of computer models calculated the various costs to ML&P. The costs were calculated with and without cogeneration present, but with no costs assigned to the operation of the cogeneration facility. The difference in the annual cost between the two simulations was the costs (capital, fuel, cost of energy not served and operation and maintenance (O&M)) that ML&P would avoid by purchasing from a QF.

Therefore, ML&P has avoided capital costs, avoided fuel costs, avoided fixed O&M costs, avoided variable O&M costs, and avoided backup purchases during forced generation outages. These costs can be allocated to avoided energy or avoided capacity values. These avoided energy and capacity costs were then adjusted to remove the effects of inflation and natural gas prices. This resulted in a set of yearly energy and capacity avoided cost formulas.

In the analysis, the avoided energy costs are both dependent upon and correlate with future natural gas prices. The rate of inflation also has a direct effect upon ML&P's avoided capacity and energy costs. Because of the sensitivity to future prices, the final avoided costs have been developed as a formula of actual future prices. The payment by ML&P using such avoided cost formulas based upon actual natural gas and inflation values will more accurately forecast future avoided costs and should neither harm nor benefit the ultimate ratepayers. In other words, the use annual formulas will leave the ratepayers neutral as to whether ML&P uses its own resources or purchases from QFs.

In addition, how the size of a QF (10MW, 25MW and 50MW),[1] how the QFs level of production (plant factor/availability), and how the year the QF goes on-line would impact ML&P's avoided costs were analyzed. These sensitivity analyses allowed us to determine the relative importance of the key parameters that affect ML&P's avoided costs and to suggest avoided cost rate formulas that ensure that the ratepayers are risk neutral.

The major elements of the studies to develop ML&P's avoided costs were: updating of the ML&P load forecast; modeling the ML&P generation system; verifying the computer models; converting avoided costs into avoided cost rate formulas; and developing standard contract language for use with future potential QFs.

I. LOAD FORECAST

How the Load Forecast Impacts Avoided Costs

The load forecast is used as an input in the computer simulation and modeling process. The annual peak demand in the load forecast is the principal factor determining when additional generation is required and, therefore, affects capacity cost payments. The energy load forecast also affects the mix of resources dispatched to meet load.

Why a Load Forecast was Prepared Now

The previous official ML&P forecast was published in June of 1986. The 1986 forecast was updated during 1988 to incorporate recent historical electric consumption information and current expectations as to the effects of reduced oil revenues on the State's economy into the utility's planning process. The most recent forecast is documented in a study titled Anchorage Municipal Light and Power Load Forecast 1988-2010." This study was finalized in September of 1988 and is included as an appendix to this document.

The last ML&P load forecast was updated because of the need to have consistent assumptions between generation avoided cost and load forecast models. The load forecast is a function of a number of economic and demographic variables, such as inflation rates, future gas and oil prices, etc. The latest estimates of these variables were incorporated into the generation avoided cost model to be consistent with the ML&P load forecast, even though the methodology and tariff are based upon actual natural gas prices and inflation rates rather than forecast prices.

Major Economic, Petroleum & Fiscal Assumptions

The electric forecast uses assumptions found in the economic forecasts of The Institute of Social and Economic Research (ISER), University of Alaska, Anchorage, as presented in its publication, "Economic and Demographic Projections for Southern Railbelt Electric Utilities," October 1987. ISER uses an econometric model to project key economic variables that are used for the electric forecast. ISER portrays a range of economic scenarios about the future course of the Anchorage and Alaskan economies.

For national economic trends, ISER forecasts assume consumer prices will rise at an annual rate of 5.4% in 1988 and 1989, 6.3% through 1994, 6.6% through 2000, and 6.8% thereafter. Growth in real average weekly earnings averages 1% annually. Growth in real per capita income averages 1.5% per year. The long run unemployment rate is estimated at 6.5%.

ISER expects the current Alaska recession to bottom out sometime in the 1990's, depending on whether low, medium, or high economic growth is assumed. In the low case, Anchorage non-agricultural employment is projected to drop to 95,655 in 1992 from the 1987 level of 98,100. The base case assumes employment in the Municipality will rise slightly to 99,168 in 1989. The high case assumes employment growth in 1989 to 99,896. Population, income, and other variables follow similar patterns, depending on the scenario for future growth.

The treatment of oil and gas prices is particularly difficult. If oil and gas prices are artificially high, then governmental economic activity in Alaska due to tax revenues will stimulate the use of electric energy in Anchorage. But similarly, costs of fuel at ML&P will be high, tending to raise electric rates and depressing the use of electricity in certain load segments. These combined effects in both loads and fuel prices impact avoided energy costs that ML&P faces.

World oil prices are projected by ISER in the low scenario to fall in real (1988) dollars, from an estimated $18 per barrel in 1988 by 1% per year through the 1990's. The base case foresees a 0.5% per year rise in oil prices. The high case envisages a rise to $21 per barrel in real terms by 1990 and a 2% annual increase thereafter.

Summary of Load Forecast Results

The medium and the high load forecasts were analyzed to determine avoided costs for ML&P. For the reasons discussed in Section III, the medium forecast represents the most probable estimate of the future and hence is the basis for developing ML&P's "avoided cost" annual formulas. The high forecast represents the case where energy costs are the highest and the need for additional capacity is the greatest. This forecast was used as the basis for a sensitivity analysis comparison.

The medium or mid-range forecast shows total annual ML&P energy requirements growing from about 830 GWh in 1988 to over 1112 GWh in 2010. Compound annual average growth rates for the mid-range forecast are 0.3% from 1987-1992; 1.0% from 1992-1997; and 1.8% from 1997-2010. Peak demand grows at comparable rates from 142 MW in 1988 to over 190 MW in 2010.

The high forecast projects total ML&P annual energy requirements growing from about 832 GWh in 1988 to over 1198 GWh in 2010. Compound annual average growth rates for the high-range forecast are 0.7% from 1987-1992; 1.7% from 1992-1997; and 2.0% from 1997-2010. Peak demand grows at comparable rates from 142 MW in 1988 to over 205 MW in 2010.

II. SYSTEM PLANNING APPROACH TO AVOIDED COST CALCULATIONS

General Approach

The method used to calculate avoided costs for ML&P was a two step process. First, computer models were used to simulate the generation costs for the ML&P system on an annual basis over the study horizon. As inputs to the computer models, economic and load data consistent with the medium forecast were used. Next, an assumed QF was forced into the resource generation dispatch stack for the years in question. The assumed QF was assigned no generation costs. The difference in total costs (capacity and energy) between the generation dispatch without the QF and with the QF then determined the annual avoided costs. The avoided costs were categorized into avoided energy and avoided capacity costs. This method produces a forecast of the cost to be avoided by inclusion of the QF within ML&P's generation mix.

Because the ML&P system does not require under current forecast loads and contract reserve margins any additional generation capacity until about 2015, the inclusion of a QF results only in avoided energy costs then. It is not until added generation capacity is required that avoided capacity costs are credited to the QF.

To provide independent verification of the modeling effort two comparisons were made. First, the results were carefully compared to current operational patterns of the ML&P system. Second, the results were compared to a medium term generation dispatch computer model used by the utility. Both comparisons confirmed the modeling results.

System Planning Approach as Viewed by Other Jurisdictions

The objective of the system planning or "differential revenue requirement" approach used by ML&P is to reflect anticipated system costs as precisely as possible in the avoided cost calculation. The system planning approach provides a higher degree of accuracy in determining avoidable costs than a "surrogate plant" or other approach can provide. This higher degree of accuracy is provided by examining a given utility's system closely. This allows the utility to determine with some precision at what point the utility will add a resource, what type of resource it will be, what the costs and generation characteristics the new resource will be, and what the cost differences would be for a QF alternative to the new resource.

Because the system planning approach most accurately calculates the costs that a utility can expect to avoid by purchasing power from a QF, it is accepted by the FERC (Preamble to 18 CFR Part 292, FERC Regulations Preambles 1977-1981, ¶30, 128 at p.30, 866) and best accomplishes the widely recognized goals of PURPA's avoided cost standard. That standard is designed to leave ratepayers indifferent as to whether their electric utility obtains power from its own resources or from a QF.

Why the Westinghouse Model was Chosen

The Westinghouse Generation Planning (WIGPLAN) computer model was used to perform the computer simulation. The WIGPLAN model is widely used in the electric utility industry and is one of the major planning models used to evaluate the needs for new generation. This model was previously used to analyze ML&P's generation needs and those of other electric utilities.

The prime reasons for the choice of this computer model were that: (1) it allows for long term (30-year) simulations; (2) through the Probabilistic Production Costing (PPC) module it can handle certain spinning reserve requirements and maintenance scheduling; and (3) the model's generation expansion section chooses the most cost-effective future resource to add for a particular utility's load characteristics. This capability includes analyzing the trade-offs between machines of varying efficiency, capital costs and fuel costs.

There are other advantages to the Westinghouse model. It will perform an economic dispatch of available units to simulate lowest cost operation that a utility would realize and it is able to evaluate resources whose heat rates vary as a function of generation level. This feature is important in the ML&P modeling since, if a QF facility is particularly large, it can force combined cycle units to operate in a simple cycle mode and require multiple machines to be operated below their most efficient load levels so that they can provide necessary spinning reserves.

One difficulty encountered in modeling the ML&P system was the inability of WIGPLAN to accurately commit resources in the dispatch simulation due to specific minimum loading and spinning reserve constraints.

This was resolved using a custom Lotus 1-2-3 spreadsheet program which defined the ability to commit the various combined cycle/simple cycle combustion turbine (CT) options. The Lotus model analyzed whether certain units could be operated due to minimum generation and/or spinning reserve requirements for typical low and high load days by season and by year over the forecast period. This information was then fed into the Westinghouse model to determine optimal dispatch and hence the appropriate cost of energy and capacity for ML&P.

Proper Planning Horizon

To compute avoided costs it was necessary to determine the proper planning horizon. The Westinghouse program is capable of a 30-year planning horizon and the Load Forecast comes on approximate 20-year time horizon from 1988 to 2010. ML&P's last generation planning study covered a 10-year period.

Most load forecasts for electric utilities extend only 20 years. Many utilities regularly forecast on only a 5- to 10-year basis. The reason for this shorter horizon is that economic data projections can become very speculative after about 10 years. Population projections, which are a prime driver of load forecasts, tend to become highly speculative after 10 to 20 years due to the effects of migration and changes in fertility and mortality rates for various age groups.

The last ML&P generation study entitled 10-Year System Planning Study, performed in July of 1985, adopted a 10-year planning horizon. A determination of the proper planning horizon should not be determined by amount of data available. A 30-year modeling study was performed to extend the study out far enough until there was a need for the next increment of capacity.

The most significant factors supporting a limited planning horizon are the volatility and impact of world oil prices on the Alaskan economy. Because of these factors, avoided costs have been calculated in a way which removes the risk of changes in oil prices and inflation rates from ratepayers. This can be approximated by the adoption of an avoided cost rate formula rather than an explicit avoided cost rate. The "heat rate" formula used to calculate an avoided energy rate is based on fuel costs at the time they are incurred. Fuel costs are determined monthly and based on the actual average cost of natural gas purchased by ML&P.

Similarly, because of the uncertainty associated with long-term purchase commitments, avoided capacity rates should not be locked in more than 20 years in advance of need by a utility. In addition to uncertainties about load growth, population growth and fuel prices, technological improvements are occurring in the CT generation manufacturing business. The lag time between introduction of technological changes in the aircraft industry and implementation of those changes in the power industry is around 10 years. Therefore, future advances in technology could significantly reduce avoided capacity costs 20 to 25 years hence.

Based on these considerations, the proper planning horizon for current ML&P avoided cost commitments has been identified as 10 to 20 years. While much can be done to minimize the nature of the speculation, technologies and industrial relationships can change dramatically in a twenty year time-frame.

Planning Horizon Considerations by Regulatory Agencies

The question of a proper avoided cost planning period has recently been addressed by several state commissions. The Idaho Commission issued Order No. 22636 on July 27, 1989 in Case No. U-1500-170, a generic proceeding on PURPA implementation. It reaffirmed the limitation of QF contracts to 20 year duration because of the types of uncertainties identified above (Order at p.77)

Similarly, the Oregon Public Utility Commission has found that avoided costs in PURPA contracts which looked reasonable less than ten years ago now appear to harm ratepayer interests. The California Energy Commission also has found that avoided cost rates projected out 20 years and levelized have created an over-commitment of QF resources that jeopardizes California utilities' ability to minimize costs to ratepayers through interference with economy energy transactions.

III. MAJOR MODELING ASSUMPTIONS AND DATA SOURCES

Consistency

Numerous assumptions were needed to model the generation resources. One primary goal was to provide a consistent set of assumptions. Specifically, the same fuel prices, inflation rates, and load levels used in the load forecast and forecast scenarios were incorporated in the WIGPLAN model.

Future Resource Options

The analysis was extended far enough in the future to evaluate imparts of new resources. This required an evaluation of resources alternatives which might be selected to meet local requirements. The principal resource choices were coal fired and CT technologies. The resource options were placed in the WIGPLAN program and the program used its "look ahead" capability to choose the most cost effective new form of generation when required.

To analyze future costs of CT technology a literature search was conducted. Because this technology is advancing rapidly, a variety of organizations were contacted for information. Future estimates of heat rates (9,224 BTU/ kWh LHV and 10,300 BTU/kWh HHV) are based on Electric Power Research Institute (EPRI) information and projections as to the size of future CT's (200 MW). Based on ML&P's current plans, this would take the form of a joint venture with another utility.

EPRI, manufacturers and trade associations were reluctant to estimate future prices of expected CT technology. Therefore, an analysis of economies of scale found in the turbine manufacturing process was performed. This analysis, when combined with information about plant costs specific to Alaska, resulted in an installed 1988 capital cost of $177/kW. A separate report is included as an appendix to this testimony which documents this information.

Coal fired power plant capital costs and heat rates used in the WIGPLAN model were taken from the EPRI Technical Assessment Guide information. Capital costs are estimated at $3,000 per kW in 1988 dollars. The heat rate for the coal plant was assumed to be 12,460 BTU/kWh.

Plant Retirements

ML&P's two oldest CT units are assumed to be retired in the year 1992. Units 1 and 2 were installed in 1962 and 1964 respectively. Units 1 and 2 have individual maximum capacities of about of 16.2 MW. Anchorage ML&P's share of Bradley Lake was modeled at about 23.3 MW of capacity starting in 1992. Because the model rarely used units 1 & 2 after Bradley Lake became operational, these units were assumed to be retired to save fixed O&M costs. Units 1 & 2 provide ML&P with substantial flexibility. The actual status of Units 1 & 2 can range from retirement, whenever Bradley Lake goes on line, to repowering if a need for new capacity develops.

CT unit 3 was assumed to be retired in 1996. This CT was added to the ML&P system in 1968. CT unit 3 was modeled with a capacity of about 19.8 MW. It was assumed that this unit would be kept on line until Bradley Lake had achieved maturity and its operation had been fully integrated into the ML&P system.

The primary modeling reason for the retirement of all three units was that with the addition of Bradley Lake, the ML&P system has more capacity and energy than it currently needs. Because these three oldest and smallest units have the "worst" or highest heat rates, the probability of use or dispatch drops with the addition of Bradley Lake. Retiring the units, therefore, represents an opportunity to save fixed O&M costs.

ML&P's other CT's are modern units installed in the 1970's and the 1980's. These units are being well maintained. ML&P's standard operation calls for annual to semiannual inspections and major overhauls approximately every 3 years. At these overhauls ML&P performs both a full inspection and destructive testing on selected (1 blade per row) hot rotating blades. In this way, the CT's are constantly checked and parts are replaced and upgraded. This program on modern CT's should result in an extended life expectancy. ** [Therefore, no other retirements were assumed for the study period. All the way through 2017 → 1980 → 2017

37 years

Existing Resource Physical Parameters

With respect to individual resources, model parameters were based on actual data, where possible, not empirical or theoretical assumptions. The first assumptions made were on the resources to be included in the generation modeling effort. Heat Rates or efficiencies for the CTs that ML&P operates were taken from actual test data performed by ML&P. The fuel rate (y) in MCF/hr was converted to a fuel consumption formula:

$$y = A + B\,(MW) + C\,(MW)^2 .$$

The coefficients for A, B, & C are shown in Table 1. Minimum and maximum generation output of the CTs was based on actual experience levels. Combined cycle units are committed to minimum operation of a full day, consistent with ML&P generation dispatch practices. This prevents unnecessary cycling and stress on the combined cycle units.

Similarly, O&M expenses were calculated from historic ML&P data, as were forced outage rates and maintenance requirements. Table 2 and Table 3 provide key physical parameters for the various CTs and hydro projects. These parameters were used as an input in the modeling effort.

Table 1
Resource Fuel & O&M Costs

	Fuel Consumption			O&M	
Unit	"A" MCF	"B" MCF/MW	"C" MCF/MW^2	Fixed $/KW	Var $/MWH
CT1	79	9.16	0.0476	10.41	6.75
CT2	76	8.50	0.0933	10.41	6.75
CT3	80	9.19	0.2310	10.41	6.75
CT4	160	7.83	0.0289	10.41	6.75
CT5	160	8.51	0.0159	12.27	0.81
CT7	160	9.60	0.0012	11.93	0.81
CT8	215	7.65	0.0196	9.54	0.81
CC5+6	168	6.74	0.0026	9.54	0.81
CC6+7	199	5.93	0.0080	9.54	0.81
Eklutna		(Hydro)		0.00	19.00
Bradley		(Hydro)		0.00	7.00

Table 2
Physical Resource Parameters

Unit	Year Added	Min (MW)	Summer Max (MW)	Winter Max (MW)	Forced Outage Rate %	Maint wks/ year
CT1	1962	5.0	14.0	16.2	21.4	8
CT2	1964	5.0	14.0	16.2	21.4	8
CT3	1968	5.0	17.7	19.8	21.4	8
CT4	1972	5.0	31.1	31.4	21.4	8
CT5	1974	10.0	33.8	35.1	4	11.7
CT7	1981	10.0	74.4	74.3	4	6
CT8	1984	10.0	77.7	86.5	4	6
CC5+6	1978	25.0	42.8	45.1	2	12.4
CC6+7	1981	35.0	99.4	99.3	2	7.5
Eklutna	1953	0.0			5	4
Bradley	1992	0.0			5	4

Table 3
Energy from Hydro Resources

Month	Eklutna MWH/week	Bradley Lake MWH/week
1	1713	2389
2	1795	2618
3	1635	2002
4	1401	1625
5	1501	1715
6	1646	1707
7	1751	1681
8	1760	1626
9	1709	1613
10	1754	2002
11	1810	2463
12	1935	2474

Installed reserve capacity requirements in the modeling are based on the formula established by contract among the interconnected Railbelt utilities. The contract requires that ML&P meet its annual system peak plus a minimum of a 30% reserve capacity requirement. The Alaska Intertie Agreement (Addendum No 1 Reserve Capacity and Operating Reserve Responsibility) was signed in December of 1985. The analysis assumes that additional generation

* is added when an ML&P reserve margin of 45% is reached. This provides a cushion in case abnormal weather or unexpected growth occurs so that generation can be added before the contract minimum is reached. The analysis also assumes that the Alaska Intertie Agreement remains in force for the study period.

Spinning reserves are also determined by the Intertie Agreement. ML&P spinning reserves are calculated by multiplying the largest unit of the total interconnected system times the largest ML&P unit on-line and then dividing that product by the sum of all interconnected utilities' largest units on-line. Historically, this spinning reserve requirement has worked out to average about 33% of total load for ML&P in the winter and about 41% in the summer.

The analysis also assumes that no economy energy sales or purchases occurred. In the interconnected Alaska power grid, economy energy sales are difficult to predict with certainty. In the past, sales have occurred at various quantities and prices. For the 20-year planning horizon, the Bradley Lake project will provide most of ML&P's traditional economy energy purchasers with energy having a low variable cost.

But allows cc to remain loaded.

Similarly, modest amounts of economy energy transactions would probably affect the "with" and "without" cogeneration scenarios equally. Modeling of other interconnected utilities with a multi-area model was beyond the scope of the studies supporting the proposed tariff and would require extensive data and forecasts from other utilities that probably are not available to ML&P. Furthermore, should economy energy sales dominate, the QF would probably contract directly with the buying utility because it would obtain the highest price.

Cogeneration Assumptions

For illustrative purposes to discuss the features of the tariff rates and the models, a number of assumptions were made about potential cogeneration resources. These assumptions were needed as inputs to the computer models. The analysis used a range of assumptions so that the tariff could provide avoided cost planning data to a broad range of QF developers.

The first major assumption was the size of a unit. Three examples, 10 MW, 25 MW and 50 MW, were used to quantify the impacts of alternate sizes. A 50 MW cogeneration unit was considered the upper limit. At 50 MW there were a number of minimum load and potential reserve problems that could occur on the ML&P system. A 50 MW or larger unit would need to have a variety of special scheduling-related operational constraints. Cogeneration units outside of the 100 kW to 50 MW range will require special analysis to calculate the appropriate annual coefficients to be used in determining avoided costs.

The sample analysis assumes that the cogeneration QF would come on-line in 1992. To test how the on-line date affects the avoided costs of ML&P, a scenario analysis using a 1998 on-line date was performed.

