

RAILBELT

ENERGY

Alaska State Legislature

Senate Resources Committee



Sen. John B. (Jack) Coghill, Chairman
Sen. Paul Fischer, Vice-Chairman
Sen. Lloyd Jones
Sen. Arliss Sturgulewski
Sen. Jim Duncan
Sen. Fred Zharoff
Sen. Dick Eliason

Box V
Juneau, Alaska 99811
(907) 465-4907

April 8, 1987

MEMORANDUM

TO: Representative ^{COTTEN}~~Cotton~~, Chairman
House Resources Committee

FROM: Senator Coghill, Chairman
Senator Resources Committee

RE: Today's Railbelt Energy Joint Meeting

Would you please announce that the Joint Senate/House Resources meeting will be today from 1:30 p.m. to 5 p.m. in the Senate Finance Chambers.

The agenda follows:

- 1:30 p.m. Overview of Railbelt Energy Council Report
- 2:00 p.m. Presentation by utilities on Railbelt Energy issues
- 2:30 p.m. Questions by House and Senate Resources Committees
- 3:00 p.m. Public Hearings on SB 205, SB 206, SB 109 and HB 120 and other energy related legislation (SB 159)

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Mary Van Nimwegen

Joint Senate + House Resources

4-8-87

Pick News

RAILBELT ENERGY PLAN

April 8, 1987

Last year, after the Susitna Hydroelectric Project was cancelled, the Legislature established the Railbelt Energy Fund and the Railbelt Energy Council. The purpose of the Railbelt Energy Fund was to reserve approximately \$280 million, previously earmarked for Susitna, for other Railbelt energy projects. A major purpose of the Railbelt Energy Council was to recommend such projects.

In creating the Railbelt Energy Fund and the Railbelt Energy Council, legislators and administration officials made one thing very clear to the seven electric utilities in the region: They needed to agree on a plan of action and they needed to work with and through the Railbelt Energy Council.

This has been done.

For the first time ever, all seven Railbelt utilities, which together serve more than three quarters of the State's population, have agreed on a Railbelt energy development plan. That plan consists of two basic elements: Completion of the Bradley Lake Hydroelectric Project and completion of a solid Railbelt transmission intertie system.

The plan was unanimously recommended by the Railbelt Energy Council in its January 24, 1987, report to the Legislature. Moreover, the plan has been endorsed by a broad Railbelt coalition that includes business, labor and government leaders. Many local governments and chambers of commerce throughout the Railbelt have passed formal resolutions of support.

Among the governmental entities are the Anchorage Municipal Assembly, Fairbanks City Council, Matanuska-Susitna Borough, Wasilla City Council, Palmer City Council, Kenai Peninsula Borough, Homer City Council, Kenai City Council and Soldotna City Council, as well as the Kenai Caucus and Unified Fairbanks organizations. Labor supporters include the Alaska AFL-CIO and its 48 unions and affiliates, including the International Brotherhood of Electrical Workers Local 1547, and Teamsters Union Local 959. Local chambers of commerce that have passed resolutions include Anchorage, Fairbanks, Wasilla, Palmer, Big Lake, Willow, Talkeetna, Kenai, North Kenai and Homer. The Alaska State Chamber of Commerce has made the Bradley Lake project and the intertie system one of its highest legislative priorities.

THE PROJECTS

The Bradley Lake Project is a 90-megawatt hydroelectric facility under construction near Homer. It is scheduled for completion in 1990, and is designed to accommodate future enlargement to 135 megawatts. The Railbelt transmission system has two components: Upgrade of the existing 138-kilovolt Anchorage-Fairbanks transmission line to 345 kilovolts, and construction of a 230-kilovolt circuit from Anchorage to the lower Kenai Peninsula.

Bradley Lake was originally estimated to cost \$408 million, including financing. That figure is now down to \$350 million, and may drop even more given the sluggish economy and lower than expected inflation growth. The interties are estimated to cost \$200 million. That figure, too, could drop.

BENEFITS

Separate studies by the Division of Policy in the Governor's Office, the House Research Agency and the Alaska Power Authority all show positive benefits for Bradley Lake and the interties, even when considered on their own.

A February 25, 1987, analysis by the Division of Policy and a March 18, 1987, analysis by the House Research Agency both estimate savings of approximately \$85 million for Bradley Lake over the natural gas-fired generation alternative. Even under a much more conservative and unlikely scenario where the gas alternative would be delayed from the early 1990s to 1998, the House Research Agency analysis still projects savings of \$36 million for Bradley Lake.

A March 1987 economic analysis prepared by a private consultant for the APA shows total quantifiable benefits of \$423 million for the Anchorage-Fairbanks and Anchorage-Kenai Peninsula interties combined. This does not count other, less quantifiable benefits such as increased power system reliability and the facilitation of economic development.

Although the utilities believe the benefits cited in the above studies are understated, and that savings may be even higher, all the work to date agrees that Bradley Lake and the interties have a positive value as independent projects. When considered together, the benefits are even greater. Among the benefits of the combined Bradley Lake-intertie plan are these:

- Long-term electric rates will be lower than otherwise for the majority of consumers in the State.
- Regional power reliability will be significantly improved.
- Generation resources, including future development, will be more diversified.
- Economic development opportunities, including jobs, will be substantially enhanced.

- Regional cooperation and coordination will be improved, as already evidenced through the establishment of the Railbelt Energy Council and the Railbelt energy coalition.

BRADLEY LAKE

The major benefit of the Bradley Lake project is the assurance of a stable, long-term supply of low-cost power, to be shared throughout the Railbelt utilizing the proposed intertie system. Because of higher capital costs, hydroelectric power is initially more expensive than that from fossil fuel plants. However, Bradley Lake energy is expected to become cheaper than the least-cost alternative of natural gas within the first five to seven years of Bradley's operation. The real payoff is that hydroelectric projects like Bradley Lake will last up to 100 years, compared to 20 or 30 years for gas turbines and other fossil-fuel generation facilities.

It is very important to remember that Bradley Lake will be more than an additional power source for the Railbelt. It will also be replacement power, because many of the region's existing gas-fired generation units will be wearing out in the early and mid-1990s.

The current plan, agreed to by all seven Railbelt utilities, is for the State and those utilities -- through long-term power sales agreements -- to split the cost of the project. Under the current \$350 million cost estimate, the State's contribution would be \$175 million, which is \$43 million less than a previously agreed-to state equity share of \$218 million. Should the cost of Bradley drop further, as many expect it will, the State's contribution would be reduced proportionately.

Of the \$175 million from the State, \$118 million already has been committed to project. The Governor has introduced legislation -- S.B. 159 and H.B. 165 -- to appropriate an additional \$50 million from the Railbelt Energy Fund, to replace \$50 million previously approved from the general fund but later rescinded. With the \$118 million, the \$50 million will bring the State's Bradley Lake contribution to \$168 million, or within \$7 million of the currently proposed \$175 million. It is expected that the final \$7 million will be appropriated by the current Legislature for fiscal 1988. Approximately \$50 million already has been spent on the project, much of it for site preparation and support facilities.

THE INTERTIES

Construction has not yet begun on the interties, but studies are well under way. An economic analysis on both the southern and northern interties has been completed. So has a preliminary engineering feasibility study on the southern intertie, with the final report due in the very near future. An engineering feasibility study on the northern intertie is in progress, with a final report due in early May. It is important that environmental work commence this year so the transmission system can be in place when the Bradley Lake project comes on line, or as soon afterward as possible.

The Railbelt intertie system has a number of benefits, some quantifiable and some not easily quantifiable but nonetheless important. Here are some of them, as listed in the economic analysis:

Economy power interchanges -- The interties will permit the displacement of higher-cost generation in one area of the Railbelt with the lowest-cost generation from any other area. This will produce substantial savings for consumers.

Sharing of generation reserves -- The interties will allow one or more utilities to forego building or maintaining the amount of reserve generation capacity that would otherwise be necessary. Instead, those utilities could rely on reserves available elsewhere in the interconnected system.

Siting flexibility for new generation plants -- The interties will provide much greater flexibility in siting new generation plants within the Railbelt wherever the costs of operation -- including, importantly, fuel costs -- are the lowest.

Improved system reliability -- The interties will greatly improve electric system reliability throughout the Railbelt. For the first time, every Railbelt utility will have access to enough power from other systems to cope with any emergency or maintenance requirement. This will translate into fewer and briefer outages.

Increased system efficiency -- Transmission losses of electric energy are reduced in higher voltage circuits, such as the interties. It is estimated that line losses between Anchorage and the lower Kenai Peninsula will be reduced by 80 percent, while losses between Anchorage and Fairbanks will be reduced by 60 percent. Transmission loss reductions of this magnitude will result in many thousands of dollars in savings.

Increased utility coordination -- By virtue of its existence, a strong regional transmission grid will foster improved coordination and cooperation among Railbelt utilities. This will lead to increased participation in future generation and other power projects, with attendant sharing of costs and savings.

Distribution of Bradley Lake benefits -- The interties will enable all seven Railbelt utilities to directly participate in the Bradley Lake project, thereby spreading the costs and the benefits over a much wider base. With the limited existing transmission facilities, only Homer Electric Association and Chugach Electric Association could directly access Bradley Lake power.

Enhanced competition among fuel suppliers -- A major benefit of the interties is that they will improve access by all seven Railbelt utilities to a variety of generation fuel sources throughout the region. For example, power generation using cheaper wellhead natural gas on the Kenai Peninsula is presently constrained by a limitation in transmission capacity. With the interties, each utility will have a broader range of energy supply alternatives, and the utilities' bargaining positions with respect to potential fuel suppliers will be strengthened.

Another very important general benefit of the interties is that they will facilitate economic development and commerce, the results of which will be felt even beyond the Railbelt. In this respect, the interties are analogous to a highway, whose contribution to economic development and commerce is easily understood yet difficult to model. Where a highway carries motor vehicles, the interties will carry an equally essential commodity -- electric energy. Like good roads, a good electric transmission system is essential to a region's development.

SUMMARY

The program to complete the Bradley Lake project and the Railbelt interties is sound. The projects will benefit the majority of Alaska's consumers, and there is unprecedented support from a broad spectrum of interests, including every electric utility in the region as well as labor, business and local government.

Both the Bradley Lake project and the interties are bona fide public works projects, and they will pay long-term dividends. The Railbelt's power supply network will be strengthened in a number of ways, including reliability and lower-cost generation in the future. The regional and statewide economies -- including the job sector -- will be stimulated during construction and for many years to come.

While there inevitably is disagreement over how best to use public funds, especially during times when revenues are less plentiful, there is a demonstrable need for the Bradley Lake project and the intertie system. This program fulfills a high public purpose.



ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

March 24, 1987

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny Fay and Gretchen Keiser
Legislative Analysts

RE: Railbelt Energy Analysis
Research Request 87.114 (Supplemental Information)

This memorandum clarifies our Bradley Lake feasibility analysis and briefly addresses a number of questions raised during yesterday's briefing on Railbelt energy issues.

BRADLEY LAKE FEASIBILITY ANALYSIS

The net savings calculations in our March 18, 1987 memorandum correctly compare the annual production of 369 gigawatt hours (gwh) from Bradley Lake (operating at an annual effective capacity of about 42 megawatts) with 369 gwh annual production from a 87 megawatt (MW) gas plant (operating at an equivalent effective capacity of roughly 41 MW). In other words, the model adjusts the gas plant output to match the projected power production from Bradley Lake.

It could be argued that a 40 MW gas turbine operating at full capacity could provide roughly the equivalent amount of energy as a larger turbine operating at 47 percent capacity. If we substitute a smaller gas turbine for the gas generation alternative under our scenario III (Bradley Lake constructed as scheduled compared with gas plant in operation in 1998), the Bradley Lake net savings decline from \$36 million to \$3 million (see Attachment A). However, we do not believe that installation of a 40 MW gas turbine in the late 1990s is a realistic alternative because it would be insufficient to meet projected Railbelt demand after about 2002. In fact, installation of a 87 MW gas plant in the late 1990s would also be insufficient to meet projected Railbelt energy demand beyond 2002 (see Attachment B).

Our demand forecast suggests that Bradley Lake power is unnecessary until the late 1990s. At that time, Bradley Lake power would provide sufficient power to postpone the installation of additional generation facilities for roughly five years. To reiterate a point made in our previous memorandum, our analysis answers the question asked: Bradley Lake will probably produce an increment of energy production more cheaply than a gas alternative over the 50-year period of analysis. We have not, however, answered what we believe to be the more appropriate question of "what is the least cost means of meeting the projected Railbelt demand for electrical power?" Addressing this question is more likely to ensure lower power rates for the Railbelt electric consumers.

CONTRACT TERMINATION AND SITE RESTORATION COSTS IF BRADLEY LAKE IS CANCELLED

If the Bradley Lake project were cancelled, approximately \$30 million in termination and site restoration costs would be incurred. The question raised during the briefing was whether these costs should be attributed to Bradley Lake or the gas generation alternative in the feasibility analysis. We believe (and our analysis assumes) that the termination and site restoration costs should be calculated as an expense of the gas alternative because these costs would be incurred only if the decision were made to proceed with the gas alternative rather than complete Bradley Lake. On the other hand, if the State completes Bradley Lake, these costs would not be incurred.

THE FEASIBILITY OF THE PROPOSED INTERTIES

A number of questions were raised during the briefing regarding the Kenai-Anchorage and Anchorage-Fairbanks interties--specifically with respect to the proposed coupling of the Bradley Lake project with State funding for the construction and/or upgrade of these interties. While we acknowledge the importance of a review and analysis of the proposed interties, we would like to point out that our present analysis was directed toward answering the question of which alternative (Bradley Lake or a gas turbine) provides power less expensively over a 50-year period of analysis. We are now examining the intertie proposals as part of this series of memorandums we are preparing on Railbelt energy issues. We intend to integrate transmission requirements into our overall analysis of Bradley Lake and the gas generation alternative.

Representative Cotten
March 24, 1987
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OTHER ISSUES

You requested that we examine two additional issues which are pertinent to the legislature's consideration of Railbelt energy projects. The issues were:

- cost estimates for site restoration which would be required by the FERC if Bradley Lake were terminated; and
- the long-term availability of natural gas in Cook Inlet for gas-fired power generation.

We will provide information regarding these issues shortly in a subsequent memorandum.

* * *

Please contact us if you have any questions.

ATTACHMENT A

TABLE A.1 DELAY OF GAS GENERATION ALTERNATIVE/WITH INSTALLATION OF A 40 MW GAS TURBINE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL RATE (C/KWH)	REAL			
									WELLHEAD GAS PRICE (\$86/HMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$86 MLN)
Cash Flow for Base	2016		1.0	0.5	0.5	12.3	14.2	3.9	2.90	2.0	6.7	8.7
Construction Cost:	2017		0.9	0.5	0.5	12.6	14.4	3.9	2.96	2.0	6.4	8.4
1987	0X 2018		0.9	0.5	0.5	12.8	14.7	4.0	3.02	2.0	6.1	8.1
1988	0X 2019		0.8	0.5	0.5	13.1	14.9	4.0	3.08	2.0	5.9	7.9
1989	0X 2020		0.8	0.5	0.5	13.3	15.1	4.1	3.14	2.0	5.6	7.6
1990	0X 2021		0.8	0.5	0.5	13.6	15.3	4.2	3.20	2.0		2.0
1991	0X 2022		0.7	0.5	0.5	13.9	15.6	4.2	3.26	2.0		2.0
1992	0X 2023		0.7	0.5	0.5	14.1	15.8	4.3	3.33	2.0		2.0
1993	0X 2024		0.7	0.5	0.5	14.4	16.1	4.4	3.40	2.0		2.0
1994	0X 2025		0.6	0.5	0.5	14.7	16.3	4.4	3.46	2.0		2.0
1995	0X 2026		0.6	0.5	0.5	15.0	16.6	4.5	3.53	2.0		2.0
1996	50X 2027		0.6	0.5	0.5	15.3	16.9	4.6	3.60	2.0		2.0
1997	50X 2028		0.6	0.5	0.5	15.6	17.1	4.6	3.68	2.0		2.0
				0.5	0.5	15.9	17.4	4.7	3.75	2.0		2.0
Load Factor: 100%	2030		0.5	0.5	0.5	16.2	17.7	4.8	3.82	2.0		2.0
Annual Energy (gwh): 369.2	2031		0.5	0.5	0.5	16.6	18.0	4.9	3.90	2.0		2.0
Transmission Cost	2032		0.5	0.5	0.5	16.9	18.3	5.0	3.98	2.0		2.0
(\$1986 Millions): \$0.0	2033		0.5	0.5	0.5	17.2	18.7	5.1	4.06	2.0		2.0
	2034		0.4	0.5	0.5	17.6	19.0	5.1	4.14	2.0		2.0
BRADLEY LAKE	2035		0.4	0.5	0.5	17.9	19.3	5.2	4.22	2.0		2.0
Cost to Complete: \$283.0	2036		0.4	0.5	0.5	18.3	19.7	5.3	4.31	2.0		2.0
Debt Service (30 yr): \$25.1	2037		0.4	0.5	0.5	18.7	20.0	5.4	4.39	2.0		2.0
	2038		0.4	0.5	0.5	19.0	20.4	5.5	4.48	2.0		2.0
NP COST GAS \$217.6	2039		0.4	0.5	0.5	19.4	20.7	5.6	4.57	2.0		2.0
+ term & site restoration \$30.0	2040		0.3	0.5	0.5	19.8	21.1	5.7	4.66	2.0		2.0
NP COST GAS \$247.6												
NP COST BRADLEY \$244.6												
NET SAVINGS BRADLEY \$3.0												

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

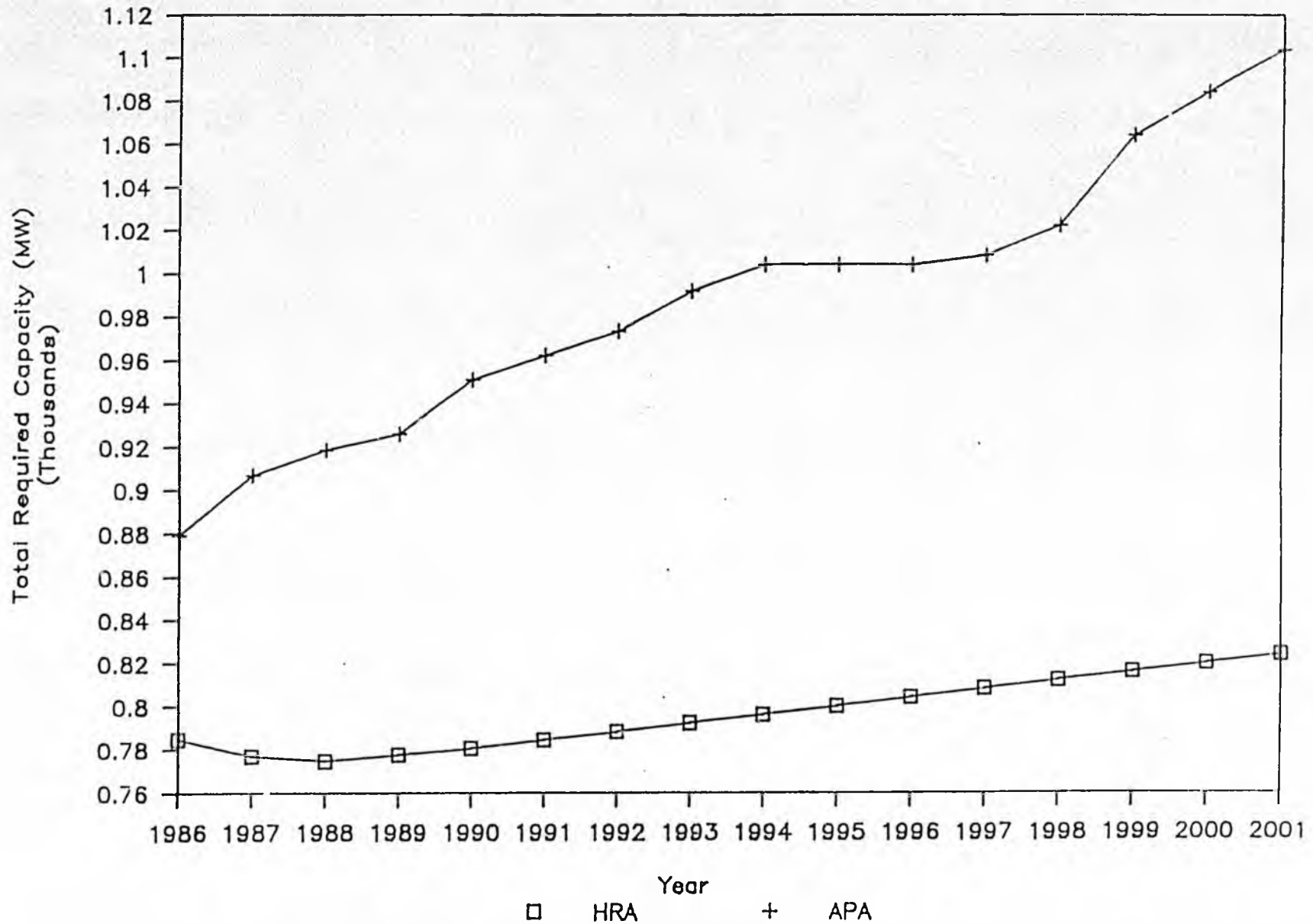
Prepared by the House Research Agency, March 1987 (40MWgas; 870109-02).

TABLE A.1 DELAY OF GAS GENERATION ALTERNATIVE/WITH INSTALLATION OF A 40 MW GAS TURBINE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL						
								REAL RATE (C/KWH)	WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$86 MLN)		
Base Capital Cost Excluding IDC (\$1986/net kw):	\$400													
	1987	0.0								\$1.63				
Capacity (net kw):	40,000									1.66				
	1988	0.0								1.70				
	1989	0.0								1.73				
Construction Period (years):	2									1.77	2.0	20.2	22.2	
Total Bonds:	\$30.8									1.80	2.0	19.3	21.3	
Bond Term (years):	20									1.84	2.0	18.5	20.5	
Long-Term Interest Rate:	10.0%									1.87	2.0	17.7	19.7	
Bond Payment (1997\$):	\$3.6									1.91	2.0	16.9	18.9	
	1995	0.0								1.95	2.0	16.2	18.2	
Inflation Rate:	4.5%									1.99	2.0	15.5	17.5	
Reinvest Rate:	6.0%		2.2				2.2	0.6		2.03	2.0	14.8	16.8	
Discount Rate:	3.5%		2.1	0.5	0.5	8.6	11.7	3.2		2.07	2.0	14.2	16.2	
	1999		2.0	0.5	0.5	8.8	11.8	3.2		2.11	2.0	13.6	15.6	
	2000		2.0	0.5	0.5	9.0	11.9	3.2		2.15	2.0	13.0	15.0	
Fixed O&M Cost (\$1986/kw/yr):	\$11.25									2.20	2.0	12.4	14.4	
	2001		1.9	0.5	0.5	9.1	12.0	3.2		2.24	2.0	11.9	13.9	
	2002		1.8	0.5	0.5	9.3	12.1	3.3		2.29	2.0	11.4	13.4	
	2003		1.7	0.5	0.5	9.5	12.2	3.3		2.33	2.0	10.9	12.9	
Variable O&M Cost (\$1986/kwh):	\$0.0014									2.38	2.0	10.4	12.4	
	2004		1.6	0.5	0.5	9.7	12.3	3.3		2.43	2.0	10.0	12.0	
	2005		1.6	0.5	0.5	9.9	12.4	3.4		2.47	2.0	9.5	11.5	
New Turbine Heat Rate (BTU/kwh):	11,500									2.52	2.0	9.1	11.1	
	2006		1.5	0.5	0.5	10.1	12.6	3.4		2.57	2.0	8.7	10.7	
	2007		1.4	0.5	0.5	10.3	12.7	3.4		2.62	2.0	8.4	10.4	
	2008		1.4	0.5	0.5	10.5	12.8	3.5		2.68	2.0	8.0	10.0	
	2009		1.3	0.5	0.5	10.7	13.0	3.5		2.73	2.0	7.7	9.7	
Wellhead Gas Price (\$1986/MMBTU):	\$1.60									2.79	2.0	7.3	9.3	
Gas Delivery (\$86):	\$0.00									2.84	2.0	7.0	9.0	
Real Wellhead Price														
Escalation Rate:	2.0%													
	2010		1.3	0.5	0.5	10.9	13.2	3.6						
	2011		1.2	0.5	0.5	11.1	13.3	3.6						
	2012		1.2	0.5	0.5	11.4	13.5	3.7						
	2013		1.1	0.5	0.5	11.6	13.7	3.7						
	2014		1.1	0.5	0.5	11.8	13.8	3.8						
	2015		1.0	0.5	0.5	12.1	14.0	3.8						

ATTACHMENT B

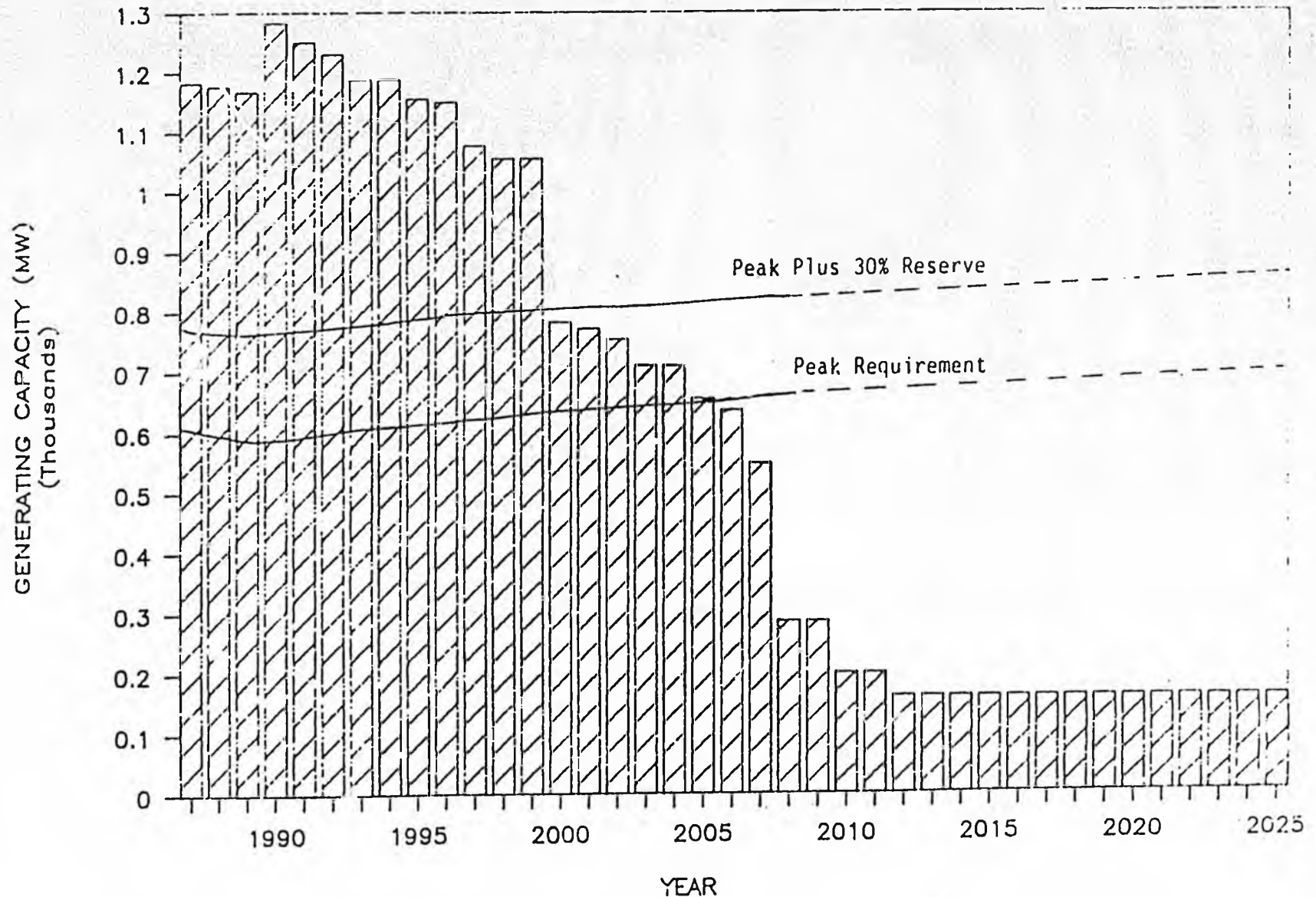
RAILBELT ELECTRICAL DEMAND FORECASTS



Prepared by the House Research Agency, March 1987.

FIGURE 2

GENERATING CAPACITY NET OF RETIREMENT RAILBELT



Prepared by the House Research Agency, March 1987.



ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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March 18, 1987

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny *Pay* and Gretchen *Keiser*
Legislative Analysts

RE: Railbelt Energy Analysis
Research Request 87.114

As presented in the House Research Agency Railbelt Energy Analysis outline, this memorandum covers Railbelt energy demand and the Bradley Lake project feasibility analysis. The first section of the memorandum provides information on Railbelt energy demand and utility capacity. This discussion is followed by an examination of the Bradley Lake feasibility analysis prepared by the Division of Policy in the Governor's Office. The final section recalculates Bradley Lake net benefits based on revised projections of Railbelt energy demand and capacity requirements and other assumptions incorporated in the Division of Policy's analysis.

SUMMARY OF FINDINGS

- This analysis of Railbelt energy demand is based on an examination of projected peak demand, capacity reserve requirements, capacity retirement schedules, the Alaska Department of Revenue's statewide population forecast, and Public Utility Regulatory Policy Act (PURPA) facilities planned in the Railbelt area.¹ Because of the influence of population on energy demand, there is no basis for forecasting a near-term increase in energy consumption while population in the Railbelt is declining (page 3).
- Actual 1986 net generation and peak demand were seven percent less than APA projections. Our forecast, for the years 1987 through 2010, incorporates this initial decline in energy consumption. It

¹Public Utility Regulatory Policy Act (PURPA) electrical power production in this memorandum generally refers to small power production and cogeneration facilities as defined and regulated by Chapter 1 of the Federal Energy Regulatory Commission, PURPA of 1978.

also incorporates further reductions in energy demand as a result of near-term population declines. The APA forecast, prepared in 1985, has not been subsequently adjusted for lower actual use in 1986. The APA forecast for required production capacity overestimated required capacity by 12.1 percent in 1986 and is 33.9 percent above our adjusted forecast by the year 2001 (pages 3-6).

- For the Railbelt as a whole, existing electrical production capacity (plus PURPA generators) will satisfy peak and reserve requirements until the year 2000. There will be over 28 percent more capacity than required for reserve margins until 2000 as a result of: 1) past power plant construction based on earlier population growth projections; and 2) lower reserve requirements as a result of integrating stand-alone systems (pages 6-18).
- Following revisions to assumptions regarding the costs to complete Bradley Lake and the projected Cook Inlet gas prices and escalation rates, the Division of Policy's analysis concluded that Bradley Lake is still economically feasible and is likely to be less expensive than alternative gas generation over the 50-year period of analysis (pages 18-20).
- The division's assumptions regarding gas prices appear to be reasonable. However, we disagree with the division's fundamental assumption regarding future Railbelt energy demand and their conclusion that additional capacity will be needed by 1991. We believe the division's analysis addresses the issue as "which is the less expensive option to construct excess capacity?" instead of "what is the least cost means of meeting projected Railbelt demand for electrical power?" (page 20).
- Following revisions to assumptions regarding gas plant fuel efficiencies and cost to complete Bradley Lake, we recalculated the net savings of Bradley Lake under three scenarios. The base case scenario, which assumes (as the Division of Policy did) that new power is needed by 1991, projects Bradley Lake net savings of \$86 million--virtually identical to those projected by the Division of Policy. Our second scenario, which delays Bradley Lake or gas plant construction until power is needed, indicates that Bradley Lake would not be economically feasible if completion of the project were delayed until Railbelt energy demand warranted new capacity in the late 1990s (pages 21-24).
- Our third scenario--which compares Bradley Lake if constructed as currently scheduled with a gas plant constructed when power is needed in the late 1990s--projects considerably lower Bradley Lake net savings of \$36 million. The positive net savings indicate that

the project should proceed, although from a public policy perspective, the relatively low net savings increase the risk that in retrospect we will have made a poor decision, if forecast gas prices are only slightly lower than assumed (page 23).

The analysis is sensitive to changes in other assumptions to varying degrees. The analysis is most sensitive to assumptions which directly affect annual fuel costs--including the gas turbine fuel efficiency assumption (pages 24-27).

RAILBELT ENERGY DEMAND AND CAPACITY REQUIREMENTS

This analysis of Railbelt energy demand is based on an examination of projected and peak demand, capacity reserve requirements, and retirement schedules that were developed by the Alaska Power Authority (APA). The demand projections and capacity retirement schedules were prepared by the APA based on estimates obtained from Railbelt utilities. In addition, we examined the Department of Revenue's (DOR) historic and forecast population numbers and information from the Alaska Public Utilities Commission (APUC) on Public Utility Regulatory Policy Act (PURPA) facilities planned in the Railbelt region.

Our analysis also looks at electrical energy demand and power plant capacity from a regional rather than individual utility standpoint. This perspective is used because the existing Alaska Intertie Agreement and proposed Bradley Lake Project Power Sales Agreement provide an interconnected, organizational framework and facilities for energy planning in the Railbelt as a region as opposed to stand-alone public utilities. Furthermore, the Railbelt Energy Fund is intended to provide energy services to residents of the region rather than to individual utilities in the Railbelt.

Energy Demand

In analyzing Railbelt energy demand, we reviewed historic net generation and the APA's projected demand (Attachment A). These trends were examined in light of historic and projected state population figures (Table 1) and actual 1986 net generation and peak demand (Table 2).² The historic energy generation and population figures, as well as numerous models of energy demand, indicate that population is a primary variable in determining energy demand levels. Because of the influence of population on energy demand, there is no basis for forecasting a near-term increase in energy consumption while population in the Railbelt is declining. We, therefore, adjusted the energy demand forecast to reflect this projected population decline.

²The Alaska Department of Revenue historic and forecasted number of Permanent Fund Dividend check recipients is used as a proxy for state population trends.

TABLE 1
ALASKA STATE POPULATION* 1981 - 1999

YEAR	DIVIDEND RECIPIENTS (in thousands)
1981	430.1
1982	478.8
1983	486.8
1984	483.1
1985	520.9
1986	530.8
1987	527.2
1988	525.8
1989	528.1
1990	530.3
1991	532.5
1992	534.6
1993	536.8
1994	538.9
1995	541.1
1996	543.3
1997	545.5
1998	547.8
1999	549.9

* Based on the number of Permanent Fund
dividend check recipients.

Source: Alaska Department of Revenue,
March 1987.

Prepared by the House Research Agency,
March 1987 (POP; 861217-29).

TABLE 2
PROJECTED* AND ACTUAL 1986 RAILBELT PEAK DEMAND AND CAPACITY AND RESERVE REQUIREMENTS.

UTILITY	PROJ. ACTUAL		CAPACITY REQUIREMENTS																										
	1986	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010			
Anchorage																													
AMP	184.0	183.0	181.6	181.1	181.7	182.3	183.0	183.7	184.4	185.1	185.9	186.6	187.3	188.1	188.8	189.6	190.3	191.1	191.8	192.6	193.3	194.1	194.9	195.6	196.4	197.2			
CEA (retail)	191.3	190.6	188.8	188.3	189.0	189.7	190.6	191.5	192.4	193.3	194.2	195.1	196.1	197.0	197.9	198.9	199.8	200.8	201.7	202.7	203.6	204.6	205.6	206.6	207.5	208.5			
MEA	30.3	31.5	30.5	30.3	30.7	31.0	31.5	31.9	32.4	32.9	33.3	33.8	34.3	34.7	35.2	35.7	36.2	36.7	37.1	37.6	38.1	38.6	39.1	39.6	40.1	40.6			
Subtotal	445.6	445.1	440.9	439.7	441.4	443.0	445.1	447.1	449.2	451.3	453.4	455.5	457.7	459.8	462.0	464.1	466.3	468.5	470.7	472.9	475.1	477.3	479.5	481.7	483.9	486.1	488.3		
Kenai Peninsula																													
SES	79.0	83.4	87.7	87.5	87.8	88.1	88.4	88.7	89.1	89.4	89.8	90.1	90.5	90.8	91.2	91.5	91.9	92.3	92.6	93.0	93.3	93.7	94.1	94.4	94.8	95.2	95.6		
SES	7.0	6.3	6.2	6.2	6.2	6.3	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.8	6.9	6.9	7.0	7.1		
Subtotal	86.0	89.7	93.9	93.7	94.0	94.4	94.7	95.1	95.4	95.8	96.2	96.6	97.0	97.3	97.7	98.1	98.5	98.9	99.3	99.7	100.1	100.5	100.9	101.3	101.7	102.1	102.5		
Fairbanks																													
FMS	29.3	28.5	28.3	28.2	28.3	28.5	28.5	28.7	28.9	29.0	29.2	29.3	29.5	29.6	29.8	29.9	30.1	30.2	30.4	30.5	30.7	30.8	31.0	31.1	31.3	31.4			
QVEA	85.8	85.2	84.3	84.1	84.4	84.8	85.2	85.6	86.0	86.5	86.9	87.3	87.8	88.2	88.7	89.1	89.5	90.0	90.4	90.9	91.4	91.8	92.3	92.7	93.2	93.7			
Subtotal	115.1	113.7	112.6	112.3	112.7	113.3	113.7	114.3	114.9	115.5	116.1	116.7	117.3	117.8	118.4	119.0	119.6	120.2	120.8	121.4	122.0	122.6	123.2	123.9	124.5	125.1			
TOTAL PEAK DEMAND																													
	645.7	638.6	635.5	635.8	638.2	640.5	643.5	646.6	649.6	652.6	655.7	658.8	661.9	665.0	668.1	671.3	674.4	677.6	680.8	684.0	687.2	690.4	693.7	697.0	700.3	703.6	706.9		
RESERVE REQUIREMENTS																													
Anchorage	---	124.5	123.3	122.9	123.4	123.9	124.5	125.1	125.8	126.4	127.0	127.7	128.3	128.9	129.6	130.2	130.9	131.5	132.2	132.9	133.5	134.2	134.9	135.5	136.2	136.9			
Kenai	---	22.4	22.2	22.1	22.2	22.3	22.4	22.5	22.6	22.7	22.9	23.0	23.1	23.2	23.3	23.4	23.6	23.7	23.8	23.9	24.0	24.1	24.3	24.4	24.5	24.6			
Fairbanks	---	34.1	33.8	33.7	33.8	34.0	34.1	34.3	34.5	34.7	34.8	35.0	35.2	35.4	35.5	35.7	35.9	36.1	36.2	36.4	36.6	36.8	37.0	37.2	37.3	37.5			
TOTAL RESERVE REQUIREMENT	---	181.1	179.3	178.7	179.4	180.2	181.1	182.0	182.9	183.8	184.7	185.6	186.6	187.5	188.4	189.4	190.3	191.3	192.2	193.2	194.2	195.1	196.1	197.1	198.1	199.1			
TOTAL SYSTEM CAPACITY REQUIREMENT																													
	826.7	818.3	814.2	815.2	818.4	821.0	825.0	829.1	833.5	837.6	841.7	845.8	849.9	854.0	858.1	862.2	866.3	870.4	874.5	878.6	882.7	886.8	890.9	895.0	899.1	903.2	907.3		
APA FORECAST																													
	279.3	281.2	283.9	286.4	289.1	291.7	294.4	297.1	299.8	302.5	305.2	307.9	310.6	313.3	316.0	318.7	321.4	324.1	326.8	329.5	332.2	334.9	337.6	340.3	343.0	345.7	348.4		
Percent Excess Demand in APA Forecast																													
	12.1	15.6	18.5	19.1	21.8	22.7	23.5	25.2	26.1	25.5	24.8	24.8	25.9	30.4	32.2	33.9	---	---	---	---	---	---	---	---	---	---	---		

* Based on APA and Railbelt utilities' forecast demand.

Source: Alaska Power Authority, Alaska Public Utilities Commission, Railbelt Utilities, Alaska Dept. of Revenue.

Prepared by the House Research Agency, March 1987 (Demand2; 861217-29).

Actual 1986 net generation and peak demand were seven percent below APA projections. We substituted actual 1986 energy usage for the APA forecast in Table 2. In subsequent years, population projections were used as an indicator of the direction and magnitude of changes in energy demand.³ The Department of Revenue forecasts a decline in population between 1986 and 1989; the Alaska population is not expected to return to 1986 levels until approximately 1991.⁴ Based on this forecast, Table 2 shows a similar decline in Railbelt energy demand for the years 1987 through 1989.

Beginning in 1990, demand increases proportionally to the slight 0.5 percent annual increase in population until the year 2000. This projection closely coincides with Chugach Electric Association's revised demand forecast of 0.55 percent annual growth as presented in the Division of Policy's feasibility analysis. Projected electrical energy demand for the years 1991 through 2010 is based on a 0.5 percent compounded growth rate.

Utility Capacity and Retirement Schedules

Information on current Railbelt standing capacity and retirement is presented in Tables 3 - 5 for the subregions of Anchorage, the Kenai Peninsula, and Fairbanks. These tables are identical to those prepared by the APA with the exception of the addition of three PURPA power plants planned in the Anchorage area and one PURPA power plant planned in the Fairbanks area. Plant retirement schedules have not been altered because the utilities believe these November 1985 Susitna hydroelectric project retirement projections continue to be valid.⁵

The utilities' retirement schedule of installed capacity is referred to as conditional retirement. It is the anticipated date that generating turbines require replacement or rebuilding. Conditional retirement is influenced by both physical and economic factors. Physical factors include the level of facility usage and the consequent "wearing out" of equipment. Because it is possible to completely or partially rebuild natural gas turbines, their retirement schedules can be incrementally adjusted. These conditional retirement dates can, therefore, be influenced significantly by economic and technological factors such as the price of natural gas and fuel efficiency of equipment.

³Because the majority of the state's population resides in the Railbelt, we believe these statewide numbers are a reliable indicator of changes in the Railbelt population.

⁴The 1986 number is based on the number of residents who claimed a Permanent Fund Dividend check for that year. They could, however, have left the state before the end of calendar year 1986.

⁵Richard Emerman, Economist, Alaska Power Authority, Anchorage, personal communication, March 4, 1987.

TABLE 3
 POWER PRODUCTION CAPACITY AND RETIREMENT IN ANCHORAGE

Unit name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
Eklutna	APAd	Hydro	30.0	----
AMLPC#1	AML	NG	16.2	1990
AMLPC#2	AML	NG	16.2	1990
AMLPC#3	AML	NG	19.9	1991
AMLPC#4	AML	NG	33.8	1992
AMLPC#56	AML	NG	47.5	1999
AMLPC#76	AML	NG	109.3	1999
AMLPC#8	AML	NG	87.0	2009
BEL CT#1	CEA	NG	16.1	1994
BEL CT#2	CEA	NG	16.1	1994
BEL CT#3	CEA	NG	49.5	1999
BEL CT#4	CEA	NG	10.0	1996
BEL CT#5	CEA	NG	67.3	1999
BEL CC#68	CEA	NG	100.6	2007
BEL CC#78	CEA	NG	100.6	2007
INT CT#1	CEA	NG	14.3	1996
INT CT#2	CEA	NG	14.3	1996
INT CT#3	CEA	NG	19.9	1996
PURPA#1*	MSE	Peat	20.0	2025
PURPA#2*	MSV	WC	20.0	2025
PURPA#3**	SGI	Coal	50.0	2027

* Anticipated start-up date is 1990.

** Anticipated start-up date is 1992.

Legend: APAd= Alaska Power Administration
 AML= Anchorage Municipal Light and Power
 CEA= Chugach Electric Association
 MSE= MatSu Energy
 MSV= MatSu Valley
 SGI= SGI, Inc.
 CT= Combustion Turbine
 NG= Natural Gas
 WC= Wood Chips

Source: Alaska Power Authority, February 1987; Alaska Public Utilities Commission, March 1987.

Prepared by the House Research Agency, March 1987 (Anchorage; 861217-29).

TABLE 4
POWER PRODUCTION CAPACITY AND RETIREMENT ON THE KENAI PENINSULA

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
BERNCT#1	CEA	NG	8.9	1988
BERNCT#2	CEA	NG	18.4	1997
BERNCT#3	CEA	NG	27.2	2004
BERNCT#4	CEA	NG	27.2	2004
COOPER LAKE	CEA	Hydro	17.4	----
SOLDOTCT#1	AEG&T	NG	38.5	2011
SE...C#1-4	HEA	OIL	2.1	2000
SES...#1-3	SES	OIL	5.5	1995

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

Source: Alaska Power Authority, February 1987; Alaska Public Utilities Commission, March 1987.

Prepared by the House Research Agency, March 1987 (Kenai; 861217-29).

TABLE 5
 POWER PRODUCTION CAPACITY AND RETIREMENT IN FAIRBANKS

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
CHENST#1	FMUS	Coal	5.1	2000
CHENST#2	FMUS	Coal	2.0	2000
CHENST#3	FMUS	Coal	1.5	2000
CHENCT#4	FMUS	Oil	6.1	1987
CHENST#5	FMUS	Coal	20.0	2005
CHENCT#6	FMUS	Oil	26.1	2006
FMUSIC#1	FMUS	Oil	2.8	1992
FMUSIC#2	FMUS	Oil	2.8	1992
FMUSIC#3	FMUS	Oil	2.8	1992
HEALST#1	GVEA	Coal	25.0	2002
HEALIC#2	GVEA	Oil	2.6	1997
NOPOCT#1	GVEA	Oil	60.9	2006
NOPOCT#2	GVEA	Oil	60.9	2007
ZENCT#1	GVEA	Oil	18.0	2001
ZENCT#2	GVEA	Oil	18.0	2002
DSLIC#1-8	GVEA	Oil	14.7	1996
PURPA#1**	AEM	WC	25.0	2025

*Chena Units #1-4 Not Currently Operating

** Anticipated start-up date is 1990.

Legend: FMUS= Fairbanks Municipal Electric Association
 GVEA= Golden Valley Electric Association
 AEM= AEM, Inc.
 ST= Steam Turbine
 CT= Combustion Turbine
 IC= Internal Combustion
 WC= Waste Coal

Source: Alaska Power Authority, February 1987; Alaska Public Utility Commission, March 1987.

Prepared by the House Research Agency, March 1987 (Fairbanks; 861217-29).

In general, declines in energy demand tend to postpone the retirement of equipment because the facility is used less, thereby decreasing physical wear. In addition, declines in the price of natural gas reduce the overall cost of plant operation which reduces the desirability of capital investments that increase operational efficiency. The reverse would also be true--increased usage accelerates the physical wearing out of equipment and higher fuel costs makes investment in newer, more efficient equipment relatively more cost-effective than the incremental rebuilding of less efficient equipment. Because these retirement schedules are "moving targets", time constraints for this analysis prevent a thorough examination of these schedules.

The Railbelt generating capacity, net of retirement, was altered to include four planned PURPA facilities in the Railbelt area. Three of these plants (PURPA # 1 - 3, Table 3) are to be built in the Anchorage area; the fourth (PURPA # 4, Table 5) is to be built in the Fairbanks area. The APUC currently has dockets open for these facilities which are scheduled to come on line in approximately 1990. At least two of these PURPA facility corporations have entered into power sales discussions with utilities in the Railbelt.⁶ Because of the stage of development of these plants, their estimated 115 megawatts of installed capacity was included in our capacity calculations.⁷

The APA's reserve capacity calculations were also adjusted in our analysis. Reserve capacity in the continental United States is usually set at 15 to 20 percent of peak demand for a totally integrated system (i.e., one which makes possible the sharing of capacity through transmission lines). The contiguous states are also divided into seven reliability councils which provide an organizational structure for the sharing of generating capacity. The ability to share power also allows the sharing of reserve capacity and results in the relatively small percentage of peak demand reserve capacity.

At the opposite end of the reserve capacity spectrum are stand-alone systems, which are common in Alaska. For smaller stand-alone systems such as a one-diesel generator in a rural community, 100 percent backup is not unusual. For larger communities with multiple generators which are not integrated with other power facilities, reserve capacity equal to the capacity of the largest single generator is the general rule. With the development of an integrated system through the construction of interties, the Railbelt has the ability to reduce required reserve capacity.⁸

⁶Michael Travella, Utilities Engineer, Alaska Public Utilities Commission, personal communication, March 6, 1987.

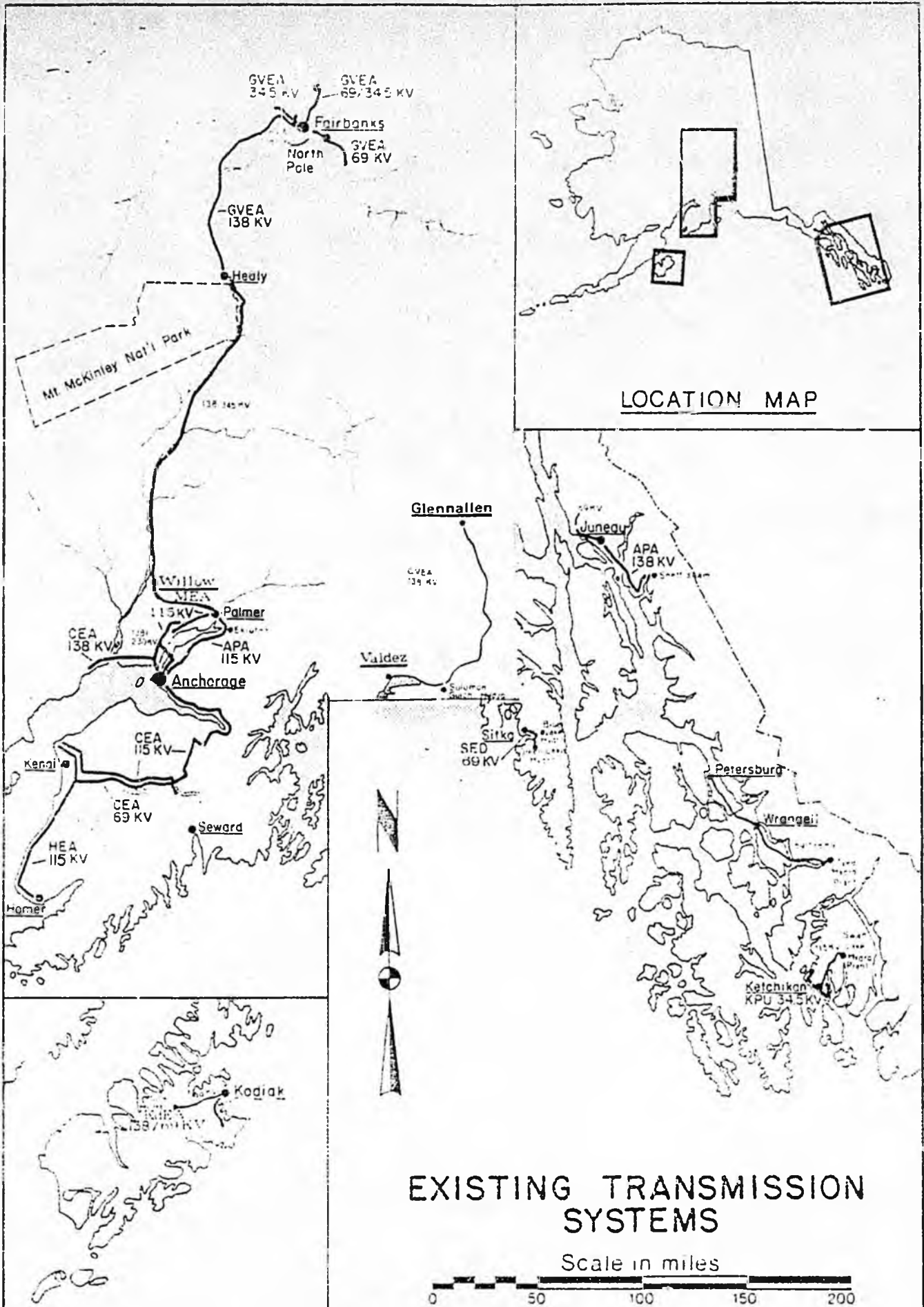
⁷These electrical power generating facilities and the Federal Energy Regulatory Commission, Public Utilities Regulatory Policies Act of 1978 (PURPA) may warrant further analysis, which this agency can conduct upon request.

