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Numbers in the "Source of Benefits," column refer to the six categories of benefits described under the heading "Sources of Benefits" on page 9 of this memorandum. The column in Table 5 entitled "Probability that Net Benefits are Positive," is based on the nine price and load scenarios making up each project's expected value. As described previously, each one of the nine scenarios has a distinct probability of occurrence; these probabilities were given in Table 4. For each, fuel and load scenarios, net benefits were computed and the column "Probability that Net Benefits are Positive" is the sum of all scenario probabilities where the estimated net benefits were positive.[12] (For example, a column value of 1.00 for "Probability that Net Benefits are Positive," as in the case of Energy Conservation projects, implies that in all nine price and load forecast scenarios the net economic benefits were positive: all APA price and load forecasts result in benefits exceeding costs. Values of 0 indicate that there was no fuel price and load scenario which resulted in benefits exceeding costs. A value between 0 and 1 indicates that under some, but not all fuel price and load scenarios, net economic benefits were positive).

**Description of Projects Having Positive Expected Net Benefits**

Limited Upgrade to Intertie

The existing intertie is limited to 70 MW input at Anchorage. The proposed upgrade to the intertie consists of electrical equipment (static var unit, one transformer, and six capacitors) which increases the Anchorage input to 100 MW. Power received at Fairbanks would increase from [illegible] MW to 84.2 MW.

Energy transfers over the study period are all from Anchorage to Fairbanks. Nearly half of the benefits of this project can be traced to reduced usage of North Pole oil-fired turbines.

The value [illegible] ranges between $1.2 million per year [illegible] and $3.3 [illegible] year [illegible] 2020.[13] This project [illegible] reducing Railbelt [illegible]ty shortages due to the limited nature of the [illegible].

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[12]This is standard statistical procedure.

[13]Mr. Thomas Stahr, the general manager of Municipal Light & Power Department of the Municipality of Anchorage has criticized this project as too limited in scope, experimental, and inconsistent with previous state energy expenditures. His testimony to the House Resource Committee is included as Attachment D.

## Natural Gas Line

A natural gas pipeline could be constructed to link the Cook Inlet gas fields with the Fairbanks area. The estimated capital cost of the project is $183 million (1987 dollars) for the main pipeline and $32.5 million (1987 dollars) for a Fairbanks distribution system.

Nearly 80 percent of the gas line benefits accrue outside the electric power sector--in commercial and residential heating uses. The cost of this project, which includes the construction of a Fairbanks commercial and residential pipeline distribution system and the discounted present value of unavoidable operating and maintenance charges, is approximately $284 million (in 1987 dollars). Although the costs are high, the net benefits for this program exceed those of any other project examined in the APA study.

The gas line project would most likely result in significant dislocations in the existing Fairbanks energy infrastructure. For example, refiners and distributors of heating oil would be adversely affected. These issues are not dealt with in this memorandum or in the APA study.

The overall effect on employment, however, is unclear since there would be increases in employment in the gas-energy sector and other sectors to the extent that lower cost energy increased disposable income and thus increases demand for other goods and services. None the less, it would be a situation of obvious winners and losers.

## Energy Conservation Programs

For APA analysis, the various proposed conservation programs were divided into two groups. The first group consists of electric-to-gas water heat conversion, fluorescent lamp rebate, and the incandescent-to-fluorescent lamp conversion programs. These programs netted about half the benefits and a third of the cost of the top eight conservation programs. The second set of programs, although not as efficient as the top three, include efficient electric water heaters, electric-to-gas clothes dryer conversions, electronic ballasts for fluorescent lights, efficient refrigerators, and sliding-scale rebates for efficient new construction of commercial buildings.

All the programs are designed to encourage the installation of energy-efficient equipment at the time of normal replacement. The programs consist of dealer/contractor rebates designed to lower the relative price of the efficient equipment to nonefficient equipment as an incentive to selection by consumers.

For the top three programs, approximately half of the benefits accrue from the conversion from electric-to-gas water heaters. Consequently most of the reported energy savings result in the Anchorage area.

The advantages of these programs include their low cost and their expected ability to generate benefits exceeding costs (even with low oil price and load projections). The primary disadvantage is that project benefits depend upon consumers adopting and continuing to abide by project guidelines. For example, efficient refrigerators require maintenance of door seals. If this maintenance is not done, the benefits of this particular component of the program gradually disappear.

## HEALY CLEAN COAL AND CONSERVATION PROGRAMS

In this section we provide the net benefits and benefit-cost ratios for the Healy Clean Coal and Energy Conservation projects for each fuel price and load scenario.

Using original APA assumptions, the data provided in Table 6 and Table 7 indicate that the Healy Clean Coal power plant is not economically efficient under any oil price and load forecast. The Energy Conservation Projects have benefits exceeding costs for all price and load forecasts.

**TABLE 6**
**ESTIMATED NET BENEFITS FOR HEALY CLEAN COAL AND ENERGY CONSERVATION PROGRAMS**
(in millions of 1987 dollars)

| | | | Estimated Net Benefits $ | |
|---|---|---|---|---|
| Price/Load | of Scenario Occurrenace % | Healy Coal | Top 3 Energy Conservation Projects | Top 8 Energy Conservation Projects |
| Low/Low | 0.30 | -94.25 | 9.57 | 11.51 |
| Low/Mid. | 0.23 | -91.55 | 10.07 | 12.85 |
| Low/High | 0.06 | -82.95 | 10.91 | 15.02 |
| Mid/Low | 0.03 | -60.75 | 12.72 | 18.66 |
| Mid/Mid. | 0.08 | -49.75 | 13.49 | 20.43 |
| Mid/High | 0.19 | -45.05 | 14.64 | 23.50 |
| High/Low | 0.00 | -20.15 | 15.73 | 25.63 |
| High/Mid. | 0.02 | -6.25 | 16.60 | 27.59 |
| High/High | 0.08 | -0.35 | 17.89 | 31.13 |
| EXPECTED VALUES | | -69.70 | 11.95 | 17.14 |
| Probability that Net Benefits are Positive | | 0.00 | 1.00 | 1.00 |

Notes:
1: All values are in 1987 dollars (present value for 1994 through 2028 discounted at 4.5 percent per year).
2: Estimated Net Benefits = Estimated Benefits - Estimated Costs.

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989.