The cogeneration unit was also assumed to have a plant factor of 80% and would be capable of operating all year long except for a 30-day scheduled maintenance period. Every 5 years a 60-day maintenance period would be required. To test the plant factor assumption and create rates for other hypothetical facilities the plant factor of the QF was reduced to a 60% value.

To model these assumptions the QF unit's forced outage rate and scheduled usage below full output when capable are needed. It was also assumed that the unit would be at full production whenever possible. Accordingly, it was determined that the forced outage rate would be 6.58% for the 80% plant factor scenario.

Assumes when on on full? Lumped it into FOR

Using the 60% plant factor, while continuing to assume full production scheduling and minimal maintenance periods, results in a 26.58% forced outage rate. Although longer maintenance periods and a lower forced outage rate could have been chosen, the main purpose was to analyze sensitivity of avoided costs to the plant factor.

Maint is scheduled, & FOR is random, penalize plant.

It also assumed that the QF was within the Anchorage ML&P service area and, therefore, that the power delivered should not be reduced for transmission losses. These assumptions were used to develop a set of appropriate examples of avoided costs theoretically available to a resource developer. Actual rates will vary depending on the specific QF which is proposed.

Economic Factors

The principal economic factors used in the modeling were the fixed charge rate, a discount rate, A&G costs, and forecasts of fuel costs, inflation, CT capital inflation, and costs of energy not served.

A fixed charge rate of 18% was assumed. This fixed charge rate is based upon the Chugach/ML&P Unit 8 CT contract.

A discount rate of 9.92% was used in the calculations. This was the average cost of capital used in ML&P's most recent rate case.

Administrative and General (A&G) costs were not included in the avoided cost calculation because they are not avoided by a purchase from a QF. In fact, complexities associated with administering a large QF contract could result in higher A&G expenses. Therefore, inclusion of A&G expenses in the forecast avoided costs would be inappropriate.

A fuel forecast was also required as an input into the modeling programs and in the calculation of the tariff avoided cost coefficients, even though the tariff is based upon actual natural gas prices that occur in the future. The fuel forecast used is based on data derived from ISER and used in the load forecast.

Because oil and natural gas prices have a large impact on state tax revenues and economic activity as well as on the costs to the utility, a consistent set of assumptions was required. An element of the analysis was to calculate one set of avoided costs based on a "high" economic activity scenario. This high scenario contained high gas or fuel prices for ML&P. The fuel price data used in the analysis are contained within (Table 20 of Appendix A) of the attached load forecast document.

ML&P's avoided costs are highly dependent upon the future price of natural gas. Because of this dependance on actual prices it was necessary to review the ISER natural gas price forecast by comparison to another Alaska natural gas price forecast. As discussed elsewhere, ISER gas prices are used for purposes of forecasting loads and calculating avoided costs. The avoided costs are then adjusted to remove the ISER-based natural gas price, so that the final avoided cost rate formula uses ML&P's actual price of natural gas.

To review the ISER-based fuel cost forecasts used in the analysis, they were compared to gas prices calculated by the Alaska Power Authority in August of 1988. The mid-level gas forecast is a little bit lower from the 1993 to 2003 than the latest APA mid-range gas forecast. The high ISER-based gas forecast is just above the high APA forecast, and the low ISER-based gas forecast is just below the APA low gas forecast. Therefore, the range of analysis is close to and slightly broader than the APA gas forecast range. This independently confirms the range of gas price values used in the computer modeling.

Another computer data requirement is the rate of inflation. Just as the tariff uses actual natural gas prices rather than forecast values, it will use actual rates of inflation. The inflation forecast used in the computer modeling is consistent with the inflation forecast contained in the attached Load Forecast (Table 16 of Appendix A of the attached Load Forecast document.) This inflation forecast was also used to inflate CT capital costs. The analysis that discusses the use of a general inflation rate to escalate future CT capital costs is found in the attached report on CT technology.

The "cost of energy not served" is a method by which the WIGPLAN model calculates energy not available to meet load due to the probabilistic nature of forced outages and then evaluates this energy cost. It was assumed that ML&P could buy the extra energy from Chugach Electric Association at an existing contractual rate tied to the price of natural gas. In practice ML&P could either utilize this rate, make purchases in the economy energy market, borrow energy from another utility to be returned at a later date, or utilize its hydro storage contract options.

An approach was chosen that assumed the needed power would be purchased at the relatively high Chugach contract rate and overstates the value of energy not served which includes the avoided costs. The Chugach rate appears in the Chugach Electric Association Emergency Power Rate Schedule for Intertie with ML&P. The rate schedule includes a basic cost of 51.9 mills/kWh and a surcharge based on a percentage increase in current natural gas prices over a price of $1.6777/MCF applied to a reference price of 34.3 mills/kWh. This rate was estimated using the natural gas price forecast found in the Load Forecast and was applied to both the "with" and "without" computer simulations.

Combined Cycle Availability and Commitment Model

A Lotus 1-2-3 computer model was created to determine for each season of each year which resources could be committed to load and scheduled consistent with economic dispatch, spinning reserve, and unit operation limitations. Typical high and low seasonal daily load shapes were analyzed. The results of the analysis provided the years and seasons in which ML&P's newer units could be operated in either combined or simple cycle mode without violating certain constraints. The principal constraints were: 1) economic dispatch; 2) combined cycle units must be run a full 24 hours, not cycled on and off daily; 3) the contract hydro resources must be fully utilized; 4) contract spinning reserve requirements must be met for all hours of operation; and, 5) when the cogeneration QF is operational its energy must be used in the ML&P system.

The resulting information on which units could be run at which times was used as input into the Westinghouse WIGPLAN model. Therefore, the combined cycle availability and commitment model and the spinning reserve model was run for each sensitivity case.

The results of this model were carefully compared to current operational patterns of the ML&P system and to medium term generation dispatch models used by the utility. This provided an independent verification of the model results, and an assessment of the limitations of the Lotus 1-2-3 model results as an input to the WIGPLAN program. The model results compared well to current practice and the medium-term generation dispatch model.

Verification of the Modeling Effort

To verify the WIGPLAN model results, two methods of cross checking were utilized. First, the WIGPLAN results were checked against recent historic data on fuel costs and hours of generation by machine. The WIGPLAN results agreed with the 1988 historical values. Second, ML&P staff choose a future year (1992) and independently calculated the generation costs and unit operation hours using a different computer program, the Powersym Plus model. This computer model is used by ML&P for analysis of optimal scheduling of its resources. The independent calculation of 1992 conditions with the use of this model confirmed the accuracy of the WIGPLAN results.

IV. RESULTS OF MODELING AVOIDED COSTS

Overview of Results

To determine an example of the avoided costs of ML&P for a specific QF, the results of two WIGPLAN computer modeling runs were subtracted. The best estimate of the costs ML&P would avoid by a firm power purchase from a 50MW, 80% plant factor, QF added in 1992 are detailed in Table 4.

The avoided costs are categorized as avoided capacity and avoided energy costs. There are no avoided capacity benefits until the year 2015, over two decades after the QF is assumed to be added.

Similarly, avoided energy benefits are relatively low because including the QF in ML&P's resource stack creates inefficiencies. Specifically, without the QF, ML&P can utilize its extremely fuel efficient combined cycle plants (units 5/6 and 6/7.) With a 50MW QF, the combined cycle plants would be shut down because of minimum load and cycling or operating requirements on combined cycle operation. This would force ML&P to use less fuel efficient units (i.e., higher heat rate units) to serve customers' needs above those met by the QF.

But economy E solves this & dispatching.

Formula Results

Table 4 presents the formula coefficients for the analysis of a 50MW, 80% plant factor, 1992 firm power QF. Tables 5 through 8 contain formula coefficients for the other sample facilities quantified in the scenario analysis.

This formula representation of avoided costs in constant 1988 dollars is the most appropriate way to calculate avoided costs. Use of the formula makes the avoided costs of ML&P accurately reflect inflation, fuel prices and amounts of energy produced by a QF. The formula makes the avoided costs less dependent on future uncertainty. In this way the risks of speculation associated with inflation and natural gas prices are not forced upon the ratapayers of ML&P.

Tables 4 through 8 contain columns labaled "A" and "B". These columns represent annual coefficients used in the sample anergy avoided cost formulas. The "A" coefficient or term relates to fuel. It is determined by taking the difference in fuel costs and energy not served costs between the "with" and "without" cogeneration computer runs, then dividing that difference by the cogenerated energy and then dividing by the current fuel price. The "B" term is the difference in variable O&M costs between the "with" and "without" cogeneration computer runs, then divided by the cogenerated energy and then divided by the amount of inflation since 1988. The formula for calculating avoided energy costs from Tables 4 through 8 is of the form:

Energy Rate ($/MWh)= (Nat. Gas P * A) + (B * O&M Inflation)

To determine the monthly capacity cost coefficient, the difference in annual capital costs and the difference in annual fixed O&M costs between the "with" and "without" cogeneration computer runs was first determined. Those differences were then divided by 12 months and by the size of the QF unit. Capacity costs can be calculated as:

Avoided capacity Rate ($/kW-Month)	=	Monthly Capacity Cost Coefficient	*	Inflation from 1988

Sensitivity Analysis Results

To supplement the example found in Table 4 and present a range of information on avoidable costs potentially available to a QF developer, some of the major QF assumptions were tested for sensitivity. It was necessary to evaluate the impact of QF size, commercial operation date and plant factor. It was also necessary to evaluate the impact of a "high economic" activity and hence a "high load" scenario on ML&P's avoided costs. This section of the report reviews the distinct scenarios and discusses the corresponding Tables of coefficients created from the computer models.

The first sensitivity analysis involved reducing the plant factor of the QF from 80% to 60%. The annual avoided capacity and energy formula coefficient results of this analysis are found in Table 5.

The second sensitivity analysis was to extended the QF commercial operation date from 1992 to 1998. These results are found in Table 6. It should be noted that the values are identical to those of the case presented in Table 4 except for the years between 1992 and 1997.

The third sensitivity analysis was to reduce the size of the QF from 50MW to 25MW. A fourth further reduced the size to 10MW. The results of these two analyses of size are contained in Table 7.

The fifth and final sensitivity analysis calculated ML&P's avoided costs under a "high economic" activity scenario. The results are contained in Table 8.

Conclusions from Modeling

It is clear from all of the scenario analyses that ML&P does not need additional capacity at this time. Therefore, there are no avoided capacity costs for the immediate future. The avoided energy costs also demonstrate that a 50MW cogeneration facility would cause inefficiency in ML&P's operation.

The sensitivity analysis shows that avoided costs are a function of the QF unit's size and plant factor. The avoided costs are also a function of ML&P's loads, future inflation and future gas prices. Because these factors affect avoided costs, rates paid to a QF should reflect as many of these factors as possible.

Avoided Capacity Rates

Because capacity is not needed on the ML&P system before the year 2015, entering a contract that requires payment of an avoided capacity rate at this time is inappropriate. There are three reasons why contracting to pay an avoided capacity rate would place an unfair risk on ML&P's ratepayers.

First, a contractual capacity rate would be zero until the year 2015 because no capacity costs could be avoided until then. Due to the level of uncertainty about load, resource and cost projections, a 20-year term is the maximum appropriate length for a contract. Therefore, a 20-year contract would set the avoided capacity rate at zero for the life of the contract. A non-zero capacity rate could be established only if the contract exceeded 25 years.

Second, the technology of CTs is changing. Based upon existing information the capacity cost of the next generation of CT technology was extrapolated. However, before the year 2015 more than one generation of improvement in CT technology could occur, probably lowering ML&P's avoided capacity costs more than modeled. Therefore, to establish contract avoided capacity costs now would limit the ability of ML&P's ratepayers to recognize the financial benefits of technological change.

Finally, an avoided capacity rate is also inappropriate at this time because ML&P does not need capacity. Utility regulation and rates should promote economic principles. To set a rate that encourages the development of additional capacity when it is not needed is an inappropriate use of funds and economic resources.

Even though it is inappropriate to contractually establish an avoided capacity rate at this time, it is appropriate to discuss how such a rate might be determined and when. ML&P proposes to use a methodology similar to that described in this document to determine avoided capacity cost coefficients. These cost coefficients would then be used as the basis for a contract capacity rate in terms of $/kW-month of firm capacity.

As a normal part of ML&P's planning process, it reviews its needs for future capacity. In the future, ML&P will update this avoided cost filing as appropriate to calculate avoided capacity cost coefficients, and propose avoided capacity rates for firm power QFs.

Avoided Energy Rates

ML&P's avoided energy rates are based upon the coefficients in the previous section. These coefficients are representative of, or examples calculated to simulate, certain specific QF characteristics. The avoided energy cost coefficients in Tables 4 through 7 can be used to calculate a spectrum of avoided energy rates. The purpose of the methodology proposed and this explanation is to provide a set of avoided energy rates that may assist in the decision making process for a variety of prospective QF developers.

To qualify for these particular avoided energy rates, a QF must meet the operational and size parameters associated with the computer model assumptions that created Tables 4 through 7. QFs with different characteristics probably will not qualify for the particular avoided energy costs presented. Such QFs will require an individualized analysis of the effects on the ML&P system and hence different avoided energy costs. The model is available for developing the specific coefficients.

Under a formula approach, avoided energy rates are more predictable than avoided capacity rates because energy rates are principally based on heat rates of existing CTs. A formula rate which takes account of actual natural gas prices, inflation, and the firm energy generated by a QF is the most appropriate method of setting avoided energy rates. Such a rate is neutral from the ratepayers' perspective toward these factors and has a higher probability of accurately representing ML&P's actual avoided energy costs at the time the power is delivered. However, prior to defining the avoided energy rate, the methods of determining natural gas prices and inflation rates must be defined.

ML&P currently purchases all of its natural gas from ENSTAR. It is proposed that ML&P calculate its average price of natural gas purchased on a monthly basis for use in its CTs. This method of calculating natural gas prices would allow ML&P to incorporate the average actual gas cost for each month in its avoided energy cost payments to a QF for that month.

The impact of inflation on avoided energy costs goes beyond fuel price changes. Inflation also affects ML&P's variable O&M costs. Therefore, as a proxy for variable O&M inflation, the ratio of the most recent Anchorage CPI to the 1988 annual Anchorage CPI should be used to adjust the "B" term (the variable O&M component.) Because the O&M component of avoided costs is relatively small compared to the fuel-related component, or the "A" term, no "true up" to account for the lag between when the CPI is available and the period it covers is proposed. Using the Anchorage CPI or its successor as the proxy for variable O&M inflation is administratively convenient. The CPI is widely applied and independently calculated.

The following sample calculation of an avoided energy rate for a firm power QF is a function of many QF operating assumptions. With the coefficients found in Table 4, the principal assumptions are 1) that the QF is a 50MW unit, with an 80% plant factor, with commercial operation in 1992, and 2) that the QF delivers firm energy directly to ML&P's transmission grid without significant losses. For such a QF, ML&P would pay on a monthly basis for energy generated using the following avoided energy rate formula:

Energy Rate ($/MWh)= (Nat. Gas P * A) + (B * O&M Inflation)

where: Nat. Gas P, is ML&P's average price ($/MCF) of natural gas purchased for use in its CTs calculated on a monthly basis.

O&M Inflation, is the most recently released monthly Anchorage Alaska CPI divided by the 1988 annual Anchorage CPI.

A and B are the annual fuel efficiency (MCF/MWh) and variable O&M, ($/MWh) avoided energy coefficients found in Table 4.

Estimating the Avoided Cost for a Cogeneration Plant Not Simulated

Visual comparison of the A and B coefficients from one table to the next indicates that the avoided costs do not vary linearly as the size of the cogeneration plant changes. The actual coefficients to be included in a contract will be determined by re-running the computer model using the specific cogenerator parameters. This computer simulation would cost about $2,500. To determine the economic feasibility of a cogeneration project which is smaller than 50 MW, the avoided cost payments to a cogenerator should be estimated using the following method.

The A and B coefficients are looked up in the tables (Attachment 2) for the next larger and smaller cogenerator capacities from the desired cogenerator size (i.e., look up 25 and 50 MW for proposed 40 MW cogenerator. For each year the A coefficient is multiplied by the annual energy output of the smaller, simulated cogenerator to produce the avoided gas purchase by ML&P. For each year the B coefficient is multiplied by the annual energy output of the smaller, simulated cogenerator to produce the avoided variable O&M cost in 1988 dollars. Similarly, the avoided gas purchases and avoided variable O&M costs are determined for the larger, simulated cogenerator. The avoided gas purchases and avoided variable O&M costs are translated into yearly payments to the simulated cogenerators using either the fuel price escalation and CPI inflation rates used in the computer model or supplied by the proposed cogenerator. Then the payments to the proposed cogenerator can be interpolated to give an estimate of the avoided cost payments. Since the change is not linear with cogenerator capacity, the interpolation is only an estimate with the simulated curves on either side providing an absolute bound on the avoided cost payments. The following graph represents a three dimensional picture of the avoided cost payments as a function of capacity assuming no increase in fuel prices and no inflation.

V. CONCLUSION

For the reasons stated in this document ML&P adopts the avoided cost rates described in this "Explanation and Support" document as reasonable and conformance with applicable requirements of PURPA.

Table 4
Sample Avoided Cost Coefficients for a 50MW QF with a 1992 start date and an 80% Plant Factor

Year	Avoided Capacity Cost ($/KW-month) (1988 $)	Avoided Energy Costs A (mcf/MWh)	Avoided Energy Costs B ($/MWh) (1988 $)
1992	0.0000	7.4603	0.8480
1993	0.0000	7.2817	0.8437
1994	0.0000	7.1025	0.8476
1995	0.0000	6.9340	0.8482
1996	0.0000	6.8393	0.8496
1997	0.0000	6.7616	0.8408
1998	0.0000	9.8255	0.8421
1999	0.0000	9.8468	0.8435
2000	0.0000	9.8335	0.8447
2001	0.0000	9.8336	0.8468
2002	0.0000	9.8149	0.8485
2003	0.0000	9.8094	0.8507
2004	0.0000	9.8068	0.8532
2005	0.0000	9.7058	0.8538
2006	0.0000	9.6950	0.8586
2007	0.0000	9.8030	0.8707
2008	0.0000	9.8796	0.8821
2009	0.0000	10.2799	0.9181
2010	0.0000	10.4907	0.9270
2011	0.0000	10.4910	0.9348
2012	0.0000	10.2872	0.9392
2013	0.0000	9.9848	0.9388
2014	0.0000	10.6250	0.9401
2015	6.9019	11.4226	0.7583
2016	6.5964	11.3624	0.7525
2017	6.3094	11.2449	0.7449

Sample calculation for 1995

assumed average monthly ML&P natural gas price = $3.1568/MCF
assumed 1995 CPI = 441.8, 1988 CPI = 299.8
Avoided Energy = ($3.1568 * 6.9340) + ($0.8482*441.8/299.8)
= 23.14 mills/kWh (in 1995 $)
Avoided Capacity = ($0.00 * 441.8/299.8)
0.00 $/kW-month (in 1995 $)

Sample calculation for 2015

assumed average monthly ML&P natural gas price = $11.7872/MCF
assumed 2015 CPI = 1492.8 1988 CPI = 299.8
Avoided Energy = ($11.7872 * 11.4226) + ($0.7583*1492.8/299.8)
= 138.42 mills/kWh (in 2015 $)
Avoided Capacity = ($ 6.9019 * 1492.8/299.8)
= 34.37 $/kW-month (in 2015 $)

Approved by OMB
1901-0286
Expires 7/31/90

PROCEDURES MANUAL FOR COMPLETING THE VOLUNTARY COORDINATED REGIONAL BULK POWER SUPPLY PROGRAM REPORT (IE-411)

This report, which continues the annual series of reports initiated in 1970 under FPC Order 383-2, is voluntary under P.L. 66-280, the Federal Power Act, P.L. 95-91, the Department of Energy Organization Act, and P.L. 93-275, the Federal Energy Administration Act of 1974.

The information collected by this report is not regarded as confidential and will not be treated as such.

U.S. Department of Energy
Assistant Secretary
for International Affairs
and Energy Emergencies
Office of Deputy Assistant Secretary
for Energy Emergencies

Item 3-A Revised 9-88
IE-411 (9-87)

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES & REMOVALS

In this item, report all generating capacity installations, removals, and equipment upratings and deratings projected for the 10 year period after the beginning of the reporting calendar year. For hydro units state the basis of the reported capacity (adverse hydro, average hydro or other).

This data shall be listed in a single composite table for the Council, or for each Reporting Party identified in this report. The capacity changes should be grouped according to the calendar year in which they are projected to occur.

Use the same method of reporting joint ownership as in Item 2-A.

To facilitate reporting, the following abbreviations are to be used:

Column 01:	Identify each utility by the same 4 character letter codes used in Item 2-A.
Column 03:	Give the location of each generating station. Use FIPS state and county codes as in Item 2-A.
Column 04:	Identify the type of unit using the same code as Item 2-A.
Columns 05 & 06:	Net capacity expected under normal conditions for the season shown, when using the primary fuel.
Columns 07 & 09:	Identify the type of fuel using the same codes as in Item 2-A.
Columns 08 & 10:	Identify the principal methods of transporting fuel to the plant site using the same codes as in Item 2-A.
Column 11:	Show the month or season and year that the unit is projected to be included, removed, or rerated as a normal operating resource.
Column 12:	Indicate footnotes as necessary.