⁸Michael Travella, Utilities Engineer, Alaska Public Utilities Commission, personal communication, March 10, 1987.

All utilities in the Railbelt are currently connected via an intertie system (Figure 1). Following the completion of the Anchorage-Fairbanks intertie, the Alaska Intertie Agreement was signed in December 1985 by Chugach Electric Association, Alaska Municipal Light and Power, Golden Valley Electric Association, Fairbanks Municipal Utility System, and the Alaska Electrical Generation and Transmission Corporation. In this agreement, each utility agreed to a required 30 percent reserve margin. Based on this intertie agreement, the fact that the Railbelt is now an integrated system, and a comparison with national standards, we believe that a 30 percent reserve capacity margin is a reasonable and conservative reserve capacity margin. This analysis, therefore, uses a⁹ 30 percent reserve requirement rather than the 40 percent used by the APA.⁹

⁹Our analysis also calculated required reserve capacity on a subregional basis (i.e., Anchorage, Kenai, and Fairbanks). This implies that utilities in a subregion will share their reserve capacity via the ability to share power over interties. The APA used this same approach in their Railbelt energy requirements forecast (Table A.2, Attachment A).

FIGURE 1



Source: "Alaska Electric Power Statistics, 1960-1984," Alaska Power Authority, 1985.

Sept. 1985

Capacity vs. Demand

Combining our demand forecast with utility capacity and retirement schedules for the Railbelt and for the Anchorage, Kenai Peninsula, and Fairbanks subregions (Figures 2 - 5), the required schedules for additional capacity are apparent. For the Railbelt as a whole, existing capacity (plus planned PURPA generators) satisfies projected peak and reserve demand until the year 2000.¹⁰ Electrical generation capacity exceeds required reserve by more than 28 percent until the year 2000 as a result of: 1) past plant construction based on earlier population growth projections; and 2) lower reserve requirements as a result of integrating stand-alone systems. Similarly for the Anchorage subregion, there is adequate capacity until the year 2000.¹¹ On the Kenai Peninsula, there is sufficient capacity until the year 2005; there is also substantial excess capacity until 1998. In the Fairbanks area, existing capacity can provide energy services until 2007. There will be approximately 65 percent excess capacity (over required reserve) in Fairbanks until 2003.¹²

A comparison of our demand analysis with APA's forecast (Table 2) shows that APA's forecast is 18.6 percent higher in 1988 and diverges to 33.9 percent higher in 2001. These differences occur primarily because the APA 1) does not take into account a decline in population and energy demand from 1986 through 1989 and 2) overestimates reserve capacity requirements. The implication of these results is that 90 megawatts of additional electrical generation capacity are not required in the Railbelt until the late 1990s.

¹⁰Capacity is sufficient to meet projected Railbelt power requirements until 2000 even without the 115 MW expected to be generated by the PURPA power facilities.

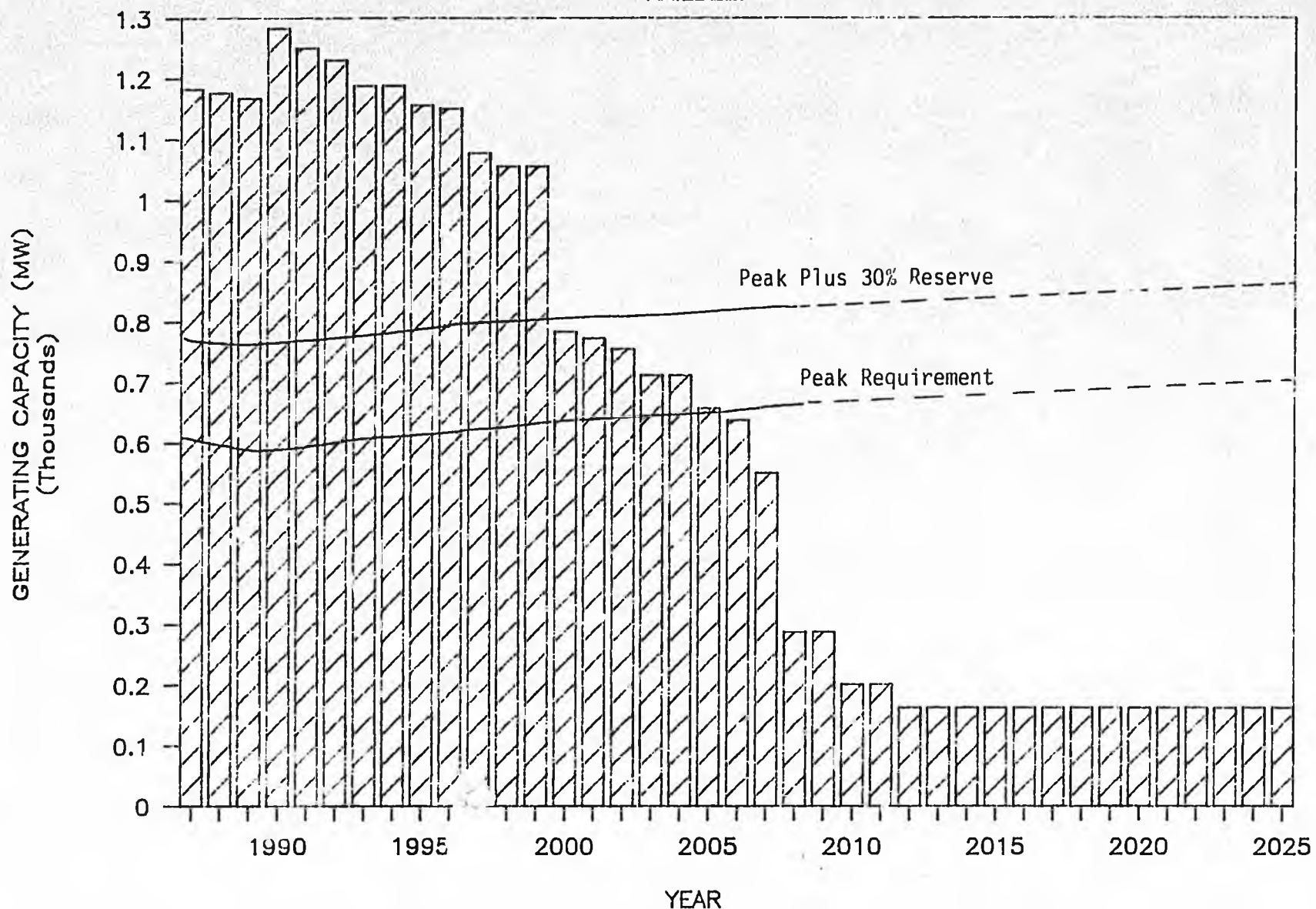
¹¹There is some discrepancy between the retirement dates for the two CEA 100.6 MW gas turbines. The APA schedule their retirement on a 30-year lifespan (2007) while CEA plans retirement in 1997 and 1999. Because of the excess production capacity in Anchorage and the rest of the Railbelt, however, this discrepancy does not alter the year 2000 result. If, however, PURPA power is not included, additional capacity would be required in 1998. In our benefit-cost analysis, we used the year 1998.

¹²Discussions with Chuck Canterbury, Fort Richardson, Public Affairs Office for the Alaska Division (March 11, 1987), indicate that the military has no intention of purchasing power from utilities in Fairbanks. They have purchased a small amount in the past to more conveniently service two buildings. In the past, until the decline in the price of fuel oil, GVEA has purchased military power.

FIGURE 2

GENERATING CAPACITY NET OF RETIREMENT

RAILBELT



Prepared by the House Research Agency, March 1987.

FIGURE 3

GENERATING CAPACITY NET OF RETIREMENT ANCHORAGE

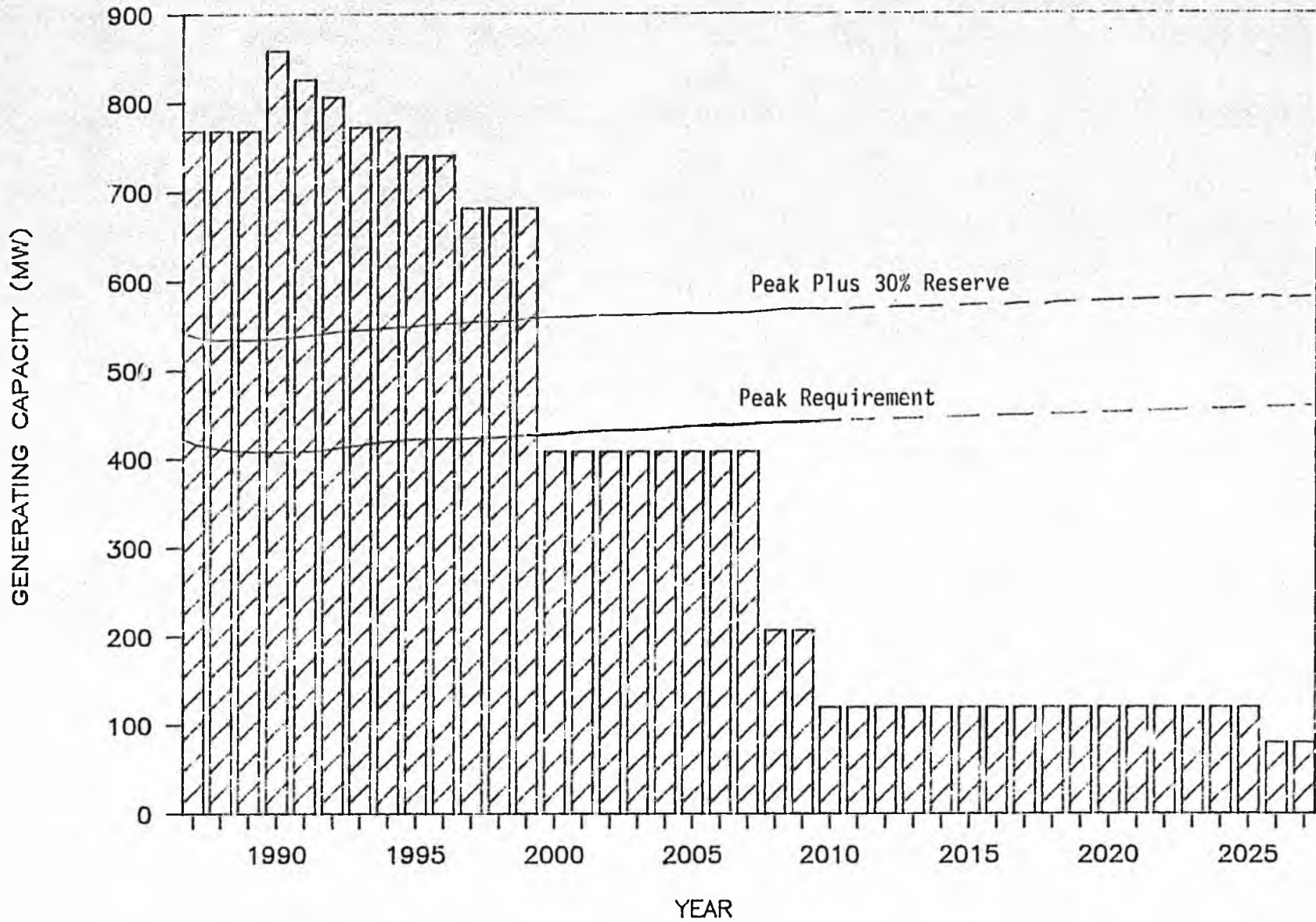
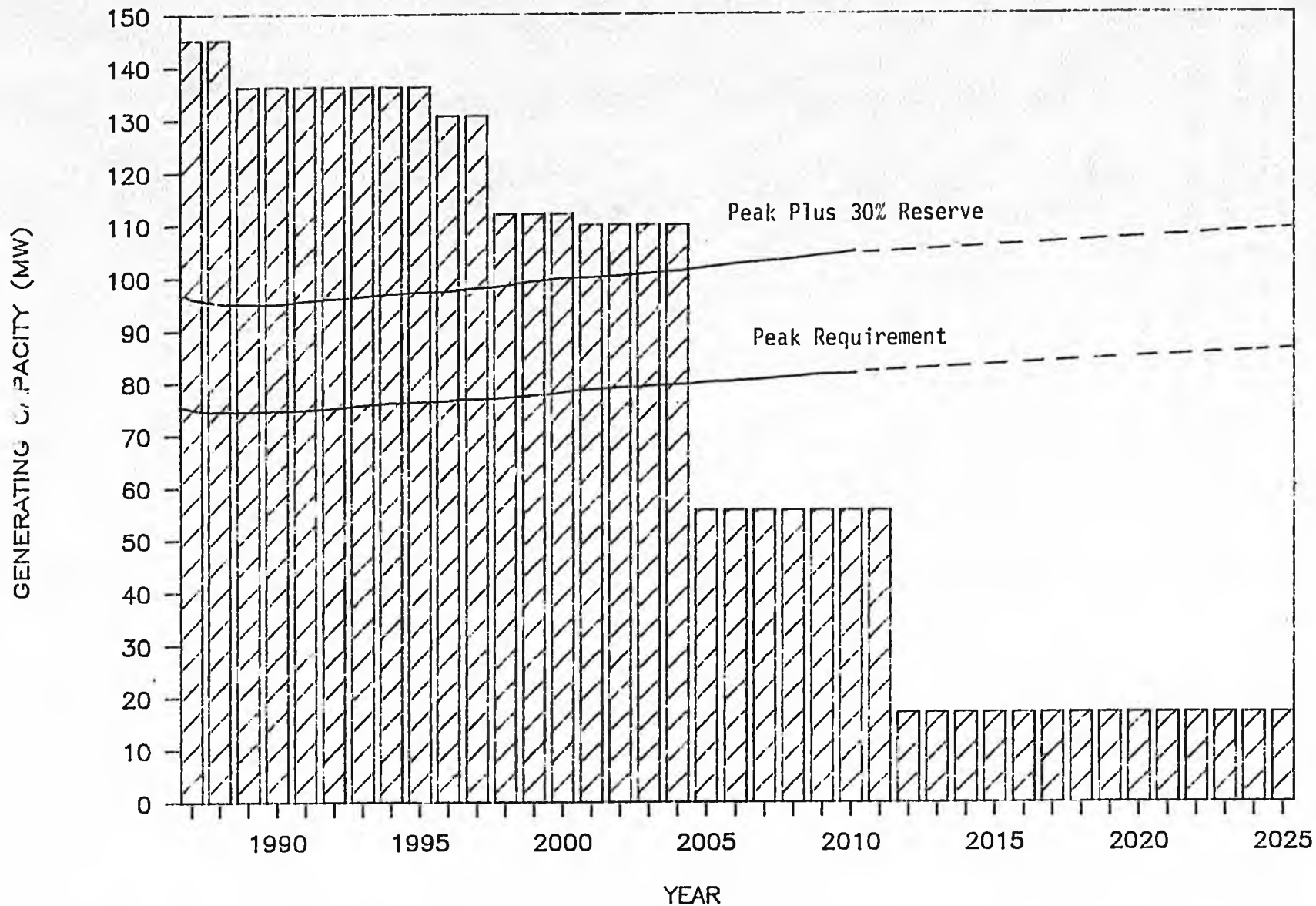


FIGURE 4

GENERATING CAPACITY NET OF RETIREMENT

KENAI

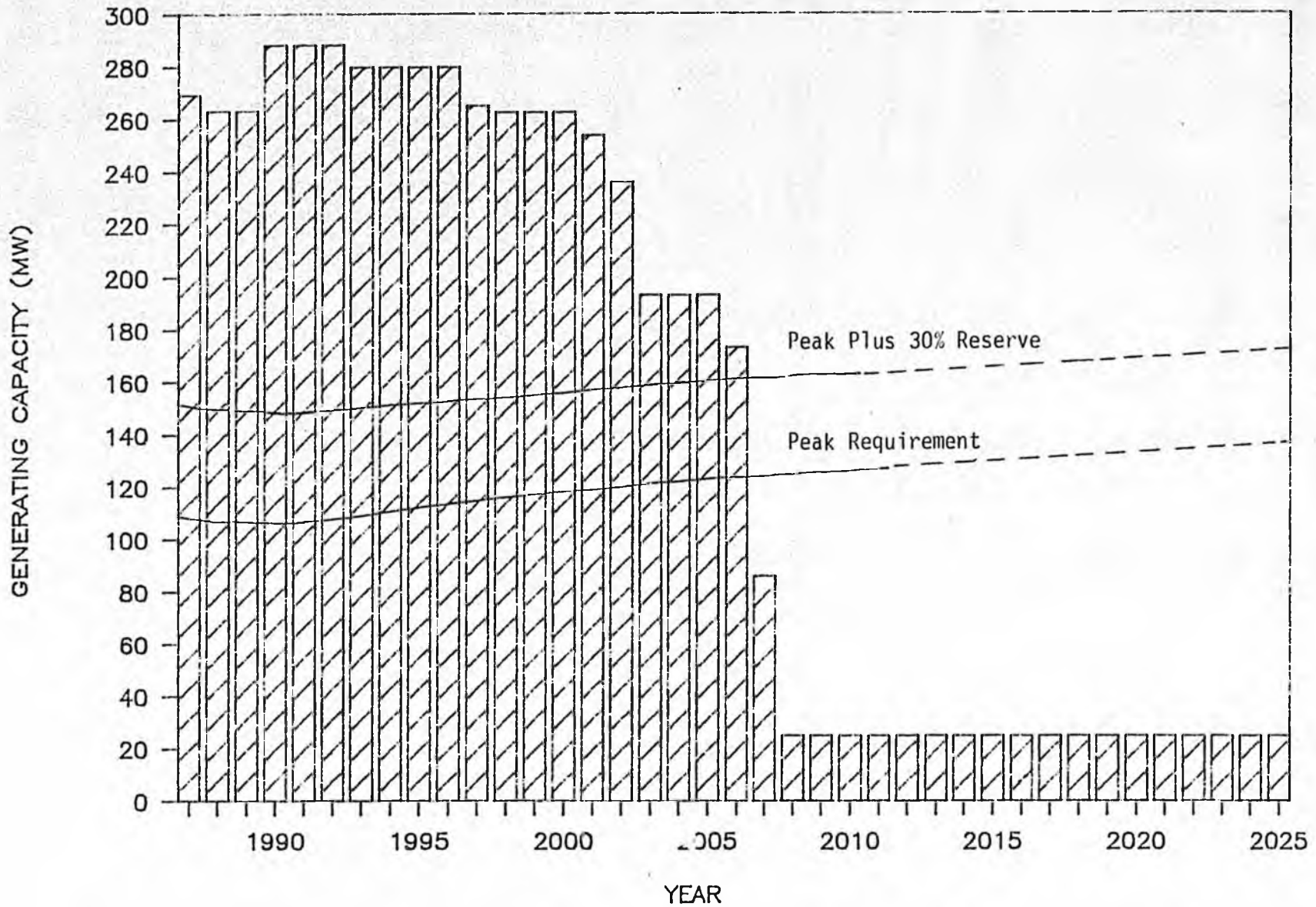


Prepared by the House Research Agency, March 1987.

FIGURE 5

GENERATING CAPACITY NET OF RETIREMENT

FAIRBANKS



Prepared by the House Research Agency, March 1987.

The feasibility analysis of the Division of Policy was based on the assumption that additional increments of generation capacity are necessary in 1991. Our examination of the Bradley Lake project economic feasibility refers to the scenario under this assumption as the "base case." As a result of our energy demand analysis, we also consider two other options as follows: 1) delaying both the Bradley Lake project and the construction of alternative natural gas facilities until they are needed in 1998; and 2) completing the Bradley Lake project as currently scheduled, while delaying gas plant construction until 1998.

Our capacity and demand analysis does not take into account the potential for further energy demand reductions through load management, more efficient use of energy, technological improvements, and energy conservation. It is likely that future capacity construction could be delayed past the year 2000 through improved energy management and utilization. This, however, would be unlikely if the State subsidizes capacity construction because the subsidization of power production and consumption often results in the inappropriate or wasteful use of energy resources.

ECONOMIC FEASIBILITY OF BRADLEY LAKE: THE DIVISION OF POLICY'S ANALYSIS

In this section, we review the February 25, 1987 feasibility analysis prepared by Jack Kreinheder of the Division of Policy (DP) in the Governor's Office. The DP analysis was directed toward the decision of whether to complete the Bradley Lake project at its marginal cost--defined as the total project cost less costs incurred or obligated to date [sunk costs]--or to suspend or abandon the project and pursue gas generation or other alternatives. As indicated by DP, a marginal cost analysis is appropriate at this time because the Bradley Lake sunk costs could not be applied toward gas generation if Bradley were terminated; the gas generation alternative would have to be constructed from scratch.

Simply put, the analysis compares the cost to complete Bradley Lake with the cost of providing the equivalent 90 megawatts of power under a gas generation alternative.¹³ Costs in both cases are presented in 1986 dollars. The analysis assumes that a 90 MW gas turbine alternative would be constructed in 1989 and 1990 if Bradley Lake were not completed. The net benefits of finishing Bradley Lake are expressed as savings in millions of 1986 dollars, once the costs of the gas alternative have been subtracted from the Bradley Lake costs.

¹³The Division of Policy analysis revises an August 1986 Stone and Webster Engineering feasibility prepared for the Alaska Power Authority (APA). The DP incorporated different assumptions for Bradley Lake costs and natural gas prices and calculated net benefits using the APA's model.

The DP concluded that Bradley Lake "is still economically feasible and that completing the project is likely to provide lower long-term power costs than alternative gas generation." However, the projected net benefits of Bradley Lake are much lower than those calculated under earlier analyses, primarily because of the dramatic decline in current and projected Cook Inlet natural gas prices. The key assumptions underlying DP's conclusion are discussed below.

Costs to complete Bradley Lake. The costs of the Bradley Lake project have been adjusted downward to take into account the following:

- sunk costs estimated at roughly \$75 million, including \$45 million already spent on the project and \$30 million as a midpoint estimate of project termination expenses and site restoration costs which would be required by FERC if Bradley Lake were terminated;
- projected savings of \$28 million on the total construction cost due to lower inflation and lower construction costs. The Alaska Power Authority's preliminary revised cost estimate for Bradley Lake is \$328 million, compared with the original 1983 estimate of \$356 million; and
- estimated savings of \$30 million in financing costs because of the APA's use of short-term, variable rate notes, coupled with arbitrage earnings on the reinvestment of the note proceeds.

The above items result in a \$133 million reduction in the cost of completing Bradley Lake. As DP's analysis indicates, the original project costs of \$408 million (\$356 million construction + \$52 million financing costs) can be reduced by almost one-third to a cost of about \$275 million to complete Bradley Lake.

Cook Inlet Natural Gas Prices. As you are aware, natural gas prices have declined dramatically since the original 1983 Stone and Webster Engineering feasibility analysis of the Bradley Lake project. Gas received under Enstar's 1982 gas contract--which ties the gas price to the price of fuel oil at Tesoro's Nikiski refinery--has declined 37 percent from \$2.32/mcf (in 1982) to \$1.47/mcf (in January 1987). As indicated in the Division of Policy's analysis, the key questions are: 1) what is the likely price of gas under new Cook Inlet gas contracts; and 2) what is the most probable rate, or range of rates, at which gas prices will increase in the future.

The DP analysis calculated Bradley Lake net savings under a range of base gas prices (\$1.10 to \$1.70/mcf) and a range of real price escalation rates (0 to 2 percent).¹⁴ Chugach Electric Association (CEA) recently paid \$1.70/mcf in short-term contracts with Beluga field producers; the consensus places the upper limit for the base price of new gas supplies at \$1.70/mcf. The DP suggests that a base price of \$1.50/mcf appears to be a good mid-range figure. With respect to real escalation rates, views vary but the DP analysis referenced forecasts of gas prices by the Department of Revenue and CEA. According to Revenue's December 1986 petroleum revenue forecast, Cook Inlet gas prices are expected to track crude oil prices, which assume an average 2.0 percent real escalation rate between 1987 and 2003. The CEA's gas price forecasts are fairly close to Revenue's.

In summary, the DP analysis calculated a series of projected net benefits which incorporate the lower cost to complete Bradley Lake as well as a range of base gas prices under real escalation rates ranging from 0 to 2 percent. Attachment B presents the DP projections of net savings; the economic feasibility of Bradley Lake (even under the lower cost estimate) remains very sensitive to gas prices and their rate of escalation. For example, at a base price of \$1.60/mcf and two percent real escalation, Bradley Lake is estimated to be \$85 million cheaper in 1986 dollars than the gas alternative. At a one percent real escalation rate and a base price of \$1.60/mcf, however, Bradley net savings drop by about \$55 million. As noted by the division, each 10 cent/mcf change in base gas prices alters the Bradley net savings by about \$15 million. Despite the uncertainties, the division concludes that "...current gas price forecasts by the Department of Revenue and Chugach Electric suggest that Bradley Lake is still likely to be less expensive than [alternative] gas generation over the 50 year period of analysis."

A REEXAMINATION OF BRADLEY LAKE NET SAVINGS UNDER KEY ENERGY ASSUMPTIONS

Based on our review of the above analysis, we conclude that the Division of Policy's assumptions regarding the base gas prices and projected escalation rates appear reasonable. However, we question the division's fundamental assumption regarding future Railbelt energy demand and the timing of installation of additional capacity. Our analysis of Railbelt energy demand and capacity requirements indicates that, even without Bradley Lake, new gas

¹⁴-----
The Division of Policy analysis does not add a delivery charge to the wellhead price of gas; it assumes that new gas generation will be located near a producing field (e.g., the Bernice Lake substation near Marathon's Steelhead platform). A 40 cent/mcf delivery charge (used in the August 1986 Stone and Webster feasibility) would increase costs of the gas alternative and enhance the projected net benefits of Bradley Lake by about \$65 million.

generation will probably not be needed until the late 1990s. This conclusion stems from: 1) lower near-term energy demand forecasts due to population declines; and 2) lower reserve capacity requirements because of existing regional inerties. In light of this conclusion, we believe that the division's analysis must be reexamined.

In this section, we first present our analysis of Bradley Lake net benefits, expressed as savings, under three scenarios:¹⁵

1. The base case incorporates the Division of Policy's implicit assumption that 90 MW of additional gas generation will be needed in 1991 if Bradley Lake is not completed. We altered the division's cost to complete Bradley Lake to be \$283 million--the revised construction cost of \$328 million minus the \$45 million already spent on construction. If the decision were made to abandon Bradley Lake and proceed with gas generation, the cost of the gas alternative would include the estimated \$30 million in Bradley Lake termination and site restoration costs.
2. Assuming that 90 MW of new power is not needed until the late 1990s, the second scenario provides a comparison of Bradley Lake and the gas alternative if construction of both were delayed and power commenced in 1998. The cost to complete Bradley Lake includes expenses to mothball the project in 1987 and reactivate the project in the mid-1990s. As above, the gas alternative includes the cost of termination and site restoration at Bradley Lake as well as gas plant construction costs in 1996-97. Since neither project would begin producing power until 1998 under this scenario, we extend the period of analysis until the year 2048 in order to provide a 50-year period of costs for analysis.
3. The third scenario assumes that the Bradley Lake project is completed under the current schedule at an estimated cost of \$283 million. However, we believe that the decision to complete Bradley Lake must be weighed against alternative gas generation which would be constructed later in the 1990s and begin producing power in 1998 when it was needed. While this feasibility analysis does not provide a year-for-year comparison, it does present a calculation of today's decision to complete Bradley Lake. In effect, this scenario calculates the merits of the public policy decision to proceed with Bradley Lake.

¹⁵Detailed tables for each of these scenarios are included in Attachment C.

Base Case Scenario. Based on an analysis of Chugach Electric Association's projections, the Division of Policy concluded that new gas generation will likely be installed by 1990 if Bradley Lake were not completed. Under this scenario, Chugach Electric indicates that a new 87 MW gas plant would likely be constructed and become part of the base load capacity, thereby delegating older, less fuel efficient turbines to peak loading.¹⁶

We recalculated the net present costs of Bradley Lake and the gas generation alternative under this base case of power needed (from either source) by 1991. In the process of verifying the APA/DP model, we made slight modifications to the spreadsheet formulas but did not alter the analytical approach. Our base case scenario, however, incorporates two notable changes in underlying assumptions. First, we believe that the gas generation's fuel efficiency should reflect the effective heat rate of a new gas turbine (approximately 11,500 Btu/kwh), rather than the 13,000 Btu/kwh rate used in the APA/DP model. It is appropriate to compare "new" Bradley Lake power with power produced at the fuel efficiency of a new turbine, rather than under a blended, less efficient rate (of 13,000 Btu/kwh) based on the combined use of new and old turbines.

The second change incorporated into the APA/DP model was to alter the cost to complete Bradley Lake to equal \$283 million. This represents the preliminary revised construction cost (\$328 million) minus the expenses to date (\$45 million). If the decision were made to terminate Bradley Lake, an estimated \$30 million in termination and site restoration expenses would be incurred in order to then proceed with the gas generation alternative. We, therefore, include these Bradley Lake termination and site restoration costs as a cost to the gas alternative.

As shown in Table 6, the Bradley Lake net savings under our base case scenario equal \$85.8 million--virtually the same as those presented by the Division of Policy. The cost savings gained through greater gas turbine fuel efficiencies incorporated into our base case are cancelled by the termination and site restoration costs added to the gas alternative if the decision were made to abandon Bradley and proceed with gas generation.

¹⁶-----
Tom Martin, Director of Planning, Chugach Electric Association, personal communication, March 9, 1987.

TABLE 6
 BRADLEY LAKE NET SAVINGS UNDER VARIOUS SCENARIOS
 (Million \$)

SCENARIO	----- NET PRESENT COST -----		BRADLEY LAKE NET SAVINGS
	GAS ALTERNATIVE	BRADLEY LAKE	
I. Base Case w/Power in 1991	\$330.4	\$244.6	\$85.8
IA. Base Case under Revised Demand Forecast	315.7	229.9	85.8
II. Construction Delay w/Power in 1998	280.6	406.7	(126.0)
III. Bradley Lake now vs Gas Plant in 1998	280.6	244.6	36.0

Note: All scenarios assume a base price of \$1.60/mcf; zero delivery charge; 2.0 percent escalation rate; 11,500 Btu/kwh heat rate; 4.5 percent inflation; and \$400/kw gas plant construction costs.

The base case scenario incorporates the flawed assumption that 90 MW of additional power will be needed in 1991. Our demand analysis concludes, instead, that an additional increment of production capacity will not be needed until the late-1990s. Therefore, the construction of either Bradley Lake or the gas alternative would result in the early retirement of existing generation capacity. It is assumed that Bradley Lake or a new, more efficient gas turbine would result in lower costs through the displacement of older, less efficient gas generation production. Because the cost reductions are the same for both types of new power, Bradley Lake net savings do not change for this base case under revised demand forecast scenario (Table 6). The net present costs, however, decline by roughly \$15 million for both Bradley Lake and the gas alternative.

Delay Construction Scenario. The net savings of Bradley Lake become negative under our second scenario in which construction of both Bradley Lake and the gas plant alternative are delayed several years until Railbelt energy demand catches up with existing capacity and new generating capacity

is warranted. As shown in Table 6, the net present cost of Bradley Lake (if construction were delayed until 1994-1997) nearly doubles from \$245 million in our base case to \$407 million.

Under this scenario, we assume Bradley Lake construction costs of \$415 million during the period 1994-97 [i.e., the 1987 estimated cost to complete Bradley of \$283 million inflated at 4.5 percent annually plus an estimated \$30 million in additional expenses (administration, licensing, and contracting)]. We estimate that the project would require \$554 million in long-term taxable bonds, issued in 1993 at 10 percent interest, in order to cover construction costs as well as four years of debt service payments prior to project revenues commencing in 1998. Bradley Lake costs would increase dramatically due to the loss of the favorable short-term financing presently in place. On the other hand, the net present cost of the gas alternative drops if construction is delayed--primarily because fuel savings during the period of delay more than offset the gas plant's increased financing costs (which are relatively minor compared with those for Bradley Lake).¹⁷ As shown in Table 6, the Bradley Lake net savings under this scenario are projected to be a negative \$126 million. On the basis of this analysis, it does not appear to be economically feasible to delay Bradley Lake and reactivate the project in the mid-1990s.

Bradley Lake in 1991 vs Delayed Gas Construction Scenario. Our third scenario calculates the net present cost of Bradley Lake constructed under the current schedule and the net present cost of the gas plant alternative if it were delayed until needed. The net savings to be gained from completing Bradley Lake decline to about \$36.0 million. From a public policy perspective, we suggest that this scenario presents a mathematical formulation of the real question: What is the benefit (or cost) of proceeding with Bradley Lake at this time, despite forecasts which suggest that the project is not needed for several years? Based on this analysis, the positive net savings of Bradley Lake indicate that the project should proceed. However, the net savings are not outstanding--and in retrospect could become marginal or negative if gas base prices and/or price escalation rates are lower than assumed.

Net Savings under Various Assumptions

We recalculated the net savings projected for the Bradley Lake project under varying assumptions (gas plant construction costs, turbine heat rate, inflation rate, and discount rate) in order to determine the sensitivity of the analysis to changes in these assumptions. Table 7 summarizes the net savings as these assumptions are varied under the base case scenario and the "Bradley Lake now vs. delayed gas construction" scenario which we believe to be most accurate representation of the current public policy choice.

¹⁷-----
We assume that gas plant construction in the mid-1990s would be financed by taxable revenue bonds at a 10 percent interest rate. The 10 percent interest rate was assumed for delayed gas plant construction in both the second and third scenarios.

TABLE 7
 BRADLEY LAKE NET SAVINGS UNDER VARYING ASSUMPTIONS
 (Millions \$)

SCENARIO/ASSUMPTION	----- NET PRESENT GAS ALTERNATIVE COST -----	----- BRADLEY LAKE	BRADLEY LAKE NET SAVINGS
Scenario I: Base Case w/ Power in 1991	\$330.4	\$244.6	\$85.8
Construction Costs of \$350/kw	325.0	244.6	80.4
Heat Rate of 13,000 Btu/kwh	359.9	244.6	115.2
Inflation Rate at 5.0 percent	327.9	231.5	96.4
Discount Rate 3.0 percent	369.3	264.0	105.2
4.0 percent	297.4	227.2	70.2
12.0 percent	100.8	88.5	12.3

Scenario III: Bradley Lake now vs Gas Plant in 1998	280.6	244.6	36.0
Construction Costs of \$350/kw	275.1	244.6	30.5
Heat Rate of 13,000 Btu/kwh	304.5	244.6	59.9
Inflation Rate of 5.0 percent	278.4	231.5	46.8
Discount Rate 3.0 percent	318.8	264.0	54.8
4.0 percent	248.4	227.2	21.2
5.0 percent	197.8	197.4	0.5

Note: Both scenarios assume a base gas price of \$1.60/mcf; zero delivery charge; 2.0 percent escalation rate; 11,500 Btu/kwh heat rate; 4.5 percent inflation; and \$400/kw gas plant construction costs.

The Division of Policy's analysis assumed that construction costs for a gas plant would run \$400/kw (in 1986 dollars). The range of construction costs is apparently estimated at \$350 to \$450/kw, based on construction costs experienced by Alaska Electric Generation & Transmission and Anchorage Municipal Light & Power during the past few years. Lowering the cost assumption to \$350/kw, however, has a fairly insignificant effect on the cost analysis. Under either scenario, the present cost of the gas alternative would be about \$5.5 million lower at a construction cost of \$350/kw.

As noted previously, we assumed a new gas turbine fuel efficiency ("heat rate") of 11,500 Btu/kwh in our three scenarios. On the other hand, the APA/DP model assumed a heat rate of 13,000 Btu/kwh to reflect newer gas turbines at 11,500 Btu/kwh (effective rate) operating as base capacity coupled with older, less existing turbines at 15,000-16,000 operating only when demand peaks. As shown in Table 7, using this higher, "blended" heat rate increases the fuel consumption under the gas alternative in both scenarios significantly and enhances the Bradley Lake net savings. The net savings analysis is very sensitive to the gas turbine fuel efficiency and other assumptions which directly affect annual fuel costs.

Annual Inflation Rate. The APA/DP model assumed 4.5 percent annual inflation over the 50-year period of analysis. In the January 1987 Revenue Sources report, the Department of Revenue projected an inflation rate of 3.89 percent in FY 87, 4.58 percent in FY 88-FY 92, 5.23 percent in FY 93 - FY 97, and 5.42 percent thereafter. If we substitute an annual inflation rate of 5.0%, the Bradley Lake net savings under both scenarios in Table 7 increase by about \$11 million. Higher inflation rates lower the net present costs of both the gas alternative and Bradley Lake. However, higher inflation favors Bradley Lake to a greater extent because most of Bradley Lake's annual costs are fixed debt service payments, which (in 1986 dollars) become cheaper in the future. In contrast, a smaller portion of the gas alternative's annual costs are fixed.

The Discount Rate. In order to calculate the net present cost during the 50-year period of analysis, one must employ a discount rate which adjusts future cash flows to a value in current dollars. The APA/DP model employed a discount rate of 3.5 percent, which is apparently the discount rate routinely used by the U.S. Army Corps of Engineers to reflect the historic real cost of government spending.

The gas alternative operational costs are higher in later years (even when adjusted to 1986 dollars) because gas prices are assumed to escalate at a real rate of 2.0 percent, whereas Bradley Lake costs (in 1986 dollars) decline over the period of analysis. A lower discount rate emphasizes the relative weight of future costs and enhances the outlook of Bradley Lake. For example, under both scenarios shown in Table 7, Bradley Lake net savings increase by about \$19 million when the discount rate is reduced to 3.0 percent.

On the other hand, a higher discount rate tends to lower the net savings of Bradley Lake because it deemphasizes future expenditures. For example, a discount rate of 4.0 percent lowers the net savings of Bradley Lake in both scenarios by about \$15 million. The sensitivity of the analysis to the discount rate becomes particularly significant when Bradley Lake's net savings are relatively low--as under the third scenario. A discount rate of 5.0 percent under this scenario produces zero net savings, whereas a 12.0 percent discount rate under the base case still results in a positive net benefit (see Table 7). The analysis indicates, however, that the net savings of Bradley Lake remain positive under discount rates within a reasonable range of 3.0 to 4.0 percent.

CONCLUSION

It has been stated that Bradley Lake was not conceived as an emergency power project needed to meet Railbelt energy demand. Instead, it was intended to provide the Railbelt with an alternate power source free from the vagaries of fossil fuel price escalation. As the price of natural gas has declined, however, the projected net savings of the Bradley Lake project have eroded considerably. Our analysis indicates that the public policy choice today is to either proceed with Bradley Lake as currently scheduled or abandon the project. Delaying Bradley for several years--so that Railbelt energy demand could "catch up" with capacity--would be too costly relative to a less expensive gas alternative.

If the Bradley Lake project is to be completed as scheduled, we conclude that it will probably provide net savings over the 50-year period of analysis. However, in order to more accurately project the benefits of the projects, we believe that an analysis computing the actual cost of all power consumed in the Railbelt under the different scenarios would be required. However, this type of analysis would require a great deal of data-gathering from the seven Railbelt utilities, the APUC, and the APA. The time-consuming nature and inherent difficulties of this type of analysis probably explain why it has not already been conducted.

At this time, we reiterate our conclusion that the Bradley Lake project will probably produce power more cheaply than gas generation over the 50-year period we analyzed. Nevertheless, the net savings are certainly less than the proposed State contribution of roughly \$164 million.¹⁸ Furthermore, the analysis is extremely sensitive to natural gas prices and their escalation. Because the projected net savings of Bradley Lake are now relatively low, there is a high risk that its completion would be a poor public policy decision if gas prices prove to be only slightly lower than assumed. The public risk grows considerably greater as the net savings projected for Bradley Lake decline. Beyond the initial State cash contribution, the Railbelt electric customers will ultimately bear the costs of today's decision regarding Bradley Lake power.

Attachments

¹⁸-----
The State contribution assumes the revised cost of \$328 million minus \$164 million (one-half of \$328 million) to be contributed by Railbelt utilities.

ATTACHMENT A

TABLE A.1

NET GENERATION OF ALASKA RAILBELT UTILITIES, 1976 - 1986

UTILITY	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Anchorage Municipal Light & Power (AHLP)	444.9	420.3	443.1	473.1	486.6	485.3	579.5	592.5	654.0	934.4	938.6
Chugach Electric Association (CEA)	1,054.5	1,179.7	1,308.6	1,401.0	1,434.1	1,467.7	1,718.4	1,781.8	1873.3	1,859.3	1,692.3
Alaska Power Administration (APAD)	118.0	203.5	180.1	171.1	184.3	222.7	147.9	149.9	164.6	150.0	154.8
Anchorage-Cook Inlet Subtotal	1,617.4	1,803.6	1,931.8	2,045.2	2,105.0	2,175.7	2,445.8	2,524.2	2,691.9	2,943.7	2,785.7
Fairbanks Municipal Utility System (FMUS)	123.3	128.5	124.7	124.7	125.6	126.1	140.7	146.9	140.2	101.0	96.8
Golden Valley Electric Association (GVEA)	344.7	353.5	341.5	322.9	317.7	316.9	350.3	346.2	401.1	408.0	420.6
Fairbanks Area Subtotal	468.0	481.7	466.2	447.6	443.3	443.0	491.1	493.1	541.3	509.0	517.4
RAILBELT TOTAL	2,085.4	2,285.3	2,398.0	2,492.8	2,548.3	2,618.7	2,936.9	3,017.3	3,233.2	3,452.7	3,303.1

Source: Alaska Power Authority, "Alaska Electric Power Statistics, 1960-1985,"; Railbelt Utilities.

Prepared by the House Research Agency, March 1987 (Demand; 861217-29).

Table A2

TOTAL RAILBELT
DEMAND REQUIREMENTS

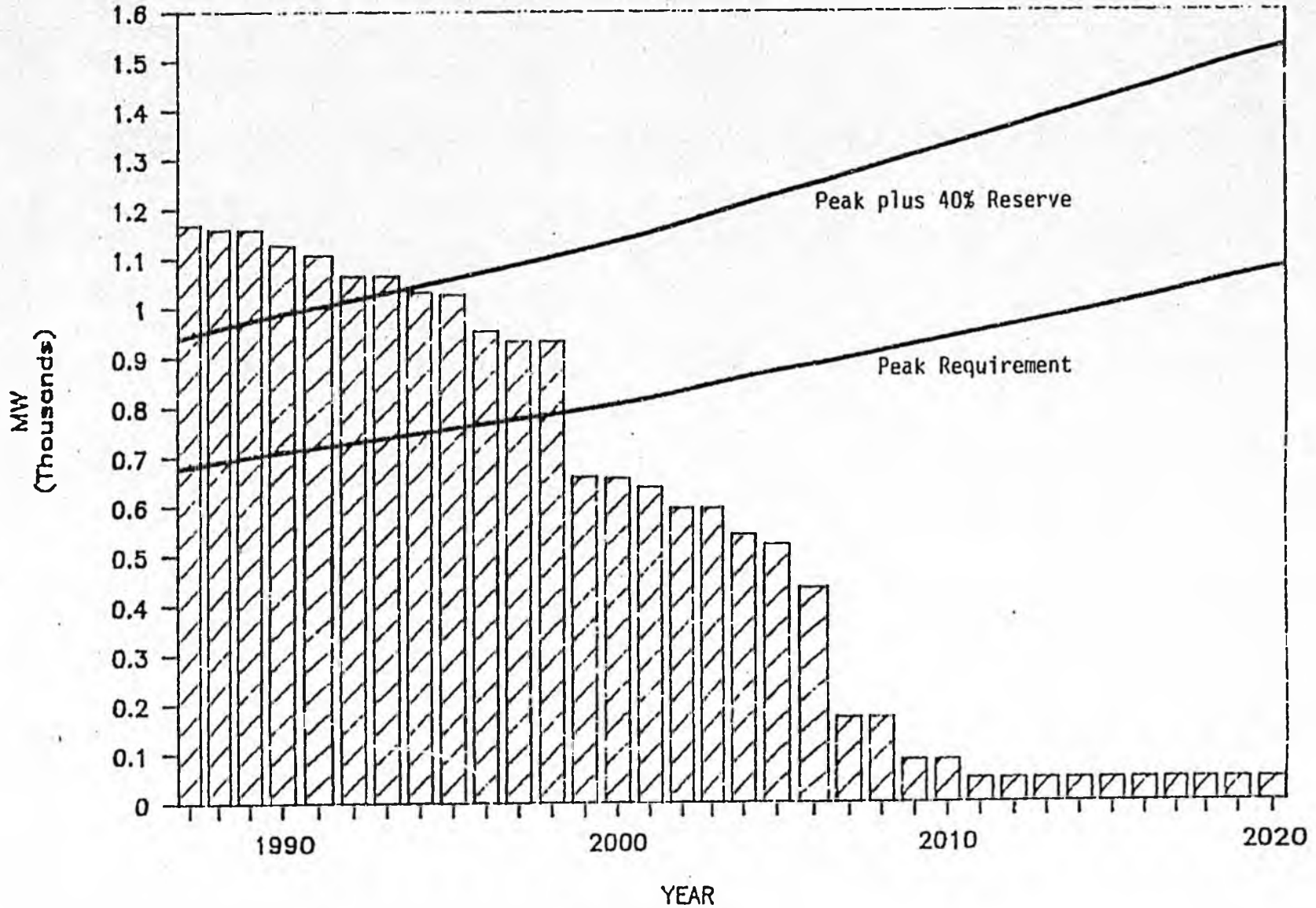
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
ANCHORAGE MUNICIPAL LIGHT AND POWER	859.8	861.6	885.7	891.7	897.1	894.3	872.6	813.4	834.5	845.3	851.8	848.0	897.0	1,011.6	1,037.6	1,064.1
DUGLICH ELECTRIC ASSOCIATION (RETAIL)	933.7	936.9	938.2	968.3	1,050.1	976.0	1,016.7	1,046.5	1,046.6	978.2	1,009.9	1,020.4	1,033.3	1,049.7	1,068.8	1,091.7
POWER ELECTRIC ASSOCIATION	286.7	311.7	311.7	316.7	376.5	417.2	427.2	432.2	417.2	401.6	412.2	417.2	417.2	427.2	427.2	432.2
PENINSULA ELECTRIC ASSOCIATION	478.1	475.2	471.0	474.5	425.9	437.7	433.7	442.8	470.3	471.3	472.1	479.5	483.1	496.2	510.4	527.6
CITY OF SEWARD	34.9	34.9	41.2	43.4	45.4	46.0	46.7	47.7	48.8	49.2	49.5	49.9	50.3	50.9	51.5	52.2
SYSTEM LOSSES	155.7	161.8	167.1	163.7	163.4	164.3	167.5	172.0	172.3	165.3	167.3	169.1	171.0	173.9	177.1	180.9
TOTAL (DEMAND)	1909.2	2040.5	2047.2	2046.7	2011.5	2054.1	2091.7	2141.2	2150.2	2053.7	2110.9	2136.1	2154.9	2192.8	2234.9	2284.0
FAIRBANKS MUNICIPAL UTILITY SYSTEM	166.7	172.9	171.6	176.3	179.9	185.3	187.0	192.8	196.6	200.5	204.5	208.6	212.8	217.0	221.4	225.8
EDEN VALLEY ELECTRIC ASSOCIATION	501.5	521.0	541.2	562.2	577.3	592.7	608.6	624.9	641.7	658.9	676.5	694.6	713.2	732.3	752.0	772.1
POWER ELECTRIC ASSOCIATION	429.0	425.0	425.0	430.0	454.3	495.0	505.0	510.0	490.0	479.4	490.0	495.0	495.0	500.0	505.0	510.0
DUGLICH ELECTRIC ASSN	386.7	391.7	391.7	396.7	376.5	417.2	427.2	432.2	412.2	401.6	412.2	417.2	417.2	422.2	427.2	432.2
RESERVE	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
PENINSULA ELECTRIC ASSN (TOTAL)	478.1	475.2	471.0	474.5	429.2	486.0	487.0	496.1	523.6	524.6	525.4	532.8	536.4	541.5	543.7	550.9
DUGLICH ELECTRIC ASSN	478.1	475.2	471.0	474.5	429.9	432.7	433.7	442.8	470.3	471.3	472.1	479.5	483.1	496.2	510.4	527.6
RESERVE (RAILBELT LINE)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CITY OF SEWARD	34.9	34.9	41.2	43.4	45.4	46.0	46.7	47.7	48.8	49.2	49.5	49.9	50.3	50.9	51.5	52.2
TOTAL	3,559.9	3,652.3	3,687.0	3,720.2	3,781.9	3,851.6	3,913.0	4,003.4	4,054.1	4,021.5	4,077.9	4,138.3	4,199.0	4,284.9	4,377.0	4,472.2
CAPACITY REQUIREMENTS																
ANCHORAGE MUNICIPAL LIGHT AND POWER	164.0	166.7	166.9	166.2	166.3	167.1	168.2	172.1	176.1	178.1	179.0	182.4	185.8	190.3	195.4	200.2
DUGLICH ELECTRIC ASSOCIATION <i>Res./</i>	111.3	108.4	107.0	107.4	108.1	105.6	103.0	207.2	200.6	191.3	190.0	185.6	178.0	201.2	204.8	209.1
FAIRBANKS MUNICIPAL UTILITY SYSTEM	29.3	30.0	30.6	31.2	32.1	33.4	34.4	35.4	36.5	37.6	38.7	39.9	41.1	42.3	43.6	44.9
EDEN VALLEY ELECTRIC ASSOCIATION	65.8	62.3	62.4	62.0	62.8	63.8	64.8	65.8	66.8	67.8	68.8	69.8	70.8	71.8	72.8	73.8
POWER ELECTRIC ASSOCIATION	79.8	81.0	81.5	81.0	87.0	95.0	91.0	97.0	93.0	92.0	93.0	94.0	95.0	96.0	97.0	97.5
PENINSULA ELECTRIC ASSOCIATION	90.3	94.9	96.5	93.6	95.5	96.4	97.5	99.3	105.8	94.9	95.7	96.5	97.0	97.5	99.7	101.2
SEWARD	7.0	7.0	10.0	11.0	12.4	12.5	12.7	13.3	13.6	13.7	13.8	13.9	14.0	14.1	14.2	14.3
TOTAL SYSTEM PEAK	616.7	670.3	681.9	690.4	701.2	712.8	722.6	738.2	747.7	733.0	743.3	754.4	765.7	780.1	797.7	816.1
RESERVE REQUIREMENTS																
ANCHORAGE AREA	133.7	138.0	138.1	137.2	138.0	137.7	139.1	142.1	144.8	139.3	140.7	142.4	144.3	146.8	150.0	153.1
FAIRBANKS AREA	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9
LENA; PENINSULA	38.0	38.0	38.0	38.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
TOTAL RESERVE REQUIREMENT	232.6	236.9	237.0	236.1	249.9	249.6	251.0	254.0	256.7	251.2	252.6	254.3	256.2	263.7	266.9	280.1
TOTAL SYSTEM CAPACITY REQUIREMENT	849.3	907.2	918.9	926.4	951.1	962.4	973.6	992.2	1,004.3	984.1	995.9	1,006.7	1,022.8	1,044.6	1,064.6	1,104.1

Alaska Power Authority
January 1987

Note: This forecast is being used for: Preliminary Economic Assessment of Railbelt Transmission Alternatives

EXISTING CAPACITY NET OF RETIREMENTS

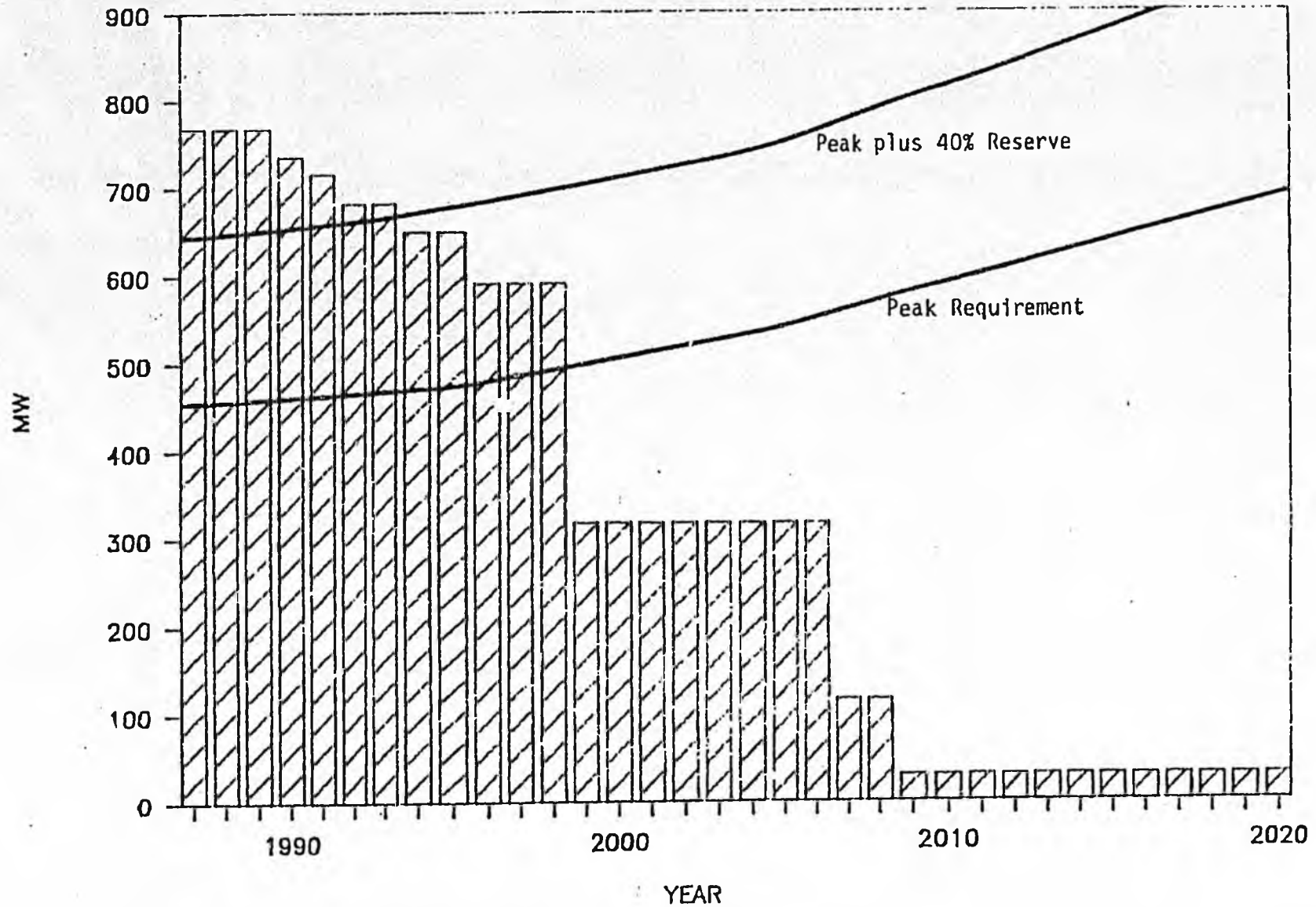
TOTAL RAILBELT



Prepared by the Alaska Power Authority, February 1987.