## TABLE 7
## BENEFIT-COST RATIOS FOR HEALY CLEAN COAL AND ENERGY REDUCTION PROGRAMS

| Scenarios Price/Load | Probability of Scenario $ | Healy Coal | Benefit-Cost Ratios: Top 3 Energy Conservation Projects | Benefit-Cost Ratios: Top 9 Energy Conservation Projects |
|---|---|---|---|---|
| Low/Low | 0.30 | 0.4[illegible] | 1.62 | 1.27 |
| Low/Mid. | 0.23 | 0.48 | 1.65 | 1.30 |
| Low/High | 0.06 | 0.53 | 1.71 | 1.36 |
| Mid/Low | 0.03 | 0.66 | 1.76 | 1.42 |
| Mid/Mid. | 0.08 | 0.72 | 1.80 | 1.46 |
| Mid/High | 0.19 | 0.75 | 1.87 | 1.52 |
| High/Low | 0.00 | 0.89 | 1.87 | 1.54 |
| High/Mid. | 0.02 | 0.96 | 1.92 | 1.58 |
| High/High | 0.08 | 1.00 | 1.99 | 1.66 |

Notes:
1: All values are in 1987 million (present value for 1994 through 2028 discounted at 4.5 percent per year).
2: Estimated Net Benefits = Estimated Benefits - Estimated Costs.
3: Benefit-cost ratios should be greater than 1.0 if the program is to be considered socially efficient.

Source: Decision Focus Inc., *Railbelt Intertie Reconnaissance Study*, prepared for the Alaska Power Authority, June 1989.

## MODIFIED BENEFIT-COST ANALYSIS FOR HEALY CLEAN COAL POWER PROJECT

In this section we describe the effect on expected net benefits of changing APA assumptions about the Healy Clean Coal project. The changes are 1) excluding the federal subsidy from cost calculations, 2) moving the plant site to a location near the existing power plant at Healy, and 3) replacing the proponents construction cost estimate with a recent construction cost estimate prepared by R.W. Beck for AIDEA. We also comment on the possibility that the price of coal might be overstated for purposes of the benefit-cost study (reducing expected net benefits).

### Cost Reductions Realized by Moving Proposed Plant Site

In the APA study the generating plant is located near the mine mouth. It has been suggested that the plant be located next to the existing facility (referred to as the South site) which is approximately four miles from the mine mouth site. It is claimed by project proponents that placing the new plant near existing facilities will reduce the combined operating costs of the two facilities by approximately $2 million annually. Table 8 presents the net benefits and benefit-cost ratios for this project using the assumption that the facility is built at the South site.[14]

**TABLE 8**
**NET BENEFITS AND BENEFIT-COST RATIOS FOR THE HEALY CLEAN COAL PROJECT BASED UPON LOCATION OF NEW FACILITY AT THE SOUTH SITE**
(in millions of 1987 dollars)

| Scenarios Price/Load | Probability of Scenario Occurrence % | Healy Clean Coal Project: Net Benefits $ | Healy Clean Coal Project: Benefit-Cost Ratio |
|---|---|---|---|
| Low/Low | 0.30 | $-45.25 | 0.65 |
| Low/Mid. | 0.23 | -42.55 | 0.67 |
| Low/High | 0.06 | -33.95 | 0.74 |
| Mid/Low | 0.03 | -11.75 | 0.91 |
| Mid/Mid. | 0.08 | -0.75 | 0.99 |
| Mid/High | 0.19 | 3.95 | 1.03 |
| High/Low | 0.00 | 28.85 | 1.22 |
| High/Mid. | 0.02 | 42.75 | 1.33 |
| High/High | 0.08 | 48.70 | 1.38 |

EXPECTED VALUE..................$-24.31
Probability that Net Benefits are Positive.................... 0.29

Notes:
1: All values are in 1987 million (present value for 1994 through 2028 discounted at 4.5 percent per year).
2: Estimated Net Benefits = Estimated Benefits - Estimated Costs.
3: Benefit-cost ratios should be greater than one if the program is to be considered socially efficient.
4: Based upon plant cost assumptions of facility backers.

Source: Decision Focus Inc., *Railbelt Intertie Reconnaissance Study*, prepared for the Alaska Power Authority, June 1989.

**Removing Federal Subsidy from Cost Calculations**

In the APA study the federal grant of $93.2 million is included as a cost. Costs, however, can be defined in two ways: opportunity costs and financial costs. Benefit-cost studies look at opportunity costs, not financial costs. The opportunity cost of the Healy Clean Coal project is the value of goods and

[14] The actual amount saved each year by moving the plant site was taken as $2,219,000 for the years 1990 through 2028 discounted back to 1987 dollars at 4.5 percent per year.

services foregone by society as a result of the project. Financial costs are the costs born by facility owners.

Since there appears to be no other use to which these particular federal grant funds could be put within Alaska, it can be argued that there is no opportunity cost to Alaska in using the funds for this specific project. (Obviously there is a cost to the federal government of giving the funds to Alaska for this project.) Table 9 presents the net benefits and benefit-cost ratios for this project excluding the cost of the federal subsidy.[15]

**TABLE 9**
**NET BENEFITS AND BENEFIT-COST RATIOS FOR THE HEALY CLEAN COAL PROJECT BASED UPON DROPPING FEDERAL SUBSIDY FROM COST CALCULATIONS**
(in millions of 1987 dollars)

| | | Healy Clean Coal Project | |
|---|---|---|---|
| Scenarios Price/Load | Probability of Scenario Occurrence % | Benefits $ | Benefit-Cost Ratio |
| Low/Low | 0.30 | $-44.25 | 0.65 |
| Low/Mid. | 0.23 | -41.55 | 0.67 |
| Low/High | 0.06 | -32.95 | 0.74 |
| Mid/Low | 0.03 | -10.75 | 0.92 |
| Mid/Mid. | 0.08 | 0.25 | 1.00 |
| Mid/High | 0.19 | 4.95 | 1.04 |
| High/Low | 0.00 | 29.85 | 1.23 |
| High/Mid. | 0.02 | 43.75 | 1.34 |
| High/High | 0.08 | 49.70 | 1.39 |

EXPECTED VALUE..................$-23.30
Probability that Net Benefits are Positive.................... 0.37

Notes:
1: All values are in 1987 million (present value for 1994 through 2028 discounted at 4.5 percent per year).
2: Estimated Net Benefits = Estimated Benefits - Estimated Costs.
3: Benefit-cost ratios should be greater than 1.0 if the program is to be considered socially efficient.
4: Based upon plant cost assumptions of facility backers.

Source: Decision Focus Inc., *Railbelt Intertie Reconnaissance Study*, prepared for the Alaska Power Authority, June 1989.

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[15] The federal subsidy used for construction was taken as $75,000,000 discounted back from 1996 to 1987 at 4.5 percent per year.

### Locating at South Site *AND* Dropping of Federal Subsidy

Table 10 presents the net benefits and benefit-cost ratios for the Healy project using the South site for the plant and excluding the federal subsidy from the cost calculations (a composite of Table 8 and Table 9).