Column 13: Show the status of projected changes as follows:

P	Planned for installation but not utility-authorized.
L	Regulatory approval pending. Not under construction.
T	Regulatory approval received but not under construction.
U	Under construction, less than approximately 50% completed.
V	Under construction, more than approximately 50% completed.
A	Generating unit capability increased (rerated or relicensed).
D	Generating unit capability decreased (rerated or relicensed).
M	Generating unit put in deactivated shutdown status.
S	Generating unit returned to service from deactivated shutdown status.
R	Generating unit permanently removed from any service.
X	None of the above. See footnote referred to in Column 12. If a lengthy explanation is needed use Item 7 in addition to the footnote.

Department of Energy Form EIA-411
ITEM 2B

Station Name	Net Capacity - MW (2) Unit Type	 Summer 60 F	 Winter 30 F	Primary Fuel Fuel Type	 Trans Method	Alternate Fuel Fuel Type	 Trans Method	Effective Date	Notes	Status
Beluga 4	gt	8.1	8.7	ng	pl	na	na	6 / 1994		r
IGT 1	gt	13.8	15.1	ng	pl	oil	tk	6 / 1996		r
IGT 2	gt	13.8	15.1	ng	pl	oil	tk	6 / 1997		r
IGT 3	gt	16.7	18.5	ng	pl	oil	tk	6 / 1998		r
IGT 4	gt	24.5	27.5	ng	pl	oil	tk	6 / 1995	4 moved	p
Bernice 4	gt	24.5	27.5	ng	pl	oil	tk	6 / 1994	4 moved	r
Bernice 1	gt	7.7	7.8	ng	pl	oil	tk	6 / 1992		r

C 283

COUNCIL________________

REPORTING PARTY________________

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS

(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System	Station Name/Unit No.	Loc.	Unit Type
01	02	03	04

Net Capacity-MW Summer/	Winter	Primary Fuel Fuel Type	Primary Fuel Transp. Method	Alternate Fuel Fuel Type	Alternate Fuel Transp. Method	Effective Date	Notes	Status
05	06	07	08	09	10	11	12	13

Chugach Electric
ASSOCIATION, INC.

RECEIVED
DEC 1 3 1989
ALASKA ENERGY AUTHORITY

CEA Form 814

Chugach Electric Association Inc.
5601 Minnesota Drive
P.O. Box 196300
Anchorage, Alaska 99519-6300
(907) 563-7494

VIA COURIER

Letter Of Transmittal

To: Alaska Energy Authority
701 East Tudor Road
Anchorage, Alaska

Date: 12/13/89

Job No:

Attn: Penny L. Haldane

Re: Request of 11/15/89 Independent Reliability Assessment on the Railbelt

We are sending the following items:

Date:	Copies	Description
12/13/89	1	NERC Reliability Assessment/IE-44 Forms

These are Transmitted:

☐ For your information ☐ For action specified below ☐ For review and comment ☐ For your use ☒ as requested

Remarks:

Copies to: Tom Lovas
File 803.8

By: for David L. Fai

Title: Manager of Planning

COUNCIL ASCC

REPORTING PARTY MLP

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System 01	Station Name/Unit No. 02	Loc. 03	Unit Type 04
AMLP	plant 1		
	plant 2		

Net Capacity-MW Summer	Net Capacity-MW Winter	Primary Fuel: Fuel Type	Primary Fuel: Transp. Method	Alternate Fuel: Fuel Type	Alternate Fuel: Transp. Method	Effective Date	Notes	Status
05	06	07	08	09	10	11	12	13
							NO changes	
							No changes	

See RAS -02

COUNCIL ____________

REPORTING PARTY GVEA

ITEM [illegible]

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System	Station Name/Unit No.	Loc.	Unit Type
01	02	03	04
GVEA	NORTH POLE 03	NP	GT

		Primary Fuel		Alternate Fuel				
Net Capacity-MW Summer	Winter	Fuel Type	Transp. Method	Fuel Type	Transp. Method	Effective Date	Notes	Status
05	06	07	08	09	10	11	12	13
20	~~25~~ 24	FO4	PL	FO2	PL	M91		(X) PRESENTLY NEGOTIATED PURCHASE.

12/13 GVEA

COUNCIL ____________

REPORTING PARTY FMUS

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System 01	Station Name/Unit No. 02	Loc. 03	Unit Type 04
FMUS	CHENA #6		GT

Net Capacity-MW Summer/ 05	Net Capacity-MW Winter 06	Primary Fuel: Fuel Type 07	Primary Fuel: Transp. Method 08	Alternate Fuel: Fuel Type 09	Alternate Fuel: Transp. Method 10	Effective Date 11	Notes 12	Status 13
20	23.6	FO2	TR			1990		R.

R. = removal

SEE RAS r02

it

.23 before 91

combustion turbine Oil { 0 after 91

Other ability 0 till 91 23 after 91

what is happening –

should there be 2 entries here ??

~~what about~~

FMUS

ATTACHMENT C

Spinning Reserve Cost Calculations

A Review of "Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt"

Funded by

Department of Commerce and Economic Development
Contract ASPS 90-028: Utility Consumer Representation

Prepared by

Alan Mitchell

Analysis North
911 W. 8th Avenue, Suite 204
Anchorage, AK 99501
907-272-3425

Report AN-90-1

February 14, 1990

fixed amount of gas must be burned per hour to turn the turbine even when no electricity is produced. As the loading on the turbine increases, this hourly "friction overhead" cost can be spread over more and more kWh produced, reducing the average fuel cost per kWh. Often, however, several units must be deliberately kept on at relatively low loading levels in order to provide spinning reserve. The *cost of spin*, then, is the difference between the low cost of providing *energy alone* from a few highly loaded turbines and the higher cost of providing *energy plus spin* from more turbines operating at lower loads. One can also think of the cost of spin as the cost of the extra "friction overhead" introduced by having more turbines spinning without any more kWh over which to spread these fixed costs.

The KA intertie allows the free spin from Bradley Lake to be available to the Anchorage load center. Economic benefit results from the substitution of this free spin for costly spin from Anchorage thermal units. DFI found that the present value of this benefit (after averaging across cases) is $8.9 million.

2.4.1 Quantified Errors

The Cost of Spin is Calculated Incorrectly

To calculate the benefits of using more free spin from Bradley Lake, one must estimate *how much spin* substitution can occur and *how costly* is the thermal spin displaced. We first dispute the derivation of the cost of the displaced spin from thermal units. We argue that the calculation *method* is wrong, not the input assumptions. We present the argument by first deriving a general formula for the cost of spin. We show how this formula produces the right answer when applied to a simple example presented by DFI in a report for the Railbelt utilities. We then discuss why DFI's formula for the cost of spin is wrong and verify that it produces the wrong answer when applied to the same simple example. Finally, we apply our formula to heat rate data for Railbelt thermal generation units to estimate the correct cost of spin and adjust accordingly the spinning reserve benefits that DFI attributes to a new Kenai-Anchorage intertie.

The Cost of Spin: a Simple Example

The principles behind the calculation of the cost of spin are best introduced by means of the following simple example, which is reproduced from page 6 of the DFI report "Value of Bradley Lake Spinning Reserves" (October 6, 1989), prepared for the Railbelt Utilities. This example prefaced their actual analysis of the cost of spin in the Railbelt. Suppose a system of five 100 MW thermal generators is running such that:

Total capacity of operating turbines:	500 MW
Total load on system:	- <u>400</u> MW
Available operating reserve (spin):	100 MW
Number of operating turbines:	5

Loading level (L) of each turbine:	80%, i.e. 80 MW
Average Heat Rate at $L = 80\%$:	12,000 Btu/kWh
Incremental Heat Rate from 80% to 100%:	2,000 Btu/kWh

(this is the incremental rate implied by DFI's example but is very low for actual generation units)

Now suppose that 100 MW of free spin becomes available from a hydro unit. It is now possible to shut down one unit completely and still serve the 400 MW load by running the four remaining units at full load. The cost savings from this rearrangement are easily calculated:

Gas saved by shutting down one unit:	80 MW * 12 MBtu/MWh = 960 MBtu/hr
Gas used by additional loading on remaining 4 units:	4 * 20 MW * 2 MBtu/MWh = 160 MBtu/hr
Net gas savings from eliminating 100 MW thermal spin:	960 MBtu/hr - 160 MBtu/hr = 800 MBtu/hr
Net gas savings per unit of spin eliminated:	(800 MBtu/hr)/(100 MW) = 8 MBtu/MWh = 8,000 Btu/kWh

The cost savings from reducing the spin in this example is amount of fuel savings that occurs by rearranging the system as described (800 MBtu/hr), divided by the spin reduction, 100 MW. The answer above, 8,000 Btu/kWh-spin, the same answer arrived at by DFI in their Bradley Lake spinning reserve report.

A General Expression for the Cost of Spin

Using this simple example as a pattern, it is possible to derive a general expression for the cost of spin. Define the following variables (values in parentheses are from the example above):

L = *The loading level in % of the generation unit turned off to reduce spin (0.8).*

U = *The size of generation unit being turned off to reduce spin (100,000 kW).*

A_L = *The average heat rate of the unit being turned off, for loading level L (12,000 Btu/kWh).*

M = *The incremental heat rate of the units that pick-up the generation loss caused by shutting off the unit (2,000 Btu/kWh).*

The amount of reduced spin in the system is U. The load on the system remains constant while U kW of generation is turned off. Therefore, the reduction in spin must be U.

$$(1)\quad \text{Reduced Spin} = U$$

The change in gas use can be thought of as consisting of two components. First, shutting the unit off causes a reduction in gas use of:

$$(2)\ \textit{Reduced gas use because of shutting unit off} = U \times L \times A_L$$

However, the remaining units must make up for the lost generation:

$$(3)\ \textit{Increase in gas use because of loading up remaining units} = U \times L \times M$$

The net decrease in gas use is found by subtracting (3) from (2):

$$(4)\ \textit{Net Decrease in Gas Use} = U \times L \times A_L - U \times L \times M = U \times L \times (A_L - M)$$

The net gas decrease per unit of spin is derived by dividing (4) by (1):

$$(5)\ \textit{Gas Decrease per Unit of Spin Reduced (Btu/kWh-spin)} = L \times (A_L - M)$$

We can further verify the formula by applying it directly to the DFI example presented above. The turbine being shut-off is 80% loaded, and its heat rate at 80% loading is 12,000 Btu/kWh. The incremental heat rate of the rest of turbines that make-up for the lost generation is 2,000 Btu/kWh (this is the incremental heat rate implied by the figures in the example but is very low for real-world generation units). Applying our formula for the cost of spin:

$$\textit{Cost of Spin} = 0.80 \times (12{,}000\ \textit{Btu/kWh} - 2{,}000\ \textit{Btu/kWh})$$

$$\textit{Cost of Spin} = 8{,}000\ \textit{Btu/kWh-spin}$$

This formula for the cost of spin gives the correct answer in the example.

Why DFI's formula for the Cost of Spin is Incorrect

After completing the simple numeric example in the Bradley Lake spinning reserve report, DFI states on page 7 that cost of spinning reserves is:

$$\textit{Cost of Spin} = (A_L - M) \times \frac{P}{PMAX - P}$$

where,

P = *Power Output of Unit*
$PMAX$ = *Unit Size*

To express this formula using the variable names above, note that $P = U \times L$ and $PMAX = U$:

$$Cost\ of\ Spin = (A_L - M) \times \frac{L}{1 - L}$$

DFI does not apply this formula to their introductory example in the report. When it is applied to the example, it produces the incorrect answer of 40,000 Btu/kWh-spin, not the correct answer of 8,000 Btu/kWh-spin:

$$Cost\ of\ Spin = (12{,}000\ Btu/kWh - 2{,}000 Btu/kWh) \times \frac{0.8}{1 - 0.8} = 40{,}000\ Btu/kWh\text{-}spin$$

This formula also produces impossible results when turbines near full loading are analyzed. As L approaches 1, the cost of spin approaches infinity, according to this formula. This is clearly not correct.

DFI claimed at the 1/30/90 Review Meeting that they actually performed their analysis of the cost of spin in the Railbelt with a different, somewhat more general formula. We now show that the derivation of this formula is also incorrect. Also, the more general expression when applied to short period of time produces the $(A_L - M) \times L/(1-L)$ formula, which we have already shown to be incorrect.

DFI's more general expression is:

$$Fuel\ Use = \lambda \times (Energy\ kWh) + \mu \times (Spin\ kWh)$$

where,

λ = *Cost of Energy, Btu/kWh*
μ = *Cost of Spin, Btu/kWh-spin*

This expression is a simple statement that the total fuel cost during a particular period of time equals the cost of energy times the amount of energy generated plus the cost of spin times the amount of spin generated over that time period. The expression does not allow one to calculate the cost of spin over the time period unless some assumption is made for λ, the cost of energy.

In DFI's empirical analysis of the Railbelt generation system, the assumption was made that λ is the incremental heat rate of the generation system, i.e. $\lambda = M$. This is the error in the derivation. Assuming that all energy is produced at the system incremental heat rate is incorrect. In order to get any energy at all from the system, a turbine must be turned on, and the fixed frictional loss of a spinning turbine must be incurred. The cheapest that energy can come out of the system is by fully loading turbines and spreading the frictional loss over the largest amount of kWh.

The assumption that the cost of energy equals the system incremental heat rate is equivalent to assigning *all* the fixed frictional loss in the system to the production of spin, and *none* to the production of energy. It is clear why this formula has problems when attempting to determine the cost of spin for turbines near full load. As a turbine approaches full load, the amount of spin decreases towards zero. DFI's formula still assigns all of the fixed frictional loss of the turbine to the cost of this spin. The cost per unit of spin becomes infinite as the turbine approaches full load because the divisor, the amount of spin, approaches zero.

We now show that DFI's more general expression produces the formula $(A_L - M) \times L/(1-L)$ when applied to a short period of time. We apply the expression to a turbine whose loading characteristics do not change over a one hour time period. Using our previous variables, the amount fuel used over that one hour period is $U \times L \times A_L$. The amount of energy produced is $U \times L$, and the amount of spin produced is $U \times (1 - L)$. Once again, DFI's assumption in the Railbelt analysis is that $\lambda = M$. Making these substitutions gives the equation:

$$U \times L \times A_L = M \times U \times L + \mu \times U \times (1 - L)$$

which simplifies to:

$$\mu = (A_L - M) \times \frac{L}{1 - L} = \textit{Cost of Spin}$$

We have already shown that this formula produces an incorrect answer when applied to a simple numeric example and produces an impossible answer when applied to turbines near full load.

Applying the Correct Formula to the Railbelt Data

We now apply our formula for the cost of spin, $L \times (A_L - M)$, to heat rate data of Anchorage/Kenai thermal units to estimate an average cost of spin. Table 3 summarizes the calculation. The units are arranged in their dispatch order, according to data provided by DFI in Appendix F of the AEA Recon report. We do not analyze units beyond the Beluga CT #1 unit, because the (load + spin) that can be served by the analyzed set of units is approximately 550 MW. This capability combined with the Railbelt Hydro capacity will serve the bulk of the load through the analysis period, if optimal economic dispatch occurs.

When determining the cost of spin for a particular unit, it is necessary to make an assumption about that unit's loading and make an assumption about the incremental heat rate of the rest of the system. We test two different assumptions about the unit loading, 50% and 75% (our heat rate data source did not have heat rates at 25% load). The results are not very sensitive to this assumption. For the system incremental heat rate, we use the 50-75% incremental heat

Table 3 - Cost of Spin for Kenai/Anchorage Thermal Generation Units

Unit	Size MW	50% HR	75% HR	100% HR	Increm HR 50-75%	Spin Cost 50% Ld	Spin Cost 75% Ld
Bel CC #78	101	10,981	9,831	9,391	7,531	Never	Marginal
Bel CC #68	101	10,981	9,831	9,391	7,531	Never	Marginal
AMLP CC #76	109	10,017	9,018	8,628	7,020	1,243	1,115
Bel CT #5	67	15,012	13,448	12,963	10,320	3,996	4,821
Bel CT #3	50	14,822	13,228	12,800	10,039	2,251	2,181
Bern CT #3	27	15,284	14,082	13,700	11,673	2,623	3,032
Bern CT #4	27	15,284	14,082	13,700	11,678	1,803	1,803
AMLP CC #56	48	13,802	11,500	10,365	6,896	1,062	(134)
Bel CT #1	16	17,119	15,602	15,314	12,568	5,112	6,530
						2,584	2,764
						Btu/kWh-spin	

NOTES: Heat rate data from "Railbelt Intertie Proposal Preliminary Economic Assessment", March 1987, Alaska Power Authority, and from "Explanation and Support for Avoided Cost Tariff Proposed by ML&P", MLP, 1989. Data from APA report for Beluga CT #3 was scaled up to match the DFI assumption of a 12,800 Btu/kWh full-load heat rate for the unit. The anomalous results for the Cost of Spin for the AMLP units are due to the fact that they are placed in the dispatch order according to their heat rate times their fuel cost/kWh plus variable O&M. Since AMLP pays a higher price for natural gas, they are placed behind less efficient Chugach units. For this societal resource cost analysis, there is no difference in cost between AMLP and Chugach gas; thus, it is justified to consider the cost of spin in terms of Btus/kWh-spin, without regard to fuel price.

rate of the unit one prior in the dispatch order. In an optimally dispatched system, it is likely that this unit will be the unit that picks up the lost generation caused by shutting off the final unit (units prior to this one are likely to have lower incremental heat rates, and therefore will operating at or near full load).

Adjusting DFI's Result to Arrive at the Correct Operating Reserve Benefit for a New Intertie

The average cost of spin for the units shown is 2,600 Btu/kWh-spin with the 50% loading assumption, and 2,800 Btu/kWh-spin for the 75% loading assumption. For our adjustment of the DFI spinning reserve benefit result, we choose the higher of the two estimates, favoring the new intertie. The average of the Case 1 and Case 2 operating reserve benefit as calculated by DFI is $8.9 million. DFI based this calculation on a cost of operating reserves of 7,000

Btu/kWh-spin (increased from 5,000 Btu/kWh-spin in the AEA Recon report). The followi expression adjusts the DFI result to correspond to our estimate of the cost of operating reserv of 2,800 Btu/kWh-spin:

$$\textit{Corrected Operating Reserve Benefit} = \$8.9 \textit{ million} \times \frac{2{,}800 \ \textit{Btu/kWh-spin}}{7{,}000 \ \textit{Btu/kWh-spin}}$$

$$\textit{Corrected Operating Reserve Benefit} = \$3.6 \textit{ million}$$

This adjustment lowers the present value operating reserve benefits of the new Kenai-Anchorag intertie by $5.3 million.

2.4.2 Unquantified Disputes

Case 1 Results use Too Low of a Transfer Capacity for the Existing Intertie

DFI analyzes two cases when calculating operating reserve benefits. Case 1 assumes that the transfer capacity of the existing intertie for the purposes of operating reserves access is 70 MW input and 61 MW output. Case 2 assumes 90 MW input and 75 MW output. In the Case 1 analysis, the operating reserve benefit of the new intertie is $10.6 million, and the result for Case 2 is $7.1 million.

Sharing operating reserves only involves transferring energy over the intertie during periods of emergencies when the operating reserves are called on. There are no routine transfers of energy associated with sharing operating reserves. Therefore, the most accurate transfer rating of the intertie to use in the calculation is the emergency transfer limit, not the secure transfer limit. The Kenai-Anchorage intertie question is simplified, however, because the Alaska Energy Authority technical consultant states that emergency *and* the secure transfer limit for the existing line will be 90 MW input, 75 MW output after the planned line compensation is installed ["Kenai Export Limits With and Without a New Line, With and Without Additional Compensation", Power Technologies Inc., November 30, 1989, page 5]. We see little justification for incorporating the Case 1 results (70 MW input, 61 MW output) into the expected benefit calculation of the new line.

There has been some dispute concerning PTI's calculation of the *secure* export limit of the existing Kenai-Anchorage line. This calculation is complex because it involves simulating the response of the system to various faults (short-circuits) occurring on the system of transmission lines. A transfer limit is considered secure if the system can "survive" after such faults.

The emergency transfer limit, however, is a much more straight-forward calculation. Simulation of faults is not involved, because the probability of a fault occurring during a period when a transmission line is being relied on for emergency purposes is very low. In the case of

A Review of

"Economic Feasibility of the Proposed 138 kV Transmission Lines In the Railbelt"

February 1990

Analysis North **Report AN-90-1**

Analysis North

Alaska's Utility Consumer Advocate

911 West 8th Avenue, Suite 204 Anchorage, Alaska 99501 907-272-3425

February 14, 1990

Dear Report Recipient:

Enclosed is our review of the Railbelt utilities' cost/benefit analysis of new 138 kV (kilovolt) electrical transmission lines for the Railbelt. The utilities propose to fund these transmission lines through a $125 million grant from the state's Railbelt Energy Fund. The utilities' analysis cost $250,000 and was performed by Decision Focus Inc. The report is available from the Alaska Rural Electric Cooperative Association (phone: 276-3235 in Anchorage).

Our review of this analysis was funded by a Utility Consumer Representation contract from the Department of Commerce and Economic Development. We undertook the review in an attempt to improve the quality of information being presented concerning these potential utility projects.