EXISTING CAPACITY NET OF RETIREMENTS

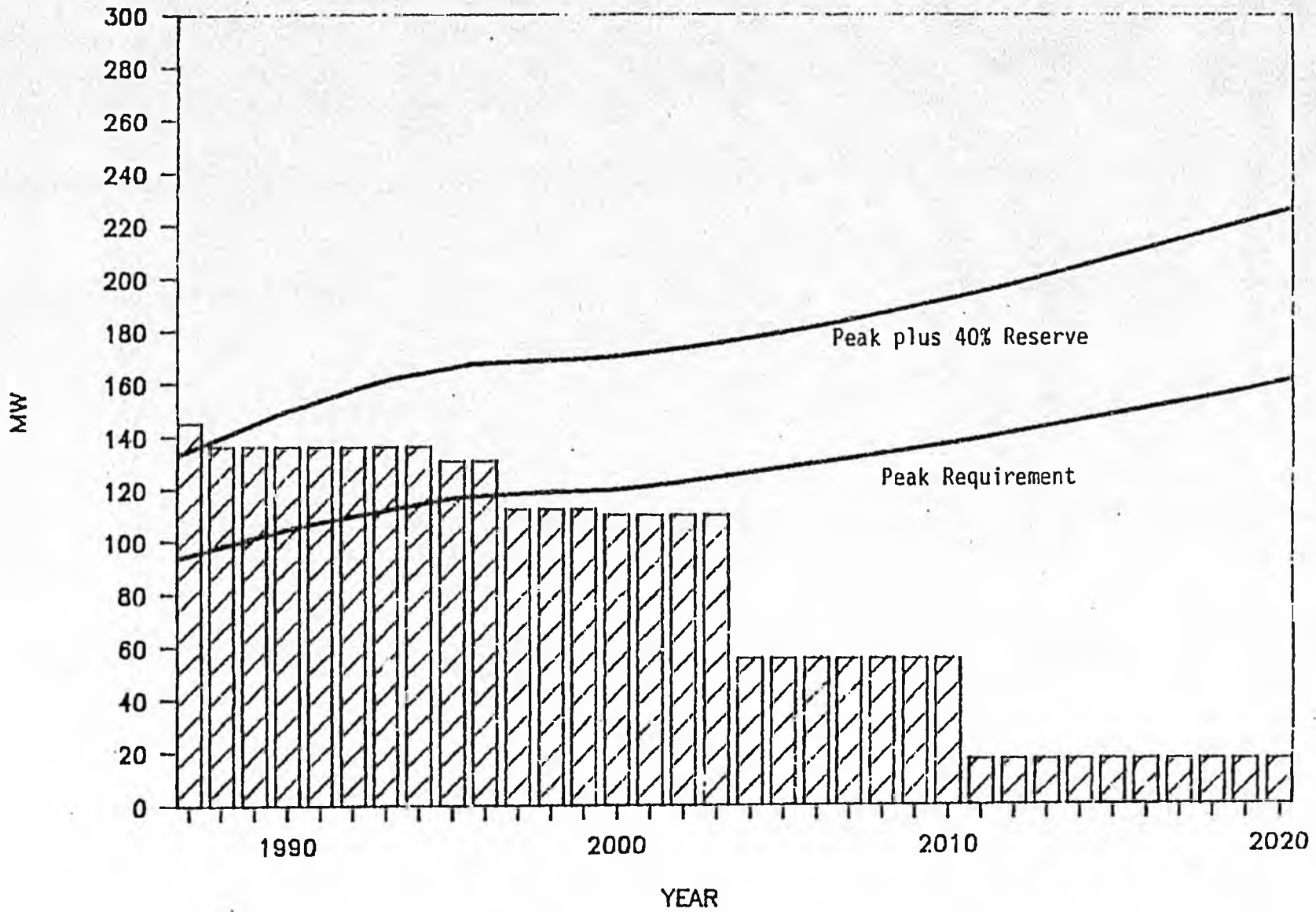
ANCHORAGE



Prepared by the Alaska Power Authority, February 1987.

EXISTING CAPACITY NET OF RETIREMENTS

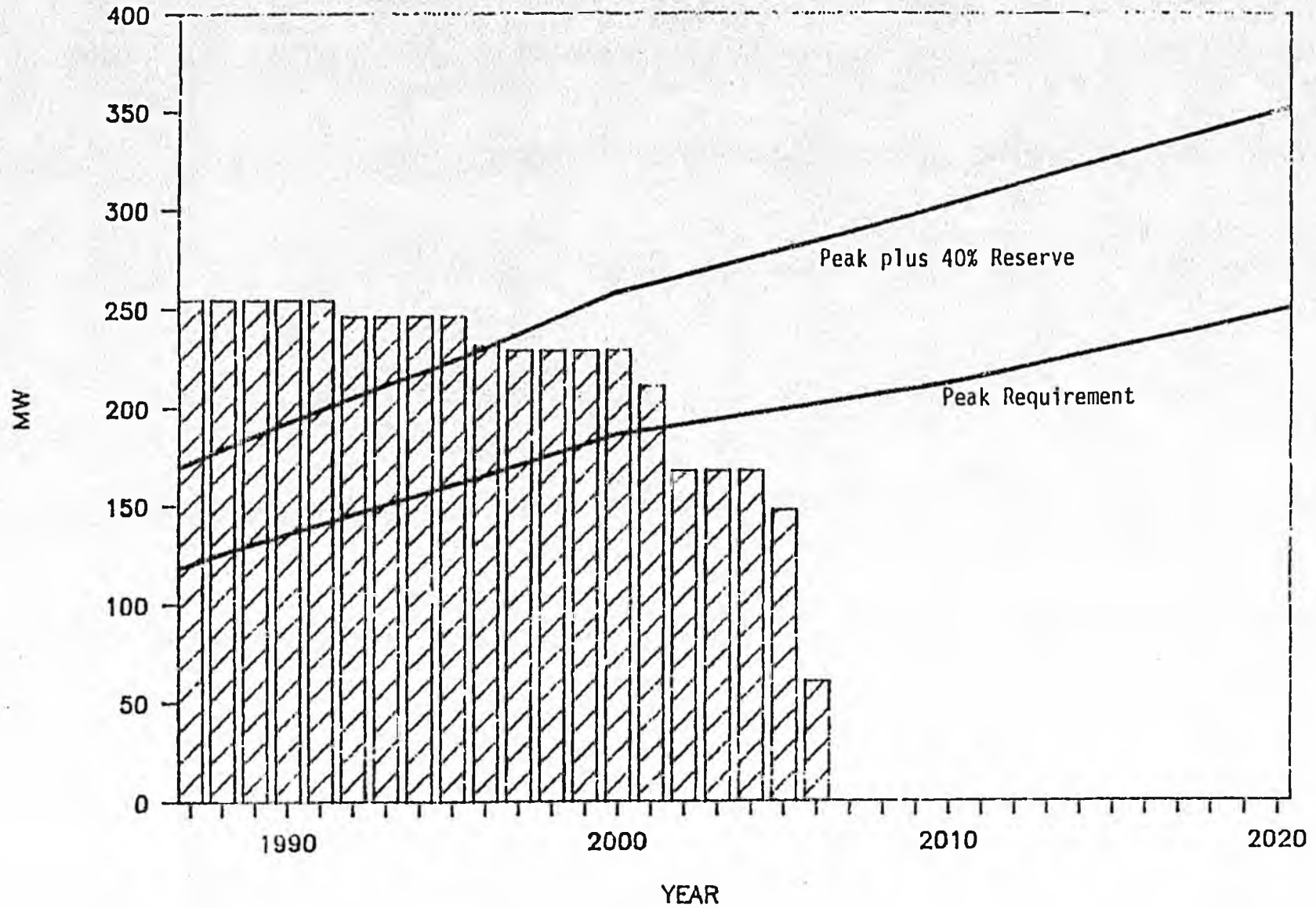
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Prepared by the Alaska Power Authority, February 1987.

EXISTING CAPACITY NET OF RETIREMENTS

FAIRBANKS

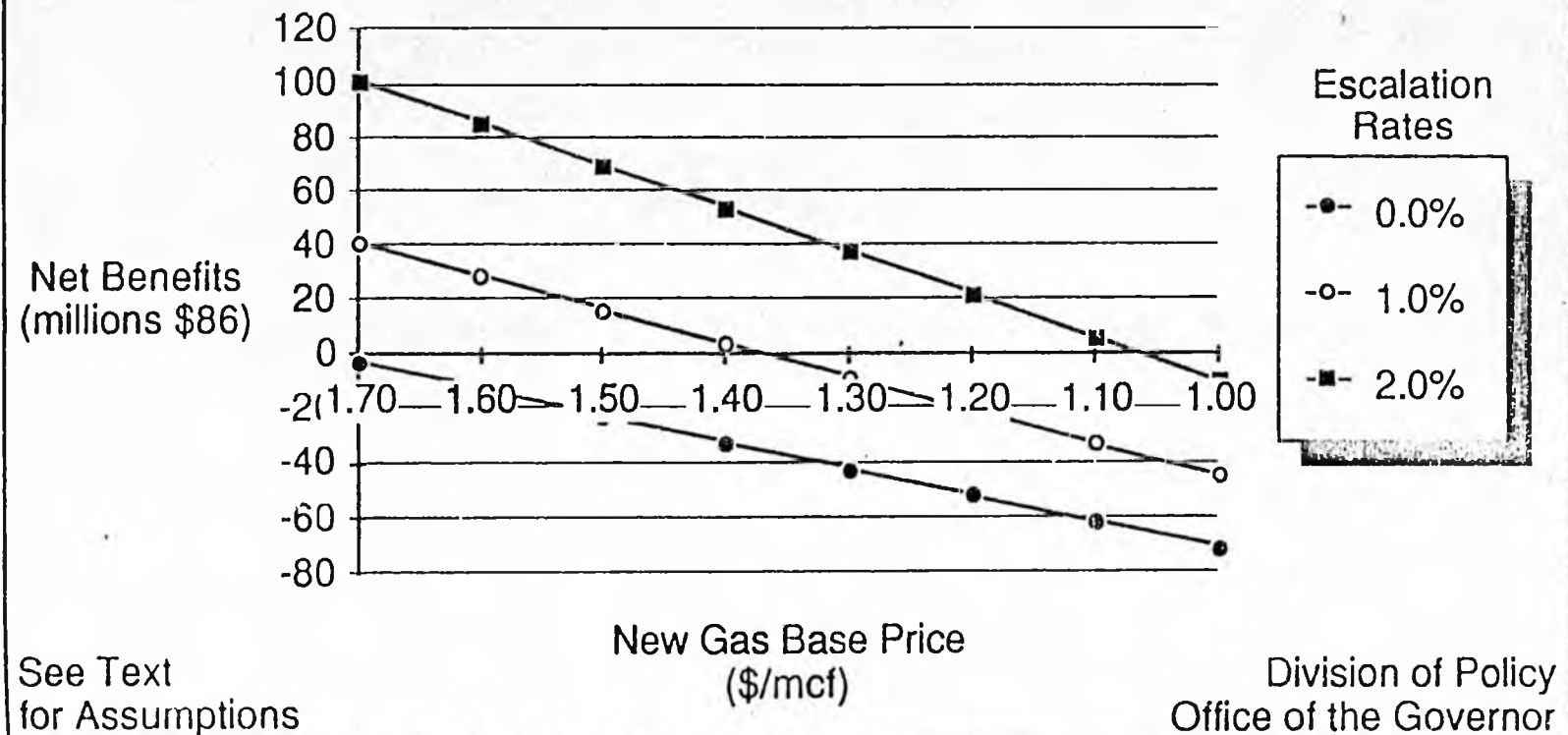


Prepared by the Alaska Power Authority, February 1987.

ATTACHMENT B

FIGURE 1

Bradley Lake Net Benefits at Varying Prices for New Gas and Real Escalation Rates



ATTACHMENT C

TABLE C.1 BASE CASE SCENARIO:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$36 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL RATE (C/KWH)	REAL			TOTAL BRADLEY (\$86 MLN)	
									WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)		
Base Capital Cost Excluding IDC (\$1986/net kw): \$400	1987	0.0										\$1.63	
Capacity (net kw): 90,000	1988	0.0										1.66	
	1989	18.0										1.70	
	1990	18.0	4.1									1.73	
Construction Period (years): 2	1991		4.0	1.0	0.5	7.5	13.0	3.5	1.77	2.0	20.2	22.2	
Total Bonds: \$48.6	1992		3.8	1.0	0.5	7.7	13.0	3.5	1.80	2.0	19.3	21.3	
Bond Term (yrs): 20	1993		3.6	1.0	0.5	7.8	13.0	3.5	1.84	2.0	18.5	20.5	
Long-Term Interest Rate: 8.0%	1994		3.5	1.0	0.5	8.0	13.0	3.5	1.87	2.0	17.7	19.7	
Bond Payment (1989\$): \$4.9	1995		3.3	1.0	0.5	8.1	13.0	3.5	1.91	2.0	16.9	18.9	
Inflation Rate: 4.5%	1996		3.2	1.0	0.5	8.3	13.0	3.5	1.95	2.0	16.2	18.2	
Reinvest Rate: 6.0%	1997		3.0	1.0	0.5	8.4	13.0	3.5	1.99	2.0	15.5	17.5	
Discount Rate: 3.5%	1998		2.9	1.0	0.5	8.6	13.1	3.5	2.03	2.0	14.8	16.8	
	1999		2.8	1.0	0.5	8.8	13.1	3.6	2.07	2.0	14.2	16.2	
	2000		2.7	1.0	0.5	9.0	13.2	3.6	2.11	2.0	13.6	15.6	
	2001		2.6	1.0	0.5	9.1	13.2	3.6	2.15	2.0	13.0	15.0	
Fixed O&M Cost	2002		2.4	1.0	0.5	9.3	13.3	3.6	2.20	2.0	12.4	14.4	
(\$1986/kw/yr): \$11.25	2003		2.3	1.0	0.5	9.5	13.4	3.6	2.24	2.0	11.9	13.9	
	2004		2.2	1.0	0.5	9.7	13.5	3.6	2.29	2.0	11.4	13.4	
Variable O&M Cost	2005		2.1	1.0	0.5	9.9	13.6	3.7	2.33	2.0	10.9	12.9	
(\$1986/kwh): \$0.0014	2006		2.1	1.0	0.5	10.1	13.7	3.7	2.38	2.0	10.4	12.4	
	2007		2.0	1.0	0.5	10.3	13.8	3.7	2.43	2.0	10.0	12.0	
New Turbine Heat Rate	2008		1.9	1.0	0.5	10.5	13.9	3.8	2.47	2.0	9.5	11.5	
(BTU/kwh): 11,500	2009		1.8	1.0	0.5	10.7	14.0	3.8	2.52	2.0	9.1	11.1	
	2010		1.7	1.0	0.5	10.9	14.2	3.8	2.57	2.0	8.7	10.7	
Wellhead Gas Price	2011		1.6	1.0	0.5	11.1	14.3	3.9	2.62	2.0	8.4	10.4	
(\$1986/MMBTU): \$1.60	2012		1.6	1.0	0.5	11.4	14.5	3.9	2.68	2.0	8.0	10.0	
Gas Delivery (\$86): \$0.00	2013		1.5	1.0	0.5	11.6	14.6	4.0	2.73	2.0	7.7	9.7	
Real Wellhead Price	2014		1.4	1.0	0.5	11.8	14.8	4.0	2.79	2.0	7.3	9.3	
Escalation Rate: 2.0%	2015		1.4	1.0	0.5	12.1	15.0	4.1	2.84	2.0	7.0	9.0	
	2016		1.3	1.0	0.5	12.3	15.2	4.1	2.90	2.0	6.7	8.7	

TABLE C.1 BASE CASE SCENARIO:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL	REAL	BRADLEY	BRADLEY	TOTAL
								WELLHEAD GAS PRICE (\$86/MMBTU)	RATE (C/KWH)	O&M (\$86 MLN)	DS (\$86 MLN)	BRADLEY (\$86 MLN)
Cash Flow for Base	2017		1.3	1.0	0.5	12.6	15.3	4.2	2.96	2.0	6.4	8.4
Construction Cost:	2018		1.2	1.0	0.5	12.8	15.5	4.2	3.02	2.0	6.1	8.1
1987	0%	2019	1.2	1.0	0.5	13.1	15.7	4.3	3.08	2.0	5.9	7.9
1988	0%	2020	1.1	1.0	0.5	13.3	16.0	4.3	3.14	2.0	5.6	7.6
1989	50%	2021	1.1	1.0	0.5	13.6	16.2	4.4	3.20	2.0		2.0
1990	50%	2022	1.0	1.0	0.5	13.9	16.4	4.4	3.26	2.0		2.0
		2023	1.0	1.0	0.5	14.1	16.6	4.5	3.33	2.0		2.0
		2024	0.9	1.0	0.5	14.4	16.9	4.6	3.40	2.0		2.0
		2025	0.9	1.0	0.5	14.7	17.1	4.6	3.46	2.0		2.0
Load Factor: 47%		2026	0.9	1.0	0.5	15.0	17.4	4.7	3.53	2.0		2.0
Annual Energy (gwh): 369.2		2027	0.8	1.0	0.5	15.3	17.6	4.8	3.60	2.0		2.0
Transmission Cost		2028	0.8	1.0	0.5	15.6	17.9	4.9	3.68	2.0		2.0
(\$1986 Millions): \$0.0		2029	0.7	1.0	0.5	15.9	18.2	4.9	3.75	2.0		2.0
		2030	0.7	1.0	0.5	16.2	18.5	5.0	3.82	2.0		2.0
BRADLEY LAKE		2031	0.7	1.0	0.5	16.6	18.8	5.1	3.90	2.0		2.0
Cost to Complete: \$283.0		2032	0.7	1.0	0.5	16.9	19.1	5.2	3.98	2.0		2.0
Debt Service (30 yr): \$25.1		2033	0.6	1.0	0.5	17.2	19.4	5.3	4.06	2.0		2.0
		2034	0.6	1.0	0.5	17.6	19.7	5.3	4.14	2.0		2.0
NP COST GAS \$300.4		2035	0.6	1.0	0.5	17.9	20.0	5.4	4.22	2.0		2.0
+ term & site restoration \$30.0		2036	0.5	1.0	0.5	18.3	20.4	5.5	4.31	2.0		2.0
NP COST GAS \$330.4		2037	0.5	1.0	0.5	18.7	20.7	5.6	4.39	2.0		2.0
		2038	0.5	1.0	0.5	19.0	21.1	5.7	4.48	2.0		2.0
NP COST BRADLEY \$244.6		2039	0.5	1.0	0.5	19.4	21.4	5.8	4.57	2.0		2.0
NET SAVINGS BRADLEY \$85.8		2040	0.5	1.0	0.5	19.8	21.8	5.9	4.66	2.0		2.0

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Newbragas; 861217-29).

TABLE C.2 BASE CASE SCENARIO UNDER REVISED DEMAND FORECAST:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	FUEL SAVINGS (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL RATE (C/KWH)	REAL			
										WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$25 MLN)
Base Capital Cost Excluding IDC (\$1986/net kw): \$400	1987	0.0								\$1.63			
Capacity (net kw): 90,000	1988	0.0								1.66			
	1989	18.0								1.70			
Construction Period (years): 2	1990	18.0	4.1							1.73			
	1991		4.0	1.0	0.5	7.5	2.6	10.4	2.8	1.77	2.0	20.2	19.6
Total Bonds: \$48.6	1992		3.8	1.0	0.5	7.7	2.7	10.3	2.8	1.80	2.0	19.3	18.6
Bond Term (yrs): 20	1993		3.6	1.0	0.5	7.8	2.7	10.3	2.8	1.84	2.0	18.5	17.8
Long-Term Interest Rate: 8.0%	1994		3.5	1.0	0.5	8.0	2.8	10.2	2.8	1.87	2.0	17.7	16.9
Bond Payment (1989%): \$4.9	1995		3.3	1.0	0.5	8.1	2.8	10.2	2.7	1.91	2.0	16.9	16.1
	1996		3.3	1.0	0.5	8.3	2.9	10.1	2.7	1.95	2.0	16.2	15.3
Inflation Rate: 4.5%	1997		3.0	1.0	0.5	8.4	2.9	10.1	2.7	1.99	2.0	15.5	14.6
Reinvest Rate: 6.0%	1998		2.9	1.0	0.5	8.6		13.1	3.5	2.03	2.0	14.8	16.8
Discount Rate: 3.5%	1999		2.8	1.0	0.5	8.8		13.1	3.6	2.07	2.0	14.2	16.2
	2000		2.7	1.0	0.5	9.0		13.2	3.6	2.11	2.0	13.6	15.6
Fixed O&M Cost (\$1986/kw/yr): \$11.25	2001		2.6	1.0	0.5	9.1		13.2	3.6	2.15	2.0	13.0	15.0
	2002		2.4	1.0	0.5	9.3		13.3	3.6	2.20	2.0	12.4	14.4
Variable O&M Cost (\$1986/kwh): \$0.0014	2003		2.3	1.0	0.5	9.5		13.4	3.6	2.24	2.0	11.9	13.9
	2004		2.2	1.0	0.5	9.7		13.5	3.6	2.29	2.0	11.4	13.4
New Turbine Heat Rate (BTU/kwh): 11,500	2005		2.1	1.0	0.5	9.9		13.6	3.7	2.33	2.0	10.9	12.9
	2006		2.1	1.0	0.5	10.1		13.7	3.7	2.38	2.0	10.4	12.4
Wellhead Gas Price (\$1986/MMBTU): \$1.60	2007		2.0	1.0	0.5	10.3		13.8	3.7	2.43	2.0	10.0	12.0
	2008		1.9	1.0	0.5	10.5		13.9	3.8	2.47	2.0	9.5	11.5
Gas Delivery (\$86): \$0.00	2009		1.8	1.0	0.5	10.7		14.0	3.8	2.52	2.0	9.1	11.1
	2010		1.7	1.0	0.5	10.9		14.2	3.8	2.57	2.0	8.7	10.7
Real Wellhead Price Escalation Rate: 2.0%	2011		1.6	1.0	0.5	11.1		14.3	3.9	2.62	2.0	8.4	10.4
	2012		1.6	1.0	0.5	11.4		14.5	3.9	2.68	2.0	8.0	10.0
	2013		1.5	1.0	0.5	11.6		14.6	4.0	2.73	2.0	7.7	9.7
	2014		1.4	1.0	0.5	11.8		14.8	4.0	2.79	2.0	7.3	9.3
	2015		1.4	1.0	0.5	12.1		15.0	4.1	2.84	2.0	7.0	9.0
	2016		1.3	1.0	0.5	12.3		15.2	4.1	2.90	2.0	6.7	8.7

TABLE C.2 BASE CASE SCENARIO UNDER REVISED DEMAND FORECAST:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	FUEL SAVINGS (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL				
									REAL RATE (C/KWH)	WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$86 MLN)
Cash Flow for Base	2017		1.3	1.0	0.5	12.6		15.3	4.2	2.96	2.0	6.4	8.4
Construction Cost:	2018		1.2	1.0	0.5	12.8		15.5	4.2	3.02	2.0	6.1	8.1
1987	0%	2019	1.2	1.0	0.5	13.1		15.7	4.3	3.08	2.0	5.9	7.9
1988	0%	2020	1.1	1.0	0.5	13.3		16.0	4.3	3.14	2.0	5.6	7.6
1989	50%	2021	1.1	1.0	0.5	13.6		16.2	4.4	3.20	2.0		2.0
1990	50%	2022	1.0	1.0	0.5	13.9		16.4	4.4	3.26	2.0		2.0
		2023	1.0	1.0	0.5	14.1		16.6	4.5	3.33	2.0		2.0
		2024	0.9	1.0	0.5	14.4		16.9	4.6	3.40	2.0		2.0
		2025	0.9	1.0	0.5	14.7		17.1	4.6	3.46	2.0		2.0
Load Factor:	47%	2026	0.9	1.0	0.5	15.0		17.4	4.7	3.53	2.0		2.0
Annual Energy (gwh):	369.2	2027	0.8	1.0	0.5	15.3		17.6	4.8	3.60	2.0		2.0
Transmission Cost		2028	0.8	1.0	0.5	15.6		17.9	4.9	3.68	2.0		2.0
(\$1986 Millions):	\$0.0	2029	0.7	1.0	0.5	15.9		18.2	4.9	3.75	2.0		2.0
		2030	0.7	1.0	0.5	16.2		18.5	5.0	3.82	2.0		2.0
BRADLEY LAKE		2031	0.7	1.0	0.5	16.6		18.8	5.1	3.90	2.0		2.0
Cost to Complete:	\$283.0	2032	0.7	1.0	0.5	16.9		19.1	5.2	3.98	2.0		2.0
Debt Service (30 yr):	\$25.1	2033	0.6	1.0	0.5	17.2		19.4	5.3	4.06	2.0		2.0
		2034	0.6	1.0	0.5	17.6		19.7	5.3	4.14	2.0		2.0
NP COST GAS	\$285.7	2035	0.6	1.0	0.5	17.9		20.0	5.4	4.22	2.0		2.0
+ term & site restoration	\$30.0	2036	0.5	1.0	0.5	18.3		20.4	5.5	4.31	2.0		2.0
NP COST GAS	\$315.7	2037	0.5	1.0	0.5	18.7		20.7	5.6	4.39	2.0		2.0
		2038	0.5	1.0	0.5	19.0		21.1	5.7	4.48	2.0		2.0
NP COST BRADLEY	\$229.9	2039	0.5	1.0	0.5	19.4		21.4	5.8	4.57	2.0		2.0
NET SAVINGS BRADLEY	\$85.8	2040	0.5	1.0	0.5	19.8		21.8	5.9	4.66	2.0		2.0

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Bradgas1; 861217-29).

TABLE C.3 DELAY OF BRADLEY LAKE AND GAS GENERATION ALTERNATIVE:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL RATE (C/KWH)	REAL			REAL RATE cents/Kwh	
									WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)		TOTAL BRADLEY (\$86 MLN)
Base Capital Cost Excluding IDC (\$1986/net kw): \$400	1987	0.0							\$1.63				
Capacity (net kw): 90,000	1988	0.0							1.66				
	1989	0.0							1.70				
	1990	0.0							1.73				
Construction Period (years): 2	1991	0.0							1.77				
Total Bonds: \$69.3	1992	0.0							1.80				
Bond Term (years): 20	1993	0.0							1.84				
Long-Term Interest Rate: 10.0%	1994	0.0							1.87				
Bond Payment (1997\$): \$8.1	1995	0.0							1.91		41.3	41.3	11.2
	1996	18.0							1.95		39.5	39.5	10.7
Inflation Rate: 4.5%	1997	18.0	5.0				5.0	1.4	1.99		37.8	37.8	10.2
Reinvest Rate: 6.0%	1998		4.8	1.0	0.5	8.6	14.9	4.0	2.03	2.0	36.2	36.2	9.8
Discount Rate: 3.5%	1999		4.6	1.0	0.5	8.8	14.9	4.0	2.07	2.0	34.6	36.6	9.9
	2000		4.4	1.0	0.5	9.0	14.9	4.0	2.11	2.0	33.2	35.2	9.5
Fixed O&M Cost (\$1986/kw/yr): \$11.25	2001		4.2	1.0	0.5	9.1	14.9	4.0	2.15	2.0	31.7	33.7	9.1
Variable O&M Cost (\$1986/kwh): \$0.0014	2002		4.0	1.0	0.5	9.3	14.9	4.0	2.20	2.0	30.4	32.4	8.8
	2003		3.9	1.0	0.5	9.5	14.9	4.0	2.24	2.0	29.1	31.1	8.4
New Turbine Heat Rate (BTU/kwh): 11,500	2004		3.7	1.0	0.5	9.7	14.9	4.0	2.29	2.0	27.8	29.8	8.1
	2005		3.5	1.0	0.5	9.9	15.0	4.0	2.33	2.0	26.6	28.6	7.7
Wellhead Gas Price (\$1986/MMBTU): \$1.60	2006		3.4	1.0	0.5	10.1	15.0	4.1	2.36	2.0	25.5	27.5	7.4
	2007		3.2	1.0	0.5	10.3	15.1	4.1	2.43	2.0	24.4	26.4	7.1
Gas Delivery (\$86): \$0.00	2008		3.1	1.0	0.5	10.5	15.1	4.1	2.47	2.0	23.3	25.3	6.9
	2009		3.0	1.0	0.5	10.7	15.2	4.1	2.52	2.0	22.3	24.3	6.6
Real Wellhead Price Escalation Rate: 2.0%	2010		2.8	1.0	0.5	10.9	15.3	4.1	2.57	2.0	21.3	23.3	6.3
	2011		2.7	1.0	0.5	11.1	15.4	4.2	2.62	2.0	20.4	22.4	6.1
Escalation Rate: 2.0%	2012		2.6	1.0	0.5	11.4	15.5	4.2	2.68	2.0	19.6	21.6	5.8
	2013		2.5	1.0	0.5	11.6	15.6	4.2	2.73	2.0	18.7	20.7	5.6
Escalation Rate: 2.0%	2014		2.4	1.0	0.5	11.8	15.7	4.3	2.79	2.0	17.9	19.9	5.4
	2015		2.3	1.0	0.5	12.1	15.9	4.3	2.84	2.0	17.1	19.1	5.2
			2.3	1.0	0.5	12.1	15.9	4.3	2.84	2.0	16.4	18.4	5.0

TABLE C.3 DELAY OF BRADLEY LAKE AND GAS GENERATION ALTERNATIVE:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL RATE (C/KWH)	REAL				REAL RATE cents/Kwh
									WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$86 MLN)	
Cash Flow for Base	2016		2.2	1.0	0.5	12.3	16.0	4.3	2.90	2.0	15.7	17.7	4.8
Construction Cost:	2017		2.1	1.0	0.5	12.6	16.2	4.4	2.96	2.0	15.0	17.0	4.6
1987	0% 2018		2.0	1.0	0.5	12.8	16.3	4.4	3.02	2.0	14.4	16.4	4.4
1988	0% 2019		1.9	1.0	0.5	13.1	16.5	4.5	3.08	2.0	13.7	15.7	4.3
1989	0% 2020		1.8	1.0	0.5	13.3	16.7	4.5	3.14	2.0	13.2	15.2	4.1
1990	0% 2021		1.7	1.0	0.5	13.6	16.9	4.6	3.20	2.0	12.6	14.6	4.0
1991	0% 2022		1.7	1.0	0.5	13.9	17.1	4.6	3.26	2.0	12.0	14.0	3.8
1992	0% 2023		1.6	1.0	0.5	14.1	17.3	4.7	3.33	2.0	11.5	13.5	3.7
1993	0% 2024		1.5	1.0	0.5	14.4	17.5	4.7	3.40	2.0		2.0	0.5
1994	0% 2025		1.5	1.0	0.5	14.7	17.7	4.8	3.46	2.0		2.0	0.5
1995	0% 2026		1.4	1.0	0.5	15.0	17.9	4.9	3.53	2.0		2.0	0.5
1996	50% 2027		1.3	1.0	0.5	15.3	18.2	4.9	3.60	2.0		2.0	0.5
1997	50% 2028		1.3	1.0	0.5	15.6	18.4	5.0	3.68	2.0		2.0	0.5
	2029		1.2	1.0	0.5	15.9	18.7	5.1	3.75	2.0		2.0	0.5
Load Factor: 47%	2030		1.2	1.0	0.5	16.2	18.9	5.1	3.82	2.0		2.0	0.5
Annual Energy (gwh): 369.2	2031		1.1	1.0	0.5	16.6	19.2	5.2	3.90	2.0		2.0	0.5
Transmission Cost	2032		1.1	1.0	0.5	16.9	19.5	5.3	3.98	2.0		2.0	0.5
(\$1986 Millions): \$0.0	2033		1.0	1.0	0.5	17.2	19.8	5.4	4.06	2.0		2.0	0.5
	2034		1.0	1.0	0.5	17.6	20.1	5.4	4.14	2.0		2.0	0.5
BRADLEY LAKE	2035		0.9	1.0	0.5	17.9	20.4	5.5	4.22	2.0		2.0	0.5
Cost to Complete: \$415.1	2036		0.9	1.0	0.5	18.3	20.7	5.6	4.31	2.0		2.0	0.5
Construction (years): 4	2037		0.9	1.0	0.5	18.7	21.0	5.7	4.39	2.0		2.0	0.5
Total Bonds: \$553.9	2038		0.8	1.0	0.5	19.0	21.4	5.8	4.48	2.0		2.0	0.5
Debt Service (30 yr): \$58.8	2039		0.8	1.0	0.5	19.4	21.7	5.9	4.57	2.0		2.0	0.5
	2040		0.8	1.0	0.5	19.8	22.1	6.0	4.66	2.0		2.0	0.5
NP COST GAS \$250.6	2041		0.7	1.0	0.5	20.2	22.4	6.1	4.75	2.0		2.0	0.5
+ term & site restoration \$30.0	2042		0.7	1.0	0.5	20.6	22.8	6.2	4.85	2.0		2.0	0.5
NP COST GAS \$280.6	2043		0.7	1.0	0.5	21.0	23.2	6.3	4.95	2.0		2.0	0.5
	2044		0.6	1.0	0.5	21.4	23.6	6.4	5.05	2.0		2.0	0.5
NP COST BRADLEY \$406.7	2045		0.6	1.0	0.5	21.9	24.0	6.5	5.15	2.0		2.0	0.5
NET SAVINGS BRADLEY (\$126.0)	2046		0.6	1.0	0.5	22.3	24.4	6.6	5.25	2.0		2.0	0.5
	2047		0.6	1.0	0.5	22.7	24.8	6.7	5.35	2.0		2.0	0.5
	2048		0.5	1.0	0.5	23.2	25.3	6.8	5.46	2.0		2.0	0.5

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Bradgas3; 861217-29).

TABLE C.4 DELAY OF GAS GENERATION ALTERNATIVE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COST (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL RATE (C/KWH)	REAL					
									WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$86 MLN)		
Base Capital Cost Excluding IDC (\$1986/net kw):	\$400													
	1987	0.0								\$1.63				
Capacity (net kw):	90,000													
	1988	0.0								1.66				
	1989	0.0								1.70				
Construction Period (years):	2													
	1990	0.0								1.73				
Total Bonds:	\$69.3													
	1991	0.0								1.77	2.0	20.2	22.2	
Bond Term (years):	20													
	1992	0.0								1.80	2.0	19.3	21.3	
Long-Term Interest Rate:	10.0%													
	1993	0.0								1.84	2.0	18.5	20.5	
Bond Payment (1997\$):	\$8.1													
	1994	0.0								1.87	2.0	17.7	19.7	
	1995	0.0								1.91	2.0	16.9	18.9	
Inflation Rate:	4.5%													
	1996	18.0								1.95	2.0	16.2	18.2	
Reinvest Rate:	6.0%													
	1997	18.0	5.0				5.0	1.4		1.99	2.0	15.5	17.5	
Discount Rate:	3.5%													
	1998		4.8	1.0	0.5	8.6	14.9	4.0		2.03	2.0	14.8	16.8	
	1999		4.6	1.0	0.5	8.8	14.9	4.0		2.07	2.0	14.2	16.2	
	2000		4.4	1.0	0.5	9.0	14.9	4.0		2.11	2.0	13.6	15.6	
Fixed O&M Cost (\$1986/kw/yr):	\$11.25													
	2001		4.2	1.0	0.5	9.1	14.9	4.0		2.15	2.0	13.0	15.0	
	2002		4.0	1.0	0.5	9.3	14.9	4.0		2.20	2.0	12.4	14.4	
	2003		3.9	1.0	0.5	9.5	14.9	4.0		2.24	2.0	11.9	13.9	
Variable O&M Cost (\$1986/kwh):	\$0.0014													
	2004		3.7	1.0	0.5	9.7	14.9	4.0		2.29	2.0	11.4	13.4	
	2005		3.5	1.0	0.5	9.9	15.0	4.0		2.33	2.0	10.9	12.9	
New Turbine Heat Rate (Btu/kwh):	11,500													
	2006		3.4	1.0	0.5	10.1	15.0	4.1		2.38	2.0	10.4	12.4	
	2007		3.2	1.0	0.5	10.3	15.1	4.1		2.43	2.0	10.0	12.0	
	2008		3.1	1.0	0.5	10.5	15.1	4.1		2.47	2.0	9.5	11.5	
	2009		3.0	1.0	0.5	10.7	15.2	4.1		2.52	2.0	9.1	11.1	
Wellhead Gas Price (\$1986/MMBTU):	\$1.60													
	2010		2.8	1.0	0.5	10.9	15.3	4.1		2.57	2.0	8.7	10.7	
	2011		2.7	1.0	0.5	11.1	15.4	4.2		2.62	2.0	8.4	10.4	
Gas Delivery (\$86):	\$0.00													
	2012		2.6	1.0	0.5	11.4	15.5	4.2		2.68	2.0	8.0	10.0	
Real Wellhead Price														
	2013		2.5	1.0	0.5	11.6	15.6	4.2		2.73	2.0	7.7	9.7	
Escalation Rate:	2.0%													
	2014		2.4	1.0	0.5	11.8	15.7	4.3		2.79	2.0	7.3	9.3	
	2015		2.3	1.0	0.5	12.1	15.9	4.3		2.84	2.0	7.0	9.0	

TABLE C.4 DELAY OF GAS GENERATION ALTERNATIVE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	YEAR	CAPITAL COST (\$86 MLN)	DEBT SERVICE (\$86 MLN)	FIXED O&M (\$86 MLN)	VARIABLE O&M (\$86 MLN)	FUEL COS (\$86 MLN)	TOTAL COST (\$86 MLN)	REAL	REAL	BRADLEY	BRADLEY	TOTAL
								REAL RATE (C/KWH)	WELLHEAD GAS PRICE (\$86/MMBTU)	BRADLEY O&M (\$86 MLN)	BRADLEY DS (\$86 MLN)	TOTAL BRADLEY (\$86 MLN)
Cash Flow for Base	2016		2.2	1.0	0.5	12.3	16.0	4.3	2.90	2.0	6.7	8.7
Construction Cost:	2017		2.1	1.0	0.5	12.6	16.2	4.4	2.96	2.0	6.4	8.4
1987	0%	2018	2.0	1.0	0.5	12.8	16.3	4.4	3.02	2.0	6.1	8.1
1988	0%	2019	1.9	1.0	0.5	13.1	16.5	4.5	3.08	2.0	5.9	7.9
1989	0%	2020	1.8	1.0	0.5	13.3	16.7	4.5	3.14	2.0	5.6	7.6
1990	0%	2021	1.7	1.0	0.5	13.6	16.9	4.6	3.20	2.0		2.0
1991	0%	2022	1.7	1.0	0.5	13.9	17.1	4.6	3.26	2.0		2.0
1992	0%	2023	1.6	1.0	0.5	14.1	17.3	4.7	3.33	2.0		2.0
1993	0%	2024	1.5	1.0	0.5	14.4	17.5	4.7	3.40	2.0		2.0
1994	0%	2025	1.5	1.0	0.5	14.7	17.7	4.8	3.46	2.0		2.0
1995	0%	2026	1.4	1.0	0.5	15.0	17.9	4.9	3.53	2.0		2.0
1996	50%	2027	1.3	1.0	0.5	15.3	18.2	4.9	3.60	2.0		2.0
1997	50%	2028	1.3	1.0	0.5	15.6	18.4	5.0	3.68	2.0		2.0
		2029	1.2	1.0	0.5	15.9	18.7	5.1	3.75	2.0		2.0
Load Factor:	47%	2030	1.2	1.0	0.5	16.2	18.9	5.1	3.82	2.0		2.0
Annual Energy (gwh):	369.2	2031	1.1	1.0	0.5	16.6	19.2	5.2	3.90	2.0		2.0
Transmission Cost		2032	1.1	1.0	0.5	16.9	19.5	5.3	3.98	2.0		2.0
(\$1986 Millions):	\$0.0	2033	1.0	1.0	0.5	17.2	19.8	5.4	4.06	2.0		2.0
		2034	1.0	1.0	0.5	17.6	20.1	5.4	4.14	2.0		2.0
BRADLEY LAKE		2035	0.9	1.0	0.5	17.9	20.4	5.5	4.22	2.0		2.0
Cost to Complete:	\$283.0	2036	0.9	1.0	0.5	18.3	20.7	5.6	4.31	2.0		2.0
Debt Service (30 yr):	\$25.1	2037	0.9	1.0	0.5	18.7	21.0	5.7	4.39	2.0		2.0
		2038	0.8	1.0	0.5	19.0	21.4	5.8	4.48	2.0		2.0
NP COST GAS	\$250.6	2039	0.8	1.0	0.5	19.4	21.7	5.9	4.57	2.0		2.0
+ term & site restoration	\$30.0	2040	0.8	1.0	0.5	19.8	22.1	6.0	4.66	2.0		2.0
NP COST GAS	\$280.6											
NP COST BRADLEY	\$244.6											
NET SAVINGS BRADLEY	\$36.0											

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Bradgas2; 861217-29).