**TABLE 10**
**NET BENEFITS AND BENEFIT-COST RATIOS FOR THE HEALY CLEAN COAL PROJECT BASED UPON DROPPING FEDERAL SUBSIDY FROM COST CALCULATIONS AND LOCATING PLANT AT THE SOUTH SITE**
(in millions of 1987 dollars)

| | | Healy Clean Coal Project | |
|---|---|---|---|
| Scenarios Price/Load | Probability of Scenario Occurence % | Net Benefits $ | Benefit-Cost Ratio |
| Low/Low | 0.30 | $4.75 | 1.06 |
| Low/Mid. | 0.23 | 7.45 | 1.10 |
| Low/High | 0.06 | 16.05 | 1.20 |
| Mid/Low | 0.03 | 38.25 | 1.49 |
| Mid/Mid. | 0.08 | 49.25 | 1.63 |
| Mid/High | 0.19 | 53.95 | 1.69 |
| High/Low | 0.00 | 78.85 | 2.01 |
| High/Mid. | 0.02 | 92.75 | 2.18 |
| High/High | 0.08 | 98.65 | 2.26 |

EXPECTED VALUE....................$29.19
Probability that Net Benefits are Positive.................... 1.00

Notes:
1: All values are in 1987 million (present value for 1994 through 2028 discounted at 4.5 percent per year).
2: Estimated Net Benefits = Estimated Benefits - Estimated Costs.
3: Benefit-cost ratios should be greater than one if the program is to be considered socially efficient.
4: Based upon plant cost assumptions of facility backers.

Source: Decision Focus Inc., *Railbelt Intertie Reconnaissance Study*, prepared for the Alaska Power Authority, June 1989.

### Healy Plant Construction Costs Using R.W. Beck Estimates

The cost of construction used in all the foregoing Healy Clean Coal benefit-cost calculations is $80 million (1987 dollars) and is the low cost estimate used in the *Railbelt Intertie Reconnaissance Study* prepared by the APA. In the *Healy Coal Project Financial Plan and Feasibility Study* prepared for AIDEA, R.W. Beck estimates the cost of plant construction to be approximately $120 million (1987 dollars). The R.W. Beck estimate may be the best estimate of plant construction costs since it includes site and technology specific information. If the $120 million estimate of plant construction cost is substituted into the benefit-cost calculations, all cost estimates are increased by $40 million, all net benefits and all expected net benefits are reduced by $40 million. The results are shown in Table 11.

**TABLE 11**
**NET BENEFITS FOR THE HEALY CLEAN COAL PROJECT ASSUMING PLANT CONSTRUCTION COST OF $120 MILLION**
**(R.W. BECK FEASIBILITY STUDY)**

| Scenarios Price/Load | | Probability of Scenario Occurrence % | Healy Clean Coal Project: Based on original APA Assumptions[1] $ | Healy Clean Coal Project: Net Benefits Based on Plant Relocation and Exclusion of Federal Subsidy from Cost Calculations[2] $ |
|---|---|---|---|---|
| Low | Low | 0.30 | $-134.25 | $-35.25 |
| Low | Mid. | 0.23 | -131.55 | -32.55 |
| Low | High | 0.06 | -120.95 | -23.95 |
| Mid. | Low | 0.03 | -100.75 | -1.75 |
| Mid. | Mid. | 0.08 | -89.75 | 9.25 |
| Mid. | High | 0.19 | -85.05 | 13.95 |
| High | Low | 0.00 | -60.15 | 38.85 |
| High | Mid. | 0.02 | -46.25 | 52.75 |
| High | High | 0.08 | -40.35 | 58.65 |
| EXPECTED VALUE | | | $-108.42 | $-10.41 |
| Probability that Net Benefits are Positive | | | 0.00 | 0.37 |

Notes:
1: Refers to assumptions underlying creation of Table 5 (except for the cost of construction).
2: Refers to assumptions underlying Table 10 (except for cost of construction). This figure may over state benefits due to possible double counting of benefits derived from building facility near existing plant.
3: All values are in 1987 million (present value for 1994 through 2023 discounted at 4.5 percent per year).
4: Estimated Net Benefits = Estimated Benefits - Estimated Costs.
5: Benefit-cost ratios should be greater than one if the program is to be considered socially efficient.
6: In the Financial Feasibility Study the cost of plant construction is given as $136.9 million (1990 dollars). Discounting back to 1987 dollars at 4.5 percent results in a construction cost of $120 million (1987 dollars).

Source: Decision Focus Inc., *Railbelt Intertie Reconnaissance Study*, prepared for the Alaska Power Authority, June 1989, and *Healy Coal Project Financial Plan and Feasibility Study*," prepared for AIDEA by Frank Moolin & Associates, Inc. in association with R.W. Beck and Associates.

Excluding the federal subsidy and relocating the plant adjacent to the existing facility allowed positive net benefits under all fuel price and load forecasts. This case was detailed in Table 10. Raising the cost of construction, however, reduces the probability of positive net benefits from 1.00 to 0.37 while expected net benefits drops from $29 million to $-10 million. For the plant to generate positive net benefits, a fuel price and load scenario at the middle-middle price/load scenario or higher is required (see Tables 1 and 2 for scenario assumptions).

**FINANCIAL FEASIBILITY - A PRIVATE SECTOR PERSPECTIVE**

In this section we provide a rationale for continued support of the Healy Clean Coal project by project proponents, despite negative net benefits.

In Table 5, $-69.72 million is given as the expected net benefits for the Healy project. Increasing expected net benefits to zero from $-69.72 million (providing benefits equal to costs or a benefit-cost ratio of 1, the minimum point of economic efficiency) requires some combination of increased benefits or reduced costs equal to $69.72 million.

The original construction cost estimate was $80 million. If construction costs could be lowered by $69.72 million, expected costs would equal expected benefits (a benefit-cost ratio of 1). Realizing this type of savings implies a plant construction cost of $10 million ($80 million - $69.72 million). No one argues that the project can be built for so small an amount.

So why would plant proponents, in this case Golden Vally Electirc Association (GVEA) management, be willing to pay more than $10 million for the new facility? The answer has two parts. First, GVEA management does not agree with all the APA assumptions: GVEA assumes a load scenario slightly higher than APA's high scenario. Under the GVEA load scenario, benefits derived from the Healy project increase to $-59 million (from -$69.9 million). This effectively increases the breakeven construction cost from $10 million to $20 million ($80 million - $59 million). Also described elsewhere in this memorandum was the GVEA estimate that moving the plant from the mine mouth to a location near the existing plant could be worth up to $49 million in benefits not reported in the APA study (1987 dollars), raising the construction breakeven point to approximately $69 million ($20 million + $49 million).