The utilities' study finds that a new Kenai-Anchorage 138 kV line, a limited upgrade of the Anchorage-Fairbanks line, and a new Healy-Fairbanks 138 kV line are cost-effective, with benefit to cost ratios of approximately 1.6, 4.4, and 1.1 respectively. Our review agrees that the limited Anchorage-Fairbanks upgrade is cost-effective, but substantially disagrees with the conclusions concerning the Kenai-Anchorage line and the Healy-Fairbanks line. We believe that more reasonable benefit/cost estimates for the projects are 0.6 - 0.8, indicating insufficient benefits to justify their construction.

Our disagreement stems from disputes concerning the input assumptions, methods, and arithmetic used in the utilities' analysis. Details of these disputes are provided in the enclosed report.

Should you have any questions concerning this review, please call us.

Sincerely yours,

Alan Mitchell

Alan Mitchell
Utility Analyst

A Review of
"Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt"

Funded by

Department of Commerce and Economic Development
Contract ASPS 90-028: Utility Consumer Representation

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February 14, 1990

Table of Contents

1. Introduction and Executive Summary

This report reviews the *"Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt"* prepared by Decision Focus Inc. (DFI) for the Railbelt utilities. A review was done of most, but not all, of the benefit categories for the proposed 138 kV line between Anchorage and Kenai. Because of time constraints and the large number of areas of dispute with the Kenai-Anchorage analysis, a less thorough review of the Healy-Fairbanks line was completed. A summary of the conclusions of the Healy-Fairbanks line review is presented here, but detailed support for the conclusions is not provided.

We appreciate the promptness with which our data requests and questions were responded to by DFI. This facilitated the completion of our review.

Kenai-Anchorage 138 kV Intertie

The DFI analysis presents the costs and benefits of an additional transmission line between Anchorage and Kenai.[1] We identified 4 major errors in the methods and computations used in the analysis. These are not disputes concerning the input assumptions used in the analysis, which will always differ between analysts. These are errors in how the input assumptions were used to calculate the final estimate of intertie benefits. Correcting these errors lowers the present value benefits of the new intertie from DFI's estimate of $123 million (1990 dollars) to $65 million.

In addition, we dispute a number of the input assumptions used in the analysis. Although not all of our disputes argue for lower benefits, we believe that more reasonable input assumptions would lower the estimated benefits of the 138 kV intertie further. The Alaska Energy Authority analysis of a more capable 230 kV intertie between Anchorage and Kenai showed benefits of $51 million, present value.[2] This analysis was also performed by DFI. We believe that a more accurate analysis of the 138 kV option would show its benefits to be equal to or less than this value.

The benefit estimates for the 138 kV intertie need to be compared to the costs of the intertie. Two cost estimates were presented in the 138 kV analysis, both assuming use of the Enstar route through the Kenai Moose Range.[3] One estimate assumed a 40 year life of the

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[1] The existing line will remain operational even if the new line is built. It is necessary to serve customers along its route.

[2] "Railbelt Intertie Reconnaissance Study, Benefit/Cost Analysis", prepared by Decision Focus Inc. for the Alaska Energy Authority, June 1989.

[3] In the Alaska Energy Authority analysis of the 230 kV alternative, a more expensive alternate route along the Tesoro right of way was also costed.

proposed submarine cable under Turnagain Arm. The present value cost of this estimate is $74 million. A second cost estimate assumes a 20 year life for the submarine cable (slightly more than the 15 year life actually experienced by Chugach Electric's Cook Inlet submarine cables). This cost estimate is $86 million, present value.

Benefits of 138 kV Kenai-Anchorage Line are Less than Costs

If the benefits of the 138 kV Kenai-Anchorage intertie are $51 million or less, as we expect, the benefit to cost ratio of project will be less than 0.69 ($51 million divided by low cost estimate of $74 million). Even using the $65 million benefit estimate, derived from correcting only 4 major method errors in the 138 kV analysis, the benefit to cost ratio of the project will be 0.88 or 0.76, depending on the cost estimate used.

4 Major Errors Quantified

Figure 1 summarizes the magnitudes of 4 major method errors that were found in the DFI Kenai-Anchorage Intertie analysis:

- A computation error was found in the calculation of the hydro-thermal coordination benefits of the new intertie.[4] DFI has agreed to the existence of the error. The error overstates the Energy Transfer benefits of the new intertie by $25 million, present value.

- The existing intertie causes power outages when it fails while transferring energy between Anchorage and Kenai. The study claims that these power outages cost customers $32 - $50 million, which will be avoided if a new intertie is built. However, the analysis fails to recognize that these outage costs can also be avoided without the construction of a new intertie by giving up the energy transfers that cause the outages. These transfers are only worth $17 million according to DFI's analysis. The $17 million transfer benefit sets a logical cap on the reliability benefits of the new intertie. This cap lowers the reliability benefit estimate of the new intertie by $24 million.

- An incorrect formula for computing the cost of spinning reserve overstates the benefits of increased access to Bradley Lake spinning reserve by $5.3 million.

- An unnecessary simplification of the hydro-thermal benefit calculation overstates the hydro-thermal benefits of the new intertie by $3.7 million.

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[4] Hydro-thermal coordination is a method for coordinating the hydro generation on the Kenai peninsula with the thermal generation in Anchorage so as to minimize the excessive part-load operation of the thermal generation.

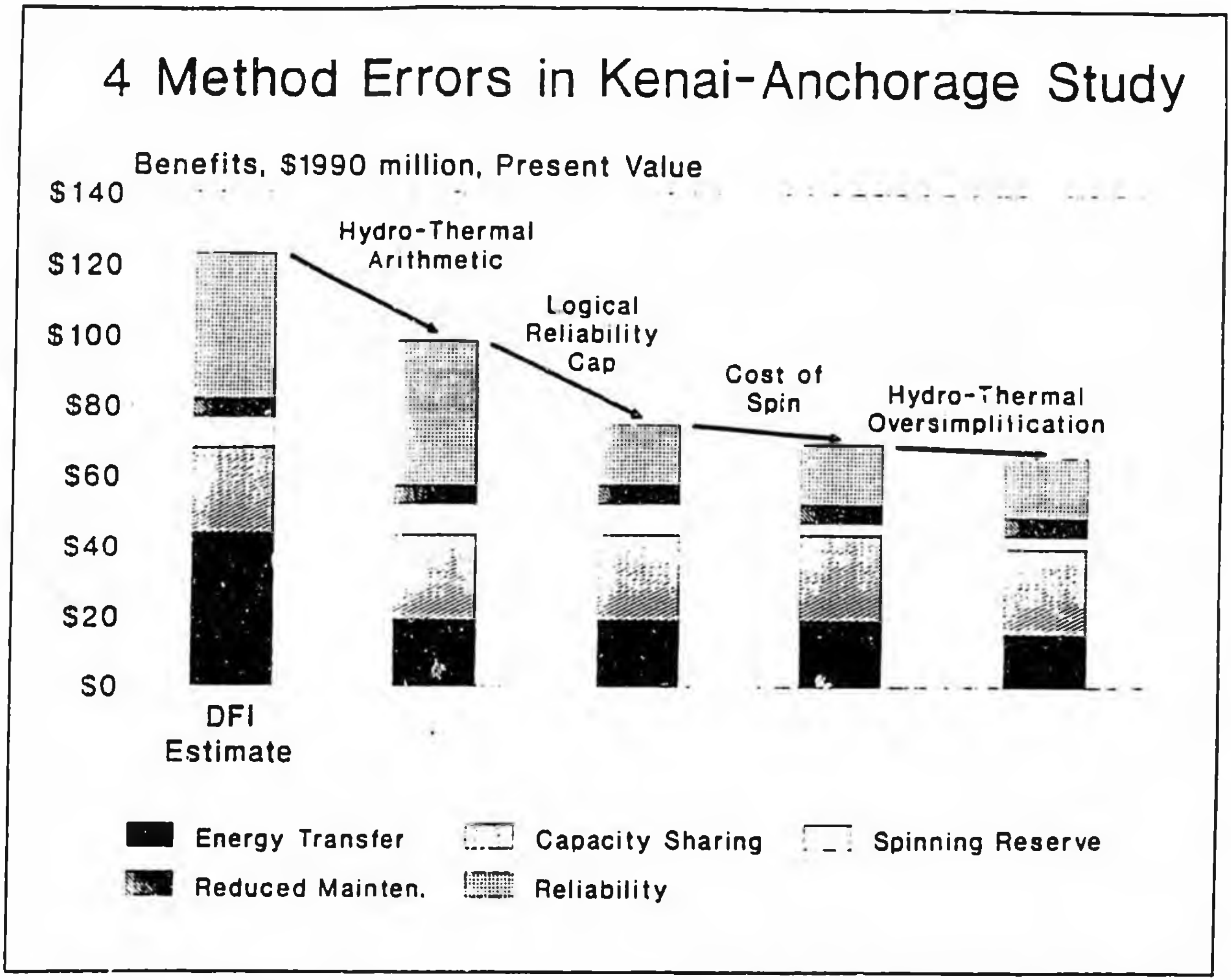

Figure 1 - Changes to Kenai-Anchorage Benefit Estimate due to 4 Major Method Errors. No other disputes are quantified in the displayed benefit adjustments.

Unquantified Areas of Dispute

In addition to the errors listed above, a number of unreasonable input assumptions tend to bias the project benefits upwards, including:

- The calculation of the increased energy transfer benefits of the new intertie assumes with certainty that a system for optimally coordinating generators will exist. Such a system does not exist now and may never exist.
- The hydro-thermal coordination regime modeled in the analysis appears is suboptimal. A more optimal regime makes better use of the existing intertie and depends far less on a new intertie for the creation of economic benefit.
- The capacity benefits provided by the new intertie are valued at the full cost of new generation capacity, despite the statement by Railbelt utilities that new capacity will be acquired through relatively cheap life-extension of existing plants.

Healy-Fairbanks 138 kV Intertie

AF100 Limited Upgrade Project Has Benefits Substantially in Excess of Costs

The northern interties analyzed in the report consist of two different projects. The AF100 intertie involves adding compensation equipment to the existing Anchorage-Fairbanks line to increase its transfer capacity. The DFI analysis finds this project to have a cost of $10 million and benefits of $46 million, present value. Most of the benefits of the project involve the solution of an operating constraint called the "North Pole Constraint". The analysis assumes that if the AF100 intertie is not built, the North Pole constraint will not be solved by some alternative means. Such an assumption inflates the benefits of the AF100; however, we believe that use of a more reasonable assumption in the analysis would still show positive net economic benefits for the AF100 project.

The Additional Benefits Achieved by the 138 kV Healy-Fairbanks Line, Over and Above the AF100 Option, are Probably Less than the Additional Costs

The second project analyzed is an additional 138 kV line between Healy and Fairbanks. The relevant question is whether the additional ("incremental") benefits of the line--over and above the benefits that will be provided by the cost-effective AF100 option--justify the additional costs of the line.[5] Advocates of this project often combine its benefits and costs with the AF100 project. The substantial benefits of the AF100 project disguise the marginal economic merit of the Healy-Fairbanks line when packaged together. Table 1 shows the estimates of *incremental* benefits and costs provided by DFI.

We believe it is probable that the incremental benefits of the Healy-Fairbanks line will be *less* than the incremental costs, because optimistic assumptions are used in the determination of the benefits.

Table 1 - DFI's Estimate of the Incremental Benefits and Costs of the Healy-Fairbanks Line

DFI's Incremental Benefits and Costs of Healy-Fairbanks Line
Millions of 1990 $, Present Value

Incremental Benefits	
Energy Transfer	
Reduced North Pole Constraint	$ 5.8
Other Economy Energy	$ 39.3
Capacity Sharing	$ 8.3
Reliability	$ 6.5
	====
TOTAL	**$ 59.9**
Incremental Costs	**$ 54.2**

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[5] The Healy-Fairbanks line requires that AF100 option also be built.

Analysis Assumes Sending Gas-Generated Electricity from Anchorage to Fairbanks will Produce Substantial Benefit for the Next 54 years

The energy transfer benefits of the line are derived from substituting more gas-fired electricity from Anchorage for oil-fired electricity in Fairbanks, and from incurring less transmission losses on those substitutions. These substitutions are assumed to occur over the 50 year life of the intertie (1994 - 2043). Any one of at least three events could dramatically reduce the benefits of such substitutions:

- A gas pipeline from the North Slope through Fairbanks could supply natural gas directly to Fairbanks generators, avoiding the need for the intertie.
- A gas pipeline from Anchorage to Fairbanks would also avoid the need for the intertie. The Alaska Energy Authority analysis of the intertie projects also looked at the costs and benefits of an Anchorage-Fairbanks gas pipeline. The analysis found the benefits of the pipeline to substantially exceed the costs.
- A decrease or elimination of the price advantage of Cook Inlet natural gas over Fairbanks oil will reduce the benefits of the intertie. The ICF-Lewin Energy Group analyzed fuel prices in the Railbelt as part of the AEA Intertie Recon analysis.[6] They concluded that depletion of Cook Inlet gas reserves would force Cook Inlet gas prices up near the year 2015, less than half way through the life of the Healy-Fairbanks line. This projection was not incorporated in the fuel price forecasts used in the 138 kV analysis. Doing so would lower the benefits of the line by roughly $10 million.

Analysis Assumes 20 MW FMUS Coal Plant will Not Run in Low Fuel Price Scenario

In determining the benefits of reducing the North Pole operating constraint, it was assumed that after the intertie is fully loaded, the North Pole oil units would be turned on next. A part-load efficiency analysis shows that turning on the Chena 20 MW coal plant is less costly than running the North Pole units. Changing this assumption would reduce the North Pole benefits of the Healy-Fairbanks intertie by approximately $3 million.

Capacity Sharing Analysis Based on High Increase in Transfer Capacity

The 138 kV analysis assumes that the Healy-Fairbanks intertie increases the emergency transfer capability over the AF100 by about 26 MW after losses, in both the Anchorage to Fairbanks direction and in the Fairbanks to Anchorage direction. The technical consultant for the intertie projects, Power Technologies Inc., claims that the increased emergency transfer level

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[6] "Fuel Price Outlook for The Alaska Railbelt Region: Oil and Natural Gas", performed by the ICF-Lewin Energy Group for the Alaska Energy Authority, June 1988.

is about 16 MW from Anchorage to Fairbanks[7] and 10 MW from Fairbanks to Anchorage.[8] Using PTI's figures will substantially lower the incremental capacity transfer benefits of the Healy-Fairbanks line. Also, the effective capacity provided by the intertie was valued at the cost of new capacity, ignoring relatively cheap life extension options.

Reliability Benefits are Based on High Customer Outage Costs

The reliability benefits of the line are determined by estimating the number of power outages avoided by the line and assigning a value to the avoidance of those outages. The cost of the outages was determined from an unrealistic interpretation of a survey performed by Ontario Hydro. This is discussed in more detail in section 2.7.2.

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[7] "Secure and Emergency Transfers from Anchorage to Fairbanks", Power Technologies Inc., October 31, 1989.

[8] Personal Communication with Harrison Clark, Power Technologies Inc., January 29, 1990.

2. Kenai-Anchorage Intertie

2.1 Comparison With AEA 230 kV Study

Table 2 - Comparison of Kenai-Anchorage Intertie Analyses. For both the AEA 230 kV analysis and the Utility 138 kV analysis, the Low and high benefit estimates are averaged.

Kenai-Anchorage Intertie Analyses

Costs and Benefits are Present Value, Millions of 1990 $

Benefit/Cost Category	AEA 230 kV Analysis	Utility 138 kV Analysis	138 kV 4 Method Errors Corrected
INTERTIE COST			
Enstar Route			
w/o Submarine Replacement	$113	$74	$74[1]
w/ Submarine Replacement	NA	$86	$86[1]
Tesoro Route			
w/o Submarine Replacement	$137	NA	NA
w/ Submarine Replacment	NA	NA	NA
BENEFIT CATEGORIES			
Energy Transfer Benefits			
Hydro-Thermal Coordination	$14.3	$37.5	$ 9.1
Other Economy Energy	$ 4.8	$ 5.9	$ 5.9[2]
Operating Reserve Benefits	$ 0.8	$ 8.9	$ 3.6
Capacity Sharing Benefits	$11.8	$24.4	$24.4[2]
Stability Cost Savings	$ 3.1	$ 0.0	$ 0.0
Maintenance Cost Savings	$ 0.0	$ 5.0	$ 5.0[2]
Reliability Benefits[3]	$ 15.5	$41.0	$17.0
TOTAL BENEFITS	**$ 51**	**$123**	**$ 65**

NOTES:

[1] - The cost estimates were not reveiwed in this report.

[2] - Leaving these benefit estimates unchanged does not constitute endorsement. Substantial concerns about the assumptions and methods used to produce the estimates are discussed in the text, but are not quantified. This column only shows the change in benefit estimates derived from correcting 4 major method errors in the analysis.

[3] - Reliability benefits will not be reflected in electric rates. These are costs and inconveniences avoided by reducing the number and extent of customer power outages.

Table 2 compares the results from the Railbelt Utility 138 kV Kenai-Anchorage analysis with the 230 kV Kenai-Anchorage analysis prepared for the Alaska Energy Authority. Also included in the table is the utility benefit estimate for the 138 kV Kenai-Anchorage line adjusted for the 4 major method errors described in the Executive Summary. None of the unquantified disputes discussed in the rest of the report are factored into this benefit estimate. All benefits and costs are expressed in 1990 dollars (the AEA 230 kV study used 1987 dollars--these were converted).

Gross Benefits for the 138 kV Analysis Exceed the Gross Benefits for the 230 kV Analysis, Indicating Changed Assumptions

If a consistent analysis of both a 230 kV intertie and a 138 kV alternative were done, the 230 kV intertie would show more gross benefits (before subtracting costs). This is because the 230 kV intertie has higher transfer capacity, lower losses, and equal reliability--the three parameters that are important in assessing the benefits of an intertie. The fact that Table 1 shows that the *138 kV* option has larger benefits than the 230 kV option indicates that the two analyses were not consistent. The assumptions used in the 138 kV study were more favorable to the construction of a new intertie.

Some of the assumptions that were changed between the Kenai-Anchorage 230 kV analysis and the 138 kV analysis were:

General Assumptions

- When averaging the benefits across the different fuel price and load forecast scenarios, all scenarios were weighted equally in the 138 kV analysis. In the 230 kV analysis, certain scenarios had more weight than others. Most significantly, the fuel price probabilities in the 230 kV study were Low - 60%, Mid - 30%, High - 10%. Re-weighting the cases caused the benefits of the 138 kV Kenai-Anchorage analysis to increase (~$7 million), while Healy-Fairbanks intertie benefits were approximately unchanged.

- In the 138 kV analysis, any changes in gas royalty payments to the state were counted as costs or benefits in the analysis. If a project causes gas use to increase, an increased gas royalty benefit is attributed to the project. The opposite holds for a gas decrease. This change decreased the benefits of the Kenai-Anchorage line (~$4.5 million), since the line decreases gas use, and increased the benefits of the Healy Fairbanks line (incremental benefits + $3.2 million), since it increases gas use.

- The lifetime of the new Kenai-Anchorage intertie was assumed to be 35 years in the 230 kV analysis and 40 years in the 138 kV analysis. This increases the present value benefits of intertie since benefits are added up over a longer time period. Because of ongoing operation and maintenance costs, present value costs are also increased, but not enough to cancel the benefit increase.

- In the 230 kV analysis, the existing Kenai-Anchorage intertie was assumed to be unavailable for transfers for two weeks per year. In the 138 kV analysis, the existing intertie was assumed to be unavailable for transfer for approximately 3 months per year during a 13 year rebuilding period, and 1 month per year thereafter. This assumption increases the benefits of a new intertie because the new intertie captures the benefits lost by the existing intertie during these periods of unavailability.

- In the 138 kV analysis, two cases with different assumptions about the transfer capacity of the existing intertie were analyzed: Case 1 - 70 MW Input / 61 MW Output, and Case 2 - 90 MW Input / 75 MW Output. In the 230 kV analysis, only Case 1 was analyzed. The addition of the second case in the 138 kV analysis reduced the benefits of the new Kenai-Anchorage line.

Intertie Costs

- Because the 138 kV interties will be built at a lower voltage, the capital cost will be less than the 230 kV alternatives. The costs were re-estimated by the same firms that provided the 230 kV estimates for the AEA study.

- In the 138 kV analysis, no cost estimates were provided for the more expensive Tesoro route, which must be used if the intertie is not granted a right-of-way along the Enstar natural gas pipeline through the Kenai Moose Range.

- The 138 kV analysis presented a cost estimate that involved replacement of the Turnagain Arm submarine cable after 20 years. This sensitivity case was not presented in the 230 kV study.

- The maintenance cost estimates for the Kenai-Anchorage line were decreased in the 138 kV study. In the 230 kV study, maintenance costs were assumed to be 1.5% of capital cost per year for the entire line. In the 138 kV study, the maintenance cost of the aerial portion of the line was dropped to 0.5% of capital cost per year. The maintenance of the submarine cable under Turnagain Arm was assumed to still have a 1.5%/year maintenance cost.

New or Deleted Benefit Categories

- In the 138 kV study, it was assumed that the existence of a new intertie would allow Chugach to defer maintenance on the existing intertie. The deferral was assumed to provide a $5 million present value benefit. This benefit was not attributed to the new intertie in the 230 kV study.

- In the 230 kV analysis, the new KA intertie was assumed to reduce the capital cost of the stability system for Bradley Lake by approximately $3.1 million. Since the stability system is now designed for use with the existing intertie, the stability system is considered a sunk cost. Thus, in the 138 kV analysis, no benefit was attributed to the new intertie for reduced stability system cost.

Energy Transfer Benefits

- In the 138 kV study, the hydro-thermal coordination benefit calculation was performed in more detail. The new calculation method produced a dramatically higher benefit estimate (+ $23 million) than determined in the 230 kV analysis. However, we show later in the report that an arithmetic error was the source of much of the increase.

Operating Reserve (Spin) Benefits

- In the 230 kV analysis, Bradley Lake was assumed to provide the same amount of operating reserve (30 MW) both with and without a new intertie. In the 138 kV analysis, it was assumed that Bradley could be relied on for more spin if a new intertie were present (50 MW vs. 30 MW). Thus, the benefits of the new intertie were increased.

- The cost of providing spin from thermal generation units was assumed to be higher in the 138 kV analysis than in the 230 kV analysis. This increased the operating reserve benefits of the new intertie.

Capacity Sharing Benefits

- In the 230 kV analysis, the capacity sharing benefits of the Kenai-Anchorage line were related to its ability to tap excess capacity on the Kenai peninsula for emergency use in Anchorage. In the 138 kV analysis, this same benefit was addressed, but it was also assumed that the new intertie would allow the reduction of the required capacity reserve margin in the Kenai and Anchorage load centers. This assumption increased the benefits of the new intertie.

Reliability Benefits

- The assumption concerning the costs suffered by customers due to power outages was increased substantially from the 230 kV analysis to the 138 kV analysis. The Ontario Hydro survey that supplied the estimate for commercial customers was interpreted in a new way that caused the costs to more than double. New surveys were examined to determine a new cost for residential outages. The surveys relied upon gave estimates more than double those used in the 230 kV analysis.

We discuss some of these changes in the following sections.

2.2 *Costs, Intertie Availability*

We were unable to review the capital or operating cost estimates provided for the 138 kV intertie, although we believe that they do deserve independent scrutiny. In the process of review, it should be determined whether interest during construction was included in the cost estimate, because the DFI analysis did not adjust the costs for this factor. Also, the question of whether the Turnagain Arm submarine cable will need to be replaced is a critical issue. Is there sufficient evidence indicating that a new submarine cable in Turnagain Arm will last more than the 15 year life experienced by Cook Inlet submarine cables?

The Existing Intertie is Assumed to be Unavailable for Transfers for Substantial Periods of the Year

DFI made the assumption in this analysis that the existing intertie will be unavailable for transfers for 99 days per year (3 + months) for the period 1994-2007 because of rebuilding, and 28 days per year for the years thereafter [page B-2, 138 kV Study]. This assumption comes directly from Chugach Electric, and should be reviewed by someone with expertise in utility construction. One version of the assumption appeared first in the final two months of the AEA Recon study. Chugach stated that existing intertie would be unavailable due to maintenance for 2 months every year from 1994 through 2004. From 2005 on, the intertie would be unavailable for one month per year. DFI did a quick analysis to see what the effects of the assumption would be, but did not include the impacts in the formal benefit estimate for the new line. The unavailability asssumptio was included in the 138 kV analysis, and the two month per year figure was increased to over three months per year.

We question whether it is optimal to extend the rebuilding of the existing intertie over such a long period of time. We also question why the fully rebuilt intertie will continue to experience one month per year of unavailability. The current unavailability of the existing intertie is not that long. Assuming a high level of unavailability increases the estimated benefits of a new intertie.

2.3 *Energy Transfer Benefits*

The Energy Transfer benefits of the KA intertie are cost savings that arise when it is cheaper to import electric energy than to produce it locally. The DFI analysis identifies two types of transfers which can effect such savings.

One type of transfer allows more efficient generation in one area to displace less efficient generation in another (there are no assumed natural gas price differences between the Kenai and Anchorage areas). The Over-Under production cost model was used to identify the savings attributable to a new intertie because of additional transfers and a reduction in transmission losses associated with the transfers. DFI concludes that the present value of this type of energy transfer benefit is about $6 million. The cost saving transfers that occur are almost entirely due to a flow of energy *from Anchorage to Kenai*, despite the existence of Bradley Lake on the Kenai Peninsula. The annual energy requirement in Kenai exceeds the hydro energy available. The modeling found that the optimal use of the hydro energy was in serving the local Kenai load. The model also found that serving the Kenai load in excess of the available hydro energy was most efficiently done by sending energy south over an intertie from Anchorage to Kenai.

The second type of transfer, called hydro-thermal coordination, essentially allows thermal generators to be run at higher average loading levels where they perform more efficiently. This opportunity arises from the fact that the Bradley Lake hydro project presumably can supply energy with equal efficiency over its full range of output, while a thermal generation unit (e.g. combustion turbine) requires substantially more fuel to produce kWh at low loadings than it does to produce kWh at high loadings. Hydro-thermal coordination involves transferring energy back and forth between the Anchorage and Kenai areas in a way that eliminates the excessive part-loading of thermal generation units in Anchorage (some part-loading, i.e. operating reserve, is required for reliability protection). The load served by means of such transfers is said to be *reshaped*. The scheme requires an intertie because there is very little thermal generation that occurs on the Kenai Peninsula. The coordination scheme suggested also involves no net increase in the amount of generation that occurs in the Kenai area. All exports of energy from Kenai for the purpose of hydro-thermal coordination are balanced by an equivalent pay-back of energy at another time from the Anchorage thermal units.

2.3.1 Quantified Errors

Computation error overstates hydro-thermal gas savings by $25 million

A computation error overstates the benefits of hydro-thermal coordination by $24.7 million. DFI has agreed that there is an error (Review meeting, 1/30/90). The error does *not* arise from the method or input assumptions used in the calculation; rather, the final result simply does not agree with the described method and input assumptions. DFI states that with a new intertie, 356 MBtu of gas savings will occur per hour of reshaping (p. A-8, 138 kV). The comparable figure stated for the existing intertie is 126 MBtu/hour. When the calculation is performed correctly, the results are 132 MBtu/hour for the new intertie and 55 MBtu/hour for the existing, under the Case 1 scenario. (We only performed the calculation for Case 1, the case that produces the maximum benefits for the new intertie.) The corrected calculation is presented in Appendix A.

To adjust the hydro-thermal benefits for this computation error, we multiply the DFI hydro-thermal benefit estimate by the ratio of the correct gas savings to the erroneous gas savings. Since reshaping is assumed to occur for 4,000 hours/year with the new intertie and

3.500 hours/year with the existing intertie, the corrected hydro-thermal benefit estimate is:

$$\text{Corrected Estimate} = \$37.5 \times \frac{132\ MBtu/hr \times 4{,}000\ hours - 55\ MBtu/hr \times 3{,}500\ hours}{356\ MBtu/hr \times 4{,}000\ hours - 126\ MBtu/hr \times 3{,}500\ hours}$$

$$\text{Corrected Estimate} = \$12.8\ million$$

Method error overstates hydro-thermal savings by additional $3.7 million

An oversimplification in the hydro-thermal calculation method further overstates the coordination benefits by $3.7 million. DFI does not dispute the existence of the oversimplification (Review meeting, 1/30/90), although they have not provided their numeric correction. The reshaping savings per kWh reshaped for a thermal unit at any particular loading level L are:

$A_L - (M \times R)$, where

A_L	is the average heat rate of the unit at loading level L,
M	is the incremental heat rate of the unit measured from loading level L to 100% loading,
R	is the reshaping energy requirement as defined by DFI on page A-6 of the 138 kV study.

In performing the calculation, DFI assumed that the average heat rate of the thermal unit is constant and equal to the average heat rate at 50% load. This assumption is highly inaccurate. The average heat rate varies substantially across loadings, rising rapidly at low loading levels. Thus, at low loadings production of energy is very inefficient and reshaping savings per kWh are correspondingly large. At high loadings the generator runs efficiently and savings available from reshaping are correspondingly small.

The assumption of a constant average heat rate discounts the benefits of reshaping at low loading levels, where the existing intertie performs nearly as well as the new intertie. The constant heat rate assumption inflates the benefits of reshaping at higher loading levels, levels where the new intertie shows its reshaping advantage. Therefore, by assuming a constant heat rate across loading levels, DFI overstates the benefits from the new intertie.

We quantified the magnitude of the overstatement by performing the hydro-thermal calculation allowing the heat rate to realistically vary across loading levels. No additional inputs beyond the DFI inputs were needed for the calculation. We used the same turbine characteristics and fractions of the year that each turbine was marginal. We used an assumption of constant incremental heat rates (as DFI implicitly did) to determine average heat rates at various loading levels. The calculation is presented in Appendix B.

The correct calculation shows that the average reshaping savings for the new intertie are 107 MBtu/hour, and the reshaping savings for the existing intertie are 54 MBtu/hour. The following procedure adjusts the original DFI hydro-thermal benefit estimate result to one that has no arithmetic error and incorporates the varying average heat rate assumption:

$$\textit{DFI Estimate} = \$37.5 \textit{ million}$$

$$\textit{Corrected Estimate} = \$37.5 \times \frac{107 \textit{ MBtu/hr} \times 4{,}000 \textit{ hours} - 54 \textit{ MBtu/hr} \times 3{,}500 \textit{ hours}}{356 \textit{ MBtu/hr} \times 4{,}000 \textit{ hours} - 126 \textit{ MBtu/hr} \times 3{,}500 \textit{ hours}}$$

$$\textit{Corrected Estimate} = \$9.1 \textit{ million}$$

Summary of quantified hydro-thermal errors

The net result of these two corrections is that the hydro-thermal benefits of the new intertie as stated by DFI are reduced by $28.4 million, from a present value of $37.5 million to $9.1 million.

2.3.2 Unquantified Disputes

The Energy Transfer Benefits of the New Intertie Assumes an Optimal Dispatch Regime, Which Does Not Exist

Both the economy energy benefits calculated through the Over-Under modeling process and the hydro-thermal coordination benefits require coordinated and optimal dispatch across the Railbelt utilities with generation resources. It is clear that this dispatch system is not currently in place. DFI has claimed that there is $3 - $6 million per year of inefficiency in the current system due to suboptimal dispatch ($50 - $100 million, present value). If the system is never developed, a substantial portion of these benefits will not materialize. The benefits in the DFI analysis were not reduced to account for the probability that optimal coordination and dispatch may not occur.

Hydro-Thermal Coordination using Eklutna Lake is Not Considered

DFI did not address the potential to perform some hydro-thermal reshaping with the 30 MW Eklutna plant located in the Anchorage area. If reshaping is possible with this plant, a larger fraction of the ultimate reshaping potential could be obtained with the existing intertie combined with Eklutna, thus reducing the benefits of the new intertie.

Suboptimal Coordination Plan Inflates Intertie Benefits

We also believe that the hydro-thermal coordination regime modeled by DFI is a sub-optimal one. A simplified example of DFI's hydro-thermal scheme is graphically depicted in the top part of Figure 2. The figure is meant to show the simplified operating regime of one particular Anchorage thermal unit. Absent hydro-thermal coordination, the unit would turn on at time t1 and its loading would increase to follow the load until it reached maximum loading at time t2. It would remain at maximum loading until time t3 when it once again becomes the marginal unit. Its output decreases until it turns off at time t4.

With the type of hydro-thermal coordination modeled by DFI, turning on the thermal unit is delayed until time t2. Between t1 and t2, Kenai hydro energy is imported over the intertie to meet the (Load + Spin) requirements in Anchorage. The thermal unit is started at t2 when it can be fully loaded, and imports are ceased. At time t3, when the thermal unit would normally start unloading, its output is maintained at full load. The power in excess of Anchorage (Load + Spin) requirements is exported back to Kenai to reimburse for the previous imports.

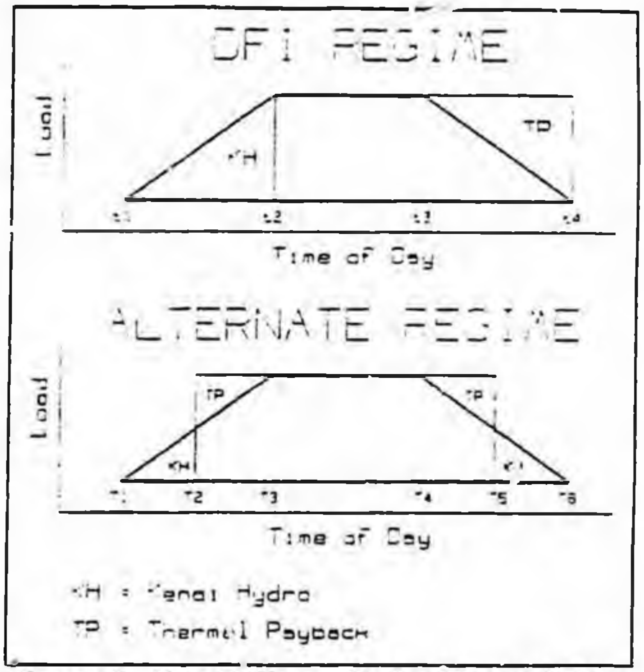

Figure 2 - Two Different Hydro-Thermal Coordination Regimes

An alternative hydro-thermal coordination regime is shown in the lower half of Figure 1. This method achieves the same objective as the DFI regime: it allows all energy produced by the thermal unit to be produced while operating at full load. However, the alternative method requires less energy transfer over the intertie, and it reduces the peak demand on the intertie for the purposes of reshaping. In doing so, it reduces transmission losses relative to the DFI method, and it reduces the periods when the reshaping requirements exceed the capacity of the intertie.

The alternative method involves importing Kenai energy when the thermal unit would otherwise be at low loadings and paying that energy back when the thermal unit would otherwise be at high loadings ("otherwise" meaning absent hydro-thermal coordination). The figure shows the Kenai import and thermal payback periods for this type of hydro-thermal regime applied to the simple example.

Had this regime been modeled when calculating the increased hydro-thermal benefits of the new intertie, the new intertie's benefits would have been less. With such a regime, the capacity constraint of the existing intertie would rarely be a problem. Further, the higher losses of the existing intertie would be less of a problem, since the average transfer required to perform the reshaping is less with this regime.

2.4 Operating Reserve (Spin) Cost Savings

Operating Reserve, or spin, is the amount of additional generating capacity which is instantly available to meet an increase in load. Spin from the Bradley Lake Hydroelectric project is essentially free, but spin from thermal units is costly. To create spin using a thermal unit, a fixed amount of gas must be burned per hour to turn the turbine even when no electricity is produced. As the loading on the turbine increases, this hourly "friction overhead" cost can be spread over more and more kWh produced, reducing the average fuel cost per kWh. Often, however, several units must be deliberately kept on at relatively low loading levels in order to provide spinning reserve. The *cost of spin*, then, is the difference between the low cost of providing *energy alone* from a few highly loaded turbines and the higher cost of providing *energy plus spin* from more turbines operating at lower loads. One can also think of the cost of spin as the cost of the extra "friction overhead" introduced by having more turbines spinning without any more kWh over which to spread these fixed costs.

The KA intertie allows the free spin from Bradley Lake to be available to the Anchorage load center. Economic benefit results from the substitution of this free spin for costly spin from Anchorage thermal units. DFI found that the present value of this benefit (after averaging across cases) is $8.9 million.

2.4.1 Quantified Errors

The Cost of Spin is Calculated Incorrectly

To calculate the benefits of using more free spin from Bradley Lake, one must estimate *how much spin* substitution can occur and *how costly* is the thermal spin displaced. We first dispute the derivation of the cost of the displaced spin from thermal units. We argue that the calculation *method* is wrong, not the input assumptions. We present the argument by first deriving a general formula for the cost of spin. We show how this formula produces the right answer when applied to a simple example presented by DFI in a report for the Railbelt utilities. We then discuss why DFI's formula for the cost of spin is wrong and verify that it produces the wrong answer when applied to the same simple example. Finally, we apply our formula to heat rate data for Railbelt thermal generation units to estimate the correct cost of spin and adjust accordingly the spinning reserve benefits that DFI attributes to a new Kenai-Anchorage intertie.

The Cost of Spin: a Simple Example

The principles behind the calculation of the cost of spin are best introduced by means of the following simple example, which is reproduced from page 6 of the DFI report "Value of Bradley Lake Spinning Reserves" (October 6, 1989), prepared for the Railbelt Utilities. This example prefaced their actual analysis of the cost of spin in the Railbelt. Suppose a system of five 100 MW thermal generators is running such that:

Total capacity of operating turbines:	500 MW
Total load on system:	- 400 MW
Available operating reserve (spin):	100 MW
Number of operating turbines:	5

Loading level (L) of each turbine:	80%, i.e. 80 MW
Average Heat Rate at L = 80% :	12,000 Btu/kWh
Incremental Heat Rate from 80% to 100%:	2,000 Btu/kWh

(this is the incremental rate implied by DFI's example but is very low for actual generation units)

Now suppose that 100 MW of free spin becomes available from a hydro unit. It is now possible to shut down one unit completely and still serve the 400 MW load by running the four remaining units at full load. The cost savings from this rearrangement are easily calculated:

Gas saved by shutting down one unit:	80 MW * 12 M Btu/MWh = 960 MBtu/hr
Gas used by additional loading on remaining 4 units:	4 * 20 MW * 2 MBtu/MWh = 160 MBtu/hr
Net gas savings from eliminating 100 MW thermal spin:	960 MBtu/hr - 160 MBtu/hr = 800 MBtu/hr
Net gas savings per unit of spin eliminated:	(800 MBtu/hr)/(100 MW) = 8 MBtu/MWh = 8,000 Btu/kWh

The cost savings from reducing the spin in this example is amount of fuel savings that occurs by rearranging the system as described (800 MBtu/hr), divided by the spin reduction, 100 MW. The answer above, 8,000 Btu/kWh-spin, the same answer arrived at by DFI in their Bradley Lake spinning reserve report.

A General Expression for the Cost of Spin

Using this simple example as a pattern, it is possible to derive a general expression for the cost of spin. Define the following variables (values in parentheses are from the example above):

L = *The loading level in % of the generation unit turned off to reduce spin (0.8).*

U = *The size of generation unit being turned off to reduce spin (100,000 kW).*

A_L = *The average heat rate of the unit being turned off, for loading level L (12,000 Btu/kWh).*

M = *The incremental heat rate of the units that pick-up the generation loss caused by shutting off the unit (2,000 Btu/kWh).*

The amount of reduced spin in the system is U. The load on the system remains constant while U kW of generation is turned off. Therefore, the reduction in spin must be U.

$$(1)\ \text{Reduced Spin} = U$$

The change in gas use can be thought of as consisting of two components. First, shutting the unit off causes a reduction in gas use of:

$$(2)\ \text{Reduced gas use because of shutting unit off} = U \times L \times A_L$$

However, the remaining units must make up for the lost generation:

$$(3)\ \text{Increase in gas use because of loading up remaining units} = U \times L \times M$$

The net decrease in gas use is found by subtracting (3) from (2):

$$(4)\ \text{Net Decrease in Gas Use} = U \times L \times A_L - U \times L \times M = U \times L \times (A_L - M)$$

The net gas decrease per unit of spin is derived by dividing (4) by (1):

$$(5)\ \text{Gas Decrease per Unit of Spin Reduced (Btu/kWh-spin)} = L \times (A_L - M)$$

We can further verify the formula by applying it directly to the DFI example presented above. The turbine being shut-off is 80% loaded, and its heat rate at 80% loading is 12,000 Btu/kWh. The incremental heat rate of the rest of turbines that make-up for the lost generation is 2,000 Btu/kWh (this is the incremental heat rate implied by the figures in the example but is very low for real-world generation units). Applying our formula for the cost of spin:

$$\text{Cost of Spin} = 0.80 \times (12{,}000\ \text{Btu/kWh} - 2{,}000\ \text{Btu/kWh})$$

$$\text{Cost of Spin} = 8{,}000\ \text{Btu/kWh-spin}$$

This formula for the cost of spin gives the correct answer in the example.

Why DFI's formula for the Cost of Spin is Incorrect

After completing the simple numeric example in the Bradley Lake spinning reserve report, DFI states on page 7 that cost of spinning reserves is:

$$\text{Cost of Spin} = (A_L - M) \times \frac{P}{PMAX - P}$$

where,

P - *Power Output of Unit*
PMAX - *Unit Size*

To express this formula using the variable names above. note that P = U × L and PMAX = U:

$$\text{Cost of Spin} = (A_L - M) \times \frac{L}{1 - L}$$

DFI does not apply this formula to their introductory example in the report. When it is applied to the example. it produces the incorrect answer of 40.000 Btu/kWh-spin. not the correct answer of 8.000 Btu/kWh-spin:

$$\text{Cost of Spin} = (12.000\ Btu/kWh - 2{,}000 Btu/kWh) \times \frac{0.8}{1 - 0.8} = 40{,}000\ Btu/kWh\text{-}spin$$

This formula also produces impossible results when turbines near full loading are analyzed. As L approaches 1. the cost of spin approaches infinity. according to this formula. This is clearly not correct.

DFI claimed at the 1/30/90 Review Meeting that they actually performed their analysis of the cost of spin in the Railbelt with a different. somewhat more general formula. We now show that the derivation of this formula is also incorrect. Also. the more general expression when applied to short period of time produces the $(A_L - M) \times L/(1\text{-}L)$ formula. which we have already shown to be incorrect.

DFI's more general expression is:

$$\text{Fuel Use} = \lambda \times (\text{Energy } kWh) + \mu \times (\text{Spin } kWh)$$

where,

λ = *Cost of Energy, Btu/kWh*
μ = *Cost of Spin, Btu/kWh-spin*

This expression is a simple statement that the total fuel cost during a particular period of time equals the cost of energy times the amount of energy generated plus the cost of spin times the amount of spin generated over that time period. The expression does not allow one to calculate the cost of spin over the time period unless some assumption is made for λ. the cost of energy.

In DFI's empirical analysis of the Railbelt generation system. the assumption was made that λ is the incremental heat rate of the generation system. i.e. $\lambda = M$. This is the error in the derivation. Assuming that all energy is produced at the system incremental heat rate is incorrect. In order to get any energy at all from the system. a turbine must be turned on. and the fixed frictional loss of a spinning turbine must be incurred. The cheapest that energy can come out of the system is by fully loading turbines and spreading the frictional loss over the largest amount of kWh.

The assumption that the cost of energy equals the system incremental heat rate is equivalent to assigning *all* the fixed frictional loss in the system to the production of spin, and *none* to the production of energy. It is clear why this formula has problems when attempting to determine the cost of spin for turbines near full load. As a turbine approaches full load, the amount of spin decreases towards zero. DFI's formula still assigns all of the fixed frictional loss of the turbine to the cost of this spin. The cost per unit of spin becomes infinite as the turbine approaches full load because the divisor, the amount of spin, approaches zero.

We now show that DFI's more general expression produces the formula $(A_L - M) \times L/(1-L)$ when applied to a short period of time. We apply the expression to a turbine whose loading characteristics do not change over a one hour time period. Using our previous variables, the amount fuel used over that one hour period is $U \times L \times A_L$. The amount of energy produced is $U \times L$, and the amount of spin produced is $U \times (1 - L)$. Once again, DFI's assumption in the Railbelt analysis is that $\lambda = M$. Making these substitutions gives the equation:

$$U \times L \times A_L = M \times U \times L + \mu \times U \times (1 - L)$$

which simplifies to:

$$\mu = (A_L - M) \times \frac{L}{1 - L} = \textit{Cost of Spin}$$

We have already shown that this formula produces an incorrect answer when applied to a simple numeric example and produces an impossible answer when applied to turbines near full load.

Applying the Correct Formula to the Railbelt Data

We now apply our formula for the cost of spin, $L \times (A_L - M)$, to heat rate data of Anchorage/Kenai thermal units to estimate an average cost of spin. Table 3 summarizes the calculation. The units are arranged in their dispatch order, according to data provided by DFI in Appendix F of the AEA Recon report. We do not analyze units beyond the Beluga CT #1 unit, because the (load + spin) that can be served by the analyzed set of units is approximately 550 MW. This capability combined with the Railbelt Hydro capacity will serve the bulk of the load through the analysis period, if optimal economic dispatch occurs.

When determining the cost of spin for a particular unit, it is necessary to make an assumption about that unit's loading and make an assumption about the incremental heat rate of the rest of the system. We test two different assumptions about the unit loading, 50% and 75% (our heat rate data source did not have heat rates at 25% load). The results are not very sensitive to this assumption. For the system incremental heat rate, we use the 50-75% incremental heat

Table 3 - Cost of Spin for Kenai/Anchorage Thermal Generation Units

Unit	Size MW	50% HR	75% HR	100% HR	Increm HR 50-75%	Spin Cost 50% Ld	Spin Cost 75% Ld
Bel CC #78	101	10,981	9,831	9,391	7,531	Never	Marginal
Bel CC #68	101	10,981	9,831	9,391	7,531	Never	Marginal
AMLP CC #76	109	10,017	9,018	8,628	7,020	1,243	1,115
Bel CT #5	67	15,012	13,448	12,963	10,320	3,996	4,821
Bel CT #3	50	14,822	13,228	12,800	10,039	2,251	2,181
Bern CT #3	27	15,284	14,082	13,700	11,678	2,623	3,032
Bern CT #4	27	15,284	14,082	13,700	11,678	1,803	1,803
AMLP CC #56	48	13,802	11,500	10,365	6,896	1,062	(134)
Bel CT #1	16	17,119	15,602	15,314	12,568	5,112	6,530
						2,584	2,764
						Btu/kWh-spin	

NOTES: Heat rate data from "Railbelt Intertie Proposal Preliminary Economic Assessment", March 1987, Alaska Power Authority, and from "Explanation and Support for Avoided Cost Tariff Proposed by ML&P", MLP, 1989. Data from APA report for Beluga CT #3 was scaled up to match the DFI assumption of a 12,800 Btu/kWh full-load heat rate for the unit. The anomalous results for the Cost of Spin for the AMLP units are due to the fact that they are placed in the dispatch order according to their heat rate times their fuel cost/kWh plus variable O&M. Since AMLP pays a higher price for natural gas, they are placed behind less efficient Chugach units. For this societal resource cost analysis, there is no difference in cost between AMLP and Chugach gas; thus, it is justified to consider the cost of spin in terms of Btus/kWh-spin, without regard to fuel price.

rate of the unit one prior in the dispatch order. In an optimally dispatched system, it is likely that this unit will be the unit that picks up the lost generation caused by shutting off the final unit (units prior to this one are likely to have lower incremental heat rates, and therefore will operating at or near full load).

Adjusting DFI's Result to Arrive at the Correct Operating Reserve Benefit for a New Intertie

The average cost of spin for the units shown is 2,600 Btu/kWh-spin with the 50% loading assumption, and 2,800 Btu/kWh-spin for the 75% loading assumption. For our adjustment of the DFI spinning reserve benefit result, we choose the higher of the two estimates, favoring the new intertie. The average of the Case 1 and Case 2 operating reserve benefit as calculated by DFI is $8.9 million. DFI based this calculation on a cost of operating reserves of 7,000

Btu/kWh-spin (increased from 5.000 Btu/kWh-spin in the AEA Recon report). The following expression adjusts the DFI result to correspond to our estimate of the cost of operating reserves of 2.800 Btu/kWh-spin:

$$\textit{Corrected Operating Reserve Benefit} = \$8.9 \textit{ million} \times \frac{2{,}800 \textit{ Btu/kWh-spin}}{7{,}000 \textit{ Btu/kWh-spin}}$$

$$\textit{Corrected Operating Reserve Benefit} = \$3.6 \textit{ million}$$

This adjustment lowers the present value operating reserve benefits of the new Kenai-Anchorage intertie by $5.3 million.

2.4.2 Unquantified Disputes

Case 1 Results use Too Low of a Transfer Capacity for the Existing Intertie

DFI analyzes two cases when calculating operating reserve benefits. Case 1 assumes that the transfer capacity of the existing intertie for the purposes of operating reserves access is 70 MW input and 61 MW output. Case 2 assumes 90 MW input and 75 MW output. In the Case 1 analysis. the operating reserve benefit of the new intertie is $10.6 million, and the result for Case 2 is $7.1 million.

Sharing operating reserves only involves transferring energy over the intertie during periods of emergencies when the operating reserves are called on. There are no routine transfers of energy associated with sharing operating reserves. Therefore, the most accurate transfer rating of the intertie to use in the calculation is the emergency transfer limit, not the secure transfer limit. The Kenai-Anchorage intertie question is simplified. however, because the Alaska Energy Authority technical consultant states that emergency *and* the secure transfer limit for the existing line will be 90 MW input, 75 MW output after the planned line compensation is installed ["Kenai Export Limits With and Without a New Line, With and Without Additional Compensation", Power Technologies Inc., November 30, 1989, page 5]. We see little justification for incorporating the Case 1 results (70 MW input, 61 MW output) into the expected benefit calculation of the new line.

There has been some dispute concerning PTI's calculation of the *secure* export limit of the existing Kenai-Anchorage line. This calculation is complex because it involves simulating the response of the system to various faults (short-circuits) occurring on the system of transmission lines. A transfer limit is considered secure if the system can "survive" after such faults.

The emergency transfer limit, however, is a much more straight-forward calculation. Simulation of faults is not involved, because the probability of a fault occurring during a period when a transmission line is being relied on for emergency purposes is very low. In the case of sharing operating reserves. the line will only transfer energy for a few dozen hours per year (number of events requiring operating reserves x time required to start a new unit to restore operating reserves). The probability of a line fault occurring during those few hours is exceptionally low.

The emergency transfer limit calculation is a steady-state calculation. The transfer limit of the line is reached when voltages along the line drop too low, or phase relationships become unstable. PTI says that this calculation is quite accurate. They state that the fact that the existing intertie was able to deliver 70 MW to Anchorage before going unstable during the December 11, 1989 outage indicates that the existing intertie should be easily able to deliver 75 MW to Anchorage (Case 2) after the line compensation is added when Bradley Lake is finished.

DFI appears to have recognized and accepted this information before the 138 kV study was performed, as indicated by the following response to a reviewer comment in the AEA Recon Study:

> 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. [Page J-20 - J-21, AEA Recon Study].

Finally, we find that the transfer limits assumed for the Anchorage-Fairbanks intertie upgrades closely match or even exceed PTI's calculations for the limits of those lines. We disagree with the asymmetrical acceptance of the PTI transfer limit calculations.

Bradley Will Not Have 50 MW of Spin Available at All Times

We also question the assumption that 50 MW of spin will be available from Bradley at all times with the new intertie. With the ability to deliver 110 MW power to Kenai, Bradley must be supplying less than 60 MW load in order for 50 MW of spinning reserve to be available. Bradley averages 42 MW of output, so there will be large amounts of time when it is operating below 60 MW.[9] However, the number of hours where Bradley operates above 60 MW is significant, especially given the use of Bradley for hydro-thermal coordination. During these hours, Anchorage will not be able to rely on Bradley for 50 MW of spinning reserves, with the new intertie. This constraint is less of a problem for the existing intertie, because Bradley is relied on for only 30 MW of spinning reserve. Only operation above 80 MW (delivered to Kenai) will reduce Bradley spin below 30 MW.

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[9] However, Bradley needs to be operating in order to provide spin. If Bradley is off-line during some periods of the year, no spin will be provided.

The Assumption Concerning the Unavailability of the Existing Intertie Substantially Increases the Operating Reserve Benefit of the New Intertie

The assumption discussed earlier concerning the assumed unavailability of the existing Kenai-Anchorage line for the 13 year reconstruction period *and* the period thereafter also substantially affects the spinning reserve benefit calculation. If it is believed that the unavailability of the existing Kenai-Anchorage will be less than stated by Chugach, then the spinning reserve benefits of the new intertie will further decline.

"Peak Rating Strategy" Will Increase Probability of Damaging Turbines

We also suspect that the probability for damaging generation units increases when the "peak rating strategy" described on page 7-4 is employed. The expected cost of damage may be significant in the calculation of the benefits of increased reliance on Bradley for spin.

2.5 Capacity Sharing Benefits

The availability of a new Kenai-Anchorage intertie allows Anchorage to utilize additional excess generation capacity present on the Kenai peninsula, and it also allows the long-term reduction of reserve margins (while maintaining equivalent reliability) because of stronger integration of the Kenai and Anchorage areas.

2.5.1 Unquantified Disputes

This calculation involves the estimation of *how much* generation capacity can be avoided by the existence of a new intertie, and the estimation of how much that capacity would have *cost* if the new intertie were not built. We first address the question of how much generation capacity can be avoided by the existence of a new intertie.

Case 2 Transfer Capacity of the Existing Intertie is Overstated, Penalizing Benefits of New Intertie

The reason the new intertie reduces the purchases of generation capacity is because it provides a higher transfer capacity between Anchorage and Kenai. The level of capacity benefits provided is related to the amount that the transfer capacity is increased over and above the existing transfer capacity. Two cases were analyzed. For both cases, the transfer capability of the new intertie was assumed to be 110 MW output. In Case 1, the existing intertie was modeled as being able to transfer 70 MW input and 60 MW output. For Case 2, the intention was to model the existing intertie as being able to transfer 90 MW input and 75 MW output. In actuality, the intertie was erroneously modeled as having an 88 MW output, thus overstating the intended Case 2 transfer capacity.

Case 1 Transfer Capacity is Too Low to Consider in the Capacity Sharing Analysis

The error in the Case 2 transfer capacity of the existing intertie caused the benefits of the new intertie to be *understated*. However, we also reject the Case 1 analysis since it relies upon a transfer capacity estimate that is substantially below the transfer capacity estimated by PTI, the technical consultant for the intertie analysis. See the discussion in section 2.4.2 on page 22. As with the use of the intertie for accessing spinning reserves, using the intertie for capacity benefits involves infrequent transfer of actual energy. Energy is only actually transferred across the intertie when one area has a set of coincident outages of generators that cause the available local capacity to be less than the local load. Such an occurrence does not happen for more than a few hundred hours per year.

We find that the error of overstating the transfer capacity in Case 2 approximately cancels the unjustified use of the low transfer capacity for Case 1. The Case 1 intertie output was modeled at 60 MW and the Case 2 output was modeled at 88 MW. The average is therefore about 75 MW, which is equal to PTI's transfer capacity estimate.

Possibility of Increasing the Transfer Capacity of the Existing Intertie by Adding Compensation is Ignored

Continuing with discussion of the amount of capacity avoided by the new intertie, another very critical issue is degree to which the transfer capacity of the existing intertie can be increased beyond the 90 MW input / 75 MW output level. If cost-effective increases are possible, the capacity benefits of a new intertie will be substantially reduced. Even a modest increase from the 75 MW output level to an 88 MW output level will decrease the benefits of the new intertie by ~ $10 million (minus the cost of the transfer capacity upgrade).

PTI states that upgrades of the existing Kenai-Anchorage line are possible, and in fact the line can be upgraded to have a transfer capacity equal to its thermal limit, approximately 145 MW. In PTI's report on the Kenai-Anchorage lines ("Kenai Export Limits With and Without a New Line With and Without Additional Compensation", PTI Report Number R106-89, November 30, 1989, page 5), PTI indicates that the transfer capacity of the existing line can be increased to 122 MW input (by our estimate, approximately 95 MW output) by the addition of series capacitors north of Quartz Creek. This type of upgrade is of the same type being proposed for the northern intertie, the AF100 upgrade. If such upgrades were analyzed for the northern intertie, they should be considered for the Kenai-Anchorage connection also.

The second part of the calculation involves estimation of the cost of capacity that is avoided. The question is: if the new intertie is not built, what will the extra capacity requirements cost? DFI estimates the cost of this capacity at the cost of installing new gas turbines, approximately $51/kW/year. We believe that this assumption, at least for the years prior to 2005, may substantially overstate the actual cost of capacity available to Railbelt utilities. We believe this primarily because the Railbelt utilities have stated that they will acquire substantial capacity through life extension of existing units, and they have also indicated that physically moving capacity from the Kenai Peninsula to Anchorage is an option that may prove cost-effective. These intentions indicate that such capacity acquisitions are less expensive than new capacity.

Cost of Capacity does Not Reflect Railbelt Utilities Intention to Extend Life of Existing Plants

The Railbelt capacity expansion plans given on page F-5 of the AEA Recon study clearly indicate that substantial amounts of capacity will be acquired through life extension of existing units. The critical question is how much less than $51/kW/year will this life extension cost. AML&P states the following in a report concerning avoided cost payments to cogeneration and independent power plants:

> ML&P's other CT's are modern units installed in the 1970's and the 1980's. These units are being well maintained. ML&P's standard operation calls for annual to semiannual inspections and major overhauls approximately every 3 years. At these overhauls ML&P performs both a full inspection and destructive testing on selected (1 blade per row) hot rotating blades. In this way, the CT's are constantly checked and parts are replaced and upgraded. This program on modern CT's should result in an extended life expectancy. Therefore, no other retirements were assumed for the study period. ["Explanation and Support for Avoided Cost Tariff Proposed by ML&P", 1989, page 9].

The study period referred to extends through 2017. Thus, the implication is that an ML&P turbine installed in 1980 will last through 2017, a total of 37 years, with only normal maintenance performed. The DFI analysis assumes existing turbines retire after 20 - 30 years of life. Thus, ML&P's statement indicates that an additional 10-15 years of capacity is available for only the cost of fixed O&M, $13/kW/year, a 74% reduction from the $51/kW/year figure used in the DFI study. The ML&P estimate may be extreme, but it does indicate the possibility of capacity acquisitions at substantially below the $51/kW/year DFI cost.

Potential to Acquire Cheap Capacity by Moving it From Kenai Peninsula is Ignored

Another potential source of capacity that may be cheaper than new capacity is moving capacity from the Kenai Peninsula where there will be substantial capacity excesses for a long period of time. Chugach is already considering moving a 25 MW Bernice unit, as indicated on their data submission to the North American Electric Reliability Council for a reliability study. Movement of the 39 MW Soldotna unit may be even more cost-effective because it is a newer unit, and there may be economies of scale in moving costs. If the Soldotna unit costs $5 million to move and has a 20 year remaining life, the levelized cost, including a $13/kW/year fixed O&M cost would be $23/kW/year, substantially cheaper than $51/kW/year.

ML&P Believes New Capacity will Cost Substantially Less than $51/kW/year in the Future

ML&P's statements in the avoided cost report also call into question the $51/kW/year cost estimate for *new* turbines. This estimate was derived from a $490/kW capital cost of a turbine, a 20 year life, and a $13/kW/year fixed O&M figure. The above quote indicates that turbine lives may be substantially longer than 20 years. Actual data also suggests lives longer than 20 years, as ML&P intends to retire their #1 and #2 units in 1992, after 30 and 28 years of life respectively (page 8, ML&P Avoided Cost Report). They even indicate the ability to repower these units in the future if further capacity is needed.

ML&P's report concludes that future *new* capacity additions (not life extension and repowering options), which they find are not needed until 2017, will cost approximately $177/kW installed, 1988 $ [page 8, ML&P Avoided Cost]. Using this figure, a 30 year life, and a $13/kW/year fixed O&M gives a $25/kW/year capacity cost (1990 $), about half of the DFI $51/kW/year figure. Once again, we do not accept ML&P's very low capacity cost estimates, but they do indicate the need to examine further the high DFI figures.

Considering the "Lumpiness" of Capacity Investments would Increase DFI's Cost of Capacity by about 10%

In the AEA Recon stud [illegible] I identifies a simplification in their capacity analysis that may have caused the capacity benefits to be understated. Capacity is most cost-effectively added in relatively large "lumps". The DFI analysis does not acknowledge this lumpiness, but instead assumes that exactly the right amount of capacity can be added at any given time. We agree that this assumption understates the cost of capacity. To determine the approximate magnitude of this effect, we built a simplified capacity addition model. If one assumes that load growth is 1.4%/year (Anchorage Mid load growth), 3% of the installed capacity retires every year, and additions of capacity are sized to be 12% of the total installed capacity, the model shows that actual capacity costs are 10% higher than that indicated by assuming perfectly tuned capacity additions. We believe that the previously mentioned concerns about the reduced cost of life extension will more than compensate for this 10% understatement in the capacity benefits.

Analysis Assumes that there is No Opportunity Cost of Using Excess Kenai Capacity

An additional capacity benefit concern is the implicit assumption in the capacity deferral calculation that accessing excess capacity on the Kenai Peninsula is free. There is an opportunity cost associated with using this capacity with an upgraded intertie. If the capacity were left idle because of no new intertie, it could be mothballed (retired early with the potential for future repowering). Doing so would save approximately $13/kW/year of fixed O&M costs. Thus, accessing the Kenai excess capacity may save the $51/kW/year cost of new capacity in Anchorage, but it costs $13/kW/year because of the lost opportunity to mothball the capacity or move and sell it.

No Credit is Given to a New Intertie for Accessing Capacity during Periods when Capacity Reserves are Sufficient

Another potential understatement of capacity benefits in the DFI report follows. No credit is given to the new intertie for increased capacity access during the period prior to additional capacity needs. Although a new intertie will save no money during this period, it will improve reliability because of additional access to capacity under emergency conditions. Even though the 30% reserve margin criteria indicates sufficient capacity for reliability needs, the sharp reserve margin criteria is somewhat arbitrary. Additional capacity beyond 30% reserves does provide some additional reliability benefit.

2.6 Maintenance Cost Savings

The new intertie is credited with the deferral of a number of maintenance activities planned for the existing intertie. When viewed in terms of present value, cost deferral results in a savings. The present value maintenance cost savings that is credited to the new intertie is $5 million. The AEA Recon study attributed no such benefit to the new intertie. This benefit only appears in the 138 kV analysis.

$5 million Maintenance Deferral Benefit does not Account for Increased Failure Repair Costs

We were unable to review this estimate. However, the estimate was supplied by Chugach Electric, an intertie advocate, and therefore deserves careful independent scrutiny. We note that some of the maintenance activities that are intended to be deferred if the new intertie is built are related to lowering the susceptibility of the existing intertie to avalanches. If these activities are deferred, it seems likely that avalanche repair costs will increase. The other deferred maintenance activities will cause similar increase in failure repair costs. It does not appear that these increased failure repair costs were accounted for in the analysis.

2.7 Reliability Benefits

Outages of the existing Kenai-Anchorage intertie sometimes cause utility customers to experience outages. The area importing energy will lose the power supplied by the intertie. If insufficient spinning reserves are present to fill-in for the lost power, some customers will lose power. The area exporting power is less likely to suffer customer outages upon line failure. Most thermal generators can scale back their power production level to maintain proper voltage and frequency conditions. It is more difficult for hydro generation to throttle back power output; however, PTI, the nation's leader in this type of work, is designing a control system for Bradley Lake that will allow a stable reduction in power output in the case of substantial loss-of-load. (The Railbelt utilities express less confidence in the ability of this system to work.)

The existence of a new Kenai-Anchorage intertie will substantially reduce the number of customer outages associated with line failure, since the new Kenai-Anchorage line will avoid much of the tough environment that the existing line traverses. Also the existing intertie will provide a back-up path if the new intertie experiences an outage. Reducing the number of power outages has value to customers. This benefit calculation estimates the amount of power outage reduction and assigns a dollar value to that improved reliability. This benefit is not a reduction in the costs incurred by the Railbelt utilities. It is essentially a measure of how much customers would be willing to pay to avoid the power outages caused by the existing Kenai-Anchorage line.

A new intertie improves reliability also by improving access to generation capacity outside a local area in times of coincident generation outages. This type of intertie benefit was quantified in the "Capacity Sharing Benefit" calculation, not in the calculation in this section.

2.7.1 Quantified Errors

DFI's reliability benefit calculation addresses the customer outages that occur when energy is being transferred over the Kenai-Anchorage line, and a line outage occurs. Loss of this energy flow may cause an outage in the importing area and may also, although much less frequently, cause an outage in the exporting area. The DFI analysis finds that the new Kenai-Anchorage intertie will eliminate all of these outages because of its improved reliability. DFI also concludes that customers would value this reliability improvement at $32 - $50 million, depending on outage assumptions.

Reliability Benefits cannot be Greater than Energy Transfer Benefits of Existing Intertie

The DFI estimate of reliability benefits from the new intertie cannot be greater than the benefits of existing routine energy transfers. The argument is straightforward. The outages which are avoided by the new intertie are an unfortunate side effect of the use of the existing intertie for energy transfer. The outages could also be avoided by stopping existing routine energy transfers. We show in the following paragraphs that the cost of stopping existing routine energy transfers is $17 million present value. Therefore, there are two ways of avoiding the outages caused by existing energy transfer:

- Option 1: stop non-emergency energy transfers and lose $17 million of transfer benefits.
- Option 2: use the new intertie.

The economic benefit of being able to choose option two over option one is $17 million dollars. Both options avoid the outages, but the intertie eliminates the need to stop the existing energy transfers. The intertie saves $17 million.

If the true cost of outages from existing energy transfers is really $32 - $50 million, we should expect to see the Railbelt Utilities stop non-emergency transfers of energy over the existing intertie as a result of the DFI study. In this case the intertie has exactly $17 million of reliability benefits because it avoids the need to stop the transfers. If the true cost of outages is less than $17 million, energy transfers should continue. In this case, the new intertie creates reliability benefits less than $17 million. In either case, the reliability benefits attributable to the intertie cannot exceed $17 million.

DFI acknowledges this type of logical cap on the reliability benefits of the new line. In the AEA Recon study they investigate the potential of using additional spinning reserves to solve the unreliability problems of the existing intertie:

> 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 in the true value of increased system reliability. [AEA Recon, page 4-21].

However, they conclude that using spinning reserves to avoid customer outages caused by failure of the existing KA line is more costly than the costs suffered because of outages.

Existing Routine Energy Transfers are Worth $17 million

We now show how the DFI analysis implies that the energy transfer benefits of the existing intertie amount to approximately $17 million. The energy transfer benefits consist of two components. First, there are the economy energy benefits that DFI's Over-Under model calculated. Second, there are the hydro-thermal coordination energy transfer benefits.

The economy energy benefits calculated by Over-Under are not directly available from the DFI 138 kV report. The report presents the *difference* between the economy energy benefits of the new line and the economy energy benefits of the existing line; i.e. the increase in benefits assignable to the new line. The figure relevant to the reliability cap calculation is the economy energy benefit of the existing line alone. DFI supplied us with the necessary Over-Under runs for the Middle Fuel Price / Middle Load forecast to perform the calculation. One Over-Under model run assumed that the existing intertie was able to transfer energy at its normal level. The other Over-Under allowed no transfers on the existing intertie. The difference between these two runs represents the economy energy value of the existing intertie. This difference, once adjusted for decreased gas royalties to the state, amounts to $9.4 million, present value. The result would be different for different load and fuel price combinations, but we expect that average result would be close to the Mid Fuel / Mid Load result.

The second component of foregone energy transfer benefits is the hydro-thermal coordination benefits. After correcting for the arithmetic error in the DFI calculation (see page 12), the existing intertie provides an average of 55 MBtu/hour of hydro-thermal benefits for an average of 3,500 hours per year. To determine the present value benefit of this gas savings, we ratio off of the original DFI hydro-thermal benefit estimate:

$$\textit{Hydro-Thermal Benefits of Existing Tie} = \$37.5 \times \frac{55\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}{356\ \textit{MBtu/hr} \times 4{,}000\ \textit{hours} - 126\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}$$

$$\textit{Hydro-Thermal Benefits of Existing Tie} = \$7.3\ \textit{million}$$

The total of these two components of energy transfer benefit is approximately $17 million.

It is important to note that stopping these routine energy transfers does not require or intend that the existing Kenai-Anchorage line be abandoned. The line would still provide capacity sharing and operating reserve sharing benefits, which only involve small amounts of energy transfer during emergency periods. In fact, the operating reserve sharing benefits of the existing line would increase, since the full line capacity is available for the transfer of spin. The line would still deliver energy to customers along the intertie route. Outages of the line would cause outages for these customers; however, the new KA line was not assumed to improve reliability for these customers either. That which is given up are the economy energy and hydro-thermal coordination transfers between the Kenai and Anchorage load centers. It is these flows of energy that cause the outages addressed by the DFI reliability analysis.

Summary: $17 million is the Upper Bound of Reliability Benefits

To summarize the argument, the reliability benefit of the new intertie is the lesser of two figures: 1) the reduced customer outage costs effected by the new intertie, and 2) the cost of achieving an equivalent reduction in outage cost by some other means. DFI estimates the reduction in outage costs attributable to the new intertie to be $32 - $50 million. However, the same level of outage cost reduction can be achieved by forgoing routine energy transfers across the existing Kenai-Anchorage line. The cost of forgoing these transfers is the amount of lost energy transfer benefits. The DFI analysis implies that these transfer benefits are approximately $17 million. Therefore, $17 million is the correct estimate for the reliability benefit of the new line.

2.7.2 Unquantified Disputes

Ignoring the logical cap on reliability benefits for the moment, we also dispute the estimate of $32 to $50 million of outage cost imposed by the existing intertie due to energy transfers over the line. The estimate involves multiplying the *amount of outages, measured in unserved kilowatt-hours*, by the customer *costs or inconveniences caused by one unserved kWh*. We first discuss the estimate used by DFI for the outage costs associated with one unserved kWh.

A Reliability Survey to Determine Costs per Unserved kWh is Misinterpreted

DFI relied upon the *same* data that was used in the AEA Recon study to determine the costs imposed on commercial customers because of power outages (approximately 90% of the outage costs are suffered by commercial customers, according to DFI). However, the interpretation of that data was changed in a way that caused the estimate of outages costs to more than double.

The survey relied upon was conducted by Ontario Hydro. They asked commercial customers what costs they would suffer as the result of outages of different lengths. The survey respondent was to assume that the outage occurred at *10 am on a Friday in January*, a time when the business was almost certainly open. To convert the respondents dollar answers into a $ per unserved kWh figure, it is necessary to divide by the electrical usage that would have occurred for the duration of the outage. Unfortunately, the survey did not collect this time-of-day load data from the respondents, so the typical usage at 10 am on a Friday in January was not known. What was collected was the *annual average demand* and the annual *peak demand* of the surveyed customers.

For the AEA Recon study, DFI used a $/unserved-kWh figure that was derived from dividing the respondents' outage cost estimates by 75% of annual peak demand. For the Railbelt Utility 138 kV study, DFI used a figure that was based on dividing by annual average demand. In order for this latter interpretation of the data to be correct, the usage during open business hours would need to be equal to the annual average usage. We find this exceptionally unlikely. Only:

1) businesses that are open 24 hours per day, or
2) businesses that use as much electricity when they are closed as when they are open,

would have an open-hour usage similar to their annual average demand. Few businesses participating in the Ontario Hydro survey are likely to fall in that category, as indicated by their load factors. A load factor is the ratio of average annual demand to peak demand. The survey data indicates load factors ranging from 21% for the large industrial customers to 46% for the retail customers. A low load factor usually indicates a usage pattern that has substantial variation over time.

We would estimate open-hour usage as being approximately 1.5 times annual average demand, based on a typical business being open for 3,000 hours per year and having a ratio of open-hour usage to closed-hour usage of 2. Such an estimate implies that DFI's outage cost per unserved kWh is a factor of 1.5 too high.

We note that the EPRI (Electric Power Research Institute) report that provided the outage cost data warns against dividing survey outage costs by annual average demand, as DFI did:

> However, most studies do not have available or do not use estimates of average kWh usage during the interruption period. Instead, outage costs are frequently unitized in terms of $/(maximum kW) or $/(average kWh). Both of these units can be deceiving, depending upon the timing of the

interruptions and the customer's usage pattern. Using maximum demand as the divisor will understate outage costs, since a customer's load during an interruption may not be near its peak level. At the other extreme, average kWh is likely to understate kWh unserved during daytime interruptions and, consequently, overstate outage costs. ["Customer Demand for Service Reliability", Laurits R. Christensen Associates, Inc., EPRI P-6510, September 1989, page 2-14].

A High Outage Cost per Unserved kWh is Applied to Unserved kWh that Occur During Hours When Businesses are Closed

Assume for the moment that the Ontario Hydro survey was interpreted correctly. The $/unserved-kWh figure derived from the survey is reflective of the costs of outages that occur during hours when businesses are open. This is because the survey respondents were asked about the costs of outage occurring at 10 am on a Friday. We find it very unlikely that the outage cost per kWh will be nearly as high for outages occurring during hours when businesses are closed. The electricity usage during closed hours will be lower, say by a factor of 2, but the costs incurred by the outage will be substantially lower, we expect by much more than a factor of 2.

DFI applied an outage cost figure reflective of outage costs during open business hours to *all* the commercial unserved energy caused by the existing Kenai-Anchorage intertie. We expect that a significant fraction of that unserved energy occurs during nights and weekends when businesses are closed. A smaller outage cost per unserved kWh should be applied to this unserved energy occurring during closed hours. DFI's failure to account for this is a further overstatement of the outage costs caused by the existing intertie.

Unserved kWh from AEA Recon Study are Not Reduced to Account for the Unavailability of the Existing Intertie

In the final benefit estimates for the AEA Recon study, the existing intertie was modeled as being available for transfers for all but two weeks of the year. In the 138 kV study, this assumption was changed, and substantial periods of unavailability for the existing intertie were assumed [see page B-2, 138 kV]. This assumption increases the energy transfer benefits and the spinning reserve benefits of the new intertie. However, it decreases the reliability benefits of the new intertie. This adjustment was not made in the 138 kV study.

If the existing intertie is expected to be unavailable for transfers for much of the year, it is also is not causing power outages during those periods. This was directly recognized in the AEA Recon study in a section where DFI briefly discussed the possible effects of an assumption of 2 month per year unavailability of the existing intertie:

> *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.* [page 13-20, AEA Recon].

This 2 month outage assumption was not included in the final benefit estimates for the AEA

Recon study. However, in the 138 kV study, a *3 month* per year intertie maintenance outage was assumed for years 1994 - 2007, and a 1 month per year maintenance outage was assumed for the years beyond 2007. Thus, the unserved kWh estimates that were taken from the AEA Recon should be adjusted downward by 25% for 1994-2007, and ~[illegible]% for 2008 onward to account for this.

The Unserved kWh in Anchorage Caused by Failures of the Existing Intertie are Substantially Overstated

DFI estimates that 30%-39% of the unserved energy caused by the existing intertie is borne by Anchorage customers. In the calculation of the unserved energy suffered by Anchorage customers, DFI made the assumption that at the times when the existing intertie suffers an outage, there is 60 MW of transfer occurring. They assumed the loss of this transfer would cause a 30 MW outage, because of some spinning reserve protection in Anchorage [see page 4-14, AEA Recon Study. These assumptions were carried forward to the 138 kV study]. These assumptions are extreme and increase the reliability benefits of a new intertie.

If the Railbelt system is optimally dispatched, DFI's analysis shows that the flow of energy northward into Anchorage with the existing intertie will rarely be 60 MW, and will average about 30 MW. (Page 5-8 of the 138 kV study shows a northward flow of energy of about 110 GWh. DFI assumes Anchorage is importing energy for 40% of the time--page 4-13 of AEA Recon. Thus, the average flow is 110,000 MWh/8766 hrs/0.4 = 30 MW.) Anchorage is assumed to have approximately 35 MW of spinning reserve if no new intertie is built (65 MW Total - 30 MW carried by Bradley, see page 7-2 138 kV). Thus, if Anchorage importation of energy occurred at a constant level, 30 MW, there would always be sufficient spinning reserve to cover loss of the line. However, the import varies about the 30 MW average, so there are times when the intertie transfer exceeds the 35 MW of spinning reserve.

To get a sense of how frequently the import exceeds the 35 MW of spinning reserve in Anchorage, we examined the hydro-thermal coordination calculation. Approximately 80% of the total Anchorage imports are due to hydro-thermal coordination. The corrected hydro-thermal calculation presented in Appendix B shows that the average level of *unprotected* transfers into Anchorage is 3 MW.[10] Adding in the additional transfers estimated by the Over-Under model will probably not raise this figure beyond 5 MW. DFI's assumption that failures of the existing intertie cause a 30 MW outage in Anchorage appears to overstate the Anchorage unserved energy by a factor of 6. Correcting this overstatement would lower the *total* reliability benefits of the new line by about 28% (ignoring the logical reliability cap).

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[10] We also note that if the more optimal hydro-thermal coordination regime described on page ? were implemented, the level of unprotected transfers into Anchorage would be substantially less.

The Analysis Implies that if a New Intertie is Built, Kenai Customers will Suffer *No* Outages due to Generation and Transmission Failures

The DFI analysis assumes that Bradley will somewhat reduce the number of outages on the Kenai peninsula due to a reduction in the amount of time Kenai is importing energy and due to the ability of Bradley Lake to restore power to customers more quickly. Beyond this reduction, DFI assumes that a new intertie will eliminate all the remaining unserved kWh on the Kenai peninsula (except unserved kWh for customers along the existing intertie route--e.g. Seward). Thus these Kenai peninsula customers will have the lowest level of G&T unserved kWh in the Railbelt, 0 kWh/customer/year, as compared to 6 kWh/year for Anchorage, 3 kWh/year for Fairbanks, and 2 kWh/year for Copper Valley. This conclusion results from assigning very high reliability benefits to the new intertie. We find the conclusion unlikely.

The Analysis Assumes that Kenai will Suffer Substantial Outages when the Existing Intertie Fails under Kenai Export Conditions, Contrary to Statements by the Technical Consultant, PTI

When the existing intertie fails under Kenai export conditions (Anchorage import), the Bradley Lake hydro project must throttle back its output in a stable manner in response to the loss of load. PTI, Power Technologies Inc., has designed a control system that they claim will perform this task up to export levels of 90 MW (75 MW received in Anchorage). They claim that stable throttling of Bradley will be substantially easier at lower export levels [phone call with Harrison Clark, January 16, 1990]. Given that the average level of export from Kenai is about 35 MW (and substantially lower if the more optimal hydro-thermal regime is implemented), the functionality of PTI's control system is more probable.

DFI assumed that failure of the existing line under conditions of Kenai export would cause Kenai customer outages 40-80% of the time [page 4-12, AEA Recon Study]. This assumption indicates very little faith in PTI's detailed technical design and analysis work.

The Analysis Assumes that Outages cannot be Directed to Those Customers with Lowest Outage Costs

DFI assumes that the unserved kWh fall on customers in proportion to how much energy they consume. For example, if the commercial customers consume 60% of the annual energy in an area, DFI assumed that 60% of the unserved energy was incident on the commercial sector. However, DFI's outage cost figures imply that the outage cost per kWh is 5 times higher for commercial customers than for residential customers ($25/unserved-kWh versus $5/unserved-kWh). If a system manager were to "optimally dispatch outages", as much of the outage burden would be placed on the residential customers. The unfairness of this approach could be mitigated by reducing residential rates relative to commercial rates, to reflect the less reliable power received by the residential customers. Dispatching outages on residential customers is physically accomplished by setting load-shedding relays to first trip distribution feeders that are predominantly residential before tripping feeders that are predominantly commercial.

Appendix A
Hydro-Thermal Computation Error Corrected

Reshaping Savings for New Intertie

101 MW CC, Beluga CC#8

50% Heat Rate = 10,981
Incremental Heat Rate = 7,801

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	0.433	2,481	41	101.7	44.0		
1.14	0.359	2,115	71	150.1	53.9		
1.15	0.116	1,981	89	176.3	20.5		
1.19	0.092	1,704	97	165.3	15.2		
					133.6	37.5%	50.1

47 MW CC, AMLP #56

50% Heat Rate = 13,700
Incremental Heat Rate = 8,718

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	1	4,201	29.4	123.4	123.4		
1.14	0	3,791		0.0	0.0		
1.15	0	3,642		0.0	0.0		
1.19	0	3,332		0.0	0.0		
					123.4	37.5%	46.3

55 MW CT, Beluga #3

50% Heat Rate = 13,136
Incremental Heat Rate = 9,552

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	1	2,728	34.4	93.8	93.8		
1.14	0	2,280		0.0	0.0		
1.15	0	2,116		0.0	0.0		
1.19	0	1,777		0.0	0.0		
					93.8	5.0%	4.7

87 MW CT, AMLP CT#8

50% Heat Rate = 14,029
Incremental Heat Rate = 9,591

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	54.8%	3,579	39.6	141.8	77.6		
1.14	41.3%	3,128	71.0	221.9	91.6		
1.15	4.0%	2,964	85.7	254.0	10.0		
1.19	0.0%	2,623		0.0	0.0		
					179.3	9.0%	16.1

66 MW CT, Beluga CT #5

50% Heat Rate = 15,012
Incremental Heat Rate = 10,914

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	82.8%	3,120	37.0	115.4	95.5		
1.14	17.2%	2,608	61.7	161.0	27.7		
1.15	0.0%	2,420		0.0	0.0		
1.19	0.0%	2,033		0.0	0.0		
					123.3	8.0%	9.9

33 MW CT, AMLP CT #4

50% Heat Rate = 18,475
Incremental Heat Rate = 9,372

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings
1.09	1.00	8,263	20.6	170.4	170.4
1.14	0.00	7,823		0.0	0.0
1.15	0.00	7,662		0.0	0.0
1.19	0.00	7,330		0.0	0.0

170.4   3.0%   5.1

100.0%   132.2 MBtu/hr

Reshaping Savings for Existing Intertie

101 MW CC, Beluga CC#8

50% Heat Rate = 10,981
Incremental Heat Rate = 7,801

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings
1.20	15.3%	1,581	30.7	48.6	7.4
1.28	22.2%	1,021	44.8	45.7	10.2
1.31	10.8%	769	57.1	43.9	4.7
1.42	19.0%	0	68.3	0.0	0.0

22.3   37.5%   8.4

47 MW CC, AMLP #56

50% Heat Rate = 13,700
Incremental Heat Rate = 8,718

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings
1.20	70.0%	3,195	24.1	77.0	53.9
1.28	30.0%	2,569	41.7	107.2	32.1
1.31	0	2,287		0.0	0.0
1.42	0	1,286		0.0	0.0

86.0   37.5%   32.3

55 MW CT, Beluga #3

50% Heat Rate = 13,136
Incremental Heat Rate = 9,552

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	55.0%	1,626	25.1	40.8	22.5		
1.28	40.4%	940	44.8	42.1	17.0		
1.31	4.6%	631	54.1	34.1	1.6		
1.42	0	0		0.0	0.0		
					41.0	5.0%	2.1

87 MW CT, AMLP CT#8

50% Heat Rate = 14,029
Incremental Heat Rate = 9,591

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	22.5%	2,472	29.1	71.9	16.2		
1.28	25.5%	1,783	44.8	79.8	20.4		
1.31	12.4%	1,473	57.1	84.2	10.4		
1.42	21.8%	371	68.3	25.4	5.5		
					52.5	9.0%	4.7

66 MW CT, Beluga CT #5

50% Heat Rate = 15,012
Incremental Heat Rate = 10,914

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	40.3%	1,861	26.5	49.3	19.8		
1.28	33.7%	1,077	44.8	48.2	16.2		
1.31	16.3%	724	57.1	41.4	6.8		
1.42	9.7%	0	63.6	0.0	0.0		
					42.8	8.0%	3.4

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33 MW CT, AMLP CT #4

50% Heat Rate =                    18,475
Incremental Heat Rate =             9,372

Reshaping                                      Unwtd       Wtd.
  Energy              Savings    Avg MW     MBtu/hr    MBtu/hr
  Req't       Prob    Btu/kWh      Load     Savings    Savings
=================================================================
     1.20   100.0%      7,182      20.6       148.1      148.1
     1.28     0.0%      6,509                   0.0        0.0
     1.31     0.0%      6,206                   0.0        0.0
     1.42     0.0%      5,129                   0.0        0.0
                                                       =========
                                                         148.1     3.0%  4.4
                                                                 =============
                                                                  100.0% 55.3
                                                                       MBtu/hr
```

Appendix B
Hydro-Thermal Oversimplification Corrected

DFI set up computation bins for particular loading levels of the intertie. With the varying heat rate assumption, we found it computationally easier to set up bins to correspond to different loading levels of each turbine. The reshaping energy requirement for each bin was calculated by interpolating between transmission loss figures given by DFI for the intertie. We used the interpolation method suggested by DFI on page 3-5 of the 138 kV study.

Beluga CC#8

Unit Size =	101 MW
Incremental Heat Rate, 50% - 100% =	7,301 Btu/kWh
Heat Rate at 50% =	10,981 Btu/kWh
Existing Transfer Limit, Output =	61 MW
New Transfer Limit, Output =	139 MW
Available Anchorage Spin =	35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	2.53	0.00%	71,401	1.01	63,529	160.4	0.00	1.00	63,578	160.5	0.00	0.0	0.00
5.0% - 10.0%	7.58	0.00%	29,001	1.03	20,948	158.7	0.00	1.01	21,124	160.0	0.00	0.0	0.00
10.0% - 15.0%	12.63	0.00%	20,521	1.06	12,243	154.6	0.00	1.02	12,588	158.9	0.00	0.0	0.00
15.0% - 20.0%	17.68	0.00%	16,887	1.09	8,413	148.7	0.00	1.02	8,898	157.3	0.00	0.0	0.00
20.0% - 25.0%	22.73	0.00%	14,868	1.12	6,130	139.3	0.00	1.03	6,811	154.8	0.00	0.0	0.00
25.0% - 30.0%	27.78	6.67%	13,583	1.15	4,612	128.1	8.54	1.04	5,469	151.9	10.13	0.0	0.00
30.0% - 35.0%	32.83	6.67%	12,693	1.19	3,434	112.7	7.51	1.05	4,522	148.4	9.90	0.0	0.00
35.0% - 40.0%	37.88	6.67%	12,041	1.23	2,479	93.9	6.26	1.06	3,806	144.1	9.61	2.9	0.19
40.0% - 45.0%	42.93	6.67%	11,542	1.25	1,808	77.6	5.17	1.06	3,236	138.9	9.26	7.9	0.53
45.0% - 50.0%	47.98	6.67%	11,148	1.25	1,358	65.2	4.34	1.07	2,782	133.5	8.90	13.0	0.87
50.0% - 55.0%	53.03	6.67%	10,830	1.28	831	44.1	2.94	1.08	2,385	126.4	8.43	18.0	1.20
55.0% - 60.0%	58.08	6.67%	10,566	1.31	359	20.9	1.39	1.09	2,060	119.6	7.97	23.1	1.54
60.0% - 65.0%	63.13	6.67%	10,345	1.35	0	0.0	0.00	1.10	1,758	111.0	7.40	0.0	0.00
65.0% - 70.0%	68.18	6.67%	10,157	1.40	0	0.0	0.00	1.11	1,506	102.7	6.85	0.0	0.00
70.0% - 75.0%	73.23	6.67%	9,994	1.46	0	0.0	0.00	1.12	1,266	92.7	6.18	0.0	0.00
75.0% - 80.0%	78.28	6.67%	9,853	1.53	0	0.0	0.00	1.13	1,041	81.5	5.43	0.0	0.00
80.0% - 85.0%	83.33	6.67%	9,728	1.60	0	0.0	0.00	1.14	845	70.4	4.69	0.0	0.00
85.0% - 90.0%	88.38	6.67%	9,618	1.70	0	0.0	0.00	1.15	650	57.4	3.83	0.0	0.00
90.0% - 95.0%	93.43	6.67%	9,520	1.75	0	0.0	0.00	1.16	466	43.5	2.90	0.0	0.00
95.0% - 100.0%	98.48	6.67%	9,432	1.79	0	0.0	0.00	1.17	293	28.8	1.92	0.0	0.00
		100%					36.2				103.4		4.33

AMLP CC#56

Unit Size = 47 MW
Incremental Heat Rate, 50% - 100% = 6,718 Btu/kWh
Heat Rate at 50% = 13,700 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	1.18	0.00%	108,358	1.00	99,601	117.0	0.00	1.00	99,628	117.1	0.00	0.0	0.00
5.0% - 10.0%	3.53	0.00%	41,931	1.01	33,094	116.7	0.00	1.00	33,177	116.9	0.00	0.0	0.00
10.0% - 15.0%	5.88	0.00%	28,646	1.02	19,728	115.9	0.00	1.01	19,867	116.7	0.00	0.0	0.00
15.0% - 20.0%	8.23	0.00%	22,952	1.04	13,912	114.4	0.00	1.01	14,137	116.3	0.00	0.0	0.00
20.0% - 25.0%	10.58	0.00%	19,789	1.05	10,665	112.8	0.00	1.01	10,949	115.8	0.00	0.0	0.00
25.0% - 30.0%	12.93	6.67%	17,776	1.06	8,525	110.2	7.35	1.02	8,899	115.0	7.67	0.0	0.00
30.0% - 35.0%	15.28	6.67%	16,383	1.07	7,045	107.6	7.17	1.02	7,480	114.3	7.62	0.0	0.00
35.0% - 40.0%	17.63	6.67%	15,361	1.09	5,891	103.8	6.92	1.02	6,433	113.4	7.56	0.0	0.00
40.0% - 45.0%	19.98	6.67%	14,579	1.10	5,020	100.3	6.69	1.03	5,614	112.1	7.48	0.0	0.00
45.0% - 50.0%	22.33	6.67%	13,962	1.11	4,244	94.7	6.32	1.03	4,972	111.0	7.40	0.0	0.00
50.0% - 55.0%	24.68	6.67%	13,463	1.13	3,604	88.9	5.93	1.04	4,434	109.4	7.29	0.0	0.00
55.0% - 60.0%	27.03	6.67%	13,050	1.14	3,073	83.0	5.54	1.04	3,996	108.0	7.20	0.0	0.00
60.0% - 65.0%	29.38	6.67%	12,704	1.16	2,590	75.8	5.05	1.04	3,611	106.1	7.07	0.0	0.00
65.0% - 70.0%	31.73	6.67%	12,408	1.18	2,111	67.0	4.46	1.05	3,290	104.4	6.96	0.0	0.00
70.0% - 75.0%	34.08	6.67%	12,154	1.20	1,704	58.1	3.87	1.05	3,009	102.5	6.84	0.0	0.00
75.0% - 80.0%	36.43	6.67%	11,932	1.22	1,299	47.3	3.16	1.05	2,742	99.9	6.66	1.4	0.10
80.0% - 85.0%	38.78	6.67%	11,737	1.23	998	38.7	2.58	1.06	2,521	97.7	6.52	3.8	0.25
85.0% - 90.0%	41.13	6.67%	11,565	1.25	663	27.3	1.82	1.06	2,309	94.9	6.33	6.1	0.41
90.0% - 95.0%	43.48	6.67%	11,411	1.25	532	23.1	1.54	1.06	2,128	92.5	6.17	8.5	0.57
95.0% - 100.0%	45.83	6.67%	11,273	1.24	471	21.6	1.44	1.07	1,950	89.4	5.96	10.8	0.72
		100%					69.8				104.7		2.04

Beluga CT#3

Unit Size = 55 MW
Incremental Heat Rate, 50% - 100% = 9,552 Btu/kWh
Heat Rate at 50% = 13,136 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	1.38	0.00%	81,232	1.00	71,637	98.5	0.00	1.00	71,667	98.5	0.00	0.0	0.00
5.0% - 10.0%	4.13	0.00%	33,445	1.02	23,719	97.8	0.00	1.01	23,840	98.3	0.00	0.0	0.00
10.0% - 15.0%	6.88	0.00%	23,888	1.03	14,073	96.8	0.00	1.01	14,256	98.0	0.00	0.0	0.00
15.0% - 20.0%	9.63	0.00%	19,792	1.04	9,841	94.7	0.00	1.01	10,119	97.4	0.00	0.0	0.00
20.0% - 25.0%	12.38	0.00%	17,516	1.06	7,427	91.9	0.00	1.02	7,803	96.6	0.00	0.0	0.00
25.0% - 30.0%	15.13	6.67%	16,068	1.07	5,837	88.3	5.89	1.02	6,314	95.5	6.37	0.0	0.00
30.0% - 35.0%	17.88	6.67%	15,066	1.09	4,690	83.8	5.59	1.03	5,270	94.2	6.28	0.0	0.00
35.0% - 40.0%	20.63	6.67%	14,331	1.10	3,783	78.0	5.20	1.03	4,508	93.0	6.20	0.0	0.00
40.0% - 45.0%	23.38	6.67%	13,768	1.12	3,069	71.7	4.78	1.03	3,904	91.3	6.08	0.0	0.00
45.0% - 50.0%	26.13	6.67%	13,325	1.14	2,471	64.6	4.30	1.04	3,418	89.3	5.95	0.0	0.00
50.0% - 55.0%	28.88	6.67%	12,965	1.16	1,874	54.1	3.61	1.04	3,017	87.1	5.81	0.0	0.00
55.0% - 60.0%	31.63	6.67%	12,669	1.18	1,386	43.8	2.92	1.05	2,677	84.7	5.64	0.0	0.00
60.0% - 65.0%	34.38	6.67%	12,419	1.20	969	33.3	2.22	1.05	2,385	82.0	5.47	0.0	0.00
65.0% - 70.0%	37.13	6.67%	12,207	1.22	557	20.7	1.38	1.06	2,123	78.8	5.25	2.1	0.14
70.0% - 75.0%	39.88	6.67%	12,024	1.25	109	4.3	0.29	1.06	1,896	75.6	5.04	4.9	0.33
75.0% - 80.0%	42.63	6.67%	11,864	1.24	0	0.0	0.00	1.06	1,708	72.8	4.85	7.6	0.51
80.0% - 85.0%	45.38	6.67%	11,724	1.24	0	0.0	0.00	1.07	1,524	69.2	4.61	0.0	0.00
85.0% - 90.0%	48.13	6.67%	11,600	1.25	0	0.0	0.00	1.07	1,356	65.2	4.35	0.0	0.00
90.0% - 95.0%	50.88	6.67%	11,489	1.28	0	0.0	0.00	1.08	1,193	60.7	4.05	0.0	0.00
95.0% - 100.0%	53.63	6.67%	11,390	1.29	0	0.0	0.00	1.08	1,049	56.3	3.75	0.0	0.00
		100%					36.2				79.7		0.98

AMLP CT#8

Unit Size = 87 MW
Incremental Heat Rate, 50% - 100% = 9,591 Btu/kWh
Heat Rate at 50% = 14,029 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	2.18	0.00%	98,351	1.01	88,673	192.9	0.00	1.00	89,733	193.0	0.00	0.0	0.00
5.0% - 10.0%	6.53	0.00%	39,178	1.03	29,322	191.3	0.00	1.01	29,506	192.5	0.00	0.0	0.00
10.0% - 15.0%	10.88	0.00%	27,343	1.05	17,259	187.7	0.00	1.01	17,617	191.6	0.00	0.0	0.00
15.0% - 20.0%	15.23	0.00%	22,271	1.07	11,998	182.7	0.00	1.02	12,477	190.0	0.00	0.0	0.00
20.0% - 25.0%	19.58	0.00%	19,453	1.10	8,937	174.9	0.00	1.03	9,604	188.0	0.00	0.0	0.00
25.0% - 30.0%	23.93	6.67%	17,660	1.13	6,866	164.3	10.95	1.03	7,741	185.2	12.35	0.0	0.00
30.0% - 35.0%	28.28	6.67%	16,419	1.16	5,335	150.9	10.06	1.04	6,444	182.2	12.15	0.0	0.00
35.0% - 40.0%	32.63	6.67%	15,508	1.19	4,124	134.5	8.97	1.05	5,462	178.2	11.88	0.0	0.00
40.0% - 45.0%	36.98	6.67%	14,812	1.22	3,115	115.2	7.68	1.05	4,701	173.8	11.59	2.0	0.13
45.0% - 50.0%	41.33	6.67%	14,263	1.23	2,430	100.4	6.70	1.06	4,079	168.6	11.24	6.3	0.42
50.0% - 55.0%	45.68	6.67%	13,818	1.24	1,935	88.4	5.89	1.07	3,561	162.7	10.84	10.7	0.71
55.0% - 60.0%	50.03	6.67%	13,450	1.27	1,230	61.5	4.10	1.08	3,134	156.8	10.45	15.0	1.00
60.0% - 65.0%	54.38	6.67%	13,141	1.29	744	40.5	2.70	1.08	2,744	149.2	9.95	19.4	1.29
65.0% - 70.0%	58.73	6.67%	12,878	1.31	278	16.3	1.09	1.09	2,405	141.2	9.42	23.7	1.58
70.0% - 75.0%	63.08	6.67%	12,652	1.35	0	0.0	0.00	1.10	2,094	132.1	8.81	0.0	0.00
75.0% - 80.0%	67.43	6.67%	12,454	1.40	0	0.0	0.00	1.11	1,835	123.7	8.25	0.0	0.00
80.0% - 85.0%	71.78	6.67%	12,281	1.44	0	0.0	0.00	1.12	1,581	113.5	7.56	0.0	0.00
85.0% - 90.0%	76.13	6.67%	12,127	1.49	0	0.0	0.00	1.12	1,349	102.7	6.84	0.0	0.00
90.0% - 95.0%	80.48	6.67%	11,990	1.56	0	0.0	0.00	1.13	1,124	90.5	6.03	0.0	0.00
95.0% - 100.0%	84.83	6.67%	11,867	1.63	0	0.0	0.00	1.14	914	77.5	5.17	0.0	0.00
		100%					58.1				142.5		5.14

Beluga CT#5

Unit Size = 66 MW
Incremental Heat Rate, 50% - 100% = 10,914 Btu/kWh
Heat Rate at 50% = 15,012 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					Wtd.
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Unprotected S -> N Transfer MW
0.0% - 5.0%	1.65	0.00%	92,374	1.00	81,911	135.2	0.00	1.00	81,945	135.2	0.00	0.0	0.00
5.0% - 10.0%	4.95	0.00%	38,234	1.02	27,070	134.0	0.00	1.01	27,259	134.9	0.00	0.0	0.00
10.0% - 15.0%	8.25	0.00%	27,306	1.04	15,988	131.9	0.00	1.01	16,270	134.2	0.00	0.0	0.00
15.0% - 20.0%	11.55	0.00%	22,623	1.05	11,148	128.8	0.00	1.02	11,540	133.3	0.00	0.0	0.00
20.0% - 25.0%	14.85	0.00%	20,021	1.07	8,331	123.7	0.00	1.02	8,876	131.8	0.00	0.0	0.00
25.0% - 30.0%	18.15	6.67%	18,365	1.09	6,510	118.2	7.88	1.03	7,173	130.2	8.68	0.0	0.00
30.0% - 35.0%	21.45	6.67%	17,219	1.11	5,110	109.6	7.31	1.03	5,979	128.3	8.55	0.0	0.00
35.0% - 40.0%	24.75	6.67%	16,378	1.13	4,036	99.9	6.66	1.04	5,075	125.6	8.37	0.0	0.00
40.0% - 45.0%	28.05	6.67%	15,735	1.16	3,123	87.6	5.84	1.04	4,384	123.0	8.20	0.0	0.00
45.0% - 50.0%	31.35	6.67%	15,228	1.17	2,431	76.2	5.08	1.05	3,812	119.5	7.97	0.0	0.00
50.0% - 55.0%	34.65	6.67%	14,817	1.20	1,734	60.1	4.01	1.05	3,352	116.2	7.74	0.0	0.00
55.0% - 60.0%	37.95	6.67%	14,477	1.23	1,100	41.7	2.78	1.06	2,939	111.5	7.44	3.0	0.20
60.0% - 65.0%	41.25	6.67%	14,192	1.23	728	30.0	2.00	1.06	2,604	107.4	7.16	6.3	0.42
65.0% - 70.0%	44.55	6.67%	13,950	1.25	267	11.9	0.79	1.07	2,295	102.2	6.82	9.6	0.64
70.0% - 75.0%	47.85	6.67%	13,740	1.25	43	2.1	0.14	1.07	2,035	97.4	6.49	12.9	0.86
75.0% - 80.0%	51.15	6.67%	13,558	1.28	0	0.0	0.00	1.08	1,777	90.9	6.06	0.0	0.00
80.0% - 85.0%	54.45	6.67%	13,398	1.29	0	0.0	0.00	1.08	1,565	85.2	5.68	0.0	0.00
85.0% - 90.0%	57.75	6.67%	13,256	1.31	0	0.0	0.00	1.09	1,355	78.2	5.22	0.0	0.00
90.0% - 95.0%	61.05	6.67%	13,129	1.33	0	0.0	0.00	1.10	1,168	71.3	4.75	0.0	0.00
95.0% - 100.0%	64.35	6.67%	13,016	1.37	0	0.0	0.00	1.10	984	63.3	4.22	0.0	0.00
		100%					42.5				103.4		2.11

AMLP CT#4

Unit Size = 33 MW
Incremental Heat Rate, 50% - 100% = 9,372 Btu/kWh
Heat Rate at 50% = 18,475 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit [illegible]tput = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	0.83	0.00%	191,432	1.00	182,060	150.2	0.00	1.00	182,060	150.2	0.00	0.0	0.00
5.0% - 10.0%	2.48	0.00%	70,059	1.01	60,602	150.0	0.00	1.00	60,661	150.1	0.00	0.0	0.00
10.0% - 15.0%	4.13	0.00%	45,784	1.02	36,241	149.5	0.00	1.01	36,360	150.0	0.00	0.0	0.00
15.0% - 20.0%	5.78	0.00%	35,381	1.02	25,794	149.0	0.00	1.01	25,943	149.8	0.00	0.0	0.00
20.0% - 25.0%	7.43	0.00%	2[illegible]501	1.03	19,927	148.0	0.00	1.01	20,137	149.5	0.00	0.0	0.00
25.0% - 30.0%	9.08	6.67%	25,923	1.04	16,159	146.6	9.78	1.01	16,433	149.1	9.94	0.0	0.00
30.0% - 35.0%	10.73	6.67%	23,377	1.05	13,568	145.5	9.70	1.01	13,873	148.8	9.92	0.0	0.00
35.0% - 40.0%	12.38	6.67%	21,509	1.06	11,610	143.7	9.58	1.02	11,979	148.2	9.88	0.0	0.00
40.0% - 45.0%	14.03	6.67%	20,081	1.07	10,090	141.5	9.43	1.02	10,524	147.6	9.84	0.0	0.00
45.0% - 50.0%	15.68	6.67%	18,954	1.08	8,869	139.0	9.27	1.02	9,384	147.1	9.81	0.0	0.00
50.0% - 55.0%	17.33	6.67%	18,042	1.09	7,862	136.2	9.08	1.02	8,444	146.3	9.75	0.0	0.00
55.0% - 60.0%	18.98	6.67%	17,288	1.09	7,060	134.0	8.93	1.03	7,663	145.4	9.69	0.0	0.00
60.0% - 65.0%	20.63	6.67%	16,654	1.10	6,305	130.0	8.67	1.03	7,017	144.7	9.65	0.0	0.00
65.0% - 70.0%	22.28	6.67%	16,115	1.11	5,667	126.2	8.42	1.03	6,450	143.7	9.58	0.0	0.00
70.0% - 75.0%	23.93	6.67%	15,650	1.13	5,102	122.1	8.14	1.03	5,958	142.5	9.50	0.0	0.00
75.0% - 80.0%	25.58	6.67%	15,245	1.14	4,596	117.5	7.84	1.04	5,525	141.3	9.42	0.0	0.00
80.0% - 85.0%	27.23	6.67%	14,889	1.15	4,111	111.9	7.46	1.04	5,155	140.4	9.36	0.0	0.00
85.0% - 90.0%	28.88	6.67%	14,574	1.16	3,691	106.6	7.11	1.04	4,813	139.0	9.26	0.0	0.00
90.0% - 95.0%	30.53	6.67%	14,293	1.17	3,357	102.5	6.83	1.04	4,504	137.5	9.16	0.0	0.00
95.0% - 100.0%	32.18	6.67%	14,040	1.18	2,970	95.6	6.37	1.05	4,237	136.3	9.09	0.0	0.00
		100%					126.6				143.9		0.00

Summary for All Units

		- - Existing - -		- - - New - - -		- - Existing - -	
Unit Name	Prob. Marginal	Reshape Savings MBtu/hr	Weighted Reshape Savings MBtu/hr	Reshape Savings MBtu/hr	Weighted Reshape Savings MBtu/hr	Unprot. Transfer MW	Weighted Unprot. Transfer MW
Beluga CC#8	37.5%	36.2	13.6	103.4	38.8	4.33	1.62
AMLP CC#56	37.5%	69.8	26.2	104.7	39.3	2.04	0.77
Beluga CT#3	5.0%	36.2	1.8	79.7	4.0	0.98	0.05
AMLP CT#8	9.0%	58.1	5.2	142.5	12.8	5.14	0.46
Beluga CT#5	3.0%	42.5	3.4	103.4	8.3	2.11	0.17
AMLP CT #4	3.0%	126.6	3.8	143.9	4.3	0.00	0.00
			54.0		107.4		3.07