HOUSE RESEARCH
RAILBELT ENERGY ANALYSIS

	<u>Completion Date</u>
I) Railbelt Energy Demand	March 18, 1987
A) Projected Railbelt Electrical Demand	
B) Demand for Bradley Lake Power	
C) Existing Installed Capacity and Retirement Schedules in Light of Current Revised Demand Forecasts.	
II) Bradley Lake Project	March 18, 1987
A) Examination of OMB's Feasibility Analysis	
B) Economic Feasibility Compared to Gas Alternative	
III) PURPA Generating Facilities	April 9, 1987
A) Regulatory background	
B) Bradley Lake Project Financing and Power Sales Agreements	
IV) Additional Issues	
A) Long-Term Gas Availability for Power Generation	April 10, 1987
B) Bradley Lake Restoration Requirements by FERC	
V) Transmission Lines	May 1, 1987
A) Kenai-Anchorage Transmission Line:	
1) Current and Projected Electrical Demand in Kenai and Anchorage	
2) Power Displacement: Generating Capacity	
3) Existing Line Reliability and Upgradability	
4) Natural Gas Price Differential Between Kenai and Anchorage	
5) Cost of Four Alternate Routes	

- Completion Date
- B) Anchorage-Fairbanks Intertie May 1, 1987
 - 1) Current and Projected Electrical Demand in Anchorage and Fairbanks
 - 2) Current Intertie Usage/Revenue Sharing/Reliability
 - 3) Impact of Fuel Oil Prices on Intertie Usage

 - C) Review/Critique Alaska Power Authority Transmission Lines Analyses May 1, 1987

 - D) Cost/Benefit Analyses for Transmission Lines May 1, 1987
 - 1) Anchorage-Kenai
 - a) No change
 - b) Upgrade existing line
 - c) New line

 - 2) Anchorage-Fairbank
 - 1) No change
 - 2) Total upgrade
 - 3) Upgrade sections over time

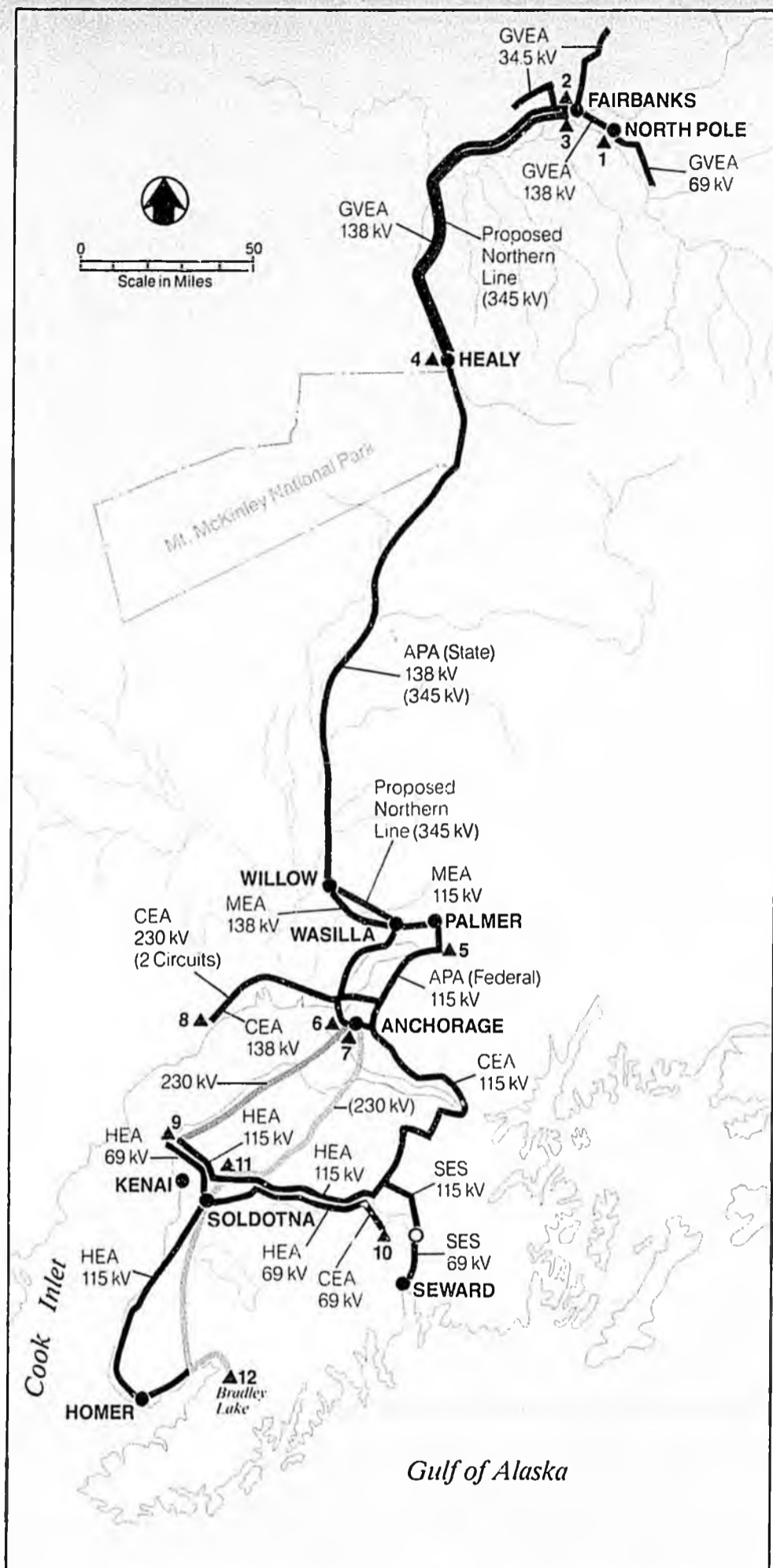
 - VII) **Financing Mechanisms for Bradley Lake and Transmission Lines** May 1, 1987
 - A) Identify Existing Funding Sources
 - 1) Railbelt Energy Fund
 - 2) Accrued Interest
 - 3) Remainder of Bradley Appropriations
 - 4) Bond Market

 - B) Financing Scenarios
 - 1) Examine various financing mechanisms with respect to State contribution, consumer rates, and the long-term integrity of a Railbelt Energy Fund
 - 2) Bradley Lake Project Only
 - a) Utilities pay \$175 million bond, State pays remainder
 - b) State contributes larger subsidy
 - c) Four-dam pool loan concept
 - 3) Bradley Lake Plus Kenai and/or Fairbanks Intertie(s)
 - a) Spend all of Railbelt Energy Fund
 - .
 - .
 - z) Railbelt Fund as a revolving loan fund to pay for transmission lines over time

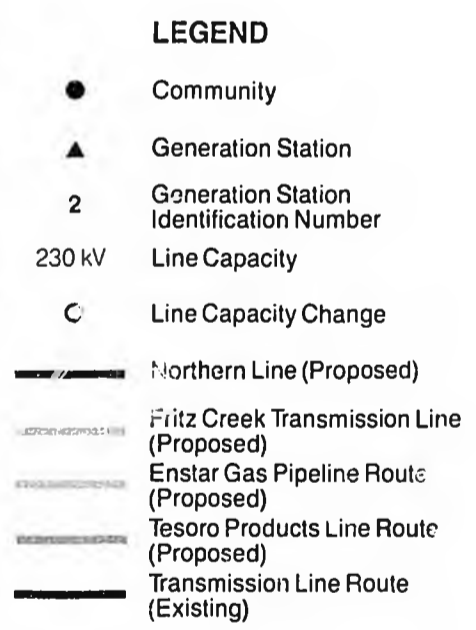
HOUSE RESEARCH
RAILBELT ENERGY ANALYSIS

	<u>Completion Date</u>
I) Railbelt Energy Demand	March 18, 1987
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3) Existing Line Reliability and Upgradability	
4) Natural Gas Price Differential Between Kenai and Anchorage	
5) Cost of Four Alternate Routes	

- | | <u>Completion Date</u> |
|---|------------------------|
| B) Anchorage-Fairbanks Intertie | May 1, 1987 |
| 1) Current and Projected Electrical Demand in Anchorage and Fairbanks | |
| 2) Current Intertie Usage/Revenue Sharing/Reliability | |
| 3) Effect of Fuel Oil Prices on Intertie Usage | |
| C) Review/Critique Alaska Power Authority Transmission Lines Analyses | May 1, 1987 |
| D) Cost/Benefit Analyses for Transmission Lines | May 1, 1987 |
| 1) Anchorage-Kenai | |
| a) No change | |
| b) Upgrade existing line | |
| c) New line | |
| 2) Anchorage-Fairbank | |
| 1) No change | |
| 2) Total upgrade | |
| 3) Upgrade sections over time | |
| VII) Financing Mechanisms for Bradley Lake and Transmission Lines | May 1, 1987 |
| A) Identify Existing Funding Sources | |
| 1) Railbelt Energy Fund | |
| 2) Accrued Interest | |
| 3) Remainder of Bradley Appropriations | |
| 4) Bond Market | |
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| 1) Examine various financing mechanisms with respect to State contribution, consumer rates, and the long-term integrity of a Railbelt Energy Fund | |
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| b) State contributes larger subsidy | |
| c) Four-dam pool loan concept | |
| 3) Bradley Lake Plus Kenai and/or Fairbanks Intertie(s) | |
| a) Spend all of Railbelt Energy Fund | |
| z) Railbelt Fund as a revolving loan fund to pay for transmission lines over time | |



Railbelt Generation and Transmission Systems



Prepared by ARECA

1. Oil Fired Generation — 121.8 mW — Golden Valley Electric Association — North Pole
2. Oil Fired Generation — 40.6 mW — Fairbanks Municipal Utilities System — Fairbanks
Coal Fired Generation — 28.6 mW — Fairbanks Municipal Utilities System — Fairbanks
3. Oil Fired Generation — 51 mW — Golden Valley Electric Association — Fairbanks
4. Coal Fired Generation — 25 mW — Golden Valley Electric Association — Healy
5. Hydroelectric Generation — 30 mW — Alaska Power Administration (Federal) — Eklutna
6. Natural Gas Generation — 330 mW — Anchorage Municipal Light & Power — Anchorage
7. Natural Gas Generation — 49.4 mW — Chugach Electric Association — Anchorage
8. Natural Gas Generation — 360 mW — Chugach Electric Association — Beluga
9. Natural Gas Generation — 81.7 mW — Chugach Electric Association — Bernice Lake
10. Hydroelectric Generation — 17.4 mW — Chugach Electric Association — Cooper Lake
11. Natural Gas Generation — 38.5 mW — Alaska Electric Generation & Transmission — Soldotna
12. Hydroelectric Generation — 90 mW — Alaska Power Authority (State) — Bradley Lake

* ORIGINAL
 * SENT: 04/08/87 TIME: 13:36 *
 * FROM: LIQ. MATSU *
 * SUBJECT: S RES ELECTRIC *
 * PRINT DATE: 04/08/87 TIME: 13:36 *
 * *

GLENN,
 OUR PARTICIPANT, ~~SENATE SENATOR~~ OF M.E.A., WILL BE ARRIVING AROUND
 3:00PM. JUST WANTED TO LET YOU KNOW IN CASE YOU NEEDED TO PASS
 THAT INFO ON TO THE CHAIR. WE WILL DIAL IN AS SOON AS HE
 ARRIVES.
 MARY - MATSU

 *
 * DELIVER TO: LTCCGTG *
 * *
 * ORIGINAL *
 * SENT: 04/08/87 TIME: 13:49 *
 * FROM: LTCCGTG FAIRBANKS *
 * SUBJECT: 4/8 SRES SB 205, 206, HB 120 *
 * PRINT DATE: 04/08/87 TIME: 13:49 *
 * *

DATE: APRIL 8, 1987
 SITE: FAIRBANKS
 SPONSOR: SENATE RESOURCES
 SUBJECT: SB 205, SB 206, HB 120
 MODERATOR: FRAN

 TESTIFY:
 NAME \ REPRESENTING ADDRESS PHONE #

 OBSERVE:
 NAME \ REPRESENTING ADDRESS PHONE #

1. ~~FRED PRONTO~~

TELECONFERENCE PARTICIPATION

SPONSOR _____

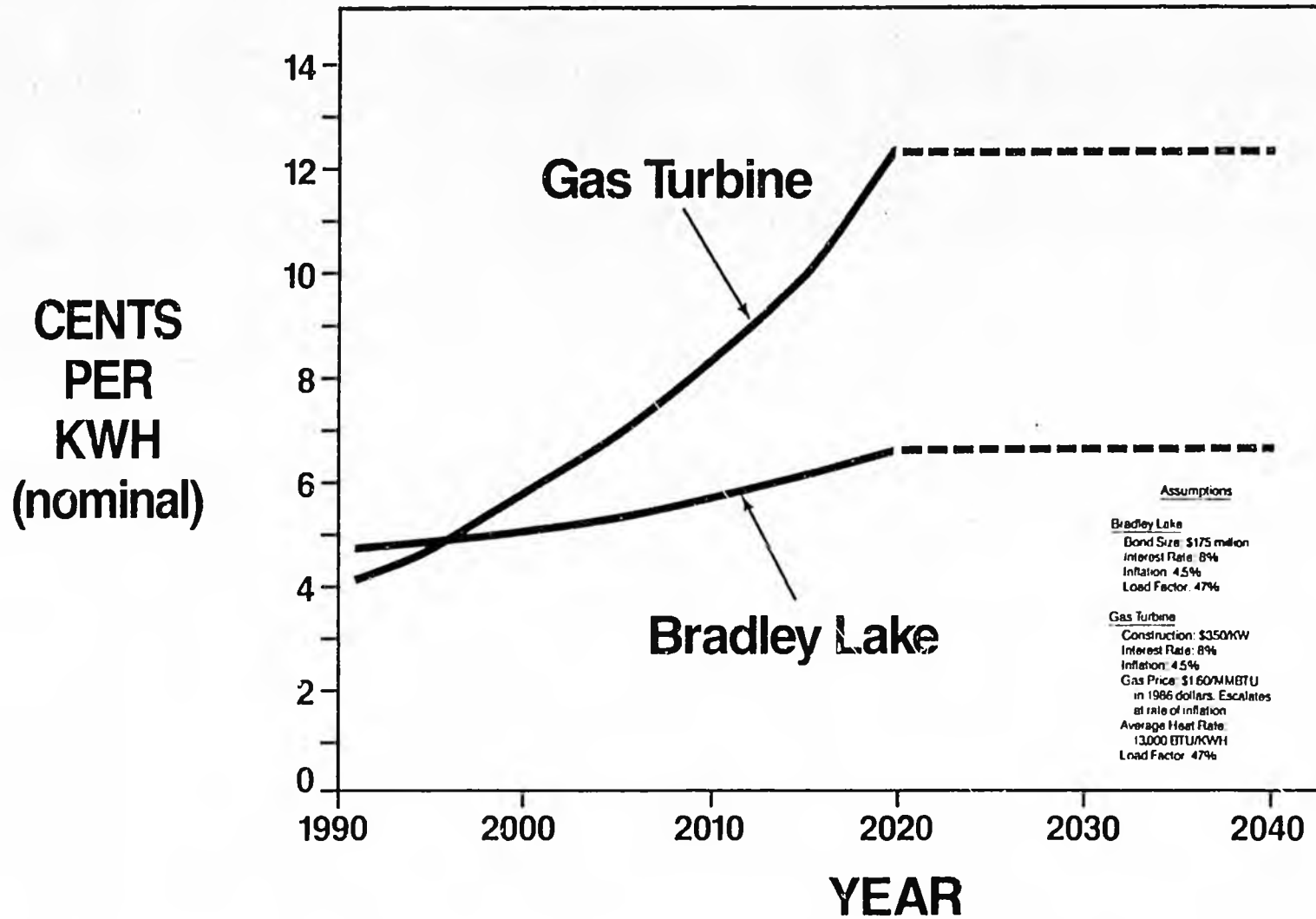
DATE/TIME _____

SUBJECT _____

LIO

<p>ANCHORAGE 2 observers — Jeff Bohman 2 to testify — Bob Rognerd</p>	PETERSBURG*
BARROW*	SITKA
BETHEL	SOLDOTNA
DELTA JUNCTION*	VALDEZ*
DILLINGHAM*	LTC
<p>FAIRBANKS Fred Pratt</p>	FT. YUKON
GLENNALLEN*	GALENA
JUNEAU	HOMER
KETCHIKAN	NAKNEK
KODIAK	NEWHALEN
KOTZEBUE*	SAINT PAUL
<p>MAT-SU (will join @ 3:00pm) Bruce Scott</p>	SAND POINT
NOME*	TOGIAK
	UNALASKA
	WRANGELL
	SEWARD (not online)

BRADLEY LAKE vs. GAS TURBINE PROJECTED RATES



- Graph Tape 461

BRADLEY LAKE PROJECT
TOTAL COST IF TERMINATED

Expenditures Through March 31, 1987	\$	52.4 million
Additional Expenditure Through May 1987		5.0 million
Contract Termination Costs		4.4 million
Site Restoration Cost		<u>8.0-33.0 million</u>
TOTAL		<u><u>\$ 69.8-94.8 million</u></u>

LeResche
#2

top # 576



Alaska Power Authority

RAILBELT INTERTIE BENEFITS

Quantified

- Economy Interchange
- Reserve Sharing
- System Efficiency
- Siting Flexibility for New Plants

Not Quantified

- System Reliability
- Increased Utility Coordination
- Distribution of Bradley Lake Benefits
- Enhanced Competition Among Fuel Suppliers

LeResche #3 Top # 657



Alaska Power Authority

RAILBELT INTERTIE **COSTS AND BENEFITS**

(Expressed in 1986 Dollars)

	<u>Estimated Benefits</u>	<u>Estimated Costs</u>
Full Intertie Proposal	\$ 423 million	\$ 270 million
Anchorage to Kenai Peninsula Only	209 million	125 million
Anchorage to Fairbanks Only	211 million	145 million

Note: Costs include operations and maintenance for 30 years

* TELECOPY COVER LETTER *

DATE 4-8-87

TIME 10:35 am.

PLEASE DELIVER THE FOLLOWING PAGES TO:

Name: REP. SAM COTTON AND REP. PAT POURCHOT

Telecopier Number: 586-9648

FROM: JANET L. VEO
6133 E. 12th
Anchorage, AK. 99504

TRANSMITTING 7 PAGES
(INCLUDING THIS COVER PAGE)

IF TRANSMISSION IS NOT COMPLETE,
PLEASE CALL: (907) 564-6452

RE: Senate Resources Joint Meeting on Railbelt Energy
April 8, 1987 at 1:30 pm.

DATE: April 8, 1987

TO: Rep. Pat Pourchot
Rep. Sam Cotton

FROM: Janet L. Veo
8133 East 12th
Anchorage, AK 99504

Today at 1:30 pm, Capitol 516 a joint meeting with Senate Resources is meeting on Railbelt Energy. I have serious concerns regarding the Bradley Lake Hydroelectric Project and Anchorage/Fairbanks and Anchorage/Kenai interties and request that the railbelt utilities and the Alaska Power Authority (APA) be questioned on some of the following points. Before I proceed with these questions I would like to provide a brief overview.

Final Bradley Lake power sales agreements were before the Alaska Power Authority Board for approval on February 27, 1987. These documents were pulled from the agenda because a conditional letter was attached which required APA to build the Anchorage/Kenai Intertie and upgrade the Anchorage/Fairbanks intertie at a cost of \$200 million. On March 13, 1987 at the Alaska Power Authority Board meeting, Bob LeResch, Executive Director of APA, reported that the utilities would wait to sign the Bradley Lake power sales agreements after approaching the legislature for funding from the Railbelt Energy Fund. Since that date legislation has been introduced to remove any obstacles which may delay approval of the power sales agreements and completion of the interties. I believe this legislation is not in the interest of the consumer and citizens of this state. The legislation I refer to is:

SSSB 22, Sec. 2 which exempts the APA from the Alaska Public Utility Commission's (APUC) oversight with respect to wholesale power agreements. Reference the attached testimony.

SB 206, Sec. 2 (2) exempts APA from proving that the interties are economically feasible and in the best interest of the citizens. The interties is would be the largest power project to date and would not be required to prove economic viability.

My concerns and the questions I would hope you would ask the railbelt utilities and the Alaska Power Authority are as follows:

1. How do the utilities intend to use the regional grid (i.e., Anch/Kenai and Anch/Fai interties) and are there

any agreements in place to assure usage?

2. What organizational structure or document is in place to assure economy energy? This is to say the cheapest energy from available sources. Cheap energy occurs due to differences in prices, systems and generating units.

Is Chugach willing to pass on their low cost gas contracts to the power grid for the benefit of other utilities?

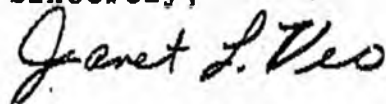
Is there central or coordinated dispatch to make low cost energy available among the utilities?

3. Why haven't the utilities made better use of the existing Anchorage/Fairbanks intertie? See the attached schedule of the 1986 Anchorage Fairbanks usage.

I would appreciate your careful review before the Legislature acts on questions regarding Bradley Lake and the specifically the interties. The concerns I express are on behalf of myself as a citizen and Anchorage area consumer. If you have any questions you may reach me at the following telephone numbers.

Day Telephone: (907) 564-6482
Evening Telephone: (907) 338-2974

Sincerely,



Janet L. Veo

TESTIMONY ON SSSB 22 - TO FINANCE COMMITTEE

APRIL 7, 1987

My name is Janet L. Veo. I reside at 6133 East 12th, Anchorage, AK. The testimony I am presenting is on behalf of myself as a private citizen.

I oppose passage of Sponsor Substitute Senate Bill 22, Section 2 (AS 42.05.431(c)). Exemption of the Alaska Power Authority from the Alaska Public Utilities Commission's oversight with respect to wholesale power sales contracts is not in the best interest of the consumer. I believe that the Bradley Lake Hydroelectric Project and the Anchorage/Kenai and Anchorage/Fairbanks transmission interties will significantly increase my cost of power as well as my cost of natural gas from Enstar for the next ten to fifteen years.

I want to give a concrete example of why I believe the Alaska Power Authority will not protect my interests as a consumer. The Alaska Power Authority has demonstrated its willingness to bypass statutory and regulatory requirements for public input as evidenced in their actions with respect to Bradley Lake and the interties. By virtue of the proposed power sales agreements, the Alaska Power Authority has contractually linked Bradley Lake and the interties as one project. The Alaska Power Authority has failed to go

through the statutory process as set forth in AS 44.83.177 through AS 44.83.187 and their own regulations.

To my knowledge, the Alaska Power Authority has not held any meetings expressly for the purpose of informing the public or for providing the opportunity for public comment regarding the interties. In fact, the Letter Agreement that spells out the conditions that would lead to execution of the power sales agreements is not available to the public. I requested copies of the proposed wholesale power sales agreements and the conditional letter agreement prior to the February 27, 1987, APA board meeting. These documents were before the Alaska Power Authority Board for final approval. I was denied copies by APA's Director of Finance. The reason given was that these documents were not signed. Furthermore, none of the power sales contract negotiation sessions with the utilities were published in the local newspaper for public notice. These measures have precluded any meaningful opportunity for public comment on the process leading up to final power sales agreements.

Alaska Power Authority stated in their board meeting of March 13, 1987, that they would proceed with construction of Bradley Lake once they have signed power sales agreements. The power sales agreements are contingent upon the utilities receiving funding by the legislature for the interties. With respect to the interties, the Alaska Power Authority has not completed a reconnaissance study which requires the

opportunity for public input, it has not held public comment meetings, it has not evaluated economic alternatives, it has not received Office of Budget and Management review and approval, nor has it completed a feasibility study and finance plan. Despite this, the Alaska Power Authority contractually committed itself to constructing the interties.

All wholesale power sales contracts by the Alaska Power Authority should be approved by the Alaska Public Utilities Commission before such agreements are finalized. Municipal ratepayers and cooperative members are one and the same. Any after-the-fact disallowance of Alaska Power Authority related costs of these entities is rendered meaningless unless Alaska Public Utilities Commission approval is obtained prior to final contracts. Repeatedly the Alaska Power Authority has refused to include the public in planning for the interties either as a stand alone project or as a newly reconfigured Bradley Lake/Intertie Project. Should the Alaska Public Utilities Commission not have oversight, the public will not be represented in the decision making process. I as a consumer will not have any protection from excessive costs and unwise decisions made by the Alaska Power Authority or the utilities. I strongly oppose passage of Sponsor Substitute Senate Bill 22, Section 2 (AS 42.05.431 (c)).

I thank you for your time and consideration of this matter.

ANCHORAGE FAIRBANKS INTERTIE

Month -----	GOLDEN VALLEY ELECTRIC (GWH)		MUS (GWH)	
	Estimated Takes -----	Actual Takes -----	Estimated Takes -----	Actual Takes -----
1986				
January	22.2	23.7		
February	22.0	18.0		
March	19.0	16.0		
April	17.9	10.6	Not available.	
May	15.0	0.4		
July	16.5	0.1		
December	25.5	0.4		
1987				
January	25.0	3.4	1.1	0.0
1986	73.5			
July '86 - Jan '87	140.0	7.5	11.0	0.1

Golden Valley is the main Anch/Fai intertie purchaser. The amount MUS takes is negligible.

Annual Line Capacity	613.2 Gwh	
GVE 1986 Takes	73.5 Gwh	= 12% of total capacity available
Jan - Apr '86 Takes	68.3 Gwh	= 93% of GVE '86 takes
May - Dec '86 Takes	5.2 Gwh	= 7% of GVE '86 takes

The decline in electrical takes from Anchorage by GVE occurred due to low low cost fuel oil in Fairbanks compared to Anchorage electrical prices.

Above data provided by Dick Emmermon, APA economist.

NOTE: There is no operating agreement in place for the proposed interties. An agreement should accompany the power sales agreements spelling out takes, payments of operating costs, maintenance, etc.



Alaska Power Authority

**Railbelt Intertie Proposal
Preliminary Economic
Assessment**

March 1987

RAILBELT INTERTIE PROPOSAL

PRELIMINARY ECONOMIC ASSESSMENT

Summary and Conclusions

A contract for \$25,000 was issued by the Alaska Power Authority to Lotus Consulting Group, an electric utility consulting firm based in California, for a preliminary assessment of economic benefits associated with two proposed transmission projects: upgrade of the existing Anchorage/Fairbanks intertie and construction of a new Anchorage/Kenai Peninsula intertie. Presented below is an overview of the issue, a summary of the benefit assessment undertaken by Lotus Consulting Group, discussion of other associated benefits that are not captured in that assessment, and a comparison of benefits with estimated project costs. The report prepared by Lotus Consulting Group is attached.

On the basis of the analysis performed, it is concluded that the proposed transmission projects are capable of delivering economic benefits in excess of their costs, and consequently warrant further consideration. The primary benefit categories that are quantified in the analysis are economy interchange, reserve sharing, system

efficiency and, to a partial extent, siting flexibility for new generating plants. Other benefits that are not quantified include improved system reliability, increased utility coordination, distribution of Bradley Lake benefits, and enhanced competition among fuel suppliers.

The sum of the benefits identified in the system modeling performed by Lotus Consulting Group is approximately \$150 million higher (in 1986 dollars) than the sum of the estimated costs. However, because most of the costs are incurred before most of the identified benefits are realized, the present value of costs and identified benefits are approximately the same. If the benefits not captured in the system modeling were brought into the comparison, then the present value of benefits would exceed the present value of costs.

Background and Purpose of the Study

A Request for Proposal (RFP) was issued by the Power Authority for a feasibility study of the Anchorage/Kenai Peninsula intertie in August 1986. The anticipated cost of that study is approximately \$300,000, with the State contributing half of the funding and the Railbelt utilities contributing the other half. The firm that won the contract included \$10,000 within its proposed budget to perform the economic cost/benefit part of the evaluation. However, despite

its superior qualifications to perform other elements of the analysis such as engineering, design, and cost estimation, that firm failed to demonstrate adequate ability regarding the estimation of economic benefits. As a result, that component of the project was deleted from the scope of work, and a decision was made by the Power Authority to pursue that analysis separately.

During the same period of time, the Railbelt Energy Council was formulating its proposal for the State to upgrade the existing Anchorage/Fairbanks intertie as well as construct a new Anchorage/Kenai Peninsula line. It became apparent that the economic merits of both transmission proposals would become a subject of interest during the 1987 legislative session. Consequently, the Power Authority decided to consolidate the economic assessment of both proposals within a single contract, and to aim for completion of that assessment as early as possible in the 1987 session. State funding in the amount of \$25,000 was identified for the effort, an RFP was developed in November 1986, and a contract was awarded to Lotus Consulting Group on December 31, 1986.

A highly detailed analysis of each alternative is not possible within the funding and time constraints that characterized this effort. The goal of the study, explicitly stated in the RFP, was to produce an understanding of the benefits of both transmission

proposals sufficient to judge whether they are promising with regard to economic feasibility criteria.

Existing Generation and Transmission System

For the following discussion, it may be helpful to refer to the simplified Railbelt transmission map shown in Figure 1.

On the Kenai Peninsula, existing generating capacity consists primarily of natural gas units at Bernice Lake and Soldotna totaling about 120 MW, and a hydroelectric facility at Cooper Lake of about 17 MW. The natural gas units are currently used primarily for reserve capacity and winter peaking requirements. Most of the electric energy currently consumed on the Kenai Peninsula is generated at the Beluga station and brought south over the existing transmission line. For the intertie economic study, it is assumed that the Bradley Lake project is operational throughout the period of analysis.

The existing transmission line between Anchorage and the Kenai Peninsula is owned by Chugach Electric Association, is constructed for operation at 115 KV and has a rated transfer capability of 55 MW. However, due to the demand of customers along the route and also due to significant line losses, it is estimated that only

40 MW can be assumed for delivery in Soldotna given a 55 MW input on the Anchorage end of the line. In addition, the line is subject to avalanche and weather induced outages, and as a result its reliability is a continuing concern. It is primarily for that reason that generating capacity has been installed on the Kenai Peninsula sufficient to meet its own peak requirements even though most of the annual energy is imported from the north. The existing transmission line should not be considered an adequate interconnection for purposes of future generation capacity expansion.

In the Anchorage/Beluga area, installed generating capacity totals about 768 MW, all of which consists of natural gas-fired units except for the 30 MW hydroelectric facility at Eklutna. Of the total gas-fired capacity, approximately 360 MW is located at the Beluga station on the west side of Cook Inlet. Sufficient transmission capability currently exists between the Beluga station and the Anchorage load center to permit moderate expansion of generating capacity at Beluga without encountering transmission constraints. The transmission system of Chugach Electric Association extends north to the Teeland substation, which is identified at the northern end of Knik Arm in Figure 1.

The intertie between Teeland substation and Fairbanks consists of three segments: approximately 25 miles of line between Teeland and Willow owned by Matanuska Electric Association, approximately 170

miles of line between Willow and Healy owned by the Alaska Power Authority, and approximately 100 miles of line between Healy and Fairbanks owned by Golden Valley Electric Association. The entire circuit from Teeland to Fairbanks is currently operated at 138 KV and has a transfer capability of 70 MW.

In the Fairbanks area, installed capacity currently operated by the local utilities consists primarily of oil-fired units totaling about 200 MW and coal-fired units totaling about 45 MW. Of the total coal-fired capacity, 25 MW is located at Healy. Because the transmission line owned by Golden Valley Electric Association between Healy and Fairbanks can accommodate power transfers up to 95 MW, the coal-fired unit at Healy can operate at full capacity and still allow transfers between Anchorage and Fairbanks of up to 70 MW.

Railbelt Intertie Proposal

There are two components of the Railbelt Intertie proposal put forward by the Railbelt Energy Council:

- 1) Upgrade of the existing Anchorage/Fairbanks intertie;
- 2) Construction of a new Anchorage/Kenai Peninsula intertie.

The portion of the Anchorage/Fairbanks intertie built by the Power Authority is constructed for operation at 345 KV. However, the line is currently operated at 138 KV due to transmission constraints at both ends of the Power Authority line, i.e. south of Willow and north of Healy. By upgrading the circuit where these constraints exist, the intertie could be operated at a full 345 KV which would increase the power transfer capability between Anchorage and Fairbanks from 70 MW to approximately 350 MW. For purposes of the economic analysis, it was assumed that upgrade of the Anchorage/Fairbanks intertie would allow a full 350 MW to be transferred over the line.

It is expected that a new Anchorage/Kenai Peninsula intertie would be constructed for operation at 230 KV, and that the full power transfer capability of that line would be approximately 250 MW. For purposes of the economic analysis, it was assumed that a new line would provide a reliable interconnection that would permit transfers up to 250 MW.

Categories of Benefit

There are several types of benefits that would be associated with the proposed Railbelt Intertie project:

* Economy Interchange: These are the savings that are produced

when a transmission project allows lower cost generation produced in one area to displace higher cost generation produced in another area. Examples of this would occur when the cost of oil-fired generation in Fairbanks exceeds the cost of natural gas-fired generation in the Cook Inlet area, or when the cost of gas-fired generation in Anchorage exceeds the cost of gas-fired generation on the Kenai Peninsula. Another example would occur if the cost of coal-fired generation in the Interior fell below the cost of generation in the Southcentral area.

* Reserve Sharing: These are the savings that are produced when a transmission project allows one or more utilities to forego building or maintaining a certain amount of reserve capacity by relying instead on reserves available elsewhere in the interconnected system. An example of this would occur if a reliable interconnection were built between Anchorage and the Kenai Peninsula. The total installed capacity needed to meet reserve requirements for both areas would be reduced as a result.

* Siting Flexibility for New Generating Plants: Improved transmission allows greater flexibility in siting new plants wherever the costs of operation, including the costs of fuel, are lowest. For example, if natural gas is available on the Kenai Peninsula at a significant savings relative to the price

of natural gas delivered to Anchorage, then siting new plants on the Kenai Peninsula rather than the Anchorage area would reduce system costs. A firm interconnection would allow that to occur. Other examples would be the possible future construction of a major coal-fired power plant or hydro project in the Railbelt. Improved transmission would allow such a plant to be built anywhere near the grid (e.g. Beluga, Matanuska Valley, Healy, Nenana) and still serve all of the major Railbelt load centers.

- * System Reliability: An improved transmission system can substantially reduce the number and extent of power outages. For example, the existing Anchorage/Fairbanks intertie made it possible for electricity demand in the Mat-Su Valley to be served from the Fairbanks area when service from Anchorage was interrupted during a recent incident. A new intertie between Anchorage and the Kenai Peninsula would produce a far more reliable connection between these two areas than currently exists, and would result in a reduction in the number and extent of power outages, particularly on the Kenai Peninsula.

- * System Efficiency: Transmission losses are reduced in higher voltage circuits. Power transfers between Anchorage and Fairbanks presently suffer losses on the order of 10% at 138 KV. For the economic study, it is assumed that such losses would be reduced to 4% at 345 KV (i.e. a reduction in

losses of 60%). Similarly, it is assumed in the economic study that losses over the existing Anchorage/Kenai Peninsula line are 10%, but that losses over a new 230 KV line would be reduced to 2% (i.e. a reduction in losses of 80%).

- * Increased Utility Coordination: It is generally agreed that the interests of Railbelt consumers would be served through increased integration of planning and operations among the seven Railbelt utilities. Strengthening the transmission network that links these utilities together would enhance the evolution of a more coordinated utility structure. Further, such improved linkage would facilitate the sharing of costs among all the utilities for future generation projects that may be economically attractive but which exceed the financial resources of any single utility or community.

- * Distribution of Bradley Lake Benefits: The Railbelt Intertie project would facilitate the distribution of Bradley Lake benefits throughout the Railbelt by providing each of the seven utilities with direct access to project output over reliable transmission facilities.

- * Enhanced Competition Among Fuel Suppliers: By improving the access of all seven utilities to energy sources throughout the Railbelt, the competition among those sources to supply utility requirements would be enhanced. Because each utility

would have a broader range of energy supply alternatives, the bargaining position of each utility with respect to potential fuel suppliers would be strengthened. The interests of consumers would be served by this improved position.

Study Methodology and Limitations

Lotus Consulting Group was directed to estimate the production costs of the Railbelt system for the period 1991 - 2020 with and without the proposed Kailbelt Intertie. A computerized production cost simulation model was used for the analysis. Because the costs of construction and maintenance of the Intertie project were not defined at the time the economic analysis was undertaken, no estimate of those costs was included. The work performed by Lotus Consulting Group therefore sheds light only on the benefit side of the ledger. It is necessary to go beyond the Lotus study in order to compare total benefits with estimated costs.

Of the various benefit categories noted above, there are several that are not accounted for in any way within the Lotus study, specifically the benefits of improved system reliability, increased utility coordination, distribution of Bradley Lake benefits, and enhanced competition among fuel suppliers. The benefit of siting flexibility for new generating plants is partially accounted for in

that the analysis assumes more advantageous siting of some new gas-fired capacity with the Intertie project in place. However, study constraints did not allow consideration of other possible siting benefits such as the impact of the Intertie on the viability of coal-fired generation or other large-scale projects.

The primary benefit categories that are quantified in the system modeling effort are economy interchange, reserve sharing, and system efficiency. All major assumptions and parameters for the study were provided to Lotus Consulting Group by the Power Authority.

Major Assumptions and Parameters

There are many assumptions that enter in to such an assessment, such as electricity demand forecasts and fuel price forecasts. For most of these assumptions, there are numerous values and trends that could be defined that fall within a range of reasonable possibilities. Yet single point estimates had to be selected for each of these assumptions because the time and dollar constraints did not permit review of multiple scenarios. The approach adopted for the study was to select values that were either suggested or agreed to by Railbelt utility representatives and that were judged by the Power Authority to be reasonable. These major assumptions and parameters are discussed below:

* Time Frame for the Analysis: System costs were modeled for the 30 year period from 1991 through 2020. Thirty years was selected as a conservative estimate of the economic life of the Intertie project. Although steel towers would be expected to last longer than 30 years, less durable elements of the Intertie project such as submarine cable may require renovation or replacement by that time. The initial year was set at 1991 because it would be difficult to complete the Intertie project prior to that time and because 1991 is expected to be the first full year of commercial operation for the Bradley Lake project.

* Fuel Price Forecasts: For an analysis of this type, the critical issue with regard to fossil fuel prices is not whether the absolute level of such prices is likely to increase, decrease, or remain the same, but rather what the price differentials are likely to be between different fuels delivered to different locations. For example, the economy interchange benefit of transmission capacity between Anchorage and Fairbanks is primarily based on the assumed differential between the price of natural gas in the Cook Inlet area and the price of fuel oil in the Fairbanks area. If the prices of those two fuels are competitive, there is little benefit in importing energy from one area to displace generation in the other area, whether or not the absolute level of prices is high or low. Conversely, a significant differential in price

can lead to a substantial benefit from economy interchange. Because the absolute level of fossil fuel prices is not central to the analysis, the approach adopted was to assume that the absolute level remains essentially constant in real terms (i.e. tracks the rate of inflation, no more and no less). This assumption was adopted for simplicity, and does not reflect any consideration by the State, the Power Authority, or the Railbelt utilities regarding the expected long-term outlook for fossil fuel prices in general.

Cook Inlet Natural Gas: Substantial gas-fired generating capacity exists in three distinct locations within the Cook Inlet area: the Beluga station on the west side of Cook Inlet, the Kenai Peninsula, and the Anchorage area itself. Because part of the Railbelt Intertie proposal consists of a new line between Anchorage and the Kenai Peninsula, and because reliable transmission already exists between Beluga and the Anchorage area, it is necessary to estimate the extent of any price differential for natural gas delivered to power plants in these three distinct locations. If a price differential exists, then the transmission proposal will produce benefit if it allows lower priced gas to be used to a greater extent.

The first step in estimating delivered price is to estimate the wellhead value. It is assumed for this analysis that the

wellhead value of natural gas is the same everywhere in the Cook Inlet area. A natural gas pipeline network is currently in place that extends from the Beluga field around Knik Arm to Anchorage, down to the Kenai Peninsula and then back across Cook Inlet to the vicinity of the Trading Bay field about 13 miles south of the Beluga station. In other words, with the exception of a short segment between Beluga and Trading Bay on the west side of the Inlet, a pipeline loop extends around the area linking the various major fields in the Cook Inlet region. The existence of this linkage supports the idea that the wellhead value of gas in one field is likely to be very much the same as the wellhead value of gas in another.

Natural gas for the Beluga generating station is obtained at the wellhead from the Beluga field through direct purchase from gas producers. Therefore, there is no charge for transporting the gas from the field to the plant. Natural gas for both Kenai Peninsula and Anchorage area plants is presently purchased from Enstar Natural Gas Company, which delivers gas to the plants through its pipeline system at a price that includes Enstar's gas acquisition cost and the cost of pipeline transportation. Based on discussion with an Enstar representative, it is estimated that the transportation cost component of the delivered price is currently \$.60 per MMBTU.

The utilities that currently operate gas-fired capacity on the Kenai Peninsula have expressed the expectation that gas in the future will be obtainable for their plants on the Kenai Peninsula at its wellhead value from suppliers other than Enstar. Consequently, it was assumed for this analysis that natural gas available to generating plants on the Kenai Peninsula will be priced at the assumed wellhead value (i.e. without a \$.60 per MMBTU transportation charge). In support of this assumption, it can be noted that the review of Bradley Lake economics issued by the State Office of Management and Budget (dated February 25, 1987) incorporates the same assumption that such gas will be available at its wellhead value.

For generating plants in the Anchorage area, it is assumed that future supplies of natural gas must still be delivered by pipeline at a price that includes a \$.60 per MMBTU transportation cost. Therefore, the approach adopted for the analysis was to assume the availability of natural gas both at Beluga and on the Kenai Peninsula at the wellhead value, but to assume that the price delivered to Anchorage area plants would equal the wellhead value plus \$.60 per MMBTU. Based on discussions with area utilities, it was assumed that the wellhead value is \$1.60 per MMBTU (implying a delivered price to Anchorage area plants of \$2.20 per MMBTU). These values were held constant in real terms throughout the period of

analysis. (1)

Fuel Oil in Fairbanks: It is necessary to estimate a fuel oil price in Fairbanks that is reasonably consistent with an assumed Cook Inlet natural gas price of \$1.60 at the wellhead. The judgment adopted for this analysis was that a Cook Inlet gas price of \$1.60 is roughly consistent with a long-run world oil price in the vicinity of \$20/barrel (in 1986 dollars). These magnitudes are supported in general by the observation that Cook Inlet wellhead values for natural gas were about \$2.30/MMBTU four years ago when the world oil price was approximately \$30/barrel. Since \$1.60 represents a reduction of about one-third, the oil price assumed to be consistent was reduced by about one-third.

Based on discussion with Fairbanks utility representatives, the assumed crude oil price of \$20/barrel was translated into an estimated fuel oil price of \$.48/gallon. That price, in turn, is equivalent to \$3.40/MMBTU. The analysis therefore assumes a long-run price differential between Cook Inlet natural gas at the wellhead and fuel oil available in Fairbanks of \$1.80/MMBTU (i.e. \$3.40 for fuel oil vs. \$1.60 for natural gas).

It is interesting to note that the feasibility study for the

existing Anchorage/Fairbanks intertie performed for the State in 1981 incorporated the assumption of a far greater differential between these two prices. Given a natural gas price of about \$1.60/MMBTU, the estimated fuel oil price assumed within that analysis was approximately \$9.00/MMBTU, a differential of \$7.40. This suggests that the estimated long-run price differential adopted for the current analysis may be conservative, as it is approximately one-fourth of the long-run differential previously estimated.

Coal in Fairbanks: As discussed below under the heading of "Expansion Plan," the scenario examined for this study involved a reduction in existing coal-fired capacity in the Fairbanks area from 45 MW today to a single 25 MW plant. The existing capacity consists of a 20 MW plant in Fairbanks that is scheduled for retirement in 2005 and a 25 MW minemouth plant at Healy that is assumed to be replaced in kind in 2002.

The current delivered price of coal to the 20 MW plant in Fairbanks is \$44.48/ton, or about \$2.85/MMBTU. The current minemouth price available to the Healy plant on long-term contract is \$1.30/MMBTU. The existing contract runs through 1994. For this analysis, it is assumed that a marginal price reduction will be negotiated for the Fairbanks plant yielding a delivered price of \$2.50/MMBTU until the plant is retired. For the Healy plant, it is assumed that the

price will remain at \$1.30/MMBTU (in 1986 dollars) through 1994, but will then increase to \$1.60/MMBTU in 1995 and remain constant in real terms thereafter. (2)

* Electricity Demand Forecast: Between 1965 and 1985, the average annual rate of increase in electricity demand in the Railbelt was 10.3%. Historical demand growth is shown in the table below:

Railbelt Utility Electric Energy Generation
(millions of kwh)

<u>Year</u>	<u>Southcentral Area</u>	<u>Fairbanks Area</u>	<u>Total Railbelt</u>
1965	367	120	487
1970	700	222	922
1975	1353	452	1805
1980	2112	440	2552
1985	2939	509	3448

During 1986, electric energy demand in the Railbelt was flat to declining. The most recent electricity demand forecasts

produced by the Railbelt utilities as of December 1986 reflect an expected average annual rate of demand growth of 1.5% over the long run. These utility forecasts were used for the present analysis, with the following three adjustments:

- 1) The utility forecasts cover the period 1987 - 2001. These forecasts were extended through the year 2020 by applying the average annual rate of increase indicated for the entire Railbelt through 2001. Because that average annual rate of increase was equal to 1.5%, the demand forecast used for this analysis reflects an average annual rate of increase of 1.5% for the entire period between 1987 and 2020.

- 2) The forecasts provided by Chugach Electric and its wholesale customers showed an anticipated dip in demand during the mid-1990s. This was based on an earlier assumption that rate shock would occur at that time due to the expiration of old Beluga gas contracts and the expectation that new gas prices would suddenly be encountered. Now, however, Chugach believes that rate shock can be avoided at that time by negotiating a gradual ramping in of the new price level. Consequently, the anticipated dip in demand has been leveled out for purposes of this analysis.

- 3) Though the military has historically generated its own power in the Fairbanks area, consideration is being given to the purchase of power from a local utility, which would result in substantial savings to the military according to the utility's estimates. The Fairbanks utility forecast has been adjusted upward to account for this alternative. Anticipated peak requirements have been increased by 30 MW as a result.

For major Railbelt studies in the past, specifically the Susitna and Bradley Lake feasibility studies, the Power Authority has produced its own electricity demand forecast in a two step process:

- 1) A forecast of employment, population, and households was generated by the Institute of Social and Economic Research (ISER) using their MAP econometric model. Assumptions provided to ISER by the Power Authority included oil price and State revenue scenarios.
- 2) These demographic forecasts were provided as inputs to the Railbelt Electricity Demand (RED) model maintained and operated by Battelle Pacific Northwest Laboratories in Richland, Washington. The demand forecast was an output of the RED model.

This modeling sequence was most recently authorized and funded by the Power Authority in 1985 in preparing a revision to the FERC license application for the Susitna project. The lowest oil price scenario specified as input to the modeling sequence was the forecast from Wharton Econometrics, which anticipated oil prices in 1985 dollars rising from \$24.80 in 1990 to \$31.30 in 2000, and then to \$40.70 in 2010. The average annual rate of electricity demand growth for the Railbelt that emerged from this scenario was 1.7%, a factor that reflected a substantial measure of anticipated, price-induced conservation. Higher oil price inputs resulted in similar long-term demand forecasts because the economic stimulus of higher prices was, in general, compensated by the effect of higher power costs in encouraging electric energy conservation through the price elasticity mechanism.

Implementation of the modeling sequence described above is time-consuming and costly, and could not have been accomplished within the constraints of the present analysis. Given the results of the modeling reported above from 1985 and the fact that electricity demand has grown at a far higher rate in the Railbelt during most of the last 25 years, an average annual rate of demand growth of 1.5% was judged to be reasonable.

* Expansion Plan: In order to model the costs of producing electricity for a future 30 year period, it is necessary to make assumptions regarding the retirement of existing generating units and the addition of new units both for replacement and for meeting anticipated load growth. A schedule of planned retirements was obtained from earlier Railbelt studies and reconfirmed with Railbelt utility representatives. The amount of new generating capacity that was assumed to be added to the system was based on the premise that a planning reserve margin of approximately 40% would be maintained in each of the three supply centers (i.e. Kenai Peninsula, Fairbanks, and Anchorage/Beluga) in the absence of any change in the existing transmission system. A planning reserve margin of 40% means that the amount of installed capacity exceeds the annual peak demand by 40%.

For most utilities in the lower 48 states, a planning reserve margin of 40% would be considered high. However, reserve margins in the Railbelt today are considerably higher than that, approximating 70% for the Railbelt as a whole. (3) Though Railbelt conditions warrant a relatively high level of reserves, it is generally agreed that evolution of the existing system has produced reserve margins today that are higher than necessary. Reserve margins for purposes of the analysis are therefore allowed to decline to a 40% level given the existing transmission system.

Transmission improvements can sometimes allow for additional sharing of reserves among regions and utilities, and consequently result in a reduction in the total amount of installed capacity required. For the present analysis, it is assumed that a new Anchorage/Kenai Peninsula line would have this effect but that an upgrade of the Anchorage/Fairbanks line would not.

For purposes of reserve planning, a given load center may rely on a transmission line from another area for a certain proportion of its reserves, but typically would not rely on the line for reserves that exceed the capacity of the largest installed unit operated within that load center. The existing Anchorage/Fairbanks intertie can now provide reliable access to 70 MW of capacity, an amount that approximates the size of the largest unit in the Fairbanks area. If the transfer capability of the line were increased to a full 350 MW, the line could be relied upon for significantly greater reserve capacity only if the size of the largest generating units in the Fairbanks area were significantly larger in the future.

In contrast, the proposed new line between Anchorage and the Kenai Peninsula would produce a far more reliable connection between these two areas than presently exists. As discussed in the report from Lotus Consulting Group, it was estimated

that the new Anchorage/Kenai Peninsula line would allow a reduction of installed reserves in the Anchorage/Beluga area from a 40% level to a 25% level, resulting in a reduction of installed capacity of approximately 100 MW relative to installed capacity required with the existing transmission system. The capacity expansion plan assumed for scenarios that include the new Anchorage/Kenai Peninsula line reflect this reduction in required installed capacity. (4)

Finally, the type and location of capacity additions had to be specified for the analysis. That specification was based primarily on the following three assumptions or principles:

- 1) The Bradley Lake project would be complete and operational throughout the analysis period.
- 2) The type of capacity additions should be consistent with the fuel price forecasts adopted for the analysis.
- 3) Within the constraints of reserve requirements and transmission capacity, new units should be located at sites that offer the lowest costs of operation.

The price level for natural gas adopted for this analysis is too low to permit effective penetration of the market by

coal-fired generation. As noted earlier, this does not constitute a conclusion by the Power Authority that expanded coal-fired generation in the Railbelt is implausible, but only that such expansion would be inconsistent with the fuel price scenario adopted for this specific analysis. The capacity "expansion plan" therefore entails a reduction of existing coal-fired capacity in the Fairbanks area from the current 45 MW to a single 25 MW plant at Healy. It is assumed that the Healy plant is replaced by a more efficient 25 MW coal-fired plant in the year 2002, which is the scheduled retirement date of the existing unit.

All other capacity additions besides Bradley Lake are assumed to consist of oil-fired combustion turbines in the Fairbanks area and natural gas-fired combustion turbines and combined cycle units in the southcentral area. Because the price of natural gas delivered to the power plant is assumed to be lower on the Kenai Peninsula than in the Anchorage area, it was further assumed for this analysis that the existing combined cycle capacity in the Anchorage area would be replaced by new combined cycle units on the Kenai Peninsula when the existing units are retired in scenarios that include the new Anchorage/Kenai Peninsula line. Those resulting production cost savings could not be realized in the "base case" because the existing transmission limitation would not allow that relocation of plant capacity to occur.

* Transmission Limitations

As noted earlier, the existing transmission line between Anchorage and the Kenai Peninsula can typically deliver about 40 MW in Soldotna given a 55 MW input on the Anchorage end of the line, due to the demands of customers along the route (e.g. Seward, Girdwood, and others) and due to transmission losses. An additional demand of approximately 5 MW is presently anticipated to occur in Seward over the next 5 years as a result of the new maximum security prison and other industrial development. Consequently, the delivery capability of 40 MW is expected to decline to about 35 MW by 1991, and to decline further thereafter to the extent that demand continues to grow along that route. Consequently, it is assumed for this analysis that the actual transfer capability of the existing line in 1991 will be 35 MW, and that such capacity will decline to 24 MW by the year 2020.

In addition, the cost of energy imported over the specified transmission lines has been increased to reflect the cost of transmission losses. For example, if the transmission loss over a particular line were 5%, the effect of that loss would be to increase the cost of the delivered energy by 5%.

Transmission losses for both the existing Anchorage/Fairbanks and Anchorage/Kenai Peninsula interties have been assumed to be 10%. Transmission loss between the Beluga station and

Anchorage has been assumed at 2%. Transmission losses for the upgraded Anchorage/Fairbanks intertie have been assumed at 4%, while 2% losses were assumed for the new Anchorage/Kenai Peninsula intertie.

- * Inflation and Discount Rate: A zero inflation rate is assumed for the economic analysis, and all costs are consequently expressed in terms of constant 1986 dollars. The real discount rate used for the calculation of net present value is 3.5%. Both of these are consistent with analysis parameters previously adopted by the Power Authority.

Results of System Modeling

Four distinct scenarios were modeled by Lotus Consulting Group:

- 1) Base Case: No change in existing transmission system.
- 2) Anchorage/Kenai Peninsula Only: A new intertie between Anchorage and the Kenai Peninsula is assumed that can transfer up to 250 MW on a reliable basis. No other change in the transmission system is assumed.
- 3) Anchorage/Fairbanks Upgrade Only: The existing intertie between Anchorage and Fairbanks is upgraded from its

present transfer capability of 70 MW to a full capability of 350 MW. No other change in the transmission system is assumed.

- 4) Full Railbelt Intertie Proposal: Both of the transmission improvements described above are assumed: the Anchorage/Kenai Peninsula Intertie and the Anchorage/Fairbanks upgrade.

The benefits that were quantified in this analysis are defined as the reduction in system cost that occurs as a result of a given transmission improvement. For example, the quantified benefit of the full Railbelt Intertie proposal is defined as the difference in system cost between scenario #1 and scenario #4, i.e. the base case cost minus the system cost given the full Intertie proposal. As discussed in greater detail in the report from Lotus Consulting Group, the value of the benefits identified in the system modeling exercise are as follows:

	Sum of Benefits in 1986 Dollars <u>(millions)</u>	Net Present Value of Benefits* <u>(millions)</u>
Full Intertie Proposal	\$423.2	\$204.6
Anchorage/Kenai Only	209.4	102.2
Anchorage/Fairbanks Only	210.6	101.2

* The base year for the net present value calculation is 1987.

Approximately 25% of the identified value of the Anchorage/Kenai Peninsula intertie is attributable to an estimated 100 MW of capacity cost savings made possible by reserve sharing. The other 75% of value is due primarily to siting flexibility for new plant capacity and economy interchange. It should be noted that the entire output of the Bradley Lake project is absorbed by the system in every scenario, including the base case. The effect of the intertie project on Bradley Lake would be to increase the distribution, not the amount, of Bradley Lake power sales.

The identified value of the Anchorage/Fairbanks upgrade is due primarily to the increased displacement of oil-fired generation in the Fairbanks area by natural gas-fired generation from the southcentral area. The key factors that contribute to this estimate are the assumed differential between the natural gas price and the fuel oil price, and the assumed electricity demand forecast over the long run for the Fairbanks area.

Other Benefits

- * System Reliability: Strengthening the transmission links between load centers creates a more resilient interconnected system that is better able to recover from disturbances such as the loss of a major generating unit. The existing transmission links between Anchorage and the Kenai Peninsula

and between Anchorage and Fairbanks will result in a separation of the three areas from one another if a significant disturbance occurs. This will usually result in the loss of load in at least two of the three areas. This separation occurs precisely at the time when it is most important to maintain the connection between areas to enable generating reserves to be transported to the area where the disturbance has occurred.

A stronger interconnection between the three load centers would reduce the probability of islanding (where one area loses its interconnection with another area), and consequently reduce the probability or magnitude of an outage.

* Enhanced Competition Among Fuel Suppliers: Though the magnitude of this benefit to Railbelt consumers is particularly difficult to assess, it could be one of the most significant aspects of the Intertie project. An example might help to illustrate the potential. A conservative estimate of natural gas consumption for electric generation during the early years of the study period is 30 BCF per year. At \$1.60 per MMBTU, the cost of that gas in 1986 dollars would be \$48 million per year. If enhanced competition resulted in a reduction in the wellhead price of 5 cents per MMBTU, the annual savings in fuel cost would amount to about \$1.5 million per year. Extending that benefit over the 30 year study

period from 1991 through 2020, the total saving achieved in this manner would be \$45 million, with a present value of about \$24 million. Oil and coal suppliers would be faced with similar competitive pressures.

Comparison of Costs and Benefits

There are two routes that are presently under consideration for a new Anchorage/Kenai Peninsula intertie. The best construction cost estimates currently available are about \$76 million for one route and about \$96 million for the other route. Because the construction cost is not the only consideration in route selection, a decision on a preferred route has not yet been made. For purposes of this preliminary comparison of costs and benefits, a construction cost of \$86 million is assumed based on the average cost of the two routes.

A study aimed at careful development of a cost estimate for the Anchorage/Fairbanks upgrade is scheduled to take place during the month of April, 1987. Until that study is complete, the best figure available continues to be a rough estimate of \$100 million. Therefore, the construction cost of the full Railbelt Intertie proposal is assumed to be \$186 million (in 1986 dollars) for purposes of this comparison. Further, it is assumed that these costs would be spread over a two year construction period,

specifically that half of the cost would be incurred in 1989 and the other half in 1990.

The annual operations and maintenance (O&M) cost of a new Anchorage/Kenai Peninsula line has been estimated at 1.5% of the construction cost by the firm that performed the preliminary engineering and design of those alternatives. Applying that 1.5% factor to the estimated construction cost of the full Railbelt Intertie proposal yields an estimated annual O&M cost of about \$2.8 million (in 1986 dollars). For this comparison, it is therefore assumed that a \$2.8 million O&M cost is incurred for the full project for each year between 1991 and 2020.

The sum of the construction and O&M costs described above for the full Railbelt Intertie proposal is approximately \$270 million (in 1986 dollars) over the period 1989 through 2020. The present value of those costs is approximately \$210 million. (5)

The sum of the benefits identified in the modeling exercise is therefore approximately \$150 million higher (in 1986 dollars) than the sum of the estimated costs (i.e. \$423 million in benefits vs. \$270 million in costs). However, because most of the costs are incurred before most of the identified benefits are realized, the present value of costs and identified benefits are approximately the same. If the benefits not captured in the modeling exercise

were brought into this comparison, then the present value of benefits would exceed the present value of costs.

As stated earlier, the goal of this study was to produce an understanding of the benefits of both transmission proposals sufficient to judge whether they are promising with regard to economic feasibility criteria. On the basis of the analysis performed, it is concluded that the proposed transmission projects are capable of delivering economic benefits in excess of their costs, and consequently warrant further consideration.

FOOTNOTES

- (1) It is recognized that Chugach Electric Association, which operates the Beluga generating station, still has access to significant quantities of old gas at Beluga at prices in the vicinity of \$.30 per MMBTU. In the initial modeling runs performed for this study, the Beluga gas price (in 1986 dollars) was assumed to ramp up from \$1.04/MMBTU in 1991 to \$1.60/MMBTU in 2003, remaining constant at \$1.60 thereafter. The price prior to 2003 represented a blend of old and new gas with a declining proportion of old. It was assumed that gas at the blended price was available to generate power for economy sales to other utilities, though such sales to Anchorage Municipal Light and Power (AML&P) were limited by forcing the AML&P units to run. (AML&P operates most of the "Anchorage area" generating capacity.) The basis for this constraint was the Chugach policy of reserving its limited supply of old gas for the benefit of its own customers.

In the final modeling runs, however, the Beluga gas price (in 1986 dollars) was assumed to be \$1.60 in 1991 and to remain constant in real terms thereafter. By ignoring the declining quantities of old gas, production costs are overestimated for the early years of the study, but are

overestimated equally in the base case (with the existing transmission system) and in the alternate case (with the improved transmission system). The benefit of ignoring the old gas for purposes of the modeling is that the price of energy for economy sales from Beluga will always reflect the price of new gas at \$1.60, which is more realistic than the assumption used initially. By assuring that economy sales from Beluga will be based only on the new gas price, it became possible to remove the "must run" requirement for the AML&P units.

Further, the analysis incorporates the assumption that natural gas will be available in sufficient quantities at wellhead prices at Beluga and on the Kenai Peninsula, and at wellhead plus transportation in Anchorage, to meet all estimated demands at these locations through the year 2020. Variations regarding the natural gas supply assumption could produce alternative patterns of use for the proposed transmission projects.

- (2) The estimated increase in the minemouth price to \$1.60/MMBTU for the Healy plant in 1995 is based on the following observations:

- 1) The current minemouth price for coal paid by

Fairbanks Municipal Utility System is \$34.48 per ton, which is approximately \$2.20/MMBTU.

- 2) The current minemouth price for coal paid by the U.S. military at Fort Wainwright is \$31.79 per ton, which is approximately \$2.05/MMBTU.

- 3) The prices noted above were recently negotiated, and suggest that the price of coal for the Healy power plant will be subject to upward pressure when the current contract expires. However, particularly as a result of the Anchorage/Fairbanks intertie, the extent of such increase will be limited by competition. The assumption of a moderate increase was therefore adopted in balancing these considerations.

- (3) The high existing reserve margins in the Railbelt are, in large part, due to the more hostile operating environment, the relatively large size of certain generating resources with respect to the loads of the individual systems, and the limited extent of interconnection among the utilities. Most of the existing generating capacity was installed prior to the construction of the Anchorage/Fairbanks intertie and also before the establishment of a high capacity interconnection

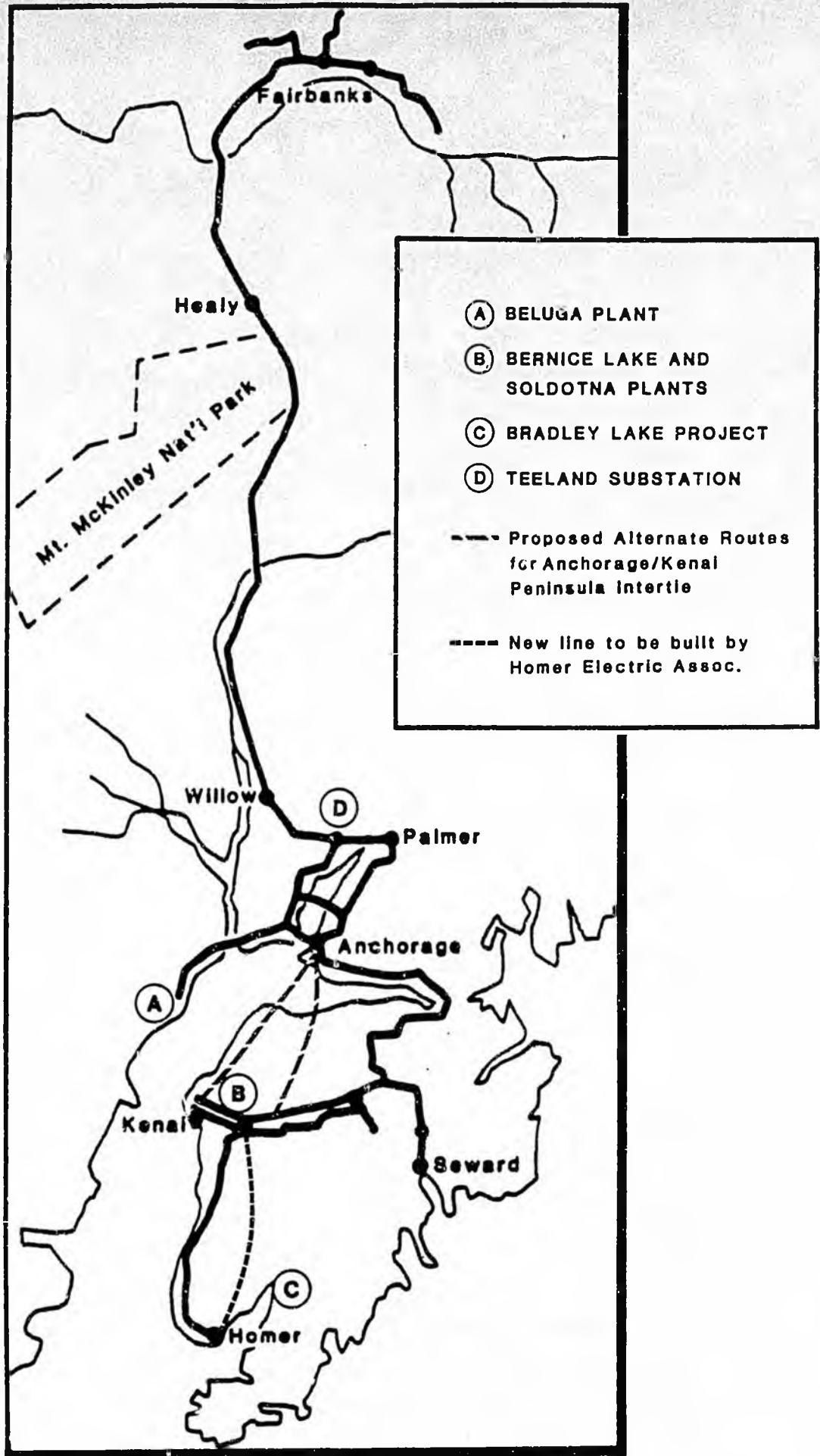
in Anchorage between Chugach Electric and Municipal Light and Power. Mild winters in recent years have also contributed to the appearance of high reserve margins.

(4) Although the reserve margins used in this analysis are considered reasonable for modeling purposes, actual reserve requirements may well depart from these general estimates according to the specific determinations and judgments of the utilities.

(5) For clarification, costs of the Intertie proposal were estimated as follows:

<u>YEAR</u>	<u>COST</u> <u>(Millions of 1986 Dollars)</u>	
1989	\$ 93.0	Construction
1990	93.0	Cost = \$186 million
1991	2.8	
1992	2.8	O&M Cost =
.	.	\$2.8 million / year
.	.	for 30 years
2020	<u>2.8</u>	
		(Net Present Value =
TOTAL	\$ 270.0	\$209.8 million)

Figure 1.



**Railbelt Transmission
Alternatives Assessment
Final Report**

March 31, 1987

Prepared For

**The Alaska Power Authority
Anchorage, Alaska**

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Executive Summary

The Alaska Power Authority (APA) contracted with Lotus Consulting Group to evaluate the benefits of alternative transmission configurations within the Alaska Railbelt region. The multi-area study was conducted using Lotus Consulting Group's propriety software program UPLAN. Based on data supplied by APA, the model determined the savings in production costs and capacity deferrals associated with the specified improvements to the transmission network.

The sum of the benefits identified over the 30 year planning horizon is \$423 million (expressed in 1986 dollars), with a net present value of \$205 million dollars. This result was based on increasing the interconnection between the Kenai Peninsula and Anchorage from 35 MW to 250 MW, and between Anchorage and Fairbanks from 70 MW to 350 Mw. These improvements allow for increased purchase of economy energy and the relocation of future generating resources to the Kenai Peninsula to take advantage of favorably priced natural gas. In addition, by creating an opportunity for reserve sharing between the Kenai Peninsula and Anchorage, the improvements allow deferral of 100 MW of new installed capacity in the Anchorage area.

The system modeling further indicates that the identified benefits are attributable to each of the two transmission proposals in nearly equal proportions. Construction of only the new intertie between the Kenai Peninsula and Anchorage produced benefits with a net present value of \$102 million dollars, while the net present value of benefits identified for the Anchorage/Fairbanks upgrade considered separately were \$101 million dollars.

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1. Introduction

In this report, we describe the data and methodology used to estimate the economic benefits associated with an increase in the transfer capability of the intertie connecting the Anchorage, Fairbanks and Kenai Peninsula regions of the Alaska Railbelt. A 30-year base case and alternative cases with expanded transmission capacities were analyzed.

The Alaska Power Authority has identified the goal of the study as the assessment of the benefits from improving the transmission network to provide for the increased integration of the Railbelt region. The benefits captured in the system modeling described in this report accrue from the increased opportunity for economy interchange, reduced capacity requirements through reserve sharing and increased system efficiency due to reduced transmission losses.

This report consists of three major sections. The first section describes the methodological foundations of the study and the data and assumptions from which the base case simulations for the region were developed. This first section includes Chapters 1 through 4.

Chapters 5 and 6 make up the second major division of the report. These chapters describe the three alternative scenarios which were evaluated. For each scenario, the major assumptions made and results obtained are presented.

Chapter 7 presents the overall results of the Railbelt Transmission assessment and our conclusions concerning the results.

The report concludes with a set of appendices, in which listings of the major input and output data sets from the simulations are provided for reference, along with a description of the UPLAN planning model.

2. Overview of Methodology

The basic outline of the existing Railbelt system is shown schematically in Figure 1. The system as modeled consists of 3 supply/demand nodes connected by bidirectional interties with known transfer capacity. Within the area covered by each node, no transmission limitations exist. Each node is modeled to serve its own local demand from its own generating resources with first priority, and will supply economy energy to the network only from excess energy available after satisfying local demand.

Figure 2 shows a typical three system network. In this network, a *terminal node* is a node tied to exactly one other node: nodes A and C are terminal nodes. An *interior node* is a node connected to two other nodes: system B is the only interior node in this network. For each node, we need the supply, financial, and load shape data normally required to model the node as an isolated system.

For each scenario, we analyze the network iteratively, beginning each solution from an opposite terminal node. The method consists of the following steps:

- 1) Starting with a terminal node, estimate its potential economy energy exports to its connecting node, given the intertie capacity and the export demand shape as seen through the intertie. The net profile for sales demand is the minimum of either the intertie capacity limit or the load shape of the connected node.
- 2) Transform the resulting potential energy export to one or more equivalent, capacity-factor limited purchase resource units, and add the unit(s) to the supply resources of the interconnected interior node.

Figure 1. Existing Transmission Capacity

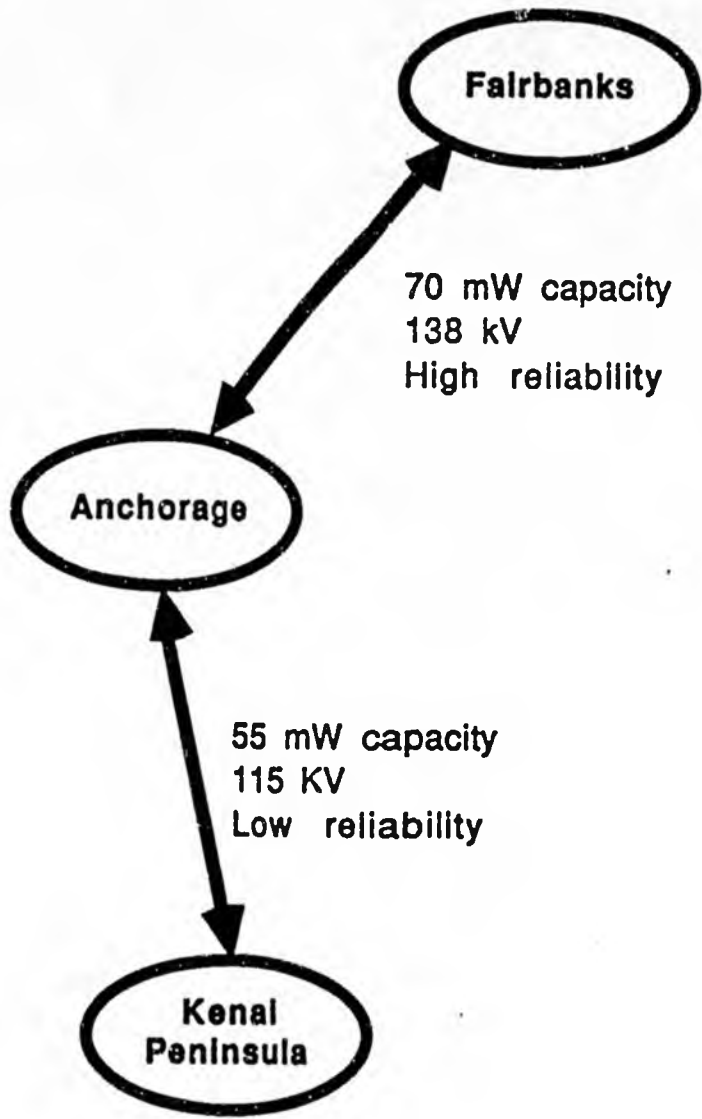
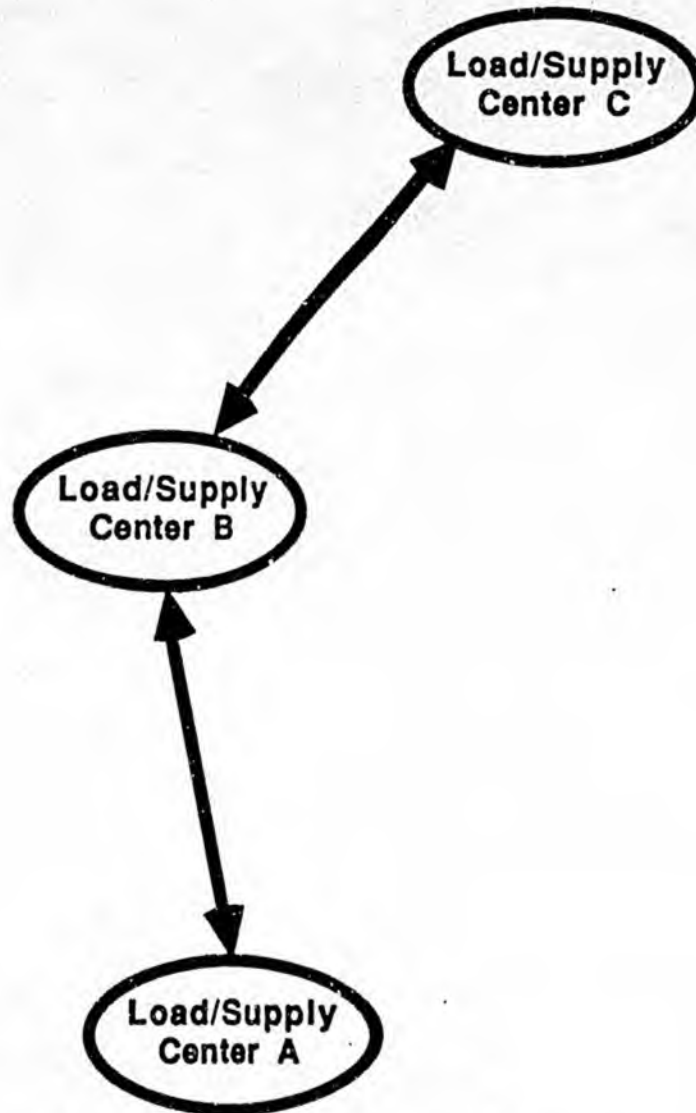


Figure 2. Simplified Network Topology



Interties are bidirectional, capacity-limited links with known transfer capacity

3) For the interior node, estimate its own production costs and potential exports to the next node, using its own generation and the purchase resources of the previous node. The potential exports will include any wheeled energy, ie. energy available from the previous node, not dispatched against the current node's native demand, and available for dispatch against the next node's net profile for sales demand.

4) Repeat step 3 for each interior node until the terminal node in the series is reached. For the terminal node, no potential export energy is estimated: its own production costs are estimated using the economy purchase units from the previous node.

5) Redo the analysis in the reverse direction, this time starting with final terminal node examined in the previous step. The final simulation in this series will estimate the own production costs of the original starting node analyzed in step 1, using available purchase resources from the other direction.

6) Compare the forward and the reverse solutions, and resolve any conflicts in intertie usage, either by repeating the process with the previous round of economy interchange data or revising the size and cost of the equivalent purchase economy units in the appropriate node.

For the network of Figure 2, the process would involve six production cost simulations. The following table shows the demands, supply systems, and results obtained from each of the six:

Case	Native Load	2nd Area Load	Supply Resources	Result
1	A	B	A	Potential exports from A (A*)
2	B	C	B + A*	1. B costs with A* purchases 2. Potential exports to C from A and B (B*)
3	C	none	C + B*	C costs with B* purchases
4	C	B	C	Potential exports from C (C*)
5	B	A	B + C*	1. B costs with C* purchases 2. Potential exports to A from B and C (B#)
6	A	none	A + B#	A costs with B# purchases

In general, another run for area B with potential purchase from both A and C may be necessary. In this study the operating costs of Fairbanks, which will be modeled as area C, are higher than anything in Anchorage and no sales will occur from Fairbanks to Anchorage.

The application of the methodology can be readily automated using the simulation capabilities of UPLAN. From the end-use demand model the net hourly load profile of the sales demand for the connecting node is constructed on a chronological basis. This profile is used in a two area monthly production simulation and UPLAN automatically determines the surplus energy and associated costs available for interchange. This information is converted into equivalent monthly constrained availabilities for economy purchase units in the connecting node to determine the area absorption.

3. DATA OVERVIEW

3.1 Supply Side Representation

General

Basic technical and operating data for all generating units was obtained from the Alaska Power Authority and is shown in the Appendix, Section 8.2.

Unit level cost data reported in 1985 dollars was escalated by 2% to yield 1986 base year dollars for study purposes. Maintenance outages were modeled using the APA values for planned outage rates, and the timing of unit maintenance followed that reported in earlier Alaska Power Authority studies.

The Anchorage supply center consists of all generating units operated by Anchorage Municipal Light and Power (AML), the Beluga and International units of Chugach Electric Association, and the Eklutna Hydro project of the Alaska Power Administration. For this study, all units were coordinated with the area requirements and dispatched on strictly economic ordering.

The Kenai Peninsula supply center includes the Bradley Lake and Cooper Lake hydro projects, and the thermal units at Soldotna, Seldovia, and Seward. It is assumed that the Bradley Lake unit will be available and on-line in 1991, and that it will operate at \$0 variable O&M costs.

The Fairbanks supply center includes all capacity owned by the Fairbanks Municipal Utility System and Golden Valley Electric Association. These units include Chena Units 5 and 6, FMUS IC units 1-3, Healy steam and IC units, and the North Pole, Zendher, and Diesel IC units operated by Golden Valley. It is assumed that the Chena units 1 through 4 will not be operated over the study period due to environmental constraints.

For the base case, planning reserve margin for all regions was established 40%. The Kenai center was modeled with commitment levels for fossil units to provide frequency control. This amounts to an operating reserve require of approximately 25 MW.

Fuel Prices

All prices, costs and revenues in the study are reported in 1986 constant dollars.

Wellhead gas prices are assumed identical throughout the Cook inlet area. A wellhead gas price of \$1.60/MMBTU is assumed, with no real escalation over the study period.

Delivered prices of gas are assumed to vary across the region. Gas delivered to Anchorage is priced at wellhead plus 60 cents/MMBTU for pipeline transportation. On the Kenai Peninsula and at Beluga, gas is priced wellhead.

Coal delivered to the Healy Station of GVEA is priced at \$1.30/MMBTU through 1994, and at \$1.60/MMBTU thereafter. Coal delivered to Fairbanks MUS is priced at \$2.50/MMBTU.

Fuel oil prices are chosen to be consistent with a crude oil price of \$20 per barrel. #4 Fuel oil is priced at \$3.40/MMBTU, and diesel fuel is priced at \$5.00/MMBTU for all sites except Seldovia, where diesel is priced at \$7.00/MMBTU.

3.2. Demand Side Representation

Fairbanks load center is modeled as the combined loads of Fairbanks Municipal Utility System and Golden Valley Electric Association. In addition, 30 MW was added to the Fairbanks peak load over the complete study period, 1991-

2020, with no change in Fairbanks load factor to accommodate the assumption that military loads in the future will be served by Fairbanks utilities.

Anchorage load center is modeled as the combined loads of Anchorage Municipal Light and Power, Chugach retail demand, and Matanuska demand.

The Kenai Peninsula load center is modeled as the combined loads of the City of Seward and the Homer Electric Association. To this is added an 8 MW incremental demand, representing northern Kenai Peninsula customers with demand characteristics identical to Anchorage demand. This increment is escalated at the same rate as AMLP demand.

Hourly load shapes were developed for two regions: Anchorage and Fairbanks. It is assumed that the hourly load shape of the Anchorage and Kenai Peninsula regions will be the same. Hourly loads were developed from information provided by APA for the years 1982 and 1983. Three distinct representative seasonal weekly load shapes were developed for each region: a winter shape, a summer shape, and a transitional Spring/Fall shape. These representative shapes were assigned to individual months, and adjusted to match the month-by-month peak and energy fractions reported in Table 8.3.1, Statement of Power Needs and Utilization, provided by the Power Authority.

For the 1991-2010 period, three separate annual load shapes were employed for each region. The first was used for the 1990-95 period, the second for 1996-2000 period, and the final for the 2001-2020 period.

Annual peak load and energy forecasts were based on Table 8.3.2 Total Railbelt Energy Requirements, which summarizes the load forecasts prepared by the Railbelt utilities. To estimate total busbar energy requirements, the system losses reported separately for Chugach Electric Association were rolled back into their reported sources on the basis of a 2.9% transmission loss associated with sales to Homer, Seward, and Matanuska, and 13.88% loss associated with retail sales.

Peak demand and energy estimates for the 1993 to 2000 period were adjusted from their tabulated values for Homer, Matanuska, and Chugach to reflect an unchanging year-to-year energy and peak demand forecast, rather than the sharp 1994-95 decline in peak and energy reported in Table 8.3.2.

For the period from 2002 to 2020, peak demand and energy are assumed to grow at the rate of 1.5% per year for all regions. The annual peak demand and energy forecast used in the analysis for all three regions are shown in Table 8.3.3 in the Appendix, Section 8.3.

3.3. Interconnection Representation: Base Case

As shown in Figure 1, the current capacity of the connection between Anchorage and the Kenai Peninsula is 55 MW. However, due primarily to the demands of customers along the route, the assumed transfer capability of the line from one end to the other is set at 35 MW in 1991. This capacity is assumed to decline from 35 MW to 24 MW over the 30 year study period due to the increasing requirement of the Seward area. The existing line from Anchorage to Fairbanks has a transfer capacity of 70 MW.

In addition to the capacity limitations, transmission losses were included. The transmission loss factors between the Kenai Peninsula and Anchorage and between Anchorage and Fairbanks are assumed to be 10% in the base case. Also, average transmission losses of 2% were assumed between Beluga and the Anchorage load center. These factors were used to increase the perceived cost of the purchase energy and factored into the valuation of the economic absorption of sales.

4. Base Case Development and Benchmarking

Generation capacity plans were developed for each supply center. It was assumed that the Anchorage area stations will retire their current capacities over the study period and expand the resources in keeping with the needs of the Anchorage area. For the Anchorage and Kenai Peninsula Regions, all new capacity consisted of gas-fired CTs and combined cycle units at \$400/KW and \$650/KW, respectively.

In Fairbanks it was assumed the current Healy unit will be replaced with a new coal-fired unit. All other new capacity for Fairbanks consisted of oil-fired CTs at \$400/KW.

For the period 1991-2020, the base case capacity was expanded to meet a reserve margin requirement of 40%.

Table 1 shows the supply resources used in the UPLAN simulations for the Kenai Peninsula. Table 2 shows the associated reserve margins over the planning horizon. Tables 3 and 4 show the same for Fairbanks and Tables 5 and 6 for Anchorage.

UPLAN was run for the 30 year planning period of 1991 to 2020 following the methodology of Chapter 2. The total production costs for each area and the region as a whole are shown in Table 7. Detailed results for four selected years from these simulations are shown in Tables 8 through 19. Tables 8 to 11 present the annual total and unit operations in the Fairbanks area for 1991, 1996, 2006 and 2015. Tables 12 to 15 show the same results for the Kenai Peninsula and Tables 16 to 19 for Anchorage. The simulation results were nominally compared to previous simulations produced by other A P A consultants, and are consistent within the differences in load and resource assumptions between the two runs.

In the base case results, Fairbanks is basically the main importer of energy. There is some interchange being conducted within the Anchorage area with

generation from Beluga serving some of the load belonging to AMLP thereby displacing the output of the AMLP units, but this interaction has not been quantified for this study.

5. Reserve Sharing

Prior to performing the final simulations for the complete 30 year planning study, a series of single year studies was done to evaluate the characteristics of the region. The main outcome of these studies was the setting of the reserve sharing level in the Anchorage-Kenai Peninsula region. The Anchorage expansion for the alternate case was revised to reflect reserve sharing between the Anchorage and the Kenai Peninsula regions.

The estimation methodology was to calculate the index of reliability for Anchorage and the Kenai Peninsula as isolated areas. The index of reliability used in UPLAN is Loss of Load Probability (LOLP) as reported in days/year. This statistic is calculated by determining the probability of the load exceeding the capacity during any hour of the simulation period. For this study, only a single year was evaluated: the year chosen was 2016. Tables 20 and 21 present the reliability simulation of these areas as isolated systems. The Anchorage area shows an index of reliability of 0.056 days per year. The Kenai Peninsula area has an index of reliability of 0.088 days per year. The joint reliability of the two isolated systems is therefore 0.144 days per year. Table 22 shows Anchorage/Kenai Peninsula as an interconnected area sharing reserves. By removing 110 MW of installed capacity from this combined system, the reliability index rises from 0.002 to 0.115 as shown in Table 23. This level is considered equivalent to the combination of the two isolated systems and no further capacity was removed. Note that all capacity removed from the expansion

plan was associated with the Anchorage area. This build-down corresponds to a 25% planning reserve margin in Anchorage.

6. Alternate Scenario Simulation Results

For the alternate cases, the intertie transfer capacities are set to 250 MW for the Anchorage/Kenai Peninsula line, and 350 MW for the Anchorage/Fairbanks line. The transmission loss factors were reduced from 10% to 2% for the Anchorage/Kenai Peninsula intertie and from 10% to 4% for the Anchorage/Fairbanks intertie. This is reflected in lower costs for the economy energy interchange and represents an additional potential benefit to the region.

In the alternate case, planning reserve margin for the Kenai Peninsula and Fairbanks areas are still modeled at 40%. However, the alternate case planning reserve margin for Anchorage was reduced to 25%, as discussed in the previous section. Table 24 shows the revised Anchorage supply resources for the alternate case. Table 25 presents the associated reserve margins.

Unit commitment for frequency control was discontinued on the Kenai Peninsula. It is assumed for purposes of this analysis that the replacement unit for Anchorage combined cycle capacity retired in 1999 is located on the Kenai Peninsula, where access is gained to natural gas priced at the assumed wellhead value. The Kenai Peninsula and Anchorage are modeled as a single, jointly dispatched supply/demand area with no effective transmission limitations in scenarios that include the new Anchorage/Kenai Peninsula line. (The single year run described earlier indicated that no significant transmission constraint existed in these alternative intertie cases and no change in the methodology described in Chapter 2 is necessary to achieve the same results. This results in a significant savings in computational requirements without any loss of accuracy. Although the installation of an additional

180 MW of combined cycle capacity on the Kenai Peninsula appears to create a surplus capacity of more than 250 MW during off-peak hours in the off-peak season, the capacity of the Kenai Peninsula hydro projects will be significantly discounted because of limited water availability at the same time. As a result, sufficient line capacity will be open during these time periods.)

UPLAN runs were made of the alternate case with increased tie lines and revised resources following the same procedure as the base case. Tables 26 through 33 show the detailed results for the four same years as are shown for the base case. Tables 26 to 29 present the production simulations for Fairbanks for 1991, 1996, 2006 and 2015. Tables 30 to 33 show the results for the Anchorage-Kenai areas as operated under the joint dispatch assumption for the same years.

By way of comparison, Table 34 shows the production simulation in the Fairbanks area for the year 2006 for the base case and the alternate case. In this year there is an operating savings of around 8.6 million dollars. This savings is achieved because of the increased availability of economy energy and the lower cost of the purchase power. Around 1 million dollars is gained from the lower average cost of purchase power and from the increased reliability provided by the larger intertie. However, the bulk of the savings (7.6 million) comes from the ability to import an additional 430 GWH at an incremental savings of about 18 \$/mwh.

The savings in the Anchorage-Kenai production costs are around 5.5 million dollars for the same year, 2006. Table 35 repeats the base case results for Anchorage and Kenai in 2006 for comparison to Table 32. The components of the savings are slightly more complicated to see. The dominant effect in the region is the availability of low cost energy out of the combined cycle unit located on the Kenai Peninsula and using wellhead gas for fuel. There is a savings of around 1 million dollars from relaxing the operating reserve requirement for frequency control and from the serving of some Kenai Peninsula load out of the new combined cycle unit at an incremental

savings of 3.5 \$/mwh. The remaining 4.5 million dollars savings occurs in the Anchorage area by having available an additional 1200 GWH of energy from the new combined cycle unit at an average production savings of around 3.8 \$/mwh.

Using the same assumptions of the alternate case, two additional studies were performed using UPLAN to evaluate the incremental benefits of the upgrading of each intertie separately. The results of these runs are similar to the alternate case and are contained in the Appendix.

7. Summary and Conclusions

Tables 36 through 38 show the complete comparisons of the various scenarios. Table 36 presents the production operating savings and capacity deferral savings between the base case and the alternate case. The capacity benefit is calculated by crediting the savings with the amortized capital costs of the deleted units over a 20 year period at a real interest rate of 3.5%. The units removed from the resource plan in the alternate case are the new 50 MW Beluga CT unit scheduled to be installed in 1994 and the new 50 MW AMLP CT unit scheduled for installation in 2007. This amounts to a savings of over 50 million dollars over the 30 year planning horizon. The savings in operating costs are 372.5 million dollars giving a total savings of 423 million dollars. The net present value of this savings discounted back to 1987 at a discount rate of 3.5% is 205 million dollars. Because no inflation was used in the study, these values are in 1986 dollars.

Table 37 shows the same comparative information for the savings achieved by upgrading only the Kenai Peninsula to Anchorage tie. The net present value of savings is 102 million dollars. Finally, Table 38 presents the savings from upgrading only the Anchorage to Fairbanks intertie. In this case, the net present value is 101 million dollars.

Table 1 - Kenai Supply Model

RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kenairsa.SPM-Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
bern	bernice2	18	1	1971	26
bern	bernice3	27	1	1978	26
bern	bernice4	27	1	1981	23
brad	bradleyH	90	1	1990	65
coop	cooper H	18	1	1975	99
gtk	soldatCT	38	1	1985	25
sldi	seldic2	1	1	1964	99
sldi	seldic34	1	1	1970	99
ses	seward3	2	1	1965	99
ses	seward4	2	1	1985	99
ses	seward5	3	1	1986	99
ses	seward6	3	1	1990	99
new	new ct1	40	1	2004	20
new	new ct2	40	1	2010	20
new	new ct3	25	1	2014	25

Table 2 - Kenai Reserve Margins

Capacity and Reserve Margin

Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin	Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin
	(MW)	(MW)	Exc. Pur (%)	Inc. Pur (%)		(MW)	(MW)	Exc. Pur (%)	Inc. Pur (%)
1991	116	230	98.962	98.962	2006	130	198	52.191	52.191
1992	117	230	96.749	96.749	2007	132	198	49.886	49.886
1993	119	230	93.766	93.766	2008	135	198	47.103	47.103
1994	119	230	93.115	93.115	2009	136	198	45.588	45.588
1995	119	230	92.953	92.953	2010	138	200	44.823	44.823
1996	119	230	92.791	92.791	2011	140	200	42.653	42.653
1997	119	212	77.554	77.554	2012	142	200	40.548	40.548
1998	120	212	77.258	77.258	2013	144	200	38.504	38.504
1999	120	212	76.962	76.962	2014	147	225	53.479	53.479
2000	120	212	76.667	76.667	2015	149	225	51.210	51.210
2001	121	212	75.497	75.497	2016	151	225	49.007	49.007
2002	123	212	72.920	72.920	2017	153	225	46.771	46.771
2003	125	212	70.281	70.281	2018	156	225	44.602	44.602
2004	126	198	56.770	56.770	2019	158	225	42.495	42.495
2005	128	198	54.446	54.446	2020	160	225	40.362	40.362

Table 3 - Fairbanks Supply Model

RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:fairrsa.SPM-Fairbanks Supply Model

Units 1-15

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
Chen	ChenaST5	20	1	1970	35
Chen	ChenaST6	26	1	1976	30
Fmus	Fmusic 1	3	1	1967	25
Fmus	Fmusic 2	3	1	1967	25
Fmus	Fmusic 3	3	1	1967	25
Heal	HealyST1	25	1	1967	35
Heal	HealyIC2	3	1	1967	30
Nopo	NoPolCT1	61	1	1976	30
Nopo	NoPolCT2	61	1	1977	30
Zen	Zender 1	18	1	1971	30
Zen	Zender 2	18	1	1972	30
DslI	DslIC 1	2	1	1961	30
DslI	DslIC 2	2	1	1961	30
DslI	DslIC 3	2	1	1961	30
DslI	DslIC 5	3	1	1970	30

RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:fairrsa.SPM-Fairbanks Supply Model

Units 16-30

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
DslI	DslIC 6	3	1	1970	30
UAFI	UAFIC 7	3	1	1970	26
UAFI	UAFIC 8	3	1	1970	26
NewH	NewHeST1	25	1	2002	35
NewF	NEWFACT A	25	1	1992	30
NewF	NEWFACT B	25	1	2002	30
NewF	NEWFACT 1	25	1	1996	30
NewF	NEWFACT 2	25	1	1999	30
NewF	NEWFACT 3	25	1	2001	30
NewF	NEWFACT 4	50	1	2005	30
NewF	NEWFACT 5	70	1	2006	30
NewF	NEWFACT 6	70	1	2007	30
NewF	NEWFACT 7	30	1	2010	30
NewF	NEWFACT 8	30	1	2016	30

Table 4 - Fairbanks Reserve Margins

Capacity and Reserve Margin

Year	Peak Load (MW)	System Capacity Exc. Pur (MW)	Reserve Margin Exc. Pur (%)	Reserve Margin Inc. Pur (%)	Year	Peak Load (MW)	System Capacity Exc. Pur (MW)	Reserve Margin Exc. Pur (%)	Reserve Margin Inc. Pur (%)
1991	176	253	43.587	43.587	2006	237	331	39.899	39.899
1992	180	269	49.279	49.279	2007	240	340	41.844	41.844
1993	184	269	45.958	45.958	2008	243	340	39.975	39.975
1994	189	269	42.630	42.630	2009	246	340	38.155	38.155
1995	193	269	39.378	39.378	2010	249	370	48.416	48.416
1996	197	288	45.897	45.897	2011	253	370	46.477	46.477
1997	202	285	41.019	41.019	2012	256	370	44.588	44.588
1998	207	285	37.814	37.814	2013	259	370	42.692	42.692
1999	212	310	46.503	46.503	2014	263	370	40.791	40.791
2000	217	304	40.286	40.286	2015	266	370	38.941	38.941
2001	222	311	40.216	40.216	2016	270	400	48.258	48.258
2002	225	318	41.522	41.522	2017	273	400	46.306	46.306
2003	228	318	39.719	39.719	2018	277	400	44.404	44.404
2004	231	318	37.901	37.901	2019	281	400	42.501	42.501
2005	234	348	48.973	48.973	2020	285	400	40.598	40.598

Table 5 - Anchorage Supply Model

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 1-15

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
EKLU	EklutnaH	30	1	1955	99
AML P	Anc CT 1	16	1	1962	25
AML P	Anc CT 2	16	1	1964	25
AML P	Anc CT 3	20	1	1968	23
AML P	Anc CT 4	34	1	1972	20
AM C	Anc CC56	48	1	1979	20
AM C	Anc CC76	109	1	1979	20
AML P	Anc CT 8	87	1	1984	25
AML P	Anc CT 9	87	1	2050	38
Bel	BelugCT1	16	1	1968	26
Bel	BelugCT2	16	1	1968	26
Bel	BelugCT3	50	1	1972	27
Bel	BelugCT4	10	1	1976	20
Bel	BelugCT5	67	1	1975	24
BelC	BelgCC68	101	1	1976	31

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 16-30

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
belg	BelgCC78	101	1	1976	31
Int	IntnCT1	14	1	1965	31
Int	IntnCT2	14	1	1968	28
Int	IntnCT3	20	1	1970	26
NewC	New CC76	180	1	1999	25
NewB	NewBCT 3	50	1	1994	27
NewB	NewBCT 4	50	1	1996	27
NewB	NewBCT 5	67	1	1999	25
NewB	NewBCT 6	50	1	1999	25
NewB	NewBCC68	101	1	2007	31
NewB	NewBCC78	101	1	2007	31
NewC	New CT10	50	1	2007	25
NewC	New CT11	87	1	2009	25
NewC	New CT12	50	1	2015	25
NewC	New CT13	50	1	2018	25
NwBC	NewBCT14	50	1	2002	25
NwBC	NewBCT15	50	1	2011	25

Table 6 - Anchorage Reserve Margins

Capacity and Reserve Margin									
Year	Peak Load (MW)	System Capacity Exc. Pur (MW)	Reserve Margin		Year	Peak Load (MW)	System Capacity Exc. Pur (MW)	Reserve Margin	
			Exc. Pur (%)	Inc. Pur (%)				Exc. Pur (%)	Inc. Pur (%)
1991	459	717	56.209	56.209	2006	555	766	38.043	38.043
1992	464	683	47.325	47.325	2007	563	816	44.886	44.886
1993	474	683	44.245	44.245	2008	572	816	42.732	42.732
1994	484	701	44.835	44.835	2009	580	816	40.617	40.617
1995	486	701	44.209	44.209	2010	589	816	38.540	38.540
1996	488	693	42.037	42.037	2011	598	866	44.865	44.865
1997	490	693	41.313	41.313	2012	607	866	42.716	42.716
1998	494	693	40.312	40.312	2013	616	866	40.607	40.607
1999	499	716	43.631	43.631	2014	625	866	38.538	38.538
2000	506	716	41.502	41.502	2015	635	916	44.366	44.366
2001	515	716	39.002	39.002	2016	644	916	42.236	42.236
2002	523	766	46.519	46.519	2017	654	916	40.125	40.125
2003	531	766	44.338	44.338	2018	673	966	43.451	43.451
2004	539	766	42.221	42.221	2019	684	966	41.331	41.331
2005	547	766	40.113	40.113	2020	694	966	39.233	39.233

Table 7

Base Case Production Costs (Mill \$)

Year	Kenai	Anchor	Fairbnk	Total
1991	8.46	58.70	32.47	99.63
1992	8.61	58.98	33.60	101.19
1993	8.82	60.35	34.56	103.73
1994	8.86	60.67	34.88	104.41
1995	8.87	60.94	35.79	105.60
1996	8.88	59.87	36.21	104.96
1997	8.77	60.18	37.19	106.14
1998	8.79	60.62	38.19	107.60
1999	8.75	59.45	37.75	105.95
2000	8.78	60.31	38.87	107.96
2001	8.88	62.77	39.78	111.43
2002	8.84	63.79	38.87	111.50
2003	9.09	64.71	39.50	113.30
2004	8.34	65.63	40.14	114.11
2005	8.55	66.59	39.93	115.07
2006	8.76	67.56	40.36	116.68
2007	8.98	67.96	41.44	118.38
2008	9.26	68.97	42.20	120.43
2009	9.42	69.65	42.93	122.00
2010	9.31	70.65	43.84	123.80
2011	9.52	71.84	44.14	125.50
2012	9.73	72.90	44.92	127.55
2013	9.95	73.98	45.72	129.65
2014	10.41	75.06	46.51	131.98
2015	10.64	76.60	47.33	134.57
2016	10.86	77.72	48.43	137.01
2017	11.10	78.88	49.30	139.28
2018	11.33	81.68	50.24	143.25
2019	11.56	82.91	51.14	145.61
2020	11.80	84.16	52.09	148.05

Table 8 - 1991 Base Case Production Operation in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 1
 RNM file:c:FAIRALL.RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	937.66	PK Load (MW)	176.20	Fix O&M	4.78
Unserve	0.51			Variable	16.73
Net. Gen.	937.15			Unservd	0.05
Storage	0.00			Fuel	10.92
Total Gen	937.15	LOLP (Dys/Yr)	0.000	Total	32.47

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
HealyST1	91.10	199.52	835.97	3332.79	4168.76	20.89
ChenaST5	56.92	99.72	65.12	3747.25	3812.37	38.23
TIEPUR91	89.74	550.28	15697.81	0.00	15697.81	28.53
NoPolCT1	15.95	85.23	124.18	3730.70	3854.88	45.23
NoPolCT2	0.44	2.33	3.39	101.87	105.26	45.23
ChenaST6	0.03	0.06	0.04	3.59	3.62	57.21
Zender 1	0.01	0.01	0.01	0.67	0.68	57.16
Zender 2	0.00	0.00	0.00	0.18	0.18	57.16
HealyIC2	0.00	0.00	0.00	0.01	0.01	67.26
UAFIC 7	0.00	0.00	0.00	0.01	0.01	67.26
DslIC 5	0.00	0.00	0.00	0.01	0.01	67.26
DslIC 6	0.00	0.00	0.00	0.00	0.01	67.26
UAFIC 8	0.00	0.00	0.00	0.00	0.00	67.26
Fmusic 1	0.00	0.00	0.00	0.00	0.00	89.69
Fmusic 2	0.00	0.00	0.00	0.00	0.00	89.69
Fmusic 3	0.00	0.00	0.00	0.00	0.00	89.69

Table 9 - 1996 Base Case Production Operation in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 2
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1996: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks base case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1038.89	PK Load (MW)	197.40	Fix O&M	5.21
Unserve	0.22			Variable	16.15
Net Gen.	1038.67			Unserve	0.02
Storage	0.00			Fuel	14.84
Total Gen	1038.67	LOLP (Dys/Yr)	0.000	Total	36.21

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
HealyST1	91.10	199.52	835.98	4102.72	4938.70	24.75
ChenaSTE	67.79	118.76	77.55	4428.44	4505.99	37.94
TIEPUR96	93.45	573.06	15021.12	0.00	15021.12	26.21
NoPolCT1	26.48	141.48	206.13	6050.55	6256.68	44.22
NoPolCT2	1.08	5.76	8.40	252.25	260.65	45.23
NEWFACT A	0.03	0.06	0.03	2.47	2.51	41.70
NEWFACT 1	0.01	0.03	0.02	1.08	1.10	41.70
ChenaST6	0.00	0.00	0.00	0.17	0.17	57.21
Zender 1	0.00	0.00	0.00	0.03	0.03	57.16
Zender 2	0.00	0.00	0.00	0.01	0.01	57.16
HealyIC2	0.00	0.00	0.00	0.00	0.00	67.26
DslIC 5	0.00	0.00	0.00	0.00	0.00	67.26
DslIC 6	0.00	0.00	0.00	0.00	0.00	67.26

Table 10 - 2006 Base Case Production Operation in Fairbanks

Detail report:a:FRASE401.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL.RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FRASE401.SPM-fairbanks basea case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	3.75			Variable	15.58
Net Gen.	1227.11			Unservd	0.37
Storage	0.00			Fuel	20.26
Total Gen	1227.11	LOLP (Dys/Yr)	0.011	Total	40.36

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
NewHeST1	87.48	191.57	823.76	3024.46	3848.21	20.09
TIEPURO6	97.88	600.21	14231.02	0.00	14231.02	23.71
NoPoICT2	57.75	308.58	449.60	12027.15	12476.74	40.43
NEWFACT A	15.99	35.03	20.32	1440.44	1460.75	41.70
NEWFACT B	9.39	20.57	11.93	846.06	858.00	41.70
NEWFACT 1	6.25	13.69	7.94	563.05	570.99	41.70
NEWFACT 2	5.04	11.04	6.41	454.15	460.55	41.70
NEWFACT 3	4.38	9.59	5.56	394.30	399.86	41.70
NEWFACT 4	3.84	16.83	9.76	692.28	702.04	41.70
NEWFACT 5	3.26	19.99	11.60	822.21	833.81	41.70

Table 11 - 2015 Base Case Production Operation in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 4
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prn 25 mw healy @97
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1385.37	PK Load (MW)	266.30	Fix O&M	4.56
Unserve	0.82			Variable	15.51
Net Gen.	1384.55			Unserve'd	0.08
Storage	0.00			Fuel	27.18
Total Gen	1384.55	LOLP (Dys/Yr)	0.028	Total	47.33

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
NewHeST1	87.49	191.60	823.86	3024.80	3848.66	20.09
TIEPUR15	98.75	605.56	14347.54	0.00	14347.54	23.69
NEWFACT A	54.70	119.78	69.47	4925.81	4995.28	41.70
NEWFACT 8	46.05	100.85	58.49	4147.15	4205.64	41.70
NEWFACT 1	32.88	72.01	41.77	2961.43	3003.20	41.70
NEWFACT 2	26.33	57.66	33.44	2371.00	2404.44	41.70
NEWFACT 3	18.60	40.73	23.62	1674.85	1698.47	41.70
NEWFACT 4	12.66	55.44	32.16	2279.93	2312.09	41.70
NEWFACT 5	10.12	62.06	35.99	2551.90	2587.89	41.70
NEWFACT 6	9.12	55.90	32.42	2298.89	2331.31	41.70
NEWFACT 7	8.74	22.97	13.32	944.43	957.76	41.70

Table 12 - 1991 Base Case Production Operation in Kenai

Detail report: a:KBAS35LS.DTL 05-17-1987 Page 1
 RNM file: c:KENAALI .RNM-kenai load 1991-2020
 Supply file: c:kbas35ls.SPM-kenai with anc 35mw purch 10% prm loss penalty
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS (M\$)	
Demand	596.25	PK Load (MW)	115.60	Fix O&M	3.70
Unserve	0.15			Variable	0.28
Net Gen.	596.10			Unreserved	0.02
Storage	0.00			Fuel	1.46
Total Gen	596.10	LQLP (Dys/Yr)	0.000	Total	8.46

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
soldatCT	51.90	172.76	247.05	4138.16	4385.20	25.38
bernice3	4.36	10.31	23.00	252.18	275.17	26.68
bernice4	1.23	2.91	6.50	71.23	77.73	26.68
bernice2	0.00	0.00	0.00	0.00	0.00	27.91
ANCPUR91	0.00	0.00	0.00	0.00	0.00	28.08
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.82	369.13	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 13 - 1996 Base Case Production Operation in Kenai

Detail report:a:KBAS35LS.DTL 03-17-1987 Page 2
 RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kbas35ls.SPM-kenai with anc 35mw purch 40% prm loss penalty
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	615.33	PK Load (MW)	119.30	Fix O&M	3.70
Unserve	0.11			Variable	0.31
Net Gen.	615.22			Unservd	0.01
Storage	0.00			Fuel	4.86
Total Gen	615.22	LOLP (Dys/Yr)	0.000	Total	8.88

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost .\$/ (MWH)
			Variable	Fuel Cost	Total		
soldatCT	56.67	188.64	269.76	4460.38	4730.14	25.07	
bernice3	5.19	12.26	27.35	299.91	327.26	26.68	
bernice4	1.77	4.19	9.33	102.35	111.68	26.68	
ANCPUR96	0.00	0.00	0.00	0.00	0.00	25.58	
bernice2	0.00	0.00	0.00	0.00	0.00	0.00	
seward3	0.00	0.00	0.00	0.00	0.00	0.00	
seward4	0.00	0.00	0.00	0.00	0.00	0.00	
seward5	0.00	0.00	0.00	0.00	0.00	0.00	
seward6	0.00	0.00	0.00	0.00	0.00	0.00	
seldic2	0.00	0.00	0.00	0.00	0.00	0.00	
seldic34	0.00	0.00	0.00	0.00	0.00	0.00	
bradleyH	46.82	369.14	0.00	0.00	0.00	0.00	
cooper H	25.99	40.98	0.00	0.00	0.00	0.00	

Table 14 - 2006 Base Case Production Operation in Kenai

Detail report: a:KBAS351.G.DTL 03-17-1987 Page 3
 RNM file:c:KENAALI .RNM-kenai load 1991-2020
 Supply file:c:kbas351s.SPM-kenai with anc 35mw purch 40% prim loss penalty

SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	670.56	PK Load (MW)	130.10	Fix O&M	3.32
Unserve	0.64			Variable	0.18
Net Gen.	669.92			Unservd	0.06
Storage	0.00			Fuel	5.20
Total Gen	669.92	LOLP (Dys/Yr)	0.000	Total	8.76

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$(/MWH)
			Variable	Fuel Cost		
new ct1	65.89	230.88	133.91	4468.02	4601.94	19.93
soldatCT	8.76	29.17	41.71	735.80	777.50	26.66
ANCPUR06	0.01	0.02	0.51	0.00	0.51	23.78
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.79	368.90	0.00	0.00	0.00	0.00
cooper H	25.98	40.96	0.00	0.00	0.00	0.00

Table 15 - 2015 Base Case Production Operation in Kenai

Detail report:a:KBAS35LS.DTL 03-17-1987 Page 4
 RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kbas35ls.SPM-kenai with anc 35mw purch 40% prm loss penalty
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	766.95	PK Load (MW)	148.80	Fix O&M	3.46
Unserve	0.76			Variable	0.21
Net Gen.	766.18			Unservd	0.08
Storage	0.00			Fuel	6.89
Total Gen	766.18	LOLP (Dys/Yr)	0.001	Total	10.64

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
new ct1	73.63	257.99	149.63	4992.65	5142.28	19.93
new ct2	22.58	79.12	45.89	1531.18	1577.07	19.93
new ct3	8.74	19.13	11.10	370.20	381.30	19.93
ANCPUR15	0.01	0.02	0.53	0.00	0.53	23.79
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.80	368.96	0.00	0.00	0.00	0.00
cooper H	25.98	40.96	0.00	0.00	0.00	0.00

Table 16 - 1991 Base Case Production Operation in Anchorage

Detail report:a:AK3540LS.DTL 03-17-1987 Page 1
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK351.AST.SPM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	2516.97	PK Load (MW)	459.00	Fix O&M	11.60
Unserve	0.14			Variable	4.93
Net Gen.	2516.83			Unservd	0.01
Storage	0.00			Fuel	42.16
Total Gen	2516.83	LOLP (Dys/Yr)	0.003	Total	58.70

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
BelgCC78	78.70	696.27	995.66	10906.26	11901.93	17.09
BelgCC68	78.48	694.38	990.88	11145.99	12136.87	17.48
BelugCT3	75.72	331.65	473.26	6417.66	6890.93	20.78
BelugCT5	63.01	369.80	527.70	8386.41	8914.11	24.11
Anc CC76	24.98	238.48	1380.30	4914.37	6294.67	26.40
KENPUR91	6.45	19.77	524.49	0.00	524.49	26.53
BelugCT2	3.18	4.46	6.36	124.50	130.86	29.37
BelugCT1	2.24	3.14	4.49	87.64	92.13	29.37
BelugCT4	1.65	1.44	2.06	47.35	49.41	34.25
Anc CC56	0.83	3.51	20.32	92.97	113.29	32.27
Anc CT 8	0.13	0.99	5.74	30.59	36.32	36.65
Anc CT 4	0.01	0.04	0.26	1.81	2.06	46.43
IntnCT1	0.01	0.01	0.09	0.32	0.41	61.52
IntnCT2	0.00	0.00	0.05	0.18	0.23	61.52
IntnCT3	0.00	0.00	0.03	0.12	0.16	61.43
EklutnaH	58.18	152.89	0.00	0.00	0.00	0.00

Table 17 - 1996 Base Case Production Operation in Anchorage

Detail report:a:AK35401.S.DTL 03-17-1996 / Page 2
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK35LAST.SPM-anc w/ 35mw ken,pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	2684.08	PK Load (MW)	487.90	Fix O&M	10.69
Unserve	0.22			Variable	3.59
Net Gen.	2683.86			Unservd	0.02
Storage	0.00			Fuel	45.56
Total Gen	2683.86	LOLP (Dys/Yr)	0.045	Total	59.87

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
BelgCC78	78.68	696.11	995.44	10904.17	11899.61	17.09
BelgCC68	78.61	695.53	992.53	11160.82	12153.35	17.47
NewBCT 3	73.44	321.68	186.57	6349.66	6536.23	20.32
NewBCT 4	67.88	297.32	172.45	5868.87	6041.31	20.32
BelugCT3	54.94	240.62	343.36	4891.75	5235.11	21.76
BelugCT5	32.27	189.39	270.27	4610.94	4881.20	25.77
Anc CC76	8.65	82.61	478.15	1702.39	2180.54	26.40
KENPUR96	1.61	4.95	131.56	0.00	131.56	26.60
Anc CC56	0.52	2.21	12.78	58.46	71.23	32.27
Anc CT 8	0.08	0.58	3.33	17.77	21.10	36.65
EklutnaH	58.17	152.86	0.00	0.00	0.00	0.00

Table 18 - 2006 Base Case Production Operation in Anchorage

Detail report:a:AK3540LS.DTL 03-17-1987 Page 3
 RNM file:c:ANGHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK3540LS.SPM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3124.08	PK Load (MW)	554.90	Fix O&M	11.16
Unserve	1.38			Variable	3.00
Net Gen.	3122.70			Unserved	0.14
Storage	0.00			Fuel	53.27
Total Gen	3122.70	LOLP (Dys/Yr)	0.225	Total	67.56

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
BelgCC78	78.71	696.35	995.78	10907.50	11903.29	17.09
BelgCC68	78.70	696.31	993.64	11171.03	12164.67	17.47
NewBCT14	77.90	341.22	197.91	6603.28	6801.18	19.93
NewBCT 3	73.51	321.97	186.74	6355.46	6542.20	20.32
NewBCT 4	66.88	292.92	169.89	5781.94	5951.84	20.32
NewBCT 5	55.35	324.87	188.43	6412.72	6601.14	20.32
NewBCT 6	37.99	166.39	96.51	3284.40	3380.90	20.32
New CC56	12.67	53.28	30.90	1152.35	1183.25	22.21
New CC76	6.15	71.09	41.23	1537.51	1578.74	22.21
KENPUR06	1.12	3.43	84.45	0.00	84.45	24.61
Anc CT 8	0.25	1.94	11.24	59.92	71.15	36.65
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Table 19 - 2015 Base Case Production Operation in Anchorage

Detail report:a:AK3540L.S.DT! 03-17-1987 Page 4
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK35LAST.SFM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS (M\$)	
Demand	3572.23	PK Load (MW)	634.50	Fix O&M	12.46
Unserve	1.77			Variable	3.88
Net Gen.	3570.45			Unservd	0.18
Storage	0.00			Fuel	60.08
Total Gen	3570.45	LOLP (Dys/Yr)	0.039	Total	76.60

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
NewBCC68	78.70	696.34	459.58	10907.41	11367.00	16.32
NewBCC78	78.71	696.36	459.60	10907.62	11367.22	16.32
NewBCT14	78.15	342.28	198.52	6623.71	6822.23	19.93
NewBCT15	77.50	339.45	196.88	6569.07	6765.96	19.93
NewBCT 3	73.33	321.17	186.28	6339.52	6525.80	20.32
NewBCT 4	68.44	299.76	173.86	5917.05	6090.92	20.32
NewBCT 5	58.44	343.00	198.94	6770.43	6969.37	20.32
NewBCT 6	44.41	194.53	112.83	3839.90	3952.73	20.32
KENPUR15	27.34	83.84	1838.16	0.00	1838.16	21.92
New CC56	9.95	41.85	24.27	905.14	929.41	22.21
New CC76	4.75	54.93	31.86	1188.06	1219.92	22.21
New CT10	0.46	2.01	1.17	53.46	54.62	27.19
New CT11	0.20	1.52	0.88	40.32	41.19	27.19
New CT12	0.11	0.50	0.29	13.40	13.69	27.19
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Table 21 - 2016 Production Operation in Anchorage
as an Isolated Area with 40% Reserves

Detail report:c:ANCH16 .DTL 03-18-1987 Page 1
 RNM file:c:anch16.RNM-anchorage 2016
 Supply file:c:ANCH .SPM-anchorage with 35 mw ken purchase units prm=40%
 SYSTEM REPORT FOR YEAR 2016

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3625.71	PK Load (MW)	644.00	Fix O&M	13.10
Unserve	0.17			Variable	2.16
Net Gen.	3625.54			Unservd	0.02
Storage	0.00			Fuel	71.19
Total Gen	3625.54	LOLP (Dys/Yr)	0.056	Total	86.47

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
NewBCC68	78.71	696.37	459.60	10952.68	11412.29	16.39
NewBCC78	78.71	696.36	459.59	10952.52	11412.11	16.39
NewBCT 3	78.17	342.40	198.59	6729.76	6928.35	20.23
NewBCT 5	77.31	453.76	263.18	8929.61	9192.79	20.26
NewBCT14	75.33	197.96	114.82	3906.59	4021.41	20.31
NewBCT15	73.44	160.83	93.28	3187.52	3280.80	20.40
NewBCT16	71.05	124.48	72.20	2481.31	2553.51	20.51
New CC56	69.94	294.08	170.56	8188.72	8359.29	28.43
New CC76	40.04	382.32	221.75	12036.34	12258.09	32.06
New CT10	15.73	68.89	39.96	2126.27	2166.23	31.44
New CT11	8.24	28.88	16.75	891.21	907.96	31.44
New CT12	3.85	16.86	9.78	520.22	530.00	31.44
New CT17	1.98	3.47	2.01	107.15	109.16	31.44
Anc CT 8	0.71	5.42	31.39	167.41	198.80	36.65
Anc CT 9	0.07	0.56	3.22	17.17	20.39	36.65
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

**Table 22 - 2016 Production Operation in Anchorage/Kenai
as a Joint Dispatch Area with 40% Reserves**

Detail report:c:\ak16 .DTL 03-18-1987 Page 1
 RNM file:c:\ak16.RNM-anchorage and kenai 2016
 Supply file:c:\ANCH .SPM-anchorage with 35 mw ken purchase units prm=40%
 SYSTEM REPORT FOR YEAR 2016

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	4475.84	PK Load (MW)	795.00	Fix O&M	16.64
Unserve	0.04			Variable	2.38
Net Gen.	4475.80			Unservd	0.00
Storage	0.00			Fuel	75.82
Total Gen	4475.80	LOLP (Dys/Yr)	0.002	Total	94.85

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
NewBCC68	78.70	696.34	459.58	10952.29	11411.88	16.39	
NewBCC78	78.70	696.32	459.57	10952.01	11411.57	16.39	
new ct1	83.81	220.25	127.75	4228.89	4356.64	19.78	
new ct2	83.81	308.35	178.84	5920.27	6099.12	19.78	
new ct3	83.77	322.87	187.26	6199.03	6386.29	19.78	
NewBCT 3	77.36	338.82	196.51	6667.39	6863.91	20.26	
NewBCT 5	76.11	446.69	259.08	8805.16	9064.24	20.29	
NewBCT14	73.82	194.01	112.53	3843.91	3956.43	20.39	
NewBCT15	71.65	156.92	91.01	3123.90	3214.91	20.49	
NewBCT16	66.15	115.90	67.22	2338.28	2405.50	20.75	
New CC56	54.53	229.29	132.99	6678.75	6811.74	29.71	
New CC76	17.27	164.88	95.63	5424.55	5520.18	33.48	
New CT10	3.18	13.92	8.08	429.72	437.80	31.44	
New CT11	1.37	4.79	2.78	147.80	150.58	31.44	
New CT12	0.54	2.37	1.37	73.15	74.53	31.44	
New CT17	0.25	0.44	0.25	13.53	13.78	31.44	
Anc CT 8	0.08	0.59	3.40	18.12	21.52	36.65	
Anc CT 9	0.00	0.04	0.22	1.17	1.39	36.65	
EklutnaH	58.18	152.91	0.00	0.00	0.00	0.00	
bradleyH	46.82	369.13	0.00	0.00	0.00	0.00	
cooper H	25.99	40.98	0.00	0.00	0.00	0.00	

Table 23 - 2016 Production Operation in Anchorage/Kenai
as a Joint Dispatch Area with 110MW Reduction in Reserves

Detail report:c:AK250 .DTL 03-18-1987 Page 1
RNM file:c:ak16.RNM-anchor and kenai 2016
Supply file:c:AK250 .SPM-reduced anchor reserve

SYSTEM REPORT FOR YEAR 2016

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	4475.84	PK Load (MW)	795.00	Fix O&M	15.68
Unserve	0.08			Variable	2.42
Net Gen.	4475.76			Unservd	0.01
Storage	0.00			Fuel	75.82
Total Gen	4475.76	LOLP (Dys/Yr)	0.115	Total	93.93

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/MWH
NewBCC68	78.70	696.30	459.56	10951.81	11411.37	16.39
NewBCC78	78.70	696.27	459.54	10951.45	11410.99	16.39
new ct1	83.81	220.24	127.74	4228.63	4356.37	19.78
new ct2	83.80	308.33	178.83	5919.92	6098.75	19.78
new ct3	83.76	322.85	187.25	6198.67	6385.92	19.78
NewBCT 3	77.35	338.80	196.50	6667.02	6863.52	20.26
NewBCT 5	76.10	446.67	259.07	8804.73	9063.80	20.29
NewBCT14	73.82	194.00	112.52	3843.72	3956.24	20.39
NewBCT15	71.65	156.91	91.01	3123.74	3214.75	20.49
NewBCT16	66.16	115.91	67.23	2338.43	2405.65	20.76
New CC56	54.56	229.40	133.05	6682.28	6815.33	29.71
New CC76	17.28	164.96	95.68	5427.40	5523.08	33.48
New CT12	3.18	13.92	8.08	429.70	437.78	31.44
Anc CT 8	0.96	7.30	42.23	225.19	267.42	36.65
Anc CT 9	0.12	0.92	5.33	28.44	33.77	36.65
EklutnaH	58.18	152.90	0.00	0.00	0.00	0.00
bradleyH	46.82	369.11	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 24 - Anchorage Supply Model with Reduced Reserves

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 1-15

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
EKLU	EklutnaH	30	1	1955	99
AML P	Anc CT 1	16	1	1962	25
AML P	Anc CT 2	16	1	1964	25
AML P	Anc CT 3	20	1	1968	23
AML P	Anc CT 4	34	1	1972	20
AM C	Anc CC56	48	1	1979	20
AM C	Anc CC76	109	1	1979	20
AML P	Anc CT 8	87	1	1984	25
AML P	Anc CT 9	87	1	2050	38
Bel	BelugCT1	16	1	1968	26
Bel	BelugCT2	16	1	1968	26
Bel	BelugCT3	50	1	1972	27
Bel	Bel gCT4	10	1	1976	20
Bel	BelugCT5	67	1	1975	24
BelC	BelgCC68	101	1	1976	31

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 16-30

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
belg	BelgCC78	101	1	1976	31
Int	IntnCT1	14	1	1965	31
Int	IntnCT2	14	1	1968	28
Int	IntnCT3	20	1	1970	26
NewC	New CC76	180	1	1999	25
*NewB	NewBCT 3	50	1	2999	27
NewB	NewBCT 4	50	1	1996	27
NewB	NewBCT 5	67	1	1999	25
NewB	NewBCT 6	50	1	1999	25
NewB	NewBCC68	101	1	2007	31
NewB	NewBCC78	101	1	2007	31
*NewC	New CT10	50	1	2999	25
NewC	New CT11	87	1	2009	25
NewC	New CT12	50	1	2015	25
NewC	New CT13	50	1	2018	25
NwBC	NewBCT14	50	1	2002	25
NwBC	NewBCT15	50	1	2011	25

Table 25 - Anchorage Reserve Margins with Reduced Reserves

Capacity and Reserve Margin

Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin	Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin
	(MW)	Exc. Pur (MW)	Exc. Pur (%)	Inc. Pur (%)		(MW)	Exc. Pur (MW)	Exc. Pur (%)	Inc. Pur (%)
1991	459	717	56.209	56.209	2006	555	716	29.032	29.032
1992	464	683	47.325	47.325	2007	563	716	27.131	27.131
1993	474	683	44.245	44.245	2008	572	716	25.241	25.241
1994	484	651	34.504	34.504	2009	580	716	23.384	23.384
1995	486	651	33.923	33.923	2010	589	716	21.562	21.562
1996	488	643	31.789	31.789	2011	598	766	28.137	28.137
1997	490	643	31.117	31.117	2012	607	766	26.236	26.236
1998	494	643	30.188	30.188	2013	616	766	24.371	24.371
1999	499	666	33.601	33.601	2014	625	766	22.540	22.540
2000	506	666	31.621	31.621	2015	635	816	28.605	28.605
2001	515	666	29.295	29.295	2016	644	816	26.708	26.708
2002	523	716	36.955	36.955	2017	654	816	24.828	24.828
2003	531	716	34.916	34.916	2018	673	866	28.601	28.601
2004	539	716	32.937	32.937	2019	684	866	26.701	26.701
2005	547	716	30.968	30.968	2020	694	866	24.820	24.820

Table 26 - 1991 Alternate Case Production Operation in Fairbanks

Detail Report: a:FBAS250X.DTL 03-17-1987 Page 1
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks

SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	937.66	PK Load (MW)	176.20	Fix O&M	4.78
Unserve	0.94			Variable	17.93
Net Gen.	936.72			Unservd	0.09
Storage	0.00			Fuel	6.77
Total Gen	936.72	LOLP (Dys/Yr)	1.062	Total	29.58

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
HealyST1	85.70	187.68	786.40	3153.41	3939.81	20.99
ChenaST5	27.54	48.25	31.51	1883.32	1914.83	39.69
TIEPUR91	84.47	517.95	12922.94	0.00	12922.94	24.95
TibPUR91	5.87	144.07	4130.56	0.00	4130.56	28.67
NoPolCT1	5.28	28.22	41.12	1235.38	1276.50	45.23
NoPolCT2	1.49	7.95	11.58	347.89	359.47	45.23
ChenaST6	0.44	1.01	0.60	57.03	57.63	57.21
Zender 1	0.41	0.65	0.39	36.92	37.31	57.16
Zender 2	0.27	0.43	0.26	24.15	24.41	57.16
HealyIC2	0.21	0.06	0.33	3.43	3.76	67.26
UAFIC 7	0.20	0.05	0.31	3.22	3.53	67.26
DslIC 5	0.23	0.06	0.36	3.74	4.09	67.26
DslIC 6	0.25	0.07	0.38	4.04	4.43	67.26
UAFIC 8	0.26	0.07	0.40	4.19	4.59	67.26
Fmusic 1	0.26	0.07	1.60	4.56	6.16	89.69
Fmusic 2	0.26	0.07	1.58	4.51	6.09	89.69
Fmusic 3	0.25	0.07	1.54	4.41	5.95	89.69

Table 27 - 1996 Alternate Case Production Operation in Fairbanks

Detail report:a:FBAS250%.DTL 03-17-1987 Page 2
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1038.89	PK Load (MW)	197.40	Fix O&M	5.21
Unserve	0.24			Variable	21.45
Net Gen.	1038.66			Unservd	0.02
Storage	0.00			Fuel	7.08
Total Gen	1038.66	LOLP (Dys/Yr)	0.295	Total	33.76

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
HealyST1	86.97	190.46	798.05	3932.84	4730.89	24.84	
ChenaST5	26.50	46.42	30.32	1812.07	1842.39	39.69	
TIEPUR96	89.41	548.24	14369.38	0.00	14369.38	26.21	
TibPUR96	9.10	223.10	6208.87	0.00	6208.87	27.83	
NoPolCT1	4.05	21.66	31.56	948.14	979.70	45.23	
NoPolCT2	1.14	6.11	8.90	267.47	276.37	45.23	
NEWFACT A	0.49	1.07	0.62	44.04	44.66	41.70	
NEWFACT 1	0.33	0.72	0.42	29.49	29.90	41.70	
ChenaST6	0.20	0.45	0.26	25.22	25.48	57.21	
Zender 1	0.14	0.23	0.14	12.82	12.95	57.16	
Zender 2	0.09	0.14	0.09	8.16	8.25	57.16	
HealyIC2	0.07	0.02	0.11	1.13	1.24	67.26	
DslIC 5	0.06	0.02	0.10	1.03	1.13	67.26	
DslIC 6	0.07	0.02	0.10	1.09	1.20	67.26	

Table 28 - 2006 Alternate Case Production Operation in Fairbanks

Detail report:a:FBAS250X.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks

SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	0.02			Variable	24.17
Net Gen.	1230.84			Unserved	0.00
Storage	0.00			Fuel	3.49
Total Gen	1230.84	LOLP (Dys/Yr)	0.030	Total	31.81

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
NewHeST1	86.38	189.17	813.42	2989.27	3802.69	20.10
TIEPURO6	96.75	593.30	12993.31	0.00	12993.30	21.90
TibPURO6	17.80	436.56	10350.95	0.00	10350.95	23.71
NoPolCT2	1.36	7.26	10.58	317.87	328.45	45.23
NEWFACT A	0.46	1.02	0.59	41.82	42.41	41.70
NEWFACT B	0.37	0.82	0.48	33.75	34.23	41.70
NEWFACT 1	0.30	0.65	0.38	26.60	26.98	41.70
NEWFACT 2	0.23	0.51	0.29	20.87	21.16	41.70
NEWFACT 3	0.18	0.40	0.23	16.45	16.68	41.70
NEWFACT 4	0.13	0.59	0.34	24.06	24.40	41.70
NEWFACT 5	0.09	0.57	0.33	23.34	23.67	41.70

Table 29 - 2015 Alternate Case Production Operation in Fairbanks

Detail report:a:FBAS250X.DTL 03-17-1987 Page 4
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks

SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1385.37	PK Load (MW)	266.30	Fix O&M	4.56
Unserve	0.00			Variable	27.72
Net Gen.	1385.37			Unservd	0.00
Storage	0.00			Fuel	3.02
Total Gen	1385.37	LOLP (Dys/Yr)	0.000	Total	35.30

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
NewHeST1	87.49	191.60	823.89	3024.89	3848.78	20.09	
TIEPUR15	98.76	605.58	12959.42	0.00	12959.42	21.40	
TibPUR15	23.98	588.19	13934.18	0.00	13934.18	23.69	
NEWFACT A	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT B	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 1	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 2	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 3	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 4	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 5	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 6	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 7	0.00	0.00	0.00	0.00	0.00	41.70	

Table 30 - 1991 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTL 03-17-1987 Page 1
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prm 2
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3113.18	PK Load (MW)	574.62	Fix O&M	15.30
Unserve	0.30			Variable	3.88
Net Gen.	3112.88			Unservd	0.03
Storage	0.00			Fuel	47.04
Total Gen	3112.88	LOLP (Dys/Yr)	0.000	Total	66.24

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
BelgCC78	78.71	696.38	995.82	10907.93	11903.75	17.09
BelgCC68	78.70	696.30	993.63	11170.91	12164.53	17.47
BelugCT3	80.71	353.52	504.47	6781.42	7285.89	20.61
BelugCT5	76.77	450.57	642.96	9762.72	10605.68	23.54
soldatCT	56.22	187.14	267.61	4226.11	4493.72	24.01
bernice3	32.77	77.50	172.82	1820.14	1992.96	25.72
bernice4	17.52	41.43	92.40	1001.00	1093.40	26.39
bernice2	10.86	17.12	38.19	436.87	475.05	27.74
Anc CC76	2.97	28.35	164.11	686.42	850.53	30.00
BelugCT2	0.42	0.58	0.83	16.33	17.16	29.37
BelugCT1	0.26	0.37	0.53	10.27	10.79	29.37
BelugCT4	0.18	0.15	0.22	5.06	5.28	34.25
Anc CC56	0.08	0.32	1.86	10.56	12.42	38.69
Anc CT 8	0.01	0.06	0.37	1.98	2.35	36.65
Anc CT 4	0.00	0.00	0.01	0.07	0.08	46.43
IntnCT1	0.00	0.00	0.00	0.01	0.01	61.52
IntnCT2	0.00	0.00	0.00	0.00	0.01	61.52
IntnCT3	0.00	0.00	0.00	0.00	0.00	61.43
seward3	0.00	0.00	0.00	0.00	0.00	116.76
seward4	0.00	0.00	0.00	0.00	0.00	116.76
seward5	0.00	0.00	0.00	0.00	0.00	116.76
seward6	0.00	0.00	0.00	0.00	0.00	116.76
seldic2	0.00	0.00	0.00	0.00	0.00	135.24
seldic34	0.00	0.00	0.00	0.00	0.00	135.24
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00
bradleyH	46.82	369.16	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 31 - 1996 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTI 03-17-1987 Page 2
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prm 2
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3299.46	PK Load (MW)	607.27	Fix O&M	13.96
Unserve	0.20			Variable	3.77
Net Gen.	3299.26			Unreserved	0.02
Storage	0.00			Fuel	50.56
Total Gen	3299.26	LOLP (Dys/Yr)	0.008	Total	68.32

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$(/MWH)
BelgCC78	78.71	696.37	995.80	10907.72	11903.52	17.09
BelgCC68	78.70	696.35	993.69	11171.43	12165.12	17.47
NewBCT 4	77.67	340.21	197.32	6715.43	6912.75	20.32
BelugCT3	77.80	340.76	486.27	6568.53	7054.80	20.70
BelugCT5	69.99	410.79	586.20	9236.52	9822.72	23.91
soldatCT	42.49	141.44	202.26	3276.18	3478.45	24.59
bernice3	21.06	49.80	111.06	1196.76	1307.83	26.26
bernice4	13.48	31.87	71.08	776.57	847.64	26.59
bernice2	6.19	9.75	21.75	250.51	272.26	27.91
Anc CC76	1.87	17.84	103.28	431.99	535.27	30.00
Anc CC56	0.19	0.82	4.74	26.93	31.67	38.69
Anc CT 8	0.03	0.19	1.12	5.95	7.06	36.65
seward3	0.00	0.00	0.00	0.07	0.08	116.76
seward4	0.00	0.00	0.00	0.07	0.08	116.76
seward5	0.00	0.00	0.01	0.10	0.10	116.76
seward6	0.00	0.00	0.00	0.09	0.09	116.76
seldic2	0.00	0.00	0.01	0.02	0.03	135.24
seldic34	0.00	0.00	0.01	0.02	0.03	135.24
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00
bradleyH	46.82	369.15	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 32 - 2006 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTL 03-17-1987 Page 3
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prm 2
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3794.58	PK Load (MW)	685.00	Fix O&M	14.03
Unserve	2.11			Variable	3.06
Net Gen.	3792.48			Unservd	0.21
Storage	0.00			Fuel	53.44
Total Gen	3792.48	LOLP (Dys/Yr)	0.787	Total	70.74

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total Cost	Total Cost \$/(MWH)
New CC76	81.76	1289.27	747.78	20386.06	21133.83	16.39
BelgCC78	78.60	695.38	994.39	10894.95	11889.34	17.10
BelgCC68	75.04	663.92	947.42	10741.97	11689.39	17.61
NewBCT14	61.11	267.65	155.24	5179.50	5334.73	19.93
newKct1	46.76	163.86	95.04	3171.02	3266.06	19.93
NewBCT 4	13.98	61.24	35.52	1208.87	1244.39	20.32
NewBCT 5	8.77	51.48	29.86	1016.21	1046.07	20.32
NewBCT 6	5.62	24.64	14.79	486.27	500.56	20.32
soldatCT	1.94	6.46	9.24	163.09	172.33	26.66
Anc CT 8	0.70	5.34	30.92	164.88	195.80	36.65
seward3	0.25	0.04	0.26	4.90	5.16	116.76
seward4	0.25	0.04	0.25	4.83	5.09	116.76
seward5	0.24	0.06	0.37	6.96	7.33	116.76
seward6	0.23	0.06	0.35	6.56	6.91	116.76
seldic2	0.22	0.02	0.75	1.81	2.56	135.24
seldic34	0.21	0.02	0.73	1.76	2.49	135.24
EklutnaH	58.18	152.90	0.00	0.00	0.00	0.00
bradleyH	46.82	369.11	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 33 - 2015 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTL 03-17-1987 Page 4
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint.anc/kenai dispatch newcc76 in kenai 40% prn 2

SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	4339.12	PK Load (MW)	783.30	Fix O&M	15.05
Unserve	0.78			Variable	2.30
Net Gen.	4338.34			Unservd	0.08
Storage	0.00			Fuel	63.50
Total Gen	4338.34	LOLP (Dys/Yr)	0.435	Total	80.92

Unit Name	Capacity Factor	Energy (GWH)	Variable	Cost in \$1,000	Fuel Cost	Total	Total Cost \$/(MWH)
NewBCC68	78.69	696.21	459.50	10905.68	11365.18	16.32	
NewBCC78	78.69	696.22	459.51	10905.78	11365.29	16.32	
New CC76	81.38	1283.20	744.26	20307.02	21051.28	16.41	
NewBCT14	72.48	317.44	184.12	6143.15	6327.27	19.93	
NewBCT15	69.06	302.50	175.45	5854.06	6029.51	19.93	
newKct1	55.42	194.18	112.63	3757.85	3870.48	19.93	
newKct2	37.86	132.66	76.94	2567.30	2644.24	19.93	
newKct3	26.32	57.64	33.43	1115.38	1148.81	19.93	
NewBCT 4	9.02	39.52	22.92	780.08	803.01	20.32	
NewBCT 5	5.62	32.99	19.14	651.26	670.39	20.32	
NewBCT 6	3.57	15.64	9.07	308.72	317.79	20.32	
New CT11	0.71	5.44	3.15	144.68	147.83	27.19	
New CT12	0.36	1.60	0.93	42.45	43.38	27.19	
seward3	0.15	0.03	0.15	2.86	3.01	116.76	
seward4	0.14	0.02	0.15	2.77	2.92	116.76	
seward5	0.14	0.04	0.21	3.95	4.16	116.76	
seward6	0.13	0.03	0.19	3.70	3.89	116.76	
seldic2	0.12	0.01	0.42	1.01	1.43	135.24	
seldic34	0.12	0.01	0.41	0.98	1.39	135.24	
EklutnaH	58.18	152.89	0.00	0.00	0.00	0.00	
bradleyH	46.81	369.08	0.00	0.00	0.00	0.00	
cooper H	25.99	40.97	0.00	0.00	0.00	0.00	

Table 34 - Comparison of 2006 Results in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	3.75			Variable	15.58
Net Gen.	1227.11			Unservd	0.37
Storage	0.00			Fuel	20.26
Total Gen	1227.11	LOLP (Dys/Yr)	0.011	Total	40.36

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
NewHeST1	87.48	191.57	823.76	3024.46	3848.21	20.09
TIEPUR06	97.88	600.21	14231.02	0.00	14231.02	23.71
NoPolCT2	57.75	308.58	449.60	12027.15	12476.74	40.43
NEWFACT A	15.99	35.03	20.32	1440.44	1460.75	41.70
NEWFACT B	9.39	20.57	11.93	846.06	858.00	41.70
NEWFACT 1	6.25	13.69	7.94	563.05	570.99	41.70
NEWFACT 2	5.04	11.04	6.41	454.15	460.55	41.70
NEWFACT 3	4.38	9.59	5.56	394.30	399.86	41.70
NEWFACT 4	3.84	16.83	9.76	692.28	702.04	41.70
NEWFACT 5	3.26	19.99	11.60	822.21	833.81	41.70

Detail report:a:FBAS250X.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	0.02			Variable	24.17
Net Gen.	1230.84			Unservd	0.00
Storage	0.00			Fuel	3.49
Total Gen	1230.84	LOLP (Dys/Yr)	0.030	Total	31.81

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
NewHeST1	86.38	189.17	813.42	2989.27	3802.69	20.10
TIEPUR06	96.75	593.30	12993.31	0.00	12993.30	21.90
TibPUR06	17.80	436.56	10350.95	0.00	10350.95	23.71
NoPolCT2	1.36	7.26	10.58	317.87	328.45	45.23
NEWFACT A	0.46	1.02	0.59	41.82	42.41	41.70
NEWFACT B	0.37	0.82	0.48	33.75	34.23	41.70
NEWFACT 1	0.30	0.65	0.38	26.60	26.98	41.70
NEWFACT 2	0.23	0.51	0.29	20.87	21.16	41.70
NEWFACT 3	0.18	0.40	0.23	16.45	16.68	41.70
NEWFACT 4	0.13	0.59	0.34	24.06	24.40	41.70
NEWFACT 5	0.09	0.57	0.33	23.34	23.67	41.70

Table 35 - Comparison of 2006 Results in Anchorage and Kenai

Detail report:a:AK3540LS.DTL 03-17-1987 Page 3
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK35LAST.SPM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3124.08	PK Load (MW)	554.90	Fix O&M	11.16
Unserve	1.38			Variable	3.00
Net Gen.	3122.70			Unservd	0.14
Storage	0.00			Fuel	53.27
Total Gen	3122.70	LOLP (Dys/Yr)	0.225	Total	67.56

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total	Total Cost \$/(MWH)
BelgCC78	78.71	696.35	995.78	10907.50	11903.29	17.09
BelgCC68	78.70	696.31	993.64	11171.03	12164.67	17.47
NewBCT14	77.90	341.22	197.91	6603.28	6801.18	19.93
NewBCT 3	73.51	321.97	186.74	6355.46	6542.20	20.32
NewBCT 4	66.88	292.92	169.89	5781.94	5951.84	20.32
NewBCT 5	55.35	324.87	188.43	6412.72	6601.14	20.32
NewBCT 6	37.99	166.39	96.51	3284.40	3380.90	20.32
New CC56	12.67	53.28	30.90	1152.35	1183.25	22.21
New CC76	6.15	71.09	41.23	1537.51	1578.74	22.21
KENPUR06	1.12	3.43	84.45	0.00	84.45	24.61
Anc CT 8	0.25	1.94	11.24	59.92	71.15	36.65
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Detail report:a:K8AS35LS.DTL 03-17-1987 Page 3
 RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kbas35ls.SPM-kenai with anc 35mw purch 40% prm loss penalty
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	670.56	PK Load (MW)	130.10	Fix O&M	3.32
Unserve	0.64			Variable	0.18
Net Gen.	669.92			Unservd	0.06
Storage	0.00			Fuel	5.20
Total Gen	669.92	LOLP (Dys/Yr)	0.000	Total	8.76

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total	Total Cost \$/(MWH)
new ct1	65.89	230.88	133.91	4468.02	4601.94	19.93
soldatCT	8.76	29.17	41.71	735.80	777.50	26.66
ANCPUR06	0.01	0.02	0.51	0.00	0.51	23.78
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.79	368.90	0.00	0.00	0.00	0.00
cooper H	25.98	40.96	0.00	0.00	0.00	0.00

Base Case vs. Alternate Case - Savings in Production Cost & Capacity

Year	-----Base Case-----				-----Alternate Case-----			Operating Savings	Capital Savings	Total Savings
	Kenai	Anchor	Fairbnk	Total	Ken/Anch	Fairbnk	Total			
1991	8.46	58.70	32.47	99.63	66.24	29.58	95.82	3.81	0	3.81
1992	8.61	58.98	33.60	101.19	66.67	30.49	97.16	4.03	0	4.03
1993	8.82	60.35	34.56	103.73	68.24	31.34	99.58	4.15	1.41	5.56
1994	8.86	60.67	34.88	104.41	69.36	33.02	102.38	2.03	1.41	3.44
1995	8.87	60.94	35.79	105.60	69.68	33.77	103.45	2.15	1.41	3.56
1996	8.88	59.87	36.21	104.96	68.32	33.76	102.08	2.88	1.41	4.29
1997	8.77	60.18	37.19	106.14	68.55	34.80	103.35	2.79	1.41	4.20
1998	8.79	60.62	38.19	107.60	69.04	35.21	104.25	3.35	1.41	4.76
1999	8.75	59.45	37.75	105.95	62.48	31.39	93.87	12.08	1.41	13.49
2000	8.78	60.31	38.87	107.96	63.28	32.14	95.42	12.54	1.41	13.95
2001	8.88	62.77	39.78	111.43	65.56	33.13	98.69	12.74	1.41	14.15
2002	8.84	63.79	38.87	111.50	66.71	31.73	98.44	13.06	1.41	14.47
2003	9.09	64.71	39.50	113.30	67.77	32.09	99.86	13.44	1.41	14.85
2004	8.34	65.63	40.14	114.11	68.51	32.14	100.65	13.46	1.41	14.87
2005	8.55	66.59	39.93	115.07	69.61	31.51	101.12	13.95	1.41	15.36
2006	8.76	67.56	40.36	116.68	70.74	31.81	102.55	14.13	2.81	16.94
2007	8.98	67.96	41.44	118.38	70.79	32.54	103.33	15.05	2.81	17.86
2008	9.26	68.97	42.20	120.43	72.06	33.60	105.66	14.77	2.81	17.58
2009	9.42	69.65	42.93	122.00	72.81	33.60	106.41	15.59	2.81	18.40
2010	9.31	70.65	43.84	123.80	73.86	34.00	107.86	15.94	2.81	18.75
2011	9.52	71.84	44.14	125.50	75.32	33.44	108.76	16.74	2.81	19.55
2012	9.73	72.90	44.92	127.55	76.58	34.39	110.97	16.58	2.81	19.39
2013	9.95	73.98	45.72	129.65	77.85	34.74	112.59	17.06	2.81	19.87
2014	10.41	75.06	46.51	131.98	79.25	34.54	113.79	18.19	1.41	19.60
2015	10.64	76.60	47.33	134.57	80.92	35.30	116.22	18.35	1.41	19.76
2016	10.86	77.72	48.43	137.01	82.24	36.31	118.55	18.46	1.41	19.87
2017	11.10	78.88	49.30	139.28	83.59	37.33	120.92	18.36	1.41	19.77
2018	11.33	81.68	50.24	143.25	86.48	37.89	124.37	18.88	1.41	20.29
2019	11.56	82.91	51.14	145.61	87.89	38.63	126.52	19.09	1.41	20.50
2020	11.80	84.16	52.09	148.05	89.35	39.85	129.20	18.85	1.41	20.26
Total								372.50	50.66	423.16
NPV 1987								178.53	26.14	204.67

Table 36 - Year by Year Results

Base Case vs. Kenai-Anchor Tie Only Case - Savings in Production Cost & Capacity

Year	I-----Base Case-----I				I---Ken-Anc Only Case---I			Operating Savings	Capital Savings	Total Savings
	Kenai	Anchor	Fairbnk	Total	Ken/Anch	Fairbnk	Total			
1991	8.46	58.70	32.47	99.63	66.24	31.76	98.00	1.63	0	1.63
1992	8.61	58.98	33.60	101.19	66.67	32.85	99.52	1.67	0	1.67
1993	8.82	60.35	34.56	103.73	68.24	33.79	102.03	1.70	1.41	3.11
1994	8.86	60.67	34.88	104.41	69.36	34.89	104.25	0.16	1.41	1.57
1995	8.87	60.94	35.79	105.60	69.67	35.79	105.46	0.14	1.41	1.55
1996	8.88	59.87	36.21	104.96	68.32	36.58	104.90	0.06	1.41	1.47
1997	8.77	60.18	37.19	106.14	68.54	37.59	106.13	0.01	1.41	1.42
1998	8.74	60.62	38.19	107.60	69.03	38.57	107.60	0.00	1.41	1.41
1999	8.75	59.45	37.75	105.95	62.47	37.00	99.47	6.48	1.41	7.89
2000	8.78	60.31	38.87	107.96	63.27	38.10	101.37	6.59	1.41	8.00
2001	8.88	62.77	39.78	111.43	65.57	38.90	104.47	6.96	1.41	8.37
2002	8.84	63.79	38.87	111.50	66.72	38.23	104.95	6.55	1.41	7.96
2003	9.09	64.71	39.50	113.30	67.76	38.86	106.62	6.68	1.41	8.09
2004	8.34	65.63	40.14	114.11	68.51	39.34	107.85	6.26	1.41	7.67
2005	8.55	66.59	39.93	115.07	69.61	39.13	108.74	6.33	1.41	7.74
2006	8.75	67.56	40.36	116.68	70.75	39.52	110.27	6.41	2.81	9.22
2007	8.98	67.96	41.44	118.38	70.79	40.62	111.41	6.97	2.81	9.78
2008	9.26	68.97	42.20	120.43	72.06	41.36	113.42	7.01	2.81	9.82
2009	9.42	69.65	42.93	122.00	72.81	42.03	114.84	7.16	2.81	9.97
2010	9.31	70.65	43.84	123.80	73.86	42.87	116.73	7.07	2.81	9.88
2011	9.52	71.84	44.14	125.50	75.32	43.42	118.74	6.76	2.81	9.57
2012	9.73	72.90	44.92	127.55	76.58	44.16	120.74	6.81	2.81	9.62
2013	9.95	73.98	45.72	129.65	77.85	44.93	122.78	6.87	2.81	9.68
2014	10.41	75.06	46.51	131.98	79.25	45.60	124.85	7.13	1.41	8.54
2015	10.64	76.60	47.33	134.57	80.92	46.37	127.29	7.28	1.41	8.69
2016	10.86	77.72	48.43	137.01	82.24	47.42	129.66	7.35	1.41	8.76
2017	11.10	78.88	49.30	139.28	83.59	48.24	131.83	7.45	1.41	8.86
2018	11.33	81.68	50.24	143.25	86.48	49.10	135.58	7.67	1.41	9.08
2019	11.56	82.91	51.14	145.61	87.90	49.96	137.86	7.75	1.41	9.16
2020	11.80	84.16	52.09	148.05	89.35	50.85	140.20	7.85	1.41	9.26
Total								158.75	50.66	209.41
NPV 1987								76.10	26.14	102.24

Table 37 - Year by Year Results

Base Case vs. Anchorage-Fairbanks Tie Only Case - Savings in Production Cost & Capacity

Year	I-----Base Case-----I				I-----Anchor-Fairbanks Case----I				Operating Savings	Cap Sav	Total Savings
	Kenai	Anchor	Fairbnk	Total	Kenai	Anchor	Fairbnk	Total			
1991	8.46	58.70	32.47	99.63	8.46	58.70	30.53	97.69	1.94	0	1.94
1992	8.61	58.98	33.60	101.19	8.61	58.98	31.49	99.08	2.11	0	2.11
1993	8.82	60.35	34.56	103.73	8.82	60.35	32.31	101.48	2.25	0	2.25
1994	8.86	60.67	34.88	104.41	8.86	60.66	32.40	101.92	2.49	0	2.49
1995	8.87	60.94	35.79	105.60	8.87	60.93	33.16	102.96	2.64	0	2.64
1996	8.88	59.87	36.21	104.96	8.88	59.87	33.01	101.76	3.20	0	3.20
1997	8.77	60.18	37.19	106.14	8.77	60.17	33.76	102.70	3.44	0	3.44
1998	8.79	60.62	38.19	107.60	8.79	60.62	34.53	103.94	3.66	0	3.66
1999	8.75	59.45	37.75	105.95	8.75	59.45	32.60	100.80	5.15	0	5.15
2000	8.78	60.31	38.87	107.96	8.78	60.31	33.44	102.53	5.43	0	5.43
2001	8.88	62.77	39.78	111.43	8.88	62.77	34.33	105.98	5.45	0	5.45
2002	8.84	63.79	38.87	111.50	8.84	63.79	32.71	105.34	6.16	0	6.16
2003	9.09	64.71	39.50	113.30	9.09	64.72	33.18	106.99	6.31	0	6.31
2004	8.34	65.63	40.14	114.11	8.34	65.63	33.59	107.56	6.55	0	6.55
2005	8.55	66.59	39.93	115.07	8.55	66.58	32.42	107.55	7.52	0	7.52
2006	8.76	67.56	40.36	116.68	8.76	67.55	32.85	109.16	7.52	0	7.52
2007	8.98	67.96	41.44	118.38	8.98	67.96	33.41	110.35	8.03	0	8.03
2008	9.26	68.97	42.20	120.43	9.26	68.97	33.97	112.20	8.23	0	8.23
2009	9.42	69.65	42.93	122.00	9.42	69.64	34.38	113.44	8.56	0	8.56
2010	9.31	70.65	43.84	123.80	9.31	70.65	35.08	115.04	8.76	0	8.76
2011	9.52	71.84	44.14	125.50	9.52	71.84	34.66	116.02	9.48	0	9.48
2012	9.73	72.90	44.92	127.55	9.73	72.90	35.13	117.81	9.74	0	9.74
2013	9.95	73.98	45.72	129.65	9.95	73.98	35.73	119.65	10.00	0	10.00
2014	10.41	75.06	46.51	131.99	10.41	75.06	36.26	121.73	10.25	0	10.25
2015	10.64	76.60	47.33	134.57	10.64	76.60	36.87	124.11	10.46	0	10.46
2016	10.86	77.72	48.43	137.01	10.86	77.72	37.72	126.30	10.71	0	10.71
2017	11.10	78.88	49.30	139.28	11.10	78.88	38.51	128.49	10.79	0	10.79
2018	11.33	81.68	50.24	143.25	11.33	81.68	39.21	132.22	11.03	0	11.03
2019	11.56	82.91	51.14	145.61	11.56	82.91	39.87	134.34	11.27	0	11.27
2020	11.80	84.16	52.09	148.05	11.80	84.17	40.62	136.59	11.46	0	11.46
Total									210.59	0	210.59
NPV 1987									101.17	0	101.17

Table 38 - Year by Year Results

8. Appendices:

8.1. Description of the UPLAN Model

UPLAN

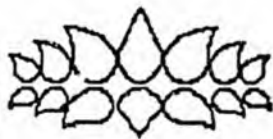
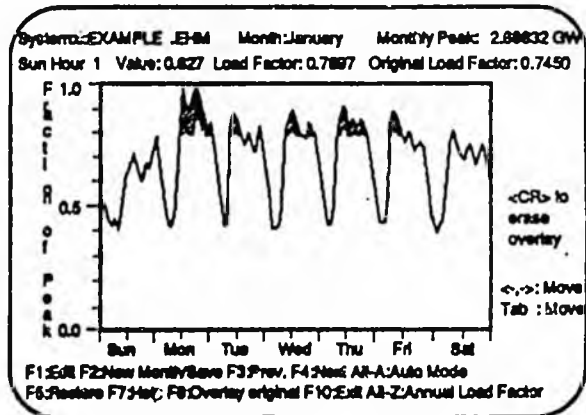
The Electric Utility Planning System

An Integrated Utility Planning Model

Major Features:

- *Supply-Side Planning*
- *Demand-Side Management*
- *Financial Planning*
- *Uncertainty Simulation*

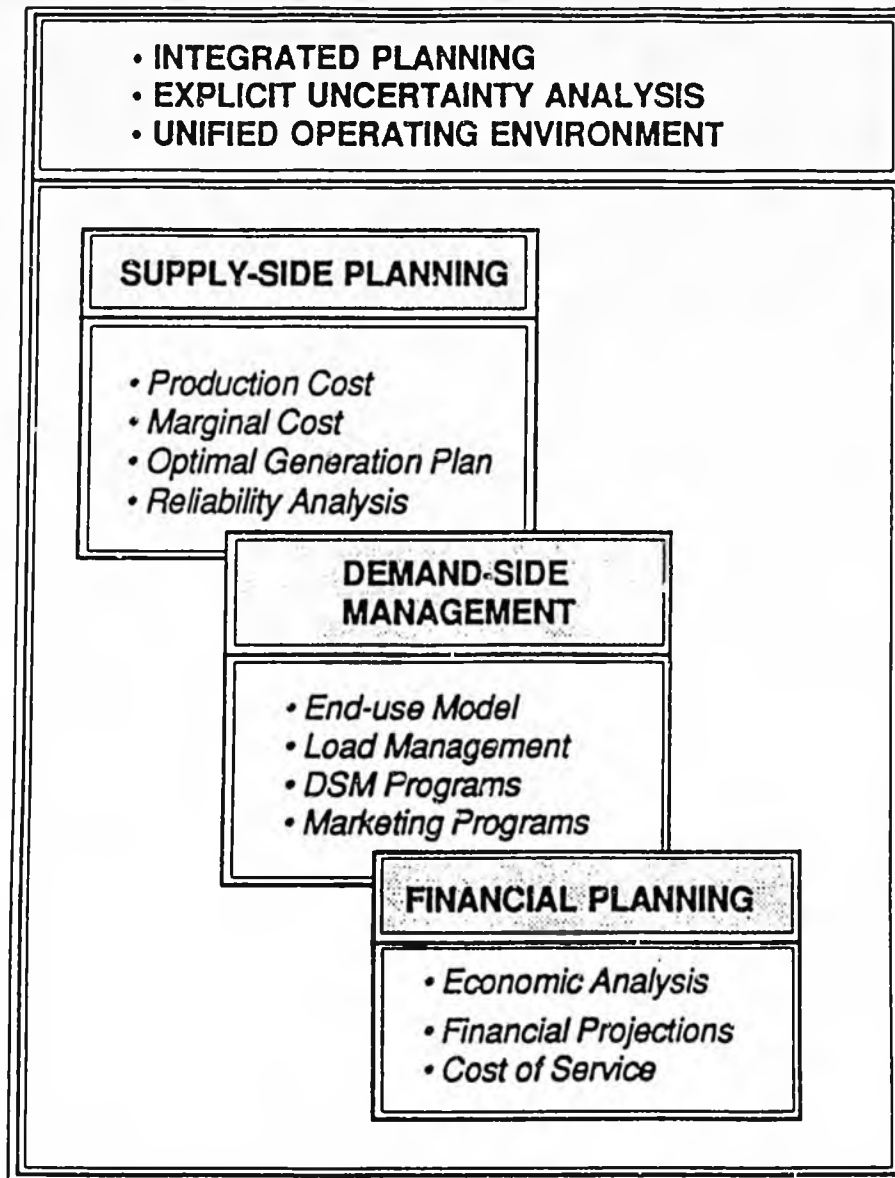
IBM PC/XT/AT/3270- or compatibles.