A second part to the answer involves the differences between economic and financial studies. In a benefit-cost study, the analytical question is whether a specific project increases society's net wealth. In answering this question, all project costs and benefits occurring anywhere in society are evaluated. In a financial study, a firm asks if a given project is profitable. Here only project costs and benefits accruing to the firm are evaluated. Thus, the results of a benefit-cost study and a financial feasibility study may well be different.

In the case of a financial feasibility study of the Healy project, two significant cost assumptions differ from those used in the benefit-cost study. First, construction of the new Healy plant would reduce intertie charges for the Fairbanks utilities (since less intertie would be used). This reduction in charges is important to GVEA because it represents a true cost savings to their operations. These savings are not realized, however, in the benefit-cost study since they represent ongoing expenses associated with the intertie whether Fairbanks uses the intertie or not. The cost is simply spread over the remaining users (the cost of the intertie to society has not changed--it has only changed for Fairbanks). Secondly, Fairbanks would be purchasing less power from Anchorage and as a result would pay Anchorage less margins (allowed sale profits). Reduction in margin payments by Fairbanks utilities represents a real savings to those utilities. In a benefit-cost study this reduction is merely a shifting of margin payments from Anchorage to Fairbanks. Since this shift does not imply a savings to society, the benefit-cost study does not take them into account. These reductions in charges are worth approximately $40 million to Fairbanks utilities over the project planning period (which ends in 2028).[16]

Reducing costs by this $40 million raises the breakeven point to approximately $109 million ($69 million + $40 million). This is well in excess of the approximate $60 million of revenue bonds that must be issued and constitute the debt obligation that must be incorporated into the rate base.

Although other differences might exist, these show the conceptual difference between the two types of studies and provide a rational for continued interest in the project by its backers despite negative expected net benefits.

## RECOMMENDATIONS FOR FUTURE PROJECTS

Despite the current increase in oil prices and state revenues, long-run estimates indicate a steady decline in revenues.[17] At the same time, population estimates indicate a constant or increasing total state population. The state is approaching a time when most likely it will not be able to afford meeting power requirements through the brute force method of building additional, subsidized power projects. In anticipation of that time, the

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[16] The savings to GVEA consists of two parts: first, a savings of $2 million per year in margins to Anchorage producers; and second, a savings of $0.7 million per year in reduced intertie operating and maintenance charges. The stream of savings is discounted back to 1987 using a 4.5 percent discount rate.

[17] State of Alaska, Department of Revenue, *Revenue Sources Book*, Spring 1990. See mid-case scenario, page 34.

Alaska state government should initiate a planning process that incorporates several key elements.[18]

First, the state should turn its attention from evaluating the feasibility of specific projects to determining how to best meet the publics need for a reliable source of energy.[19] The legislature should require the APA to focus on developing a plan to meet the power requirements of the population at least cost. The emphasis needs to change from studying and approving specific capital power projects to determining the best (least-cost) combination of supply and demand side power programs that meet energy requirements.[20,21]

Second, power projects should be evaluated strictly for their ability to help meet energy requirements at least cost. Accordingly, employment, income, and other distribution goals should be met through programs specifically designed for those purposes. Related issues, however, should be adequately addressed to assure rational discussion of the various omitted topics.

Third, the AEA and the APUC should work more closely with the private sector to implement the plan. Successful planning would require the state to work with industry to devise a rate structure and other incentives that assure a plan consistent with the best interests of the state, the utilities, and consumers.

Fourth, the state should expend no funds that assist energy projects that are not consistent with the energy plan developed jointly between the state, industry, and other groups.

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[18]See Governor's Energy Policy Task Force, "Recommended Guiding Principles for Alaska's Overall Energy Policy," January 20, 1988. The stated objectives of the task force and those outlined here are not exactly the same. Attachment B contains the recommendations of the task force.

[19]Attachment E contains relevant sections of *Energy Planning in Alaska: Past Efforts and a Future Direction*, published by the House Research Agency, February 1988, that explain the relevance and importance of demand side planning and the need for an integrated resource plan if a sensible, cost-efficient energy strategy is to be developed in Alaska.

[20]Attachment C contains definitions of demand side management programs.

[21]The APA study did not include analysis to determine the least-cost solution for meeting the power requirements of the Railbelt through the study horizon of 2028. For example, the possibility exists that a combination of two demand side management programs (energy conservation and the limited upgrade to the intertie) at a combined cost of approximately $30 million are the energy equivalent of the Healy Clean Coal project (at around $150 million - 1987 dollars).

Finally, the existing tax structure should be evaluated to assure that no group unfairly prospers from state-subsidized power projects. This recommendation is especially important when private firms directly benefit from the expenditure of state funds.

Ideally a least-cost solution or integrated resource plan for meeting the energy requirements of the Railbelt area during the next quarter century will involve a planning process that includes participation from both the public and private sectors. The state is in an ideal position to garner such cooperation because of its role as the provider of economic subsidies and as the facilitator of debt financing through agencies such as APA and AIDEA.

I hope this information is useful. If you have any questions, please contact this agency.

Attachment

ATTACHMENT A
"Decription and Costs of Alternatives,"
*Railbelt Intertie Reconnaissance Study*
Section 2, Volume 11, June 1989
Prepared by Decision Focus Incorporated for APA

# Section 2

# DESCRIPTION AND COSTS OF ALTERNATIVES

## 2.1 NEW INTERTIE BETWEEN ANCHORAGE AND THE KENAI PENINSULA

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

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

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

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

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

## 2.2 FULL UPGRADE OF THE EXISTING ANCHORAGE-FAIRBANKS INTERTIE

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

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

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

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

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

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

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

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

## 2.3 LIMITED UPGRADE OF THE EXISTING ANCHORAGE-FAIRBANKS INTERTIE

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

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

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

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

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

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

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

## 2.5 COAL-FIRED POWER PLANTS IN THE RAILBELT

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

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

**Table 2-1**

**CAPITAL COST ESTIMATES**
(1988 dollars)

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

**Table 2-2**

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

| | Healy | Nenana | Beluga | Matanuska |
|---|---|---|---|---|
| 50 MW | 7.2 | 7.2 | 7.2 | 7.4 |
| 100 MW | 10.2 | 10.2 | 10.3 | 10.5 |
| 150 MW | 13.0 | 13.0 | 13.0 | 13.4 |

* Excludes first year costs for training and commissioning

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

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

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

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

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

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

## 2.6 NATURAL GAS PIPELINE LINKING FAIRBANKS WITH THE COOK INLET AREA

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

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

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

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

## 2.7 ELECTRIC END-USE CONSERVATION PROGRAMS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ATTACHMENT B

"Recommended Guiding Principles for Alaska's Overall Energy Policy"
Alaska Energy Policy Task Force, Draft, January 20, 1988
pp D-2 to D-4

**ALASKA ENERGY POLICY TASK FORCE**
January 20, 1988
Draft

**RECOMMENDED GUIDING PRINCIPLES FOR ALASKA'S OVERALL ENERGY POLICY**

1. The overall goal of Alaska's energy policy should be the long-term availability to all Alaskans of an adequate supply of energy at the lowest total costs to the users, the environment and the State.

2. Recognizing the need to avoid rate-shock--particularly in those rural areas of Alaska where energy costs are very high, it is the policy of the State to avoid actions that in themselves create rate-shock, and also to pursue strategies intended to achieve the lowest combined costs to the State and the consumer.

3. Recognizing the value of free-market forces in bringing about the most effective uses of energy at the least overall cost, State government shall seek to develop a climate that fosters private industry, and in general, the state shall not compete with private enterprise.

4. Recognizing that Alaska's current mix of energy programs may not be the most efficient and cost-effective, and that some programs may work at cross-purposes to others, it is an immediate objective of State energy policy to integrate and modify the various energy programs where necessary to effectively serve the needs of Alaska's citizens, and with the least overall cost.

5. Recognizing that energy conservation is in the best interests of Alaska's citizens, and that efforts directed toward conservation can be more cost-effective than development of additional energy resources, the State's energy policy shall be to promote energy conservation by various means that may include education, technical assistance, development of use technologies, and perhaps direct assistance.

6. Recognizing that state government should take the primary role in necessary energy-related regulatory activities, the state's energy policy shall be to conduct these regulatory activities efficiently and cost-effectively and, as much as is practical, in coordination with other state activities.

7. Recognizing that the federal government has been conducting energy programs in Alaska and that it may continue these or similar programs in future, Alaska's energy policy shall be to coordinate closely with the federal government so that the combined federal and state activities are mutually complimentary and are directed toward the long-term benefit of Alaska's citizens.

8. Recognizing that Alaska has copious energy resources of nearly all forms--including petroleum crude, natural gas, coal, hydropower, geothermal energy, wind energy and biomass--the State's energy policy shall be to make these resources available for development.

9. Recognizing the diversity of Alaska's peoples and the fact that they live in a variety of settings within a land having several distinctly different climatic zones, the State's energy policy shall be to conduct the state's energy activities with a high awareness of the differing regional needs.

10. Recognizing the value of a proper level of planning, it is the policy of the State of Alaska, where expenditure of State funds is involved, to assist as is necessary in such planning activities as are required to accomodate the future energy needs of the State.

11. Recognizing that the state, at no or minimal cost to itself, can sometimes assist local and regional organizations in reducing capital costs of energy-related projects, it is the policy of the State to provide such assistance by either offering at cost (market-rate) loans or by assisting entities to obtain loans from other sources at the lowest cost.

12. Recognizing that it is the proper role of the state to develop information and to provide it to all parties--private industry, publicly owned organizations, and energy users--the State shall promote and participate in the collection, archival, analysis and dissemination of information needed for the conduct of energy activities; and to foster and participate in education and in research and development of energy technologies specifically useful in Alaska.

13. Recognizing that Alaska is highly subject to natural disasters, and also that Alaska is a non-contiguous state which occupies a strategic location in world affairs, thereby possibly making it subject to man-made disasters, the State's energy policy shall be to encourage local and regional energy self-sufficiency so as to mitigate the effects of such events.

14. Recognizing the high cost of energy in rural Alaska and the relative insecurity of rural Alaska economic and energy systems, it is the policy of the State of Alaska to give emphasis to the special energy needs of rural areas.

15. Recognizing that it is in the financial interest of Alaska to so, the State should continue to own the present power production and transmission systems. It should avoid ownership of any new generation facilities if local or regional utilities can plan and build the facilities at lower combined cost to the State and the consumers. The State should continue to be involved in the planning, building and financing of transmission facilities in those cases where it is determined that the utilities or the private sector cannot provide the facilities at lower total cost to the State and the users.

ATTACHMENT C

"Demand-Side Management," Appendix A

*Energy Planning in Alaska: Past Efforts and Future Direction,*

House Research Agency Report 88-B, February 1988

## APPENDIX A

### Demand-Side Management[1]

Demand-side management is the planning and implementation of utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape--i.e., changes in the time pattern and magnitude of a utility's load. Utility demand-side management programs include: load management, new uses, strategic conservation, electrification, customer generation and adjustments in market share. Demand-side management includes only those activities that involve a deliberate intervention by the utility in the marketplace to alter its load shape. Demand-side management extends beyond conservation and load management to include programs designed specifically to build load in both peak and off-peak periods.

The optimal approach to assessing the viability of demand-side management is to incorporate that assessment into the utility's formal strategic planning process with demand-side alternatives being one of many choices available to meet utility objectives. Using a three step hierarchic process to incorporate demand-side management into the planning process is an effective technique. These three steps are: establish broad utility objectives, set specific operational objectives, and determine desired load shape modifications.

The first level of a utility's formal planning process [illegible] tablish overall organizational objectives. These strategic objectives are quite broad and generally include such examples as improving cash flow, increasing earnings, or improving customer and employee relations. While overall organizational objectives are important guidelines for utility long-range planning, there is a need for a second level of the formal planning process in which a utility's objectives are operationalized to determine specific actions. It is at this operational level that demand-side management alternatives should be examined and evaluated. Specific operational objectives are established on the basis of each utility's unique situation. Operational objectives that can be addressed by demand-side management include:

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[1]Unless otherwise noted, this section is based on information from Battelle-Columbus Division and Synergic Resources Corporation, Demand-Side Management, Volume 1: Overview of Key Issues, Prepared for the Edison Electric Institute and Electric Power Research Institute, EA/EM-3597, August 1984.

- Reducing the need for critical fuels;
- Reducing or postponing capital investment in construction programs;
- Avoiding electrical rate increases;
- Increasing revenues or sales;
- Providing customers with options for controlling their monthly utility bills;
- Reducing risks by investing in diverse alternatives;
- Increasing operating flexibility and system reliability;
- Decreasing unit cost through more efficient loading of existing and planned generating facilities;
- Satisfying regulatory constraints or rules;
- Minimizing potential environmental impacts; and
- Improving the image of the utility.

Once established, operational objectives are translated into the desired load shape changes.

Because there are so many demand-side alternatives, the process of identifying potential candidates can be conducted more effectively by considering several aspects of the alternatives in an orderly fashion. Demand-side activities can be categorized in a two-level process in which the second level has three steps:

Level I:
- Load Shape Objectives

Level II:
- End Use
- Technology Alternatives
- Market Implementation Methods

The first step in the identification of demand-side alternatives is typically the selection of an appropriate load shape objective to ensure that the desired result is consistent with utility goals and constraints. Once the load shape objective has been established, it is necessary to find ways to achieve it. This is the second level in the identification process which involves three steps. The first step is identifying the appropriate end uses whose peak load and energy consumption characteristics generally match the requirements of the load shape objectives. In general, each end use (e.g., residential space heating, commercial lighting) exhibits typical and predictable load patterns. The extent to which a given end use can be used to achieve the desired load shape modification is one factor used to select an end use for demand-side management.

The second step involves choosing appropriate technology alternatives for each target end use. This process considers the suitability of the technology for satisfying the load shape objective. Even though a technology is suitable for a given end use, it may not produce the desired results. For example, although water heater wraps are appropriate for reducing domestic consumption water heater electric consumption (strategic conservation), they are not appropriate for load shifting. If load shifting was the primary objective, an option such as direct load control via receiver/switches would be a better choice. Residential demand-side technologies can be grouped into four general categories:

- Building envelope alternatives;
- Efficient equipment and appliances;
- Thermal storage equipment; and
- Energy and demand control options.

Examples of technologies in these four categories are shown in Table A.1.

The final step in identifying demand-side management alternatives involves the methods for encouraging the customer to participate in the program. Marketing methods vary for different technologies. Frequently, two or more customer adoption strategies are used simultaneously to promote a given program. The different types of customer adoption techniques require differing levels of utility involvement. Direct incentive programs, for example, represent a high degree of utility support in promoting demand-side programs. In contrast, customer awareness strategies require less. Examples of customer adoption techniques are presented in Table A.2

TABLE A.1 RESIDENTIAL DEMAND-SIDE TECHNOLOGY ALTERNATIVES

**EFFICIENT EQUIPMENT AND APPLIANCE ALTERNATIVES**

- **HEAT PUMPS**
  - Central Air Source Heat Pump
  - Ground-Water Source Heat Pump
  - Ground-Coupled Heat Pump
  - Multizone Heat Pump
  - Room Heat Pump
- **HIGH EFFICIENCY APPLIANCES**
  - High-EER Air Conditioner
  - Energy-Efficient Cooking Appliances
  - Energy-Efficient Washers and Dishwashers
  - Energy-Efficient Refrigerators and Freezers
  - Efficient Lighting Fixtures and Lamps
- **DUAL FUEL AND ELECTRIC HEATING**
  - Dual Fuel Heating Systems
  - Add-On Heat Pump
  - Active Solar Space Heating
  - Task Heating
  - Zoned Resistance Heating
- **WATER HEATING EQUIPMENT**
  - Heat Pump Water Heater
  - Heat Recovery Water Heater
  - Solar Water Heating

**THERMAL STORAGE EQUIPMENT**

- **HEAT STORAGE**
  - Central Ceramic Heat Storage
  - Room Ceramic Heat Storage
  - Slab Heating
- **COOL STORAGE**
  - Residential Ice Storage Air Conditioning

**BUILDING ENVELOPE ALTERNATIVES**

- **THERMAL TREATMENT**
  - Insulation (Ceilings, Walls, Floors)
  - Storm and Thermopane Windows, Storm Doors
  - Window Treatments (Shades, Solar Screens)
  - Duct and Pipe Insulation
  - Water Heater Blanket
- **INFILTRATION AND INDOOR AIR QUALITY**
  - Infiltration and Indoor Air Quality Control
- **PASSIVE SOLAR DESIGN AND DAYLIGHTING**
  - Passive Solar Design
  - Daylighting

**ENERGY AND DEMAND CONTROL EQUIPMENT**

- **DIRECT UTILITY CONTROL**
  - Receiver Switches
  - Water Heater Cycling Control
  - Air Conditioner Cycling Control
- **LOCAL UTILITY OR CUSTOMER CONTROL**
  - Variable-Service-Level Devices
  - Timers
  - Appliance Interlocks
  - Programmable Controllers
  - Temperature-Activated Time Switches
  - Load Management Thermostats
  - Swimming Pool Pump Control

SOURCE: Battelle-Columbus Division and Synergic Resources Corporation, Demand-Side Management, Vol. 1: Overview of Key Issues, August 1984.

TABLE A.2 EXAMPLES OF CUSTOMER ADOPTION TECHNIQUES

| CUSTOMER ADOPTION TECHNIQUE | OBJECTIVE | SPECIFIC ALTERNATIVES |
|---|---|---|
| Customer Education | Increase customer awareness of utility programs. | Bill inserts, brochures, information packets, displays, clearinghouses, direct mailings. |
| Direct Customer Contact | Through face-to-face communication encourage greater customer response to utility programs. | On-site energy service audits, workshops/energy clinics, store fronts/vendor sales and service. |
| Trade Ally Cooperation (i.e., architects, engineers, appliance dealers, heating, cooling contractors) | Increase utility capability in marketing and implementing programs. | Cooperative advertising and marketing, training, certification, selected product sales/service. |
| Advertising and Promotion | Increase public awareness of new programs, influence and control customer response. | Mass media (radio, TV, and newspaper), point-of-purchase advertising. |
| Alternative Pricing | Provide customers with pricing signals that are reflective of real economic costs and encourage a desired market response. | • Demand rates—rates based on the maximum kilowatt usage of a customer; the rate thus provide an incentive for customers to improve their load factor.<br>• Time-of-use rates—rates where higher costs are incurred by the customer for using during a utility's peak period and lower costs during off-peak periods.<br>• Off-peak rates—rates priced to reflect lower off-peak costs which offer customer service for specific end uses such as storage heating or storage water heating<br>• Seasonal rates—rates where the season in which the utility reaches its peak has a higher flat rate than other seasons.<br>• Inverted rates—rates where consumers pay more for each unit of electric consumed in later tail blocks. The first block may or may not consist of a lifeline rate.<br>• Variable levels of service—rates where customers subscribe to a minimum electric service consistent with their needs—e.g., interruptible rates.<br>• Promotional rates—rates designed to attract targeted groups of customers to a utility service area for the purpose of encouraging economic development.<br>• Conservation rates—reduced rates based on a customer's dwelling meeting minimum energy efficiency standards, including mechanical systems. |
| Direct Incentives | Reduce up front purchase price and risk of hardware investments to the customer and increase short-term market penetration. | • Low/no interest loans—loans issued to customers below the current lending rate with the length of time for repayment varying.<br>• Cash Grants/Rebates/Buy Back—money paid to customers based on some criteria, usually the efficiency of the device, energy/demand saved, and difference in utility average and marginal costs.<br>• Subsidized installation/modification—utility arranges to have demand-side options installed for a reduced fee or free-of-charge. |

SOURCE: Battelle-Columbus Division and Synergic Resources Corporation, Demand-Side Management, Vol. 1: Overview of Key Issues, August 1984.

Taken in sequence, the four steps described above are:

- Establish the load shape objective to be met;
- Determine which end uses can be appropriately modified to meet the load shape objective;
- Select technology options that can produce the desired end use-load shape change; and
- Identify an appropriate market implementation program.

The selection of the most appropriate demand-side management alternatives is probably the most crucial and difficult question a utility faces. This process is difficult because of the number of demand-side alternatives. In addition, because the relative attractiveness of alternatives depends upon specific utility characteristics, such as load shape, summer and winter peaks, generation types, customer characteristics, and load growth, transfer of results from one service area to another may not be appropriate.

Because there are so many different demand-side alternatives available to a utility, they should be analyzed through a hierarchy of evaluation levels, starting with an intuitive selection, continuing with an aggregate analysis, and ending with a detailed and comprehensive evaluation. The first level, intuitive selection, is based on a thorough understanding of the conditions within the service area, of the generating system and any planned expansion, and of the operating characteristics of the demand-side alternatives. The intuitive selection process does not identify those alternatives that are "best" but instead identifies a number of alternatives that are, at least initially, appropriate to achieve stated goals.

The next level in identifying alternatives is a more quantitative analysis that examines costs and benefits to all parties affected by implementation of the specific program over the program's lifetime. Interested parties include the utility, program participants, other customers, and society-at-large. To calculate the costs and benefits requires quantitative information on the impact of the alternative on peak and total energy sales, the expected participation in the program, the costs of implementation, and generating system data (such as costs for existing and planned capacity and fuel costs for base and peaking units). Comparison of the benefit/cost ratios will yield a preliminary ranking of programs.

The final step in the selection of the most appropriate demand-side alternatives is a detailed analysis of the most cost-effective alternatives. In a typical detailed analysis, the performance of the utility system from both an operational and financial viewpoint is simulated over time, with and without the selected demand-side alternative. This analysis estimates changes in the generating system and its operation that will result from the altered load shape produced by the selected demand-side alternatives.

Implicit in the selection process is a definite strategy to reduce the information requirements to manageable levels consistent with the trade-off between the data collection/analysis expense and the resulting level of accuracy in the evaluation. This strategy focuses on quickly and efficiently reducing the number of alternatives appropriate for a given utility. Detailed analyses of demand-side management alternatives are data intensive, requiring information in four major categories:

- Service area specific customer and end-use characteristics (type of equipment in use, stock estimates of equipment, patterns of usage);
- Operating/technical characteristics of the alternatives;
- Characteristics of the supply system (operating costs, reliability, initial cost); and
- Customer acceptance of alternatives.

Once the cost-effectiveness of demand-side management programs has been determined, programs can be implemented. Program implementation involves the many detailed day-to-day decisions that must be made to realize the goals of the program. Developing, installing, and operating a generating plant takes years of planning and scheduling, rigorous analytical modeling, calculations concerning reliability and maintenance, and strict construction scheduling. Similarly, the implementation of a demand-side management program intended to replace the need for all or part of a generating plant requires equally rigorous evaluation. The lack of data, inadequate experience with building models, and problem complexity are challenges to be overcome.

The implementation phase usually occurs in distinct stages. As a result of logistics and uncertainty over customer acceptance and response, a demand-side program can be introduced gradually through pilot projects. If the results from the pilot experiments look promising, the utility may proceed with full-scale implementation and operation.

ATTACHMENT D

Testimony of Thomas R. Starr to the Alaska House Resource Committee

TESTIMONY OF THOMAS R. STAHR

TO THE HOUSE RESOURCES COMMITTEE

Mr. Chairman, members of the House Resources Committee, my name is Thomas Stahr and I am General Manager of the Municipal Light and Power Department of the Municipality of Anchorage. I am testifying in favor of the funding and construction of new electric transmission interties, both from Anchorage to the Kenai and from Anchorage to Fairbanks.

In its draft study the Alaska Power Authority assumed that certain technological fixes applied to existing old, low capacity transmission lines would result in performance nearly as good as a new transmission line. The result of this assumption was a perceived low benefit to cost ratio for both interties and a anomolously high benefit to cost ratio for the limited upgrade of the northern intertie. I want to explain why, in my professional opinion, these results are illusory and why implementation of the proposed enhancements may result in serious problems.

First, it is necessary to understand that the Bradley Project, as designed, has certain rather unique control features which limit normal operation to operating interconnected with a relatively large power system. Since there is no surge tank or surge chamber in the turbine water supply, operation of the power control valves are restricted to a very slow rate so it is necessary to have other generation units operating in parallel to absorb sudden load variations. There is a device to deflect water away from the turbine runner (wheel) which is normally used to prevent dangerous overspeed on sudden loss of load and it is hoped this device can be used to help govern the unit but there may be no way short of adding the usual surge tank to markedly improve load pick up ability. The braking resistor being proposed as a part of the technological fix is also to help control the tendency toward speed and voltage increase before the deflectors can operate. It is incomprehensible to me why a project would be designed so that strong interconnections are absolutely necessary for successful operation and then the agency ultimately responsible for that design would attempt to argue that the strong interconnection is not cost effective.

The existing Chugach line connecting Anchorage to the Kenai is thirty some years old and in need of major repair. Certainly well within the study period it will have to be replaced. While I have no detailed estimates of what this will cost, location and route alone indicate ths cost will be high compared to the cost of constructing a line on the route proposed for the new line. This old line is also subject to frequent faults and interruptions due to snow slides and other environmental factors. I can personally attest to problems this causes our customers in Anchorage and to the strains the repeated short circuits place on ML&P generators which absorb much of the surge on the Anchorage end. Faults on this old line have frequently caused Providence Hospital and other ML&P customers with sensitive load requirements to be forced to transfer to emergency generation. Supercharging this old line with technological fixes will militate against efforts to isolate Anchorage customers from efforts of faults on this line.

The technical fixes proposed to transform the old line into something approaching a real new transmission line are the addition of power system stabilizers, series capacitors and static var units. All of these devices are used in certain instances to overcome transmission or stability problems when a more conventional approach is inadequate. But to the best of my knowledge, they have not heretofore been considered as a surrogate to a proper transmission line. Each of these devices can cause serious problems if misapplied or if unanticipated operating conditions occur. Series capacitors have, on occasion, engendered sub-synchronous resonance conditions which can be damaging to generators and large industrial motors. Power Technologies, Inc., who proposed the technological fixes, admit they cannot be sure that sub-synchronous problems can be precluded and that other fixes must be used. Unless exhaustive studies are done beforehand we may find out we have a problem the same way most series capacitor problems are found, that is by bitter and expensive experience. Static var units are active devices, hence, subject to failure and miss operation. With the Anchorage/Fairbanks tie line we went through several years of problems before getting the static var units to perform properly. They also create harmonics on the power system which can cause problems for customers' electronic equipment. Certainly the few static var units we now have in service have not caused a problem but with massive additions the situation may be different. The power system stabilizers will help system stability only when they operate as planned but unless all possible situations are modeled, conditions may arise where they destabilize the system. Additionally, the combination of all these devices together means we will be operating a power system in the outer limits of standard utility operating practice. It has long been a fundamental Alaskan power system design principle that this is not the place to experiment with new technology when our customers are the experimental subjects. We should take heed from the recent Ontario Hydro experience where the whole Province was blacked out by Auroral currents and the cause was the saturation of a static var unit used in conjunction with series capacitors, exactly the same combination the Power Authority is suggesting we use. Ontario Hydro had used this combination because they had no alternative in bringing power from remote hydro plants. It is being proposed in our case because it is perceived as a cheap fix. Personally, I doubt that it is a fix or that in the long run that it will be cheap.

If one examines the alleged benefits from the new transmission line one does not find any benefits due to not having to rebuild the old transmission line. I have been told that it is because they expect the utilities to rebuild the old line in any case. To test this hypothesis, one should imagine the case where the new line has been built and the benefits of replacing the old line are being considered. Certainly part of it would be required in any case, to get power to Girdwood and Seward. Much cheaper distribution lines could bring power to Portage and Whittier and for Sunrise and Hope a small automated diesel could be installed at an insignificant fraction of the cost of rebuilding a major transmission line segment. Now, if we accept the Power Authority's "silk purse" scenario that a few high tech gadgets will transform the "sows ear" of the old line into something nearly as good as a new line let's examine what it will do for the new line and what the additional benefits of rebuilding the old line are if we have an enhanced new line. Looking at the benefits shown, the major ones are for reduced transmission losses, increased economy energy, capacity sharing and reliability improvements. These constituted 92% of the benefits of building the new line. Starting with losses and assuming the 138Kv new line was in place there would be very minor loss reduction from rebuilding the old line because it is so much longer. There would be little if any reliability improvements. In fact, I believe rebuilding the old line would likely make reliability worse. On capacity sharing, the longer length of the old line makes it of marginal value and finally, it's effect on economy energy would be marginal. Therefore, at least qualitatively, using the study logic, we can see there is very little value in rebuilding the old line so under this premise it would not be done. But the study assumed it would be done so the study impeaches itself.

At this point, I want to make it clear that we have not determined that the old line should or should not be rebuilt. What we have determined is that the cost of rebuilding the old line cannot be ignored and it either must be included in the benefits of the new line or the benefit of the existing line with the high tech fixes are not as great as assumed. Thus, the benefits of a real new line are much greater than represented. I am convinced either of these resolutions to the logical fallacy will result in a benefit to cost ratio well in excess of one.

I urge you to fund the Interties so we can obtain needed transmission lines which will continue to benefit railbelt ratepayers for years to come.

ATTACHMENT E

*Energy Planning in Alaska: Past Efforts and A Future Direction*, House Research Agency Report 88-B

pp 20 to 28

### Statewide Overview Approach

The statewide overview focuses on a comparison of utility plans with a continuously updated statewide analysis of energy supply and demand. The premise underlying this approach is that utility plans are acceptable if they do not conflict with an independent, integrated statewide overview of demand forecasts, conservation and other demand-management measures, and supply alternatives. This statewide analysis is conducted by the utility regulatory commission or state energy office. The state overview need not include a plan, but must at least provide a general assessment of opportunities for cost reductions and risk management from a statewide societal perspective as opposed to a strictly utility perspective.[26]

The states of Wisconsin, Vermont, New York, Indiana, Kentucky, and Texas have adopted a statewide approach. The need for a statewide approach is described by the Kentucky Public Service Commission as follows:

> "Kentucky's electric utilities have traditionally concerned themselves with meeting the needs of their separate service areas. But given the enormous cost of building new power plants and the uncertainties of a changing economy, the time has come to explore a more cooperative approach in which utilities work together to meet the needs of the entire state. The commission strongly believes that a statewide strategy may generate significant long-term savings for ratepayers, utility companies, and their stockholders. These savings occur through improved long-range planning and better use of the current abundance in Kentucky of electric generating capacity."[27]

### Countervailing Recommendation Approach

The countervailing recommendation approach works on the theory that the utilities will present reasonable integrated resource planning options if they face the threat that the commission staff or independent parties will present credible conservation, demand management, and supply-side alternatives in rate cases and other proceedings before the commission. To reply to that threat, the utilities must develop their own credible plans. West Virginia, the District of Columbia, and Maine use aspects of this approach. In addition, the states of Nevada and Pennsylvania have used this approach when the utility planning approach has not been productive.

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[26] Ibid.

[27] Kentucky Public Service Commission, Order, Adm. Case No. 308, p. 2.

Countervailing recommendations are also part of a statewide approach to insure that utility proposals are compatible with statewide overviews and objectives.

The three prototypical approaches to integrated resource planning are three points along a continuum. At one end (utility planning approach), planning consists of the state developing utility reporting requirements and reviewing utility reports for compliance with requirements. In this case, the utility regulatory commission is heavily dependent on the utility to do the planning. At the other end (statewide and countervailing approaches), planning consists of the commission developing plans or analyses against which utility plans are compared for consistency. This approach gives the public planning entity the greatest degree of independence in the planning process.

The State of Nevada, a leader in the development of integrated resource planning, has developed comprehensive statutes and rules which establish integrated planning. Additionally, Nevada has reviewed the statutes of other states implementing integrated planning and identified components important to the planning process as follows:[28]

1) Planning Process Integration: Integration involves two aspects; substance and procedure. Substantively, integration includes a forecast of future demand and a comprehensive analysis of demand and supply options available to meet or alter demand which are then unified to derive the "least-cost" resource plan. On a procedural level, regulators strive for integration of utility rate making and utility construction permit proceedings to ensure that the resource process actually takes hold and leads to long-term economic benefits to ratepayers and financial health for the utility.

2) Sufficient Methodological Specification: Specification of the methodology and models to be used by the utilities is necessary to insure: 1) use of state-of-the-art approaches; 2) consistency over time between plan filings by various utilities; and 3) the establishment of a systematic review process for interested parties and regulators. This methodological specification must not be so rigorous, however, as to thwart innovation by utility resource planning staffs.

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[28]Jon B. Wellinghoff and Cynthia K. Mitchell, "A Model for Statewide Integrated Resource Planning," Public Utilities Fortnightly, August 8, 1985, p. 20.

3) **Required Implementation:** Integrated planning is accompanied by action plans detