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

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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.

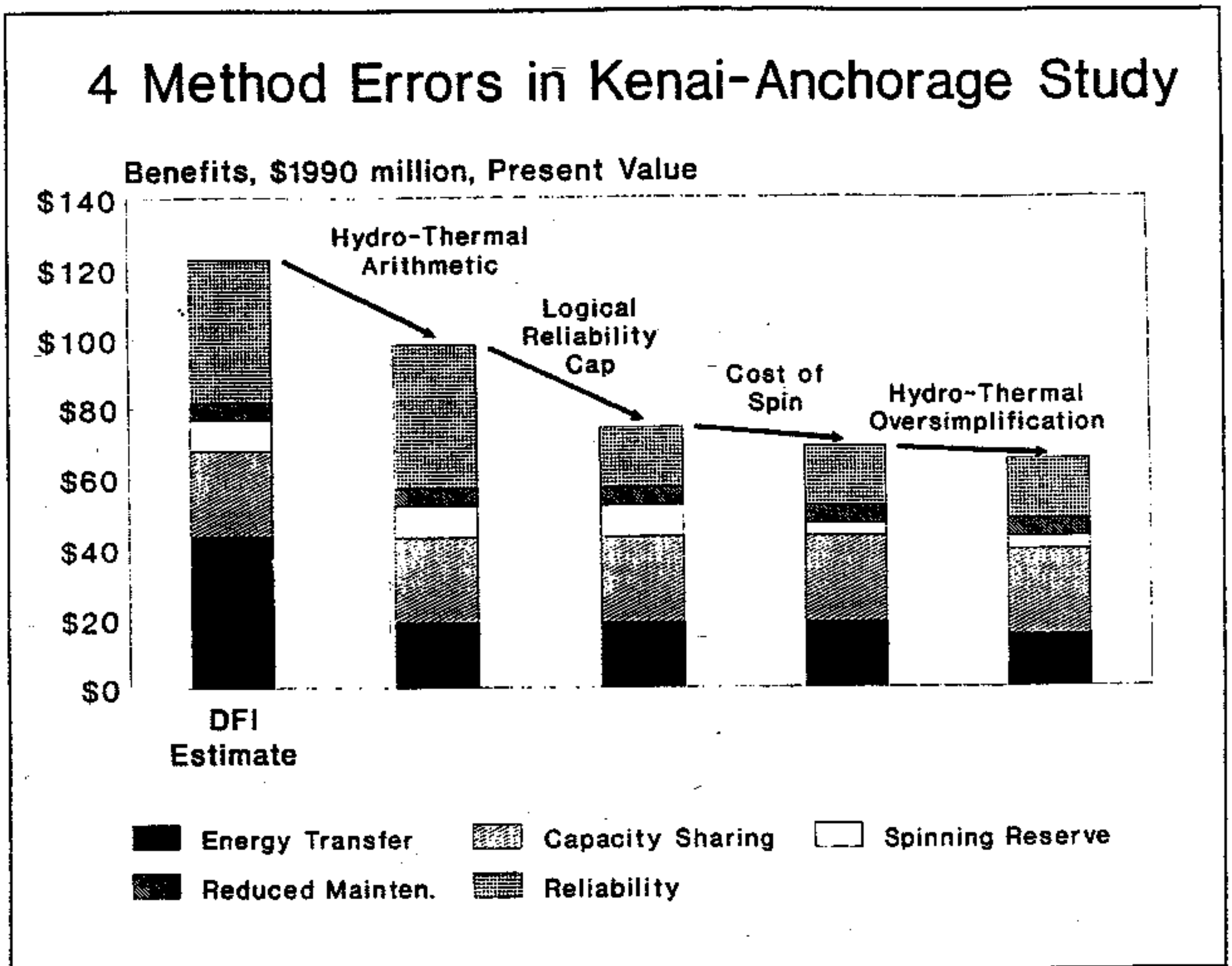

Figure 1 - Changes to Kenai-Anchorage Benefit Estimate due to 4 Major Method Errors. No other disputes are quantified in the displayed benefit adjustments.

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**

[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

[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.

[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:

$$\textit{Corrected Estimate} = \$37.5 \times \frac{132\ \textit{MBtu/hr} \times 4{,}000\ \textit{hours} - 55\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}{356\ \textit{MBtu/hr} \times 4{,}000\ \textit{hours} - 126\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}$$

$$\textit{Corrected Estimate} = \$12.8\ \textit{million}$$

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 x 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.

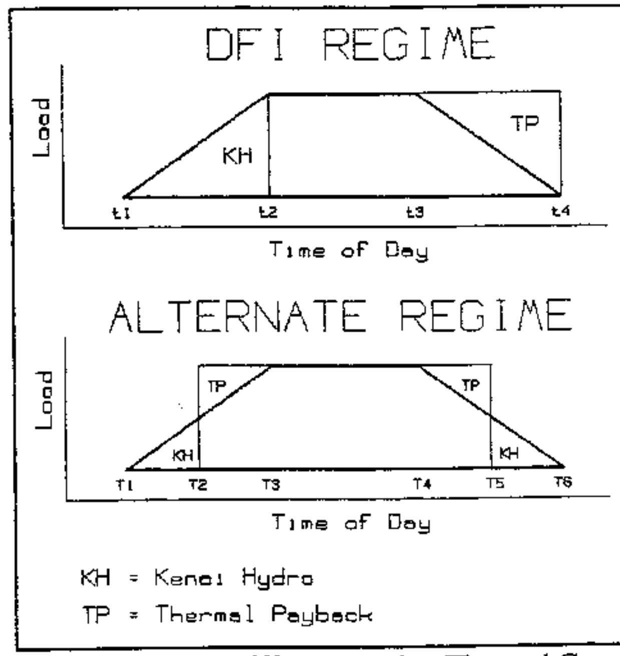

Figure 2 - Two Different Hydro-Thermal Coordination Regimes

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 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) 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 × 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	11,678	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.

[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 study, DFI 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 ~8% 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.