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The Electric Utility Planning System



Features:

- State-of-the-art utility planning system
- Fast, accurate and flexible
- Window-based, menu-driven environment
- Integrated workstation (IBM PC/XT/AT/3270PC/AT)
- Powerful batch interactive processing

UPLAN INTRODUCTION

The Electric Utility Planning System

The Electric Utility Planning System (UPLAN) is a powerful simulation tool designed to facilitate the analysis and evaluation of demand, supply and financial options facing utilities.

This sophisticated, yet easy to use, system expands the decision-making process by combining demand-side management (DSM), optimal generation planning, production costing, reliability analysis, economic analysis and financial planning in a unified operating environment.

Comprehensive Modeling System

UPLAN offers advanced modeling capabilities for:

- Multi-area Production Costing
- Chronological Dispatch of Time-Dependent Resources
- Hourly Marginal Costing
- Optimal Generation Planning
- Reliability Analysis
- Revenue Requirements and Economic Analysis
- DSM Benefit Analysis
- Integrated Demand/Supply and Financial Planning
- Uncertainty Simulation
- Cost of Service Determination

UPLAN in Action

Since the systems' first commercial introduction in 1984, UPLAN electric utility planning systems have found broad service in utility and research studies. UPLAN has demonstrated the accuracy, speed, ease of use, and dependability needed to support critical testimony.

The range of applications which UPLAN can address is very wide. Some UPLAN studies already completed include:

- Demand-side management evaluation in California
- Resource planning and marginal cost analysis for West Coast utilities
- Estimation of region-wide benefits of demand-side management programs for EPRI regional system

- Merger analysis and testimony in the Northeast
- Long-term avoided cost analysis of cogeneration in Maine
- Risk and financial analysis in Texas
- Strategic planning, fuel planning, and short-term avoided cost analysis in the Northeast
- Least-cost resource planning in Nevada
- Regional resource adequacy assessment by the U.S. Congressional Office of Technology Assessment
- Optimal resource mix identification and service area benefits assessment in the Northwest
- Minimum-load studies for a West Coast utility

UPLAN INTERFACE

UPLAN is an easy-to-run interactive software package consisting of a series of interrelated modules that simulate the planning process. The system uses multiple windows, function keys, on-screen help, and dedicated data entry editors to provide a user-friendly environment for entering, viewing, and on-screen editing tables and graphs.

Window Based System

UPLAN communicates with the user through extensive use of windows. These windows help organize and present related data in a logical and easy-to-follow way. The system uses several types of windows, such as:

- Command menu windows
- File choice windows
- Report windows
- Status and help windows

Command menus are used to choose and execute modules in UPLAN. These menus are

organized hierarchically: if a command has a series of subcommands, secondary or sub-menus are displayed on the screen.

Function Keys

Predefined function keys, displayed on the appropriate menu, allow the user to instruct the system to perform transactions such as help, show, save, delete and print.

On-line Help

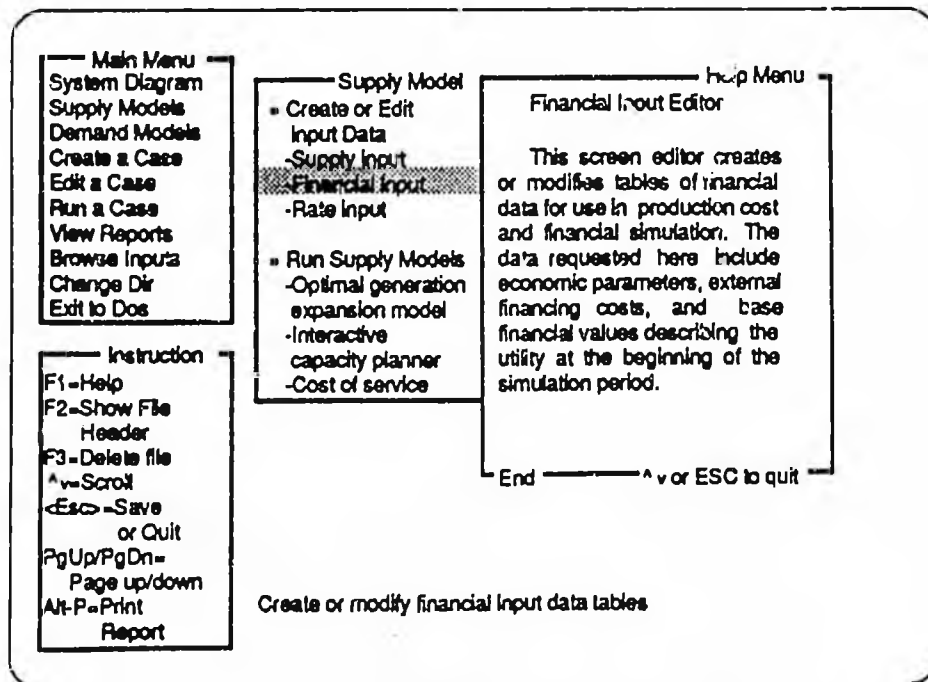
The on-line help facility provides detailed information about individual modules, as well as a system diagram that explains schematically the data and logic flow typical of any UPLAN study.

Data Entry Editors

To create and edit data, UPLAN provides customized screen editors. Each class of input data; supply, financial, and load, has its own individually tailored screen-editor.

UPLAN Unified Operating Environment

UPLAN's window based batch-interactive operating system manages both the system of models and the data base.



UPLAN SUPPLY-SIDE MODELS

UPLAN has supply-side modules for:

- Production Costing
- Chronological Production Costing
- Marginal Costing
- Optimal Generation Planning
- Reliability Analysis
- Economic Analysis
- Interactive Capacity Planning
- Uncertainty Simulation

PRODUCTION COSTING

UPLAN incorporates a two-area probabilistic costing simulation algorithm to provide fast and accurate month-by-month unit-by-unit production costing for up to 30 years.

Each generating unit can be specified to be primarily dedicated to either the native area or a

secondary service area. For the native service area, UPLAN uses the Mixture of Normal Approximation (MONA) algorithm. The MONA technique has proved superior to conventional production costing methods because the load is represented by a combination of distributions rather than by the single distribution common to traditional methods.

Production costing features include:

- Hydro optimization
- Pumped storage dispatch
- Power purchase modeling
- Multiple-block treatment of units
- Non-economic dispatch capability
- Unit commitment algorithm
- Chronological dispatch of time-dependent units

Production Cost Report: Annual Detail

UPLAN produces several production cost reports with varying degree of detail. The reports are:

- Unit-by-unit monthly report
- Unit-by-unit annual report
- Aggregate fuel report
- Summary report
- 2nd area dispatch report

Main Menu Detail

c:\up\data\SAMPLE1.DTL Screen 1

RNM file:c:\NEWDEMO2.RNM-Change case sample run
Supply file:c:\NEWDEMO2.SPM-Base case sample run

SYSTEM REPORT FOR YEAR 1985

ENERGY (GWh)		RELIABILITY		COSTS(M\$)	
Demand	16402.17	PK Load (MW)	3215.30	Fix O&M	32.50
Unserve	49.95	Capacity (MW)	4080.00	Var O&M	17.45
Not Gen.	16352.22	Reserve (%)	26.89	Consum.	4.73
Storage	96.01	LOEP (%)	0.303	Fuel	272.06
Total Gen	16448.23	LOLP (Dys/Yr)	7.410	Total	256.74

Unit Name	Capacity Factor	Energy (GWh)	Cost in \$1,000		Total Cost
			Var O&M	Fuel Cost	\$(/MWH)
NUC0800	71.23	4991.55	8485.63	44620.87	53106.50
COL6SUB	75.14	3349.57	3949.57	62156.42	66105.99
COL6SPRF	64.34	3381.80	7778.15	53153.32	60931.47
COL2SSUB	42.05	920.84	920.84	16322.39	17243.22
COL2SSUB	23.65	522.35	522.35	10157.07	10679.42
COAL10J	13.10	114.72	114.72	2801.75	2916.47
COAL100	9.77	85.62	85.62	2206.06	2291.68
COAL100	6.85	60.05	60.05	1620.30	1680.35
COAL100N	5.44	47.63	47.63	1298.55	1346.13

F2 Select screen, F3 Prev, F4 Next, F9 to main menu, Esc to quit, ^v, PgUp, PgDn
Alt-P to print file

UPLAN SUPPLY-SIDE MODELS

CHRONOLOGICAL PRODUCTION SUBMODEL

Using this module, generating units with capacity which varies from hour to hour can be modeled directly. Planning applications for which this submodel is particularly well-suited include:

- studies of minimum loading conditions due to unit commitment requirements, qualified facilities, and other restrictions
- modeling time-varying power purchases

Under this approach, an hour-by-hour capability shape is entered for each time-varying unit, and two-pass chronological dispatch simulation is performed.

MARGINAL COSTING

UPLAN determines the marginal cost of electri-

city by computing the probability of a unit being at a margin for a given load level.

The system reports marginal costs on an hourly, monthly percent of peak load, and percent of time basis. Marginal costs aid in the analysis of potential transactions, and can be used for rate-making.

UNCERTAINTY SIMULATION

UPLAN's uncertainty simulation is the first of its kind for the utility industry. This option allows systematic evaluation of uncertainty and risk factors associated with alternative planning options using the Monte Carlo analysis technique.

The user may define a number of critical variables as uncertain, such as load growth, capital costs and fuel prices, and specify low, high, most-likely values for them. Based on these uncertainty variables, UPLAN processes production costing simulations and produces distributions of variable and fixed production costs and financial projections.

Defining an Uncertainty Distribution

The range of the uncertainty variables such as load growth, capital costs and fuel prices is specified by choosing low, high and most likely values at run time.

<p>Main Menu</p> <ul style="list-style-type: none"> System Diagram Supply Models Demand Models Create a Case Edit a Case Plan a Case View Reports Browse Inputs Change Dir Exit to DOS 	<p>Pick a unit</p> <table border="1"> <thead> <tr> <th>Unit ID</th> <th>Unit Name</th> <th>Inst Year</th> </tr> </thead> <tbody> <tr> <td>N001</td> <td>NUC0800</td> <td>1977</td> </tr> <tr style="background-color: #cccccc;"> <td>C001</td> <td>COL6SPRF</td> <td>1974</td> </tr> <tr> <td>C002</td> <td>COL6SUB</td> <td>1967</td> </tr> <tr> <td>C003</td> <td>COL25SUB</td> <td>1965</td> </tr> <tr> <td>C004</td> <td>COAL100</td> <td>1962</td> </tr> </tbody> </table> <p>ESC: Enter value</p>	Unit ID	Unit Name	Inst Year	N001	NUC0800	1977	C001	COL6SPRF	1974	C002	COL6SUB	1967	C003	COL25SUB	1965	C004	COAL100	1962	<p>Progress</p> <p>In-service Date</p>
Unit ID	Unit Name	Inst Year																		
N001	NUC0800	1977																		
C001	COL6SPRF	1974																		
C002	COL6SUB	1967																		
C003	COL25SUB	1965																		
C004	COAL100	1962																		
<p>Instruction</p> <ul style="list-style-type: none"> F1=Help F2=Show File Header F3=Delete file ^v=Scroll <Esc>=Save or Quit PgUp/PgDn=Page up/down Alt-P=Print Report 	<p>Enter Values</p> <table border="1"> <thead> <tr> <th>ENTRIES CHOSEN</th> <th>LOW</th> <th>MOST LIKELY</th> <th>HIGH</th> </tr> </thead> <tbody> <tr> <td>N001 NUC0800</td> <td>1970</td> <td>1980</td> <td>1990</td> </tr> <tr> <td>C001 COL6SPRF</td> <td>1975</td> <td>1985</td> <td>1990</td> </tr> </tbody> </table> <p>ESC to Exit</p>			ENTRIES CHOSEN	LOW	MOST LIKELY	HIGH	N001 NUC0800	1970	1980	1990	C001 COL6SPRF	1975	1985	1990					
ENTRIES CHOSEN	LOW	MOST LIKELY	HIGH																	
N001 NUC0800	1970	1980	1990																	
C001 COL6SPRF	1975	1985	1990																	

UPLAN SUPPLY-SIDE MODELS

OPTIMAL GENERATION EXPANSION (OGE)

The OGE module determines the plant investment program that minimizes total present value of capital and operating cost over a planning horizon. This option can be used in conjunction with the price elasticity option and uncertainty simulation option.

INTERACTIVE CAPACITY PLANNER

The interactive capacity planner can be used to quickly examine the major features of a capacity expansion plan. This module allows the user to modify the installation and retirement dates, and allows treatment of constraints which cannot be modeled with an optimization model.

Input Data

UPLAN's requirements for supply data are extremely flexible to allow a wide-range level of detail.

To generate unit information for screening studies, data can be entered for the first year of the simulation period and remain constant throughout the life cycle of the study. For detailed analysis, unit data can be updated every study year.

Supply data includes the following:

- Capacity, installation date, and tax depreciation schedule
- Outage rates (forced and daily unavailability)
- Heat rates (four load levels and average)
- Fixed and variable O&M, consumables, and fuel costs
- Monthly energy and capacity limitation
- SO_x, NO_x, and particulate emissions
- Construction time and cost
- Multiple block loading
- Monthly planned maintenance schedule
- Variable cost data for second area dispatch and parameters for unit commitment algorithm.

Supply Data Editor

With the Supply Data editor, users enter all supply system cost, engineering, and transaction information. The general unit information is the first of nine data entry screens.

File Name: c:\BASECASE.SPM

Description: Base Case Tutorial Run
Screen One: General Unit Information

Unit ID	Unit Name	Size (MW)	Number of Units	Flue gas Scrubber (yes/no)	Super-Critical (yes/no)	Date Installed	Units 1-15	
							Book Life (Yr)	ACRS Type 1-3
N001	NUC0800	800	1	NO	NO	1977	30	1
C001	COL6SPRF	600	1	YES	YES	1974	40	2
C002	COL6SUB	600	1	NO	NO	1967	40	2
C003	COL2SSUB	250	2	NO	NO	1965	40	2
C004	COAL100	100	3	NO	NO	1962	40	2
C005	COAL100N	100	2	NO	NO	1968	40	2
CT01	CT100A	50	3	NO	NO	1972	30	1
CT02	CT100B	50	2	NO	NO	1970	30	1
CT03	CT100C	50	2	NO	NO	1975	30	1
H001	HYDRO	830	1	NO	NO	1975	45	2
PS01	PUMPSTOR	100	1	NO	NO	1975	30	1
CT04	NEWCT	200	1	NO	NO	1989	30	1

F1: Save F3: Prev F4: Next F5: Left F6: Right F10: Quit Alt-A: Insert/Delete line

UPLAN DEMAND-SIDE MODELS

UPLAN integrates powerful demand-side capabilities with supply and financial modules. The system offers tools to:

- Manage load-side data
- Build daily load shapes libraries
- Combine daily loads to form monthly end-use loads
- Build hourly system loads
- Display graphically and modify load shapes at all levels of aggregation.

With UPLAN, a user can create an annual load shape for a group of customers or appliances. This end-use annual shape can be represented by seven hourly typical shapes for each month. In this manner, demand-side programs, which have been targeted for a particular customer class, can be analyzed individually.

GRAPHICAL MODIFICATION OF LOAD SHAPES

UPLAN can automatically modify load shapes to accommodate specified user requirements.

Modify Annual Load Shapes

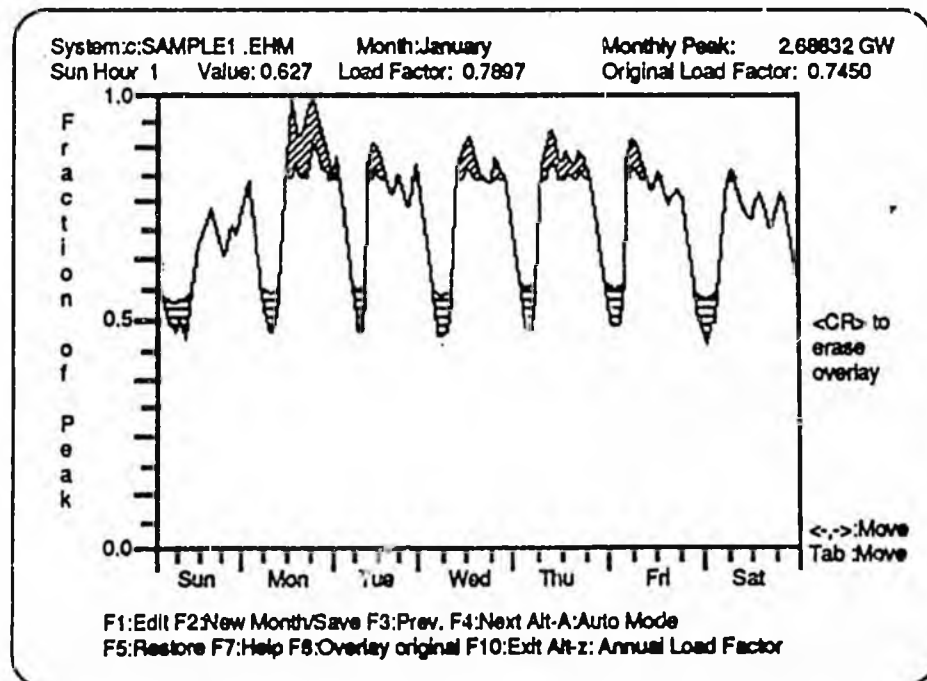
The Annual Load Shape Graphics Editor graphically displays typical monthly load shapes and energies, and allows modifications to be made to these curves by directly working with graphs of the curves rather than with tables of data values.

Modify Typical Day Type

The Typical Day Graphics editor displays a 24 hour shape created in the day type editor. Changes can be made directly on the curve: as changes are made, the underlying data base is automatically updated.

Load Shape Editor Modify Loads and Overlay Changes

The graphic load shape editor allows on-screen load modification using the cursor keys.



UPLAN DEMAND-SIDE MODELS

AGGREGATE LOAD SHAPES

Aggregation of Day Type Into End-Use Loads
In this module, month-by-month load shapes for end uses are created. The building blocks of an end-use shape are typical daily load shapes and energy forecasts for each day.

Aggregation of End-Use into Annual Loads
This module enables the user to group monthly end-use files into monthly system load files. The module is also used to add end-uses to, or subtract end-uses from, existing system load shapes.

Compare Two Annual Loads
This module computes and graphically displays differences between monthly system-wide load shapes. Differences can be used as residual load shapes.

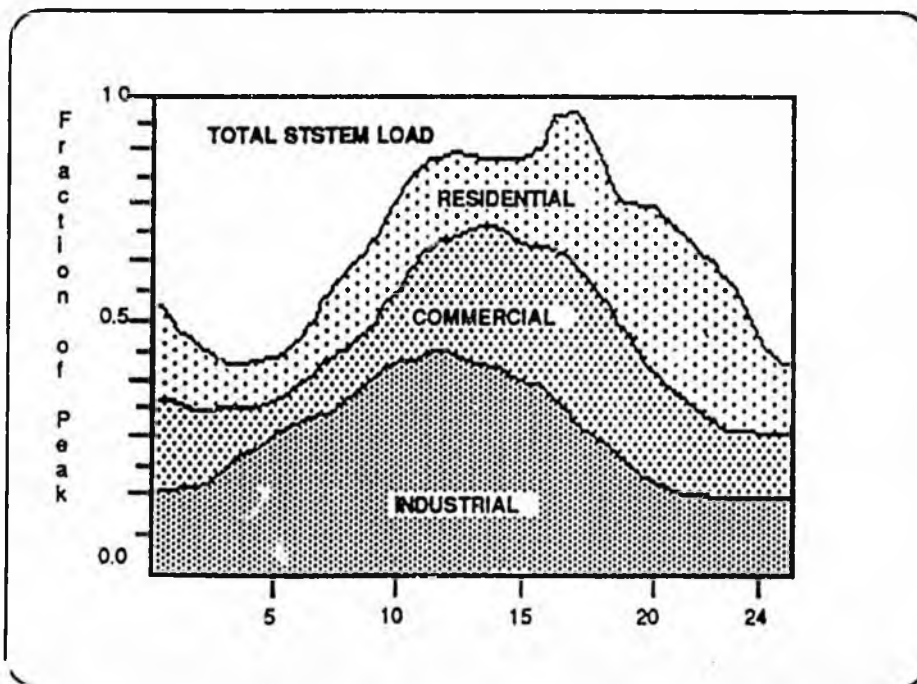
DEMAND-SIDE MANAGEMENT

UPLAN offers two complementary models for simulating demand-side management options.

STRATEGIC LOAD MANAGEMENT (SLM) MODEL

The SLM model handles changes at the strategic level to the load shape. Using an on-screen graphics editor, the following changes can be performed on hourly loads:

- Peak shaving
- Valley filling
- Load shifting and
- Load factor modification.



Aggregate Load Shapes

Up to 40 end-use load shapes can be aggregated using load aggregation models.

UPLAN DEMAND-SIDE MODELS

PROGRAMMATIC LOAD MANAGEMENT (PLM) MODEL

The PLM model handles detailed changes to the load shape. Using a spread-sheet-like interface, specific amounts of energy may be added to, subtracted from, or shifted among hours or block of hours.

In this way, utility load data can be used in other models.

- Shifts energy from a particular hour or block of hours to other hours
- Shifts energy from classes of days to other classes
- Substitutes one day type for another day type. Useful in modeling DSM programs (DLC, appliance, AC cycling, etc.)

Load Management Programmatic Load Changes

PLM module allows implementation of load management option interactively by specifying one of the three types of changes.

Month	Select months for demand management			
	Energy(GWH)	Peak(GW)	% of Energy	% of Peak
January	1604.524	2.95043	8.9560	84.0100
February	1547.226	2.84507	8.6361	81.0100
March	1305.832	2.63435	7.2888	75.0100
April	1253.605	2.52899	6.9972	72.0100
May	1340.649	2.70459	7.4831	77.0100
June	1581.275	3.19627	8.8262	91.0100
July	1563.900	3.16115	8.7292	90.0100
→ August	1737.474	3.51200	9.6981	100.0000
September	1497.328	3.02067	8.3576	86.0100
October	1358.058	2.73971	7.5803	78.0100
November	1445.102	2.91531	8.0661	83.0100
December	1680.729	3.09056	9.3813	88.0000

C:--Continue Esc-Quit ^, v

Select a type of shift

Hour by hour load shift
Strategic load shift
Load shift by equipment type

Esc:Quit ^, v

UPLAN DEMAND-SIDE MODELS

MARKET PENETRATION MODEL

The market penetration model enables the user to estimate the load shape impact and program-by-program market shares of up to twelve demand-side management (DSM) or energy marketing programs. The penetration level is calculated using a diffusion theory approach, and market shares are estimated by means of a logit-type model. The model evaluates energy changes on an hourly basis, and develops benefit-cost ratios based on levelized program cost and marginal production costs.

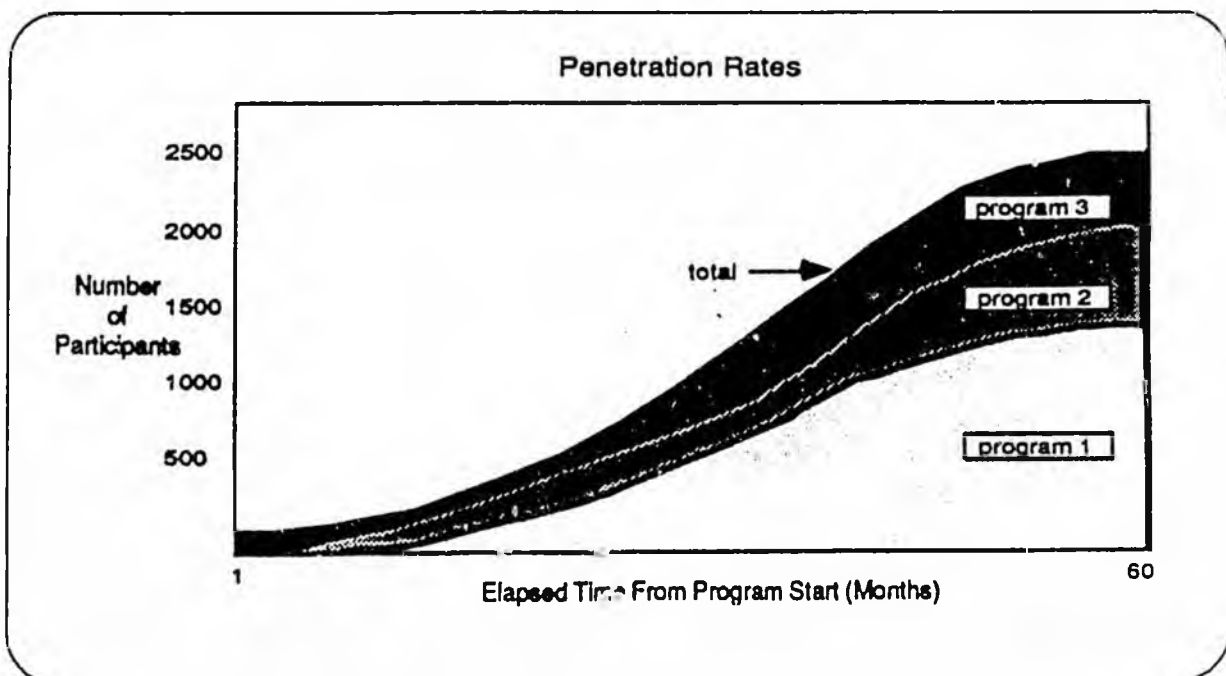
Estimating Market Penetration and Program Market Shares

UPLAN uses diffusion theory to estimate the number of customers expected to adopt the program. The user specifies the starting date of

the program and its duration as well as the expected number of participants. UPLAN will generate an S-curve which graphically displays the level of customer participation.

DSM Program Energy Savings

When the participation levels have been determined, the user enters the seasonal energy savings by time-of-use periods. When more than one program is specified, a cost-effectiveness measure is used to determine program market shares. UPLAN uses an iterative procedure to estimate a stable level of market penetration among programs. Hourly marginal costs for the specific customer classes are required for this calculation.



UPLAN DEMAND-SIDE MODELS

BENEFIT-COST ANALYSIS FOR DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS

The UPLAN benefit-cost model uses avoided costs from production cost simulation to estimate benefit-cost ratios, net present value, and rate impacts for demand-side management (DSM) programs. These estimates are developed and reported on a class-by-class basis for each customer class, and for the utility.

Benefit-Cost Calculation

The benefit calculation for a DSM program is

based on the avoided costs associated with the program for each class of customer. The energy component of avoided cost is allocated among the customer classes on an hourly basis.

Capacity savings are allocated across classes using a coincident peak rate design method. Rate impacts are calculated, and using the rate impact measure information, benefit-cost ratios and net present program value are calculated for each customer class.

UPLAN Benefit- Cost Model Output Report

c:\upindata\SAMPLE .CBO

<u>UPLAN Benefit-Cost</u>			
Class	PV Rate Impact 1986 mills/kWh	B/C per Customer	NPV (\$/customer)
Participants:			
Class 2	-35.420	19.19	562.54
Non-Participants			
Class 1	0.714	0.00	-166.70
Class 3	0.863	0.00	-140.76
Class 4	0.538	0.00	-160.95
Utility:	0.008	0.00	-45.05

Esc: Return to Main Menu. Alt-P: Print Screen.

UPLAN FINANCIAL MODELS

Financial Simulation

UPLAN has three financial models:

- Strategic Model
- Long Range Model
- Short-term Tactical Model

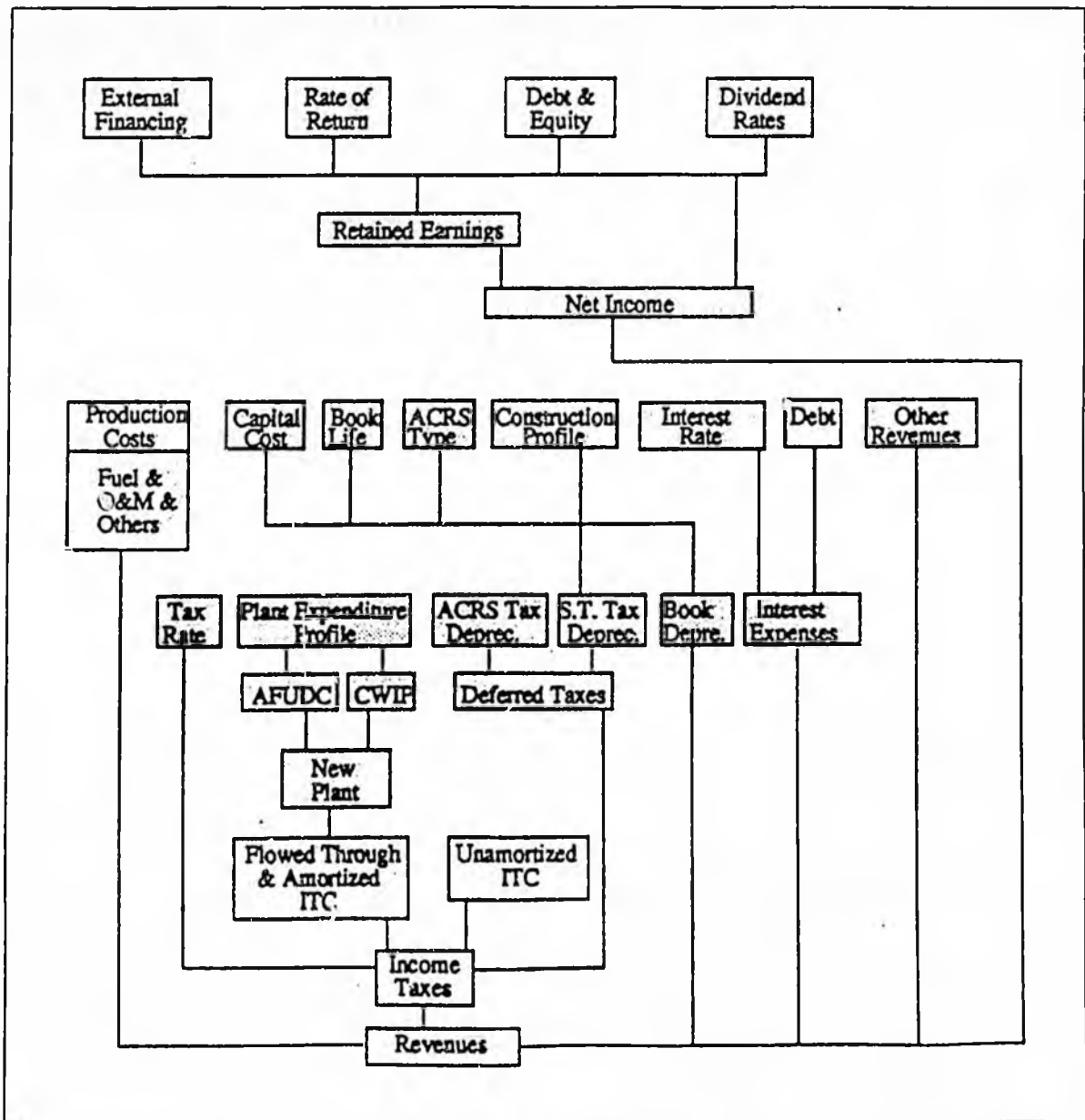
The Strategic Financial Model determines the net income, retained earnings, income taxes and required revenue on an annual basis. The other two models are written in IFPS, the fourth generation

financial language. These two models can be used where greater detail is required. Additionally, the users can modify the codes to meet their individual needs.

The Strategic Model produces:

- Annual balance sheets
- Income statements
- Flow of funds statements
- Financial report summaries

Strategic Financial Model



UPLAN FINANCIAL MODELS

COST OF SERVICE

The Cost of Service module uses the time-of-day rate structure. This module is used to compute both time-differentiated and nontime-differentiated rates for up to twelve customer rates.

The standard module allocates energy-related

costs using the time-differentiated marginal cost method, while the fixed cost is distributed by non-coincident peak responsibility. If necessary, USAM Center can customize the Cost-of-Service module for other rate-making methodologies.

Rate Report: Peak-Period Changes

Rate report produces rates by customer classes for peak period, off-peak period and average base. Up to 12 customer classes can be specified.

Main Menu		Rate Reports			Screen 1
c:\up\data\SAMPLE1.COS					
Distribution of Rates Prior to Adjustment					
Peak Period					
Year 1990					
Customer Class (Mills/KWH)					
	Class 1	Class 2	Class 3	Average	
Generation					
Energy	16.70	20.04	15.18	17.33	
Customer	0.00	0.00	0.00	0.00	
Demand	3.95	4.74	3.59	4.10	
Transmission					
Energy	0.00	0.00	0.00	0.00	
Customer	0.00	0.00	0.00	0.00	
Demand	4.70	5.36	6.26	5.42	
Distribution					
Energy	0.43	0.51	0.39	0.44	
Customer	7.21	4.88	0.38	4.25	
Demand	1.50	1.80	1.37	1.56	
Total	34.49	37.33	27.17	33.09	

F2 Select screen, F3 Prev, F4 Next, F9 to main menu, Esc to quit, ^, v, PgUp, PgDn
Alt-P to print file

UPLAN FINANCIAL MODELS

LONG-RANGE FINANCIAL MODEL

The UPLAN Long-Range Financial Model simulates utility financial operations on an annual basis in full detail. While the Long-Range Model is completely integrated with the UPLAN system, it can also be customized by the user to meet the particular modeling needs and reporting requirements of the individual utility.

The LRFM simulates utility financial operations to determine annual external financing requirements and rate adjustments. It also simulates revenue and revenue requirements, and calculates the effects of regulatory lag. The principal driver of the model can either be rate of return or rates. The long-range model's major features include:

- fuel inventory modeling
- project construction analysis
- detailed tax modeling
- explicit regulatory lag simulation
- project-level accounting
- extended external finance options

Six standard reports are produced by the model. These reports include income statements, O&M breakdown, sources and uses of funds, balance sheet, financial performance, financial

statistics, coverage ratios, electric rates, and sources of contributions to revenue.

The long-range model makes use of the IFPS Interactive Financial Planning System. IFPS is a fourth-generation interactive financial modeling language. IFPS includes facilities which enable the financial planner to easily modify the default model to customize the content and layout of reports.

SHORT-TERM TACTICAL MODEL

The Short-Term Tactical Model offers highly detailed, month-by-month financial simulation and reporting. The model's design support the tracking of short-term flows and budgeting. It includes disaggregate monthly reporting of revenues, broken out by major customer class, current and deferred tax status, operating revenues and expenses, interest expenses by call of investment, and full financial and operating statistics, including Moody's ratios, key financial indicators, and rates. The model allows customization of plant accounting, rate calculations, revenue calculations, and fuel clause adjustment mechanisms.

Like the Long Range Financial Model, the Short-Term Tactical Model makes use of the IFPS Interactive Financial System.

UPLAN REPORT WRITERS

REPORTING

UPLAN produces a wide range of reports. These reports summarize the results of supply, demand and financial models. The number of reports and the level of detail in these reports

can be controlled by the users.

UPLAN command menus are used to select, display and print all reports produced by UPLAN.

Detail Finance Report: Financial and System Performance

Financial Model reports include:

- Balance Sheet
- Income Statement
- Flow of Funds
- Supplemental Reports

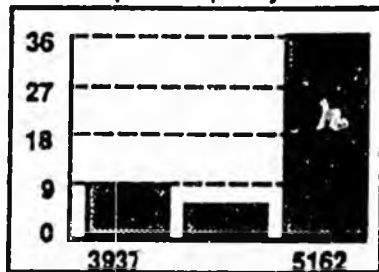
Main Menu		Detail Finance			
c:\up\data\SAMPLE1.FDL					
Screen 3					
RNM file:c:\NEWDEMO.RNM-DEMO					
Supply file:C:\DEMO.SPM-Demonstration supply data file					
System and Financial Report					
	1990	1991	1992	1993	
Energy Demand (Billion KWH)	18.23	18.43	18.68	18.79	
Peak Load (Megawatts)	3562.00	3600.00	3650.00	3670.00	
Capacity Margin(%)	19.05	22.58	21.51	21.08	
Reserve Margin (%)	23.53	29.17	27.40	26.70	
Fuel Price (\$/MWH)	17.72	18.92	20.77	22.63	
Base Price (\$/MWH)	46.89	53.91	54.92	62.16	
Total Price (\$/MWH)	64.61	72.84	75.69	84.79	
Base Price Increase (M\$)	635.97	128.41	18.85	136.06	
Return on Equity (%)	10.00	10.00	10.00	10.00	
Earnings Per Share (\$)	\$ 1.05	\$ 1.78	\$ 1.76	\$ 1.95	
# of Shares Outstanding	53.55	56.78	58.57	75.83	
Market Price-Common Stock\$	20.00	18.93	20.77	22.77	
Book Value/Share-Common \$	17.21	18.89	20.70	22.92	
Interest Coverage Ratio	1.258	1.396	1.373	1.236	
Ext. Fin. as % of Construc.	4531.23	86.16	49.44	81.29	
PV of Revenue Req. (M\$)	1,177.63	2,471.40	3,784.75	5,251.39	
Smoothed Elec. Cost(\$)	64.61	68.67	70.96	74.34	

F2 Select screen, F3 Prev, F4 Next, F9 to main menu, Esc to quit, ^, v, PgUp, PgDn
Alt-P to print file

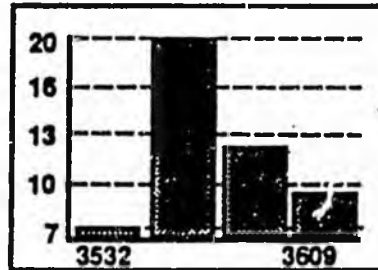
Uncertainty Outcome: Frequency Plots

The results of the UPLAN Uncertainty Model are shown as frequency charts as well as in tables and sample statistics.

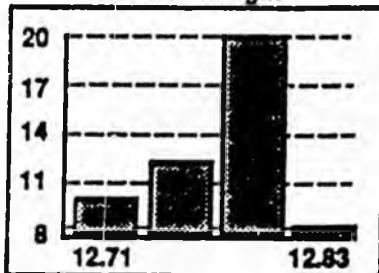
Nameplate Capacity



Peak Load



Reserve Margin



LOLP



UPLAN REPORT WRITERS

UPLAN Report Types

<i>Name of Report</i>	<i>Description</i>
Summary	System-wide summary production cost reports, to both deterministic and uncertainty cases.
Aggregate	Aggregate annual production cost reports, with generating units grouped by fuel type.
Detail	Annual unit-by-unit production cost reports for standard production cost and second area dispatch cases.
Monthly	Month-by-month, unit-by-unit production cost reports for standard production cost and second area dispatch cases.
Marginal Cost	Annual and monthly marginal costs at percentages of peak load.
Time of Day	Hour-by-hour marginal costs.
Percent of Time	Expected marginal costs along the time axis of the load duration curve.
Summary Finance	Summary financial indicators for the full study period.
Detail Finance	Detailed annual financial reports.
2nd Area Detail	Annual detailed production reports from the second area dispatch model.
2nd Area Monthly	Monthly detailed dispatch reports from the second area dispatch model.
Opt Exp Report	Optimal generation expansion plan report.
Cost of Service	Cost per KWH for residential, commercial and industrial customers (selected customer classes) for generation, transmission and distribution.

These reports can also be transferred to Lotus 1-2-3 or Symphony spread sheet/graphic package. In this way the user can develop custom-

ized reports and charts. Customized spread sheets and interfaces to financial language package are available from the USAM Center.

About USAM Center

The Utility Software and Modeling Center offers a full range of software products and consulting services in support of electric utility system analysis. Since 1982, we have served the utility industry with:

- basic research in utility modeling methods
- software development of utility planning tools
- consulting, study design and execution for supply-side and demand-side studies
- training and customer support in utility planning methods and in the use of our software systems
- expert witness testimony

Our commitment to complete client support is indicated by the range of our services.

Training and Seminars

USAM Center offers both specific training in the use of UPLAN and special topic seminars on techniques for strategic planning. Training in the use of our models is provided either at our facility in Los Altos or at a client's home site.

Users Group

Active UPLAN Users' Groups exist throughout the United States. The groups teleconference and meet periodically to exchange ideas and techniques about the use of UPLAN in modeling different utility problems.

Advisory Council

The UPLAN Advisory Council offers high level, independent evaluation and recommendations for UPLAN system extensions and enhancements. For a list of current members, please contact USAM Center

Support Services

USAM Center provides complete client support for our utility modeling systems. These are available through:

• Telephone hotline service:

Our technical analysts are available to respond to inquiries concerning UPLAN software, and responses are provided within a single working day.

• On-site visits:

Our client service staff is available for support to review and recommend UPLAN applications and trouble-shoot problem areas.

• Consulting services:

Our consulting staff has the experience and capabilities to support our clients needing assistance to meet strict deadlines and special project requirements including:

- Least-Cost Resource Planning Studies
- Regulatory Analysis and Expert Testimony
- Strategic Planning and Scenario Analysis
- Custom Utility Model Development
- Litigation Support

• USAM Center Newsletter:

The *Newsletter* is published quarterly. It provides a forum for users and other interested parties to exchange ideas and methods about the use of our planning system. The *Newsletter* includes correspondence from users, new product and update information, and general and technical planning articles, and ways to tame Julie.

Least-Cost Utility Planning

- UPLAN integrates Demand-Side and Supply-Side options to develop the least-cost resource plan which satisfies economic, reliability, and financial criteria.
- UPLAN includes a comprehensive financial model for evaluating the impact of the least-cost plan on the utility's financial integrity.
- UPLAN includes optional operation planning, production costing, reliability analysis, and uncertainty models to facilitate development of a least-cost plan that is flexible in coping with risk, considering uncertainties such as load growth, capital costs, and fuel costs.

HARDWARE REQUIREMENTS

Computer:	IBM PC/XT/AT, 3270-PC/AT or compatibles
Memory:	Minimum 640KB (Optional: 4MB RAM Disk)
Hard disk:	Required (code: 1.75MB, data: 1.5MB)
Mathematical coprocessor:	8087/80287 math coprocessor required
Display:	IBM color graphics adapter, enhanced graphics adapter, or compatibles

USAM CENTER

Utility Software and Modeling Center
4962 El Camino Real
Los Altos, CA 94022
(415) 962-9670

8.2. Supply Input Data Sets

Table 8.2.1

ANCHORAGE-COOK INLET AREA EXISTING PLANT DATA, DEC. 1984 (Page 1 of 3)

Unit Name	Operation Period		Generating Capacity 30°F	Heat Rate @ Gen. Capacity	O&M Costs (1985 \$)		Outage Rates	
	Online Date	Retire Date			Fixed	Variable	Planned Outage	Forced Outage
			(MW)	(Btu/kWh)	(\$/kW/yr)	(\$/MWh)	(%time)	(%time)
<u>Alaska Power Administration</u>								
Eklutna	1955	2055	30.0	-	-	19.0	-	-
<u>Anchorage Municipal Light and Power</u>								
AML PCT#1	1962	1990	16.2	15,329	10.12	5.67	12.0	5.0
AML PCT#2	1964	1990	16.2	15,329	10.12	5.67	9.7	5.0
AML PCT#3	1968	1991	19.9	14,089	10.12	5.67	12.3	5.0
AML PCT#4	1972	1992	33.8	13,901	10.12	5.67	13.5	5.0
AM CC#56	1979	1999	47.5	10,570	12.79	0.92	11.0	5.0
AM CC#76	1979	1999	109.3	9,365	12.79	0.92	11.0	5.0
AML PCT#8	1984	2009	87.0	12,000	12.79	0.92	14.8	5.0
Total AMLP Capacity			329.9					

Table 8.2.1

Unit Name	Operation Period		Generating Capacity 30°F (MW)	Heat Rate @ Gen. Capacity (Btu/kWh)	O&M Costs (1985 \$)		Outage Rates	
	Online Date	Retire Date			Fixed (\$/kW/yr)	Variable (\$/MWh)	Planned Outage (%time)	Forced Outage (%time)
<u>Chugach Electric Association</u>								
BEL CT#1	1968	1994	16.1	16,100	11.21	1.40	10.3	5.0
BEL CT#2	1968	1994	16.1	16,100	11.21	1.40	9.0	5.0
BEL CT#3	1972	1999	49.5	12,800	11.21	1.40	12.8	5.0
BEL CT#4	1976	1996	10.0	17,500	11.21	1.40	11.5	5.0
BEL CT#5	1975	1999	67.3	12,400	11.21	1.40	12.8	5.0
BEL CC#68	1976	2007	100.6	9,600	11.21	1.40	11.5	6.0
BEL CC#78	1976	2007	100.6	9,600	11.21	1.40	11.5	6.0
BERNCT#1	1963	1988	8.9	17,300	10.03	2.19	9.0	5.0
BERNCT#2	1971	1997	18.4	14,500	10.03	2.19	9.0	5.0
BERNCT#3	1978	2004	27.2	13,700	10.03	2.19	10.3	5.0
BERNCT#4	1981	2004	27.2	13,700	10.03	2.19	12.8	5.0
INT CT#1	1965	1996	14.3	18,000	19.39	13.47	7.7	5.0
INT CT#2	1968	1996	14.3	18,000	19.39	13.47	7.7	5.0
INT CT#3	1970	1996	19.9	14,500	19.39	13.47	15.4	5.0
COOPER	1960	2055	17.4	-	-	7.4	-	-
Total GEA Capacity			507.8					

Table 8.2.1

Unit Name	Operation Period		Generating Capacity @ 30°F	Heat Rate @ Gen. Capacity	O&M Costs (1985 \$)		Outage Rates	
	Online Date	Retire Date			Fixed	Variable	Planned Outage	Forced Outage
			(MW)	(Btu/kWh)	(\$/kW/yr)	(\$/MWh)	(%time)	(%time)
<u>Homer Electric Association</u>								
SELDIC#1	1952	1990	0.3	14,998	2.81	38.80	4.0	5.0
SELDIC#2	1964	1994	0.6	12,006	2.81	38.80	4.0	5.0
SELDIC#3	1970	2000	0.6	12,006	2.81	38.80	4.0	5.0
SELDIC#4	1982	2012	0.6	12,006	2.81	38.80	4.0	5.0
Total HEA Capacity			2.1					
<u>Seward Electric System</u>								
SES IC#1	1965	1990	1.5	15,000	0.59	5.72	1.0	5.0
SES IC#2	1965	1990	1.5	15,000	0.59	5.72	1.0	5.0
SES IC#3	1965	1995	2.5	15,000	0.59	5.72	1.0	5.0
Total SES Capacity			5.5					

Table 2.2

FAIRBANKS-TANANA VALLEY AREA EXISTING PLANT DATA, DEC. 1984

Unit Name	Operation Period		Generating Capacity @ 30°F	Heat Rate @ Gen. Capacity	O&M Costs (1985 \$)		Outage Rates	
	Online Date	Retire Date			Fixed	Variable	Planned Outage	Forced Outage
			(MW)	(Btu/kWh)	(\$/kW/yr)	(\$/MWh)	(%time)	(%time)
<u>Fairbanks Municipal Utility System</u>								
CHENST#1	1954	2000	5.1	15,968	51.12	1.22	6.0	5.0
CHENST#2	1952	2000	2.0	18,049	51.12	1.22	6.0	6.0
CHENST#3	1952	2000	1.5	18,091	51.12	1.22	6.0	6.0
CHENST#4	1963	1985	6.1	12,894	8.76 ^{1/}	0.58 ^{1/}	3.0	8.0
CHENST#5	1970	2005	20.0	14,236	73.57	0.64	6.0	6.0
CHENST#6	1976	2006	26.1	12,733	8.76 ^{1/}	0.58 ^{1/}	3.0	8.0
FMUSIC#1	1967	1992	2.8	12,128	0.87	22.82	2.0	5.0
FMUSIC#2	1968	1992	2.8	12,128	0.87	22.82	2.0	5.0
FMUSIC#3	1969	1992	2.8	12,128	0.87	22.82	2.0	5.0
Total FMUS Capacity			69.2					
<u>Golden Valley Electric Association</u>								
HEALST#1	1967	2002	25.0	12,750	69.96	4.11	7.0	1.8
HEALIC#2	1967	1997	2.6	11,210	0.59	5.72	20.0	1.0
NOPOCT#1	1976	2006	60.9	9,500	7.42	1.43	15.0	1.0
NOPOCT#2	1977	2007	60.9	9,500	7.42	1.43	15.0	1.0
ZEN CT#1	1971	2001	18.0	14,869	8.79	0.59	15.0	1.0
ZEN CT#2	1972	2002	18.0	14,869	8.79	0.59	15.0	1.0
DSL IC#1	1961	1991	1.9	11,209	0.59	5.72	20.0	5.0
DSL IC#2	1961	1991	1.9	11,209	0.59	5.72	20.0	5.0
DSL IC#3	1961	1991	1.9	11,209	0.59	5.72	20.0	5.0
DSL IC#5	1970	2000	2.6	11,210	0.59	5.72	20.0	5.0
DSL IC#6	1970	2000	2.6	11,210	0.59	5.72	20.0	5.0
UAF IC#7	1970	1996	1.9	11,209	0.59	5.72	20.0	5.0
UAF IC#8	1970	1996	1.9	11,209	0.59	5.72	20.0	5.0
Total GVEA Capacity			200.1					

^{1/} Applicant's estimate of O&M costs used.

-8.2.4-

03-23-1987 13:06:34

File Name: b:KENAIRSA.SPM
Description :Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Number of Units	Flue gas Scrubber (yes/no)	Super-Critical (yes/no)	Date Installed	Book Life (Yr)	ACRS Type 1-3
bernct2	bernice2	18.0	1	no	no	1971	26	1
bernct3	bernice3	27.0	1	no	no	1978	26	1
bernct4	bernice4	27.0	1	no	no	1981	23	1
bradley	bradleyH	90.0	1	no	no	1990	65	1
cooper1	cooper H	18.0	1	no	no	1975	99	1
gtk ct1	soldatCT	38.0	1	no	no	1985	25	1
sldic2	seldic2	1.0	1	no	no	1964	99	1
sldic34	seldic34	1.0	1	no	no	1970	99	1
ses ic3	seward3	2.0	1	no	no	1965	99	1
ses ic4	seward4	2.0	1	no	no	1985	99	1
ses ic5	seward5	3.0	1	no	no	1986	99	1
ses ic6	seward6	3.0	1	no	no	1990	99	1
new ct1	new ct1	40.0	1	no	no	2004	20	1
new ct2	new ct2	40.0	1	no	no	2010	20	1
new ct3	new ct3	25.0	1	no	no	2014	25	1

File Name: b:KENAIRSA.SPM
 Description :Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Unsche. Outage Rate (%)	Daily Unavail. (%)
bernct2	bernice2	18.0	5.0	0.0
bernct3	bernice3	27.0	5.0	0.0
bernct4	bernice4	27.0	5.0	0.0
bradley	bradleyH	90.0	0.0	0.0
cooper1	cooper H	18.0	0.0	0.0
gtk ct1	soldatCT	38.0	5.0	0.0
sldic2	seldic2	1.0	5.0	0.0
sldic34	seldic34	1.0	5.0	0.0
ses ic3	seward3	2.0	5.0	0.0
ses ic4	seward4	2.0	5.0	0.0
ses ic5	seward5	3.0	5.0	0.0
ses ic6	seward6	3.0	5.0	0.0
new ct1	new ct1	40.0	8.0	
new ct2	new ct2	40.0	8.0	
new ct3	new ct3	25.0	8.0	

File Name: b:KENAIRSA.SPM
 Description :Kenai Supply Model

Unit ID	Unit Name	Size (MW)	HEAT RATES (BTU/KWH AT % OUTPUT)				AVERAGE
			100%	75%	50%	25%	
bernct2	bernice2	18.0	14500	14805	16050		14805
bernct3	bernice3	27.0	13700	14082	15284		14082
bernct4	bernice4	27.0	13700	14082	15284		14082
bradley	bradleyH	90.0					
cooper1	cooper H	18.0					
gtk ct1	soldatCT	38.0	12785	13763	15768		13763
sldic2	seldic2	1.0	12006	12362	13667		12362
sldic34	seldic34	1.0	12006	12362	13667		12362
ses ic3	seward3	2.0	15000	15451	17064		15451
ses ic4	seward4	2.0	15000	15451	17064		15451
ses ic5	seward5	3.0	15000	15451	17064		15451
ses ic6	seward6	3.0	15000	15451	17064		15451
new ct1	new ct1	40.0					12095
new ct2	new ct2	40.0					12095
new ct3	new ct3	25.0					12095

File Name: b:KENAIRSA.SPM
 Description :Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Maximum Capacity Factor														
			Jan (%)	Feb (%)	Mar (%)	Apr (%)	May (%)	Jun (%)	Jul (%)	Aug (%)	Sep (%)	Oct (%)	Nov (%)	Dec (%)			
bernct2	bernice2	18.0															
bernct3	bernice3	27.0															
bernct4	bernice4	27.0															
bradley	bradleyH	90.0	62.4	59.4	47.2	39.6	30.4	19.9	25.9	41.9	92.5	94.1	154.8	59.4	59.4	62.4	4
cooper1	cooper H	18.0	45.7	30.4	22.8	30.4	11.4	11.4	7.6	15.2	15.2	230.4	45.7	45.7	45.7	7	7
gtk ct1	soldatCT	38.0															
sldic2	seldic2	1.0															
sldic34	seldic34	1.0															
ses ic3	seward3	2.0															
ses ic4	seward4	2.0															
ses ic5	seward5	3.0															
ses ic6	seward6	3.0															
new ct1	new ct1	40.0															
new ct2	new ct2	40.0															
new ct3	new ct3	25.0															

File Name: b:KENAIRSA.SPM
 Description :Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Fixed O&M Cost (\$/KW-YR)	Variable O&M Cost (\$/MWH)	Cost of Consumables (\$/MWH)	Fuel Cost (\$/MBTU)	Fuel Type
bernct2	bernice2	18.0	10.230	2.23	0.0	1.60	GAS
bernct3	bernice3	27.0	10.230	2.23	0.0	1.60	GAS
bernct4	bernice4	27.0	10.230	2.23	0.0	1.60	GAS
bradley	bradleyH	90.0	24.600	0.00	0.0	0.00	WAT
cooper1	cooper H	18.0	17.360	0.00	0.0	0.00	WAT
gtk ct1	soldatCT	38.0	11.265	1.43	0.0	1.60	GAS
sldic2	seldic2	1.0	2.864	39.57	0.0	7.00	F02
sldic34	seldic34	1.0	2.864	39.57	0.0	7.00	F02
ses ic3	seward3	2.0	0.603	5.84	0.0	6.50	F02
ses ic4	seward4	2.0	0.603	5.84	0.0	6.50	F02
ses ic5	seward5	3.0	0.603	5.84	0.0	6.50	F02
ses ic6	seward6	3.0	0.603	5.84	0.0	6.50	F02
new ct1	new ct1	40.0	8.760	0.58	0.0	1.60	GAS
new ct2	new ct2	40.0	8.760	0.58	0.0	1.60	GAS
new ct3	new ct3	25.0	8.760	0.58	0.0	1.60	GAS

File Name: b:KENAIRSA.SPM
 Description :Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Maintenance Days											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
bernct2	bernice2	18.0					8						25	
bernct3	bernice3	27.0						20	17					
bernct4	bernice4	27.0				14			14	18				
bradley	bradleyH	90.0												
cooper1	cooper H	18.0												
gtk ct1	soldatCT	38.0				10	10	12						
sldic2	seldic2	1.0									8	7		
sldic34	seldic34	1.0			8	7								
ses ic3	seward3	2.0		1	3									
ses ic4	seward4	2.0		1					3					
ses ic5	seward5	3.0				1					3			
ses ic6	seward6	3.0			1				3					
new ct1	new ct1	40.0				10	10	12						
new ct2	new ct2	40.0					12	10	10					
new ct3	new ct3	25.0				12			10	10				

File Name: c:ANCHRSA .SPM

Description :Anchorage Supply Model

Unit ID	Unit Name	Size (MW)	Number of Units	Flue gas Scrubber (yes/no)	Super-Critical (yes/no)	Date Installed	Book Life (Yr)	ACRS Type 1-3
EKLU	EklutnaH	30	1	no	no	1955	99	1
AML PCT1	Anc CT 1	16	1	no	no	1962	25	1
AML PCT2	Anc CT 2	16	1	no	no	1964	25	1
AML PCT3	Anc CT 3	20	1	no	no	1968	23	1
AML PCT4	Anc CT 4	34	1	no	no	1972	20	1
AM CC56	Anc CC56	48	1	no	no	1979	20	1
AM CC76	Anc CC76	109	1	no	no	1979	20	1
AML PCT8	Anc CT 8	87	1	no	no	1984	25	1
AML PCT9	Anc CT 9	87	1	no	no	2050	38	1
Bel CT1	BelugCT1	16	1	no	no	1968	26	1
Bel CT2	BelugCT2	16	1	no	no	1968	26	1
Bel CT3	BelugCT3	50	1	no	no	1972	27	1
Bel CT4	BelugCT4	10	1	no	no	1976	20	1
Bel CT5	BelugCT5	67	1	no	no	1975	24	1
BelCC68	BelgCC68	101	1	no	no	1976	31	1
belgC78	BelgCC78	101	1	no	no	1976	31	1
Int CT1	IntnCT1	14	1	no	no	1965	31	1
Int CT2	IntnCT2	14	1	no	no	1968	28	1
Int CT3	IntnCT3	20	1	no	no	1970	26	1
NewCC76	New CC76	180	1	no	no	1999	25	1
NewBCT3	NewBCT 3	50	1	no	no	1994	27	1
NewBCT4	NewBCT 4	50	1	no	no	1996	27	1
NewBCT5	NewBCT 5	67	1	no	no	1999	25	1
NewBCT6	NewBCT 6	50	1	no	no	1999	25	1
NewBCC6	NewBCC68	101	1	no	no	2007	31	1
NewBCC7	NewBCC78	101	1	no	no	2007	31	1
NewCT10	New CT10	50	1	no	no	2007	25	1
NewCT11	New CT11	87	1	no	no	2009	25	1
NewCT12	New CT12	50	1	no	no	2015	25	1
NewCT13	New CT13	50	1	no	no	2018	25	1
NwBCT14	NewBCT14	50	1	no	no	2002	25	1
NwBCT15	NewBCT15	50	1	no	no	2011	25	1

File Name: c:ANCHRSA .SPM
 Description :Anchorage Supply Model

Unit ID	Unit Name	Size (MW)	Unsche. Outage Rate(%)	Daily Unavail. (%)
EKLU	EklutnaH	30	0.0	0.0
AML PCT1	Anc CT 1	16	2.0	0.0
AML PCT2	Anc CT 2	16	2.0	0.0
AML PCT3	Anc CT 3	20	2.0	0.0
AML PCT4	Anc CT 4	34	2.0	0.0
AM CC56	Anc CC56	48	2.0	0.0
AM CC76	Anc CC76	109	2.0	0.0
AML PCT8	Anc CT 8	87	2.0	0.0
AML PCT9	Anc CT 9	87	2.0	0.0
Bel CT1	BelugCT1	16	6.0	0.0
Bel CT2	BelugCT2	16	6.0	0.0
Bel CT3	BelugCT3	50	6.0	0.0
Bel CT4	BelugCT4	10	6.0	0.0
Bel CT5	BelugCT5	67	6.0	0.0
BelCC68	BelgCC68	101	8.0	0.0
belgCT78	BelgCC78	101	8.0	0.0
Int CT1	IntnCT1	14	6.0	0.0
Int CT2	IntnCT2	14	6.0	0.0
Int CT3	IntnCT3	20	6.0	0.0
NewCC76	New CC76	180	8.0	0.0
NewBCT3	NewBCT 3	50	8.0	0.0
NewBCT4	NewBCT 4	50	8.0	0.0
NewBCT5	NewBCT 5	67	8.0	0.0
NewBCT6	NewBCT 6	50	8.0	0.0
NewBCC6	NewBCC68	101	8.0	0.0
NewBCC7	NewBCC78	101	8.0	0.0
NewCT10	New CT10	50	8.0	0.0
NewCT11	New CT11	87	6.0	0.0
NewCT12	New CT12	50	8.0	0.0
NewCT13	New CT13	50	8.0	0.0
NwBCT14	NewBCT14	50	8.0	0.0
NwBCT15	NewBCT15	50	8.0	0.0

File Name: c:\ANCHRSA GPM
 Description :Anchorage Supply Model

Unit ID	Unit Name	Size (MW)	HEAT RATES (BTU/KWH AT % OUTPJT)				AVERAGE
			100%	75%	50%	25%	
EKLU	EklutnaH	30					
AML PCT1	Anc CT 1	16	15329	16743	20193		16743
AML PCT2	Anc CT 2	16	15329	16743	20193		16743
AML PCT3	Anc CT 3	20	14089	15439	18147		15439
AML PCT4	Anc CT 4	34	13901	14910	18475		14910
AM CC56	Anc CC56	48	11209	12039			12039
AM CC76	Anc CC76	109	9017	9367			9367
AML PCT8	Anc CT 8	87	11810	12095	14029		12095
AML PCT9	Anc CT 9	87	11810	12095	14029		12095
Bel CT1	BelugCT1	16	15314	15602	17119		15602
Bel CT2	BelugCT2	16	15314	15602	17119		15602
Bel CT3	BelugCT3	50	11344	11723	13136		11723
Bel CT4	BelugCT4	10	17500	18284	20110		18284
Bel CT5	BelugCT5	67	12963	13448	15012		13448
BelCC68	BelgCC68	101	9391	9831	10981		9831
belgC78	BelgCC78	101	9391	9831			9391
Int CT1	IntnCT1	14	19371	19894	21716		19894
Int CT2	IntnCT2	14	19371	19894	21716		19894
Int CT3	IntnCT3	20	16627	18248	21679		19894
NewCC76	New CC76	180	9391	9831			9831
NewBCT3	NewBCT 3	50					12095
NewBCT4	NewBCT 4	50					12095
NewBCT5	NewBCT 5	67					12095
NewBCT6	NewBCT 6	50					12095
NewBCC6	NewBCC68	101	9391	9831			9391
NewBCC7	NewBCC78	101	9391	9831			9391
NewCT10	New CT10	50					12095
NewCT11	New CT11	87					12095
NewCT12	New CT12	50					12095
NewCT13	New CT13	50					12095
NwBCT14	NewBCT14	50					12095
NwBCT15	NewBCT15	50					12095

File Name: c:ANCHRSA .SPM

Description :Anchorage Supply Model

Unit ID	Unit Name	Size (MW)	Maximum Capacity Factor											
			Jan (%)	Feb (%)	Mar (%)	Apr (%)	May (%)	Jun (%)	Jul (%)	Aug (%)	Sep (%)	Oct (%)	Nov (%)	Dec (%)
EKLIJ	EklutnaH	30	63.9	54.7	54.7	45.7	45.7	45.7	45.9	45.9	46.3	46.3	46.3	46.3
AMLPC1	Anc CT 1	16												
AMLPC2	Anc CT 2	16												
AMLPC3	Anc CT 3	20												
AMLPC4	Anc CT 4	34												
AM CC56	Anc CC56	48												
AM CC76	Anc CC76	109												
AMLPC8	Anc CT 8	87												
AMLPC9	Anc CT 9	87												
Bel CT1	BelugCT1	16												
Bel CT2	BelugCT2	16												
Bel CT3	BelugCT3	50												
Bel CT4	BelugCT4	10												
Bel CT5	BelugCT5	67												
BelCC68	BelgCC68	101												
belgC78	BelgCC78	101												
Int CT1	IntnCT1	14												
Int CT2	IntnCT2	14												
Int CT3	IntnCT3	20												
NewCC76	New CC76	180												
NewBCT3	NewBCT 3	50												
NewBCT4	NewBCT 4	50												
NewBCT5	NewBCT 5	67												
NewBCT6	NewBCT 6	50												
NewBCC6	NewBCC68	101												
NewBCC7	NewBCC78	101												
NewCT10	New CT10	50												
NewCT11	New CT11	87												
NewCT12	New CT12	50												
NewCT13	New CT13	50												
NWBCT14	NewBCT14	50												
NWBCT15	NewBCT15	50												

File Name: c:ANCHRSA .SPM
 Description :Anchorage Supply Model

Unit ID	Unit Name	Size (MW)	Fixed O&M Cost (\$/KW-YR)	Variable O&M Cost (\$/MWH)	Cost. of Consumables (\$/MWH)	Fuel Cost (\$/MBTU)	Fuel Type
EKLU	EklutnaH	30	99.484				WAT
AMLPT1	Anc CT 1	16	10.320	5.79	0.0	2.20	GAS
AMLPT2	Anc CT 2	16	10.320	5.79	0.0	2.20	GAS
AMLPT3	Anc CT 3	20	10.320	5.79	0.0	2.20	GAS
AMLPT4	Anc CT 4	34	10.320	5.79	0.0	2.20	GAS
AM CC56	Anc CC56	48	13.044	5.79	0.0	2.20	GAS
AM CC76	Anc CC76	109	13.044	5.79	0.0	2.20	GAS
AMLPT8	Anc CT 8	87	13.044	5.79	0.0	2.20	GAS
AMLPT9	Anc CT 9	87	13.044	5.79	0.0	2.20	GAS
Bel CT1	BelugCT1	16	11.436	1.43	0.0	1.63	GAS
Bel CT2	BelugCT2	16	11.436	1.43	0.0	1.63	GAS
Bel CT3	BelugCT3	50	11.436	1.43	0.0	1.63	GAS
Bel CT4	BelugCT4	10	11.436	1.43	0.0	1.63	GAS
Bel CT5	BelugCT5	67	11.436	1.43	0.0	1.63	GAS
BelCC68	BelgCC68	101	11.436	1.43	0.0	1.63	GAS
belgC78	BelgCC78	101	11.436	1.43	0.0	1.63	GAS
Int CT1	IntnCT1	14	19.777	13.74	0.0	2.20	GAS
Int CT2	IntnCT2	14	19.777	13.74	0.0	2.20	GAS
Int CT3	IntnCT3	20	19.777	13.74	0.0	2.20	GAS
NewCC76	New CC76	180	13.260	0.58	0.0	2.20	GAS
NewBCT3	NewBCT 3	50	8.760	0.58	0.0	1.63	GAS
NewBCT4	NewBCT 4	50	8.760	0.58	0.0	1.63	GAS
NewBCT5	NewBCT 5	67	8.760	0.58	0.0	1.63	GAS
NewBCT6	NewBCT 6	50	8.760	0.58	0.0	1.63	GAS
NewBCC6	NewBCC6	101	13.260	0.66	0.0	1.63	GAS
NewBCC7	NewBCC7	101	13.260	0.66	0.0	1.63	GAS
NewCT10	New CT10	50	8.760	0.58	0.0	2.20	GAS
NewCT11	New CT11	87	8.760	0.58	0.0	2.20	GAS
NewCT12	New CT12	50	8.760	0.58	0.0	2.20	GAS
NewCT13	New CT13	50	8.760	0.58	0.0	2.20	GAS
NwBCT14	NewBCT14	50	8.760	0.58	0.0	1.60	GAS
NwBCT15	NewBCT15	50	8.760	0.58	0.0	1.60	GAS

File Name: c:\ANCHRSA .SPM
 Description :Anchorage Supply Model

Unit ID	Unit Name	Size (MW)	Maintenance Days														
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec			
EKLU	EklutnaH	30															
AML PCT1	Anc CT 1	16	10	10							23						
AML PCT2	Anc CT 2	16	6	6					24								
AML PCT3	Anc CT 3	20							20	25							
AML PCT4	Anc CT 4	34	10						20	19							
AM CC56	Anc CC56	48	5	5	5	5	5	5	5	5	5						
AM CC76	Anc CC76	109				5	5	5	5	5	5	5	5	5	5	5	
AML PCT8	Anc CT 8	87			15	15	15	15	9								
AML PCT9	Anc CT 9	87							15	15	15	9					
Bel CT1	BelugCT1	16					14	14	11								
Bel CT2	BelugCT2	16					16	8	8								
Bel CT3	BelugCT3	50			12	12	12	10									
Bel CT4	BelugCT4	10			8	8	8	8	8	8							
Bel CT5	BelugCT5	67		9			9	9	9	9	11						
BelCC68	BelgCC68	101							13	13	13	13					
belgC78	BelgCC78	101					13		13		13				13		
Int CT1	IntnCT1	14								14	14						
Int CT2	IntnCT2	14									14	14					
Int CT3	IntnCT3	20								14	14	14	14	14			
NewCC76	New CC76	180			5	5	5	5	5	5	5	5	5	5	5		
NewBCT3	NewBCT 3	50			15	15	15	9									
NewBCT4	NewBCT 4	50			15	15	15	9									
NewBCT5	NewBCT 5	67							9	15	15	15					
NewBCT6	NewBCT 6	50							9	15	15	15					
NewBCC6	NewBCC68	101							13	13	13	13					
NewBCC7	NewBCC78	101			13	13	13	13									
NewCT10	New CT10	50			15	15	15	9									
NewCT11	New CT11	87			15	15	15	9									
NewCT12	New CT12	50			15	15	15	9									
NewCT13	New CT13	50							9	15	15	15					
NWBCT14	NewBCT14	50							9	15	15	15					
NWBCT15	NewBCT15	50							9	15	15	15					

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File Name: c:FAIRRSA .SPM
 Description :Fairbanks Supply Model

Unit ID	Unit Name	Size (MW)	Number of Units	Flue gas Scrubber (yes/no)	Super-Critical (yes/no)	Date Installed	Book Life (Yr)	ACRS Type 1-3
Chenst5	ChenaST5	20	1	no	no	1970	35	1
Chenst6	ChenaST6	26	1	no	no	1976	30	1
Fmusic1	Fmusic 1	3	1	no	no	1967	25	1
Fmusic2	Fmusic 2	3	1	no	no	1967	25	1
Fmusic3	Fmusic 3	3	1	no	no	1967	25	1
HealSt1	HealyST1	25	1	no	no	1967	35	1
HealIC2	HealyIC2	3	1	no	no	1967	30	1
Nopoct1	NoPolCT1	61	1	no	no	1976	30	1
Nopoct2	NoPolCT2	61	1	no	no	1977	30	1
Zen ct1	Zender 1	18	1	no	no	1971	30	1
Zen ct2	Zender 2	18	1	no	no	1972	30	1
DslIC1	DslIC 1	2	1	no	no	1961	30	1
DslIC2	DslIC 2	2	1	no	no	1961	30	1
DslIC3	DslIC 3	2	1	no	no	1961	30	1
DslIC5	DslIC 5	3	1	no	no	1970	30	1
DslIC6	DslIC 6	3	1	no	no	1970	30	1
UAFIC7	UAFIC 7	3	1	no	no	1970	26	1
UAFIC8	UAFIC 8	3	1	no	no	1970	26	1
NewHeal	NewHeST1	25	1	no	no	2002	35	1
NewFctA	NEWFACT A	25	1	no	no	1992	30	1
NewFct8	NEWFACT 8	25	1	no	no	2002	30	1
NewFct1	NEWFACT 1	25	1	no	no	1996	30	1
NewFct2	NEWFACT 2	25	1	no	no	1999	30	1
NewFct3	NEWFACT 3	25	1	no	no	2001	30	1
NewFct4	NEWFACT 4	50	1	no	no	2005	30	1
NewFct5	NEWFACT 5	70	1	no	no	2006	30	1
NewFct6	NEWFACT 6	70	1	no	no	2007	30	1
NewFct7	NEWFACT 7	30	1	no	no	2010	30	1
NewFct8	NEWFACT 8	30	1	no	no	2016	30	1

File Name: c:FAIRRSA .SPM
 Description :Fairbanks Supply Model

Unit ID	Unit Name	Size (MW)	Unsche. Outage Rate(%)	Daily Unavail. (%)
Chenst5	ChenaST5	20	6.0	0.0
Chenst6	ChenaST6	26	8.0	0.0
Fmusic1	Fmusic 1	3	5.0	0.0
Fmusic2	Fmusic 2	3	5.0	0.0
Fmusic3	Fmusic 3	3	5.0	0.0
HealSt1	HealyST1	25	1.8	0.0
HealIC2	HealyIC2	3	1.0	0.0
Nopoct1	NoPolCT1	61	1.0	0.0
Nopoct2	NoPolCT2	61	1.0	0.0
Zen ct1	Zender 1	18	1.0	0.0
Zen ct2	Zender 2	18	1.0	0.0
DslIC1	DslIC 1	2	5.0	0.0
DslIC2	DslIC 2	2	5.0	0.0
DslIC3	DslIC 3	2	5.0	0.0
DslIC5	DslIC 5	3	5.0	0.0
DslIC6	DslIC 6	3	5.0	0.0
UAFIC7	UAFIC 7	3	5.0	0.0
UAFIC8	UAFIC 8	3	5.0	0.0
NewHeal	NewHeST1	25	5.7	0.0
NewFctA	NEWFCT A	25	8.0	0.0
NewFct8	NEWFCT 8	25	8.0	0.0
NewFct1	NEWFCT 1	25	8.0	0.0
NewFct2	NEWFCT 2	25	8.0	0.0
NewFct3	NEWFCT 3	25	8.0	0.0
NewFct4	NEWFCT 4	50	8.0	0.0
NewFct5	NEWFCT 5	70	8.0	0.0
NewFct6	NEWFCT 6	70	8.0	0.0
NewFct7	NEWFCT 7	30	8.0	0.0
NewFct8	NEWFCT 8	30	8.0	0.0

File Name: c:FAIRRSA SPM
 Description :Fairbanks Supply Model

Unit ID	Unit Name	Size (MW)	HEAT RATES (BTU/KWH AT % OUTPUT)				AVERAGE
			100%	75%	50%	25%	
Chenst5	ChenaST5	20	14236	14693	15613		14693
Chenst6	ChenaST6	26	12733	13574	16652		13574
Fmusic1	Fmusic 1	3	12128	12425	13283		12425
Fmusic2	Fmusic 2	3	12128	12425	13283		12425
Fmusic3	Fmusic 3	3	12128	12425	13283		12425
HealSt1	HealyST1	25	12750	13012	13876		12753
HealIC2	HealyIC2	3	11210	11486	12285		11486
Nopoct1	NoPolCT1	61	9500	10781	12874		10781
Nopoct2	NoPolCT2	61	9500	10781	12874		10781
Zen ct1	Zender 1	18	14869	15218	16634		15218
Zen ct2	Zender 2	18	14869	15218	16634		15218
DslIC1	DslIC 1	2	11210	11486	12284		11486
DslIC2	DslIC 2	2	11210	11486	12284		11486
DslIC3	DslIC 3	2	11210	11486	12284		11486
DslIC5	DslIC 5	3	11210	11486	12284		11486
DslIC6	DslIC 6	3	11210	11486	12284		11486
UAFIC7	UAFIC 7	3	11210	11486	12284		11486
UAFIC8	UAFIC 8	3	11210	11486	12284		11486
NewHea1	NewHeSTi	25	9750	9950	10611		9950
NewFctA	NEWFCT A	25					12095
NewFct8	NEWFCT 8	25					12095
NewFct1	NEWFCT 1	25					12095
NewFct2	NEWFCT 2	25					12095
NewFct3	NEWFCT 3	25					12095
NewFct4	NEWFCT 4	50					12095
NewFct5	NEWFCT 5	70					12095
NewFct6	NEWFCT 6	70					12095
NewFct7	NEWFCT 7	30					12095
NewFct8	NEWFCT 8	30					12095

File Name: c:FAIRRSA .SPM
 Description :Fairbanks Supply Model

Unit ID	Unit Name	Size (MW)	Fixed O&M Cost (\$/KW-YR)	Variable O&M Cost (\$/MWH)	Cost of Consumables (\$/MWH)	Fuel Cost (\$/MBTU)	Fuel Type
Chenst5	ChenaST5	20	75.030	0.65	0.0	2.50	CO1
Chenst6	ChenaST6	26	8.933	0.59	0.0	3.40	F06
Fmusic1	Fmusic 1	3	0.887	23.27	0.0	5.00	F02
Fmusic2	Fmusic 2	3	0.887	23.27	0.0	5.00	F02
Fmusic3	Fmusic 3	3	0.887	23.27	0.0	5.00	F02
HealSt1	HealyST1	25	71.349	4.19	0.0	1.30	CO2
HealIC2	HealyIC2	3	0.602	5.84	0.0	5.00	F02
Nopoct1	NoPolCT1	61	7.568	1.46	0.0	3.40	F06
Nopoct2	NoPolCT2	61	7.568	1.46	0.0	3.40	F06
Zen ct1	Zender 1	18	8.963	0.60	0.0	3.40	F06
Zen ct2	Zender 2	18	8.963	0.60	0.0	3.40	F06
DslIC1	DslIC 1	2	0.602	5.84	0.0	5.00	F02
DslIC2	DslIC 2	2	0.602	5.84	0.0	5.00	F02
DslIC3	DslIC 3	2	0.602	5.84	0.0	5.00	F02
DslIC5	DslIC 5	3	0.602	5.84	0.0	5.00	F02
DslIC6	DslIC 6	3	0.602	5.84	0.0	5.00	F02
UAFIC7	UAFIC 7	3	0.602	5.84	0.0	5.00	F02
UAFIC8	UAFIC 8	3	0.602	5.84	0.0	5.00	F02
NewHeal	NewHeST1	25	61.429	4.30	0.0	1.30	CO2
NewFctA	NEWFACT A	25	8.760	0.58	0.0	3.40	F06
NewFctB	NEWFACT B	25	8.760	0.58	0.0	3.40	F06
NewFct1	NEWFACT 1	25	8.760	0.58	0.0	3.40	F06
NewFct2	NEWFACT 2	25	8.760	0.58	0.0	3.40	F06
NewFct3	NEWFACT 3	25	8.760	0.58	0.0	3.40	F06
NewFct4	NEWFACT 4	50	8.760	0.58	0.0	3.40	F06
NewFct5	NEWFACT 5	70	8.760	0.58	0.0	3.40	F06
NewFct6	NEWFACT 6	70	8.760	0.58	0.0	3.40	F06
NewFct7	NEWFACT 7	30	8.760	0.58	0.0	3.40	F06
NewFct8	NEWFACT 8	30	8.760	0.58	0.0	3.40	F06

File Name: c:\FAIRRSA 6PM

Description :Fairbanks Supply Model

Unit ID	Unit Name	Size (MW)	Maintenance Days													
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
Chenst5	ChenaST5	20				10					12					
Chenst6	ChenaST6	20			10						12					
Fmusic1	Fmusic 1	3				3							4			
Fmusic2	Fmusic 2	3					3					4				
Fmusic3	Fmusic 3	3			3						4					
HealSt1	HealyST1	25									9	9	8			
HealIC2	HealyIC2	3				10	10	10	10	10	10	10	10			
Nopoct1	NoPolCT1	61						20	20	15						
Nopoct2	NoPolCT2	61									20	20	15			
Zen ct1	Zender 1	18				20	20	15								
Zen ct2	Zender 2	18				20	20	15								
DslIC1	DslIC 1	2									25	25	23			
DslIC2	DslIC 2	2									25	25	23			
DslIC3	DslIC 3	2						25	25	23						
DslIC5	DslIC 5	3						25	25	23						
DslIC6	DslIC 6	3			25	25	23									
UAFIC7	UAFIC 7	3						25	25	23						
UAFIC8	UAFIC 8	3									25	25	23			
NewHeal	NewHeST1	25									9	9	8			
NewFctA	NEWFCT A	25			20	20	15									
NewFctB	NEWFCT B	25						20	20	15						
NewFct1	NEWFCT 1	25			20	20	15									
NewFct2	NEWFCT 2	25				20	20	15								
NewFct3	NEWFCT 3	25					15	20	20							
NewFct4	NEWFCT 4	50						20	20	15						
NewFct5	NEWFCT 5	70							20	20	15					
NewFct6	NEWFCT 6	70								20	20	15				
NewFct7	NEWFCT 7	30			20	20	15									
NewFct8	NEWFCT 8	30				20	20	15								

8.3. Load Data Sets

TABLE 8.3.1 MONTHLY DISTRIBUTION
OF PEAK POWER DEMAND

(Page 1 of 2)

Anchorage - Cook Inlet Area				
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	88.5	100.0	100.0	100.0
February	87.4	92.5	88.0	90.2
March	78.4	82.1	80.5	81.3
April	69.4	76.5	72.8	74.6
May	60.9	63.5	65.3	64.4
June	58.5	60.5	62.5	61.5
July	58.5	61.4	62.1	61.8
August	59.2	62.9	64.4	63.6
September	66.8	72.9	72.6	72.8
October	80.1	90.6	81.0	85.8
November	88.0	95.8	84.7	90.2
December	99.2	93.7	93.6	93.6

Fairbanks - Tanana Valley Area				
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	92.7	100.0	100.0	100.0
February	91.8	97.2	86.6	91.9
March	79.1	84.5	79.7	85.6
April	68.0	76.3	67.9	72.1
May	60.2	69.4	67.1	68.2
June	56.9	68.4	62.9	65.6
July	57.1	64.6	63.4	64.0
August	58.6	66.0	67.6	66.8
September	64.1	69.5	71.3	70.4
October	75.4	84.6	79.8	82.2
November	84.2	99.4	82.6	91.0
December	95.0	94.9	97.2	96.0

Total Railbelt Area				
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	89.8	100.0	100.0	100.0
February	87.7	92.8	87.6	90.2
March	78.9	83.0	80.6	81.8
April	69.2	77.3	72.2	74.8
May	60.9	65.1	65.1	65.1
June	58.3	61.2	62.1	61.6
July	57.9	62.4	62.1	62.2
August	59.8	63.0	64.4	63.7
September	66.4	72.7	72.0	72.4
October	79.5	89.8	81.0	85.4
November	87.7	96.3	84.3	90.3
December	98.9	94.6	93.5	94.0

TABLE 8.3.1) (Page 2 of 2)

Anchorage - Cook Inlet Area				
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	10.0	10.7	10.4	10.6
February	8.9	9.0	8.7	8.8
March	8.9	8.9	8.9	8.9
April	7.8	7.9	7.8	7.8
May	7.2	7.1	7.3	7.2
June	6.6	6.5	6.7	6.6
July	6.7	6.8	6.9	6.8
August	6.9	6.9	7.2	7.0
September	7.2	7.2	7.6	7.4
October	8.7	9.0	8.7	8.8
November	9.8	9.6	9.3	9.4
December	11.2	10.2	10.4	10.3

Fairbanks - Tanana Valley Area				
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	10.8	11.0	10.7	10.8
February	9.7	9.2	8.8	9.0
March	9.2	8.9	9.0	9.0
April	7.7	7.8	7.5	7.6
May	6.9	7.3	7.2	7.2
June	6.3	6.6	6.7	6.6
July	6.5	6.8	6.8	6.8
August	6.6	6.9	7.2	7.0
September	7.1	7.2	7.7	7.4
October	8.5	8.8	8.5	8.6
November	9.4	9.4	9.1	9.2
December	11.3	10.2	10.6	10.4

Total Railbelt Area				
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	10.2	10.7	10.5	10.6
February	9.1	9.0	8.8	8.9
March	9.0	8.9	8.9	8.9
April	7.8	7.9	7.8	7.8
May	7.1	7.2	7.2	7.2
June	6.5	6.5	6.7	6.6
July	6.7	6.8	6.9	6.8
August	6.8	6.9	7.2	7.0
September	7.2	7.2	7.6	7.4
October	8.7	9.0	8.7	8.8
November	9.7	9.6	9.2	9.4
December	11.2	10.2	10.4	10.3

Source: Data for 1976-1982 are taken from Alaska Electric Power Statistics 1960-1983, Alaska Power Administration (1984). Data for 1982 and 1983 are based on Applicant's evaluation of hourly load data provided by the Railbelt Utilities.

Table 8.3.2

TOTAL RAILBELT
ENERGY REQUIREMENTS

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
ANCHORAGE MUNICIPAL LIGHT AND POWER	859.1	884.6	885.7	881.7	882.1	884.3	872.6	913.4	934.5	945.3	954.8	948.0	987.0	1,041.6	1,037.6	1,044.1
CHUBACH ELECTRIC ASSOCIATION (RETAIL)	933.7	976.9	978.2	988.3	1,000.1	996.0	1,016.7	1,046.5	1,046.6	998.3	1,009.9	1,020.4	1,033.3	1,009.7	1,048.8	1,091.2
HOMER ELECTRIC ASSOCIATION	386.7	391.7	391.7	396.7	376.5	417.2	427.2	432.2	412.2	401.6	412.2	417.2	417.2	422.2	427.2	432.2
MATANUSKA ELECTRIC ASSOCIATION	478.1	475.2	474.0	476.5	425.9	435.7	433.7	442.8	470.3	471.3	472.1	479.5	483.1	496.2	510.4	527.6
CITY OF SEWARD	34.9	34.9	41.2	43.4	45.6	46.0	46.7	47.7	48.8	49.2	49.5	49.9	50.3	50.9	51.5	52.2
SYSTEM LOSSES	135.7	161.8	162.1	163.7	163.4	164.3	167.5	172.0	172.3	165.3	167.3	169.1	171.0	173.9	177.1	180.9
TOTAL (CEA)	1999.2	2046.5	2047.2	2046.7	2011.5	2054.1	2091.7	2141.2	2130.2	2085.7	2110.9	2136.1	2134.9	2192.0	2234.9	2284.0
FAIRBANKS MUNICIPAL UTILITY SYSTEM	166.2	172.9	174.6	176.3	179.9	185.3	189.0	192.8	196.6	200.5	204.5	208.6	212.8	217.0	221.4	225.8
GOLDEN VALLEY ELECTRIC ASSOCIATION	301.5	321.0	341.2	362.2	377.3	392.7	408.6	424.9	441.7	458.9	476.6	494.6	513.2	532.3	552.0	572.1
HOMER ELECTRIC ASSOCIATION	420.0	425.0	425.0	430.0	454.3	495.0	505.0	510.0	490.0	479.4	490.0	495.0	495.0	500.0	505.0	510.0
CHUBACH ELECTRIC AREA	386.7	391.7	391.7	396.7	376.5	417.2	427.2	432.2	412.2	401.6	412.2	417.2	417.2	422.2	427.2	432.2
NEBAT	33.3	33.3	33.3	33.3	77.8	77.8	77.8	77.8	77.8	77.8	77.8	77.8	77.8	77.8	77.8	77.8
MATANUSKA ELECTRIC AREA (TOTAL)	478.1	475.2	474.0	474.5	479.2	486.0	487.0	496.1	523.6	524.6	525.4	532.0	536.4	549.5	563.7	580.9
CHUBACH ELECTRIC AREA	478.1	475.2	474.0	474.5	425.9	432.7	433.7	442.8	470.3	471.3	472.1	479.5	483.1	496.2	510.4	527.6
NEBAT (BRADLEY LAKE)	0.0	0.0	0.0	0.0	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
CITY OF SEWARD	34.9	34.9	41.2	43.4	45.6	46.0	46.7	47.7	48.8	49.2	49.5	49.9	50.3	50.9	51.5	52.2
TOTAL	3,539.9	3,652.3	3,642.0	3,720.2	3,781.9	3,851.6	3,913.0	4,003.4	4,054.1	4,021.5	4,077.9	4,138.5	4,199.0	4,284.9	4,377.0	4,477.2

CAPACITY REQUIREMENTS

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
PEAK DEMAND																
ANCHORAGE MUNICIPAL LIGHT AND POWER	164.0	166.7	166.9	166.2	166.3	167.1	168.2	172.1	176.1	178.1	179.9	182.4	185.9	190.5	195.4	200.2
CHUBACH ELECTRIC ASSOCIATION	191.3	198.4	197.0	197.4	198.1	195.6	198.0	202.2	200.6	191.3	193.5	195.6	198.0	201.2	204.8	209.1
FAIRBANKS MUNICIPAL UTILITY SYSTEM	29.3	30.0	30.6	31.2	32.1	33.4	34.4	35.4	36.5	37.6	38.7	39.9	41.1	42.3	43.6	44.9
GOLDEN VALLEY ELECTRIC ASSOCIATION	85.8	92.3	99.4	107.0	109.8	112.8	115.8	118.9	122.1	125.4	128.7	132.2	135.7	139.3	143.1	146.9
HOMER ELECTRIC ASSOCIATION	79.0	81.0	81.5	84.0	87.0	93.0	96.0	97.0	93.0	92.0	93.0	94.0	95.0	96.0	97.0	97.5
MATANUSKA ELECTRIC ASSOCIATION	90.3	94.9	96.5	93.6	95.5	96.4	97.5	99.3	105.8	94.9	95.7	96.5	97.0	97.5	99.7	101.2
SEWARD	7.0	7.0	10.0	11.0	12.4	12.5	12.7	13.3	13.6	13.7	13.8	13.9	14.0	14.1	14.2	14.3
TOTAL SYSTEM PEAK	646.7	670.3	681.9	690.4	701.2	712.8	722.6	738.2	747.7	733.0	743.3	754.4	766.7	780.9	797.7	814.1
RESERVE REQUIREMENTS																
ANCHORAGE AREA	133.7	138.0	138.1	137.2	138.0	137.7	139.1	142.1	144.8	139.3	140.7	142.4	144.3	146.8	150.0	153.1
FAIRBANKS AREA	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9
KENAI PENINSULA	38.0	38.0	38.0	38.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
TOTAL RESERVE REQUIREMENT	232.6	236.9	237.0	236.1	249.9	249.6	251.0	254.0	256.7	251.2	252.6	254.3	256.2	263.7	286.9	290.1
TOTAL SYSTEM CAPACITY REQUIREMENT	879.3	907.2	918.9	926.4	951.1	962.4	973.6	992.2	1,004.3	984.1	995.9	1,008.7	1,022.8	1,044.6	1,084.6	1,104.1

Note: Load Forecast Prepared by Railbelt Utilities
Data obtained by APA, Dec 1986

Table 8.3.3

**Peak Demand, Energy and Load Factor Forecast
1986-2020**

Year	Kenai			Anchorage			Fairbanks			Railbelt		
	Peak (mW)	Energy (mWh)	Load Factor	Peak (mW)	Energy (mWh)	Load Factor	Peak (mW)	Energy (mWh)	Load Factor	Peak (mW)	Energy (mWh)	Load Factor
1986	94.0	484.8	58.9%	445.6	2443.6	62.6%	145.1	772.2	60.7%	684.7	3700.6	61.7%
1987	96.0	495.2	58.9%	460.0	2522.5	62.6%	152.3	810.5	60.7%	708.3	3828.2	61.7%
1988	99.5	513.2	58.9%	460.4	2524.7	62.6%	160.0	851.4	60.7%	719.9	3889.4	61.7%
1989	103.0	531.3	58.9%	457.2	2507.2	62.6%	168.2	895.1	60.7%	728.4	3933.5	61.6%
1990	107.5	554.5	58.9%	459.9	2521.9	62.6%	171.9	914.8	60.7%	739.3	3991.1	61.6%
1991	115.6	596.3	58.9%	459.0	2517.0	62.6%	176.2	937.7	60.7%	750.8	4050.9	61.6%
1992	116.9	603.0	58.9%	463.6	2542.2	62.6%	180.2	958.9	60.7%	760.7	4104.1	61.6%
1993	118.7	612.2	58.9%	473.5	2596.5	62.6%	184.3	960.8	60.7%	776.5	4189.5	61.6%
1994	119.1	614.3	58.9%	484.4	2654.0	62.6%	188.6	1003.6	60.7%	792.1	4272.0	61.6%
1995	119.2	614.8	58.9%	486.1	2665.7	62.6%	193.0	1027.1	60.7%	798.3	4307.5	61.6%
1996	119.3	617.4	59.1%	487.9	2684.1	62.8%	197.4	1039.3	60.1%	804.6	4340.8	61.6%
1997	119.4	618.2	59.1%	490.4	2697.8	62.8%	202.1	1064.0	60.1%	811.9	4380.0	61.6%
1998	119.6	619.0	59.1%	493.9	2717.1	62.8%	206.8	1088.8	60.1%	820.3	4424.8	61.6%
1999	119.8	620.0	59.1%	498.5	2742.4	62.8%	211.6	1114.0	60.1%	829.9	4476.4	61.6%
2000	120.0	621.0	59.1%	506.0	2783.6	62.8%	216.7	1140.9	60.1%	842.7	4545.6	61.6%
2001	120.8	622.6	58.8%	515.1	2899.9	64.3%	221.8	1153.9	59.4%	857.7	4676.5	62.2%
2002	122.6	631.9	58.8%	522.8	2943.3	64.3%	224.7	1169.0	59.4%	870.1	4744.2	62.2%
2003	124.5	641.7	58.8%	530.7	2987.8	64.3%	227.6	1184.1	59.4%	882.8	4813.6	62.2%
2004	126.3	651.0	58.8%	538.6	3032.2	64.3%	230.6	1199.7	59.4%	895.5	4882.9	62.2%
2005	128.2	660.8	58.8%	546.7	3077.8	64.3%	233.6	1215.3	59.4%	908.5	4953.9	62.2%
2006	130.1	670.6	58.8%	554.9	3124.0	64.3%	236.6	1230.9	59.4%	921.6	5025.5	62.2%
2007	132.1	680.9	58.8%	563.2	3170.7	64.3%	239.7	1247.1	59.4%	935.0	5098.7	62.3%
2008	134.6	693.8	58.8%	571.7	3218.6	64.3%	242.9	1263.7	59.4%	949.2	5176.0	62.2%
2009	136.1	701.5	58.8%	580.3	3267.0	64.3%	246.1	1280.4	59.4%	962.5	5248.8	62.3%
2010	138.1	711.8	58.8%	589.0	3316.0	64.3%	249.3	1297.0	59.4%	976.4	5324.8	62.3%
2011	140.2	722.6	58.8%	597.8	3365.5	64.3%	252.6	1314.2	59.4%	990.6	5402.3	62.3%
2012	142.3	733.5	58.8%	606.8	3416.2	64.3%	255.9	1331.3	59.4%	1005.0	5481.0	62.3%
2013	144.4	744.3	58.8%	615.9	3467.4	64.3%	259.3	1349.0	59.4%	1019.6	5560.7	62.3%
2014	146.6	755.6	58.8%	625.1	3519.2	64.3%	262.8	1367.2	59.4%	1034.5	5642.1	62.3%
2015	148.8	767.0	58.8%	634.5	3572.1	64.3%	266.3	1385.4	59.4%	1049.6	5724.6	62.3%
2016	151.0	778.3	58.8%	644.0	3625.6	64.3%	269.8	1403.7	59.4%	1064.8	5807.6	62.3%
2017	153.3	790.2	58.8%	653.7	3680.2	64.3%	273.4	1422.4	59.4%	1080.4	5892.8	62.3%
2018	155.6	802.0	58.8%	663.5	3735.5	64.3%	277.0	1441.1	59.4%	1096.1	5978.7	62.3%
2019	157.9	813.9	58.8%	673.4	3791.3	64.3%	280.7	1460.4	59.4%	1112.0	6065.5	62.3%
2020	160.3	826.2	58.8%	683.5	3848.1	64.3%	284.5	1480.1	59.4%	1128.3	6154.5	62.3%

8.4. Production Cost Results

Tables 8.4.1 through 8.4.8 present the detail results for four year as were previously shown for the base case and the alternate case, namely, 1991, 1996, 2006, and 2015. Tables 8.4.1 to 8.4.4 show the annual production operation in the Fairbanks area with only the Anchorage to Kenai Peninsula intertie upgraded. The availability of energy to Fairbanks was determined from the alternate case but constrained by the 70 MW existing tie to Fairbanks. This case is summarized in Table 37 where the Anchorage/Kenai results are the same as the alternate case, but the Fairbanks results are revised to reflect the existing tie.

Tables 8.4.5 to 8.4.8 show the annual results for the same four years for Fairbanks with only the Anchorage to Fairbanks line upgraded. In this Case, the availability of energy to Fairbanks was determined from the base case but the intertie is upgraded to 350 MW. This case is summarized in Table 38 where the Anchorage and Kenai Peninsula results are the same as the base case, but the Fairbanks results are revised to reflect the new tie.

**Table 8.4.3 - 2006 Production Operation in Fairbanks
Anchorage/Kenai Peninsula Upgraded Line only**

REPORT FOR YEAR 2006
 RNM file:c:FAIRALL RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks base case with anchor/kenai upgrade only
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	3.84			Variable	14.75
Net Gen	1227.02			Unreserved	0.38
Storage	0.00			Fuel	20.25
Total Gen	1227.02	LOLP (Dys/Yr)	0.010	Total	39.52

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
NewHeST1	87.48	191.58	823.80	3024.61	3848.41	20.09
TIEPUR06	97.93	600.49	13402.27	0.00	13402.27	22.32
NoPolCT2	57.84	309.07	450.31	12044.04	12494.35	40.43
NEWFACT A	15.94	34.90	20.24	1435.12	1455.36	41.70
NEWFACT B	9.33	20.44	11.85	840.49	852.35	41.70
NEWFACT 1	6.20	13.58	7.87	558.29	566.17	41.70
NEWFACT 2	4.99	10.92	6.33	449.14	455.48	41.70
NEWFACT 3	4.34	9.51	5.51	390.99	396.50	41.70
NEWFACT 4	3.81	16.70	9.69	686.94	696.63	41.70
NEWFACT 5	3.23	19.84	11.51	815.75	827.26	41.70

**Table 8.4.4 - 2015 Production Operation in Fairbanks
Anchorage/Kenai Peninsula Upgraded Line only**

RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks base case with anchor/kenai upgrade only
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1385.37	PK Load (MW)	266.30	Fix O&M	4.56
Unserve	0.76			Variable	14.63
Net Gen.	1384.61			Unservd	0.08
Storage	0.00			Fuel	27.11
Total Gen	1384.61	LOLP (Dys/Yr)	0.022	Total	46.37

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/MWH
NewHeST1	87.48	191.59	823.83	3024.68	3848.50	20.09
TIEPUR15	99.04	607.32	13466.69	0.00	13466.69	22.17
NEWFCT A	54.71	119.82	69.49	4927.25	4996.74	41.70
NEWFCT B	46.01	100.76	58.44	4143.44	4201.88	41.70
NEWFCT 1	32.87	71.98	41.75	2960.07	3001.82	41.70
NEWFCT 2	26.12	57.21	33.18	2352.58	2385.76	41.70
NEWFCT 3	18.41	40.32	23.39	1658.15	1681.54	41.70
NEWFCT 4	12.50	54.76	31.76	2251.78	2283.54	41.70
NEWFCT 5	10.10	61.93	35.92	2546.80	2582.72	41.70
NEWFCT 6	9.13	55.95	32.45	2301.03	2333.48	41.70
NEWFCT 7	8.74	22.98	13.33	944.99	958.32	41.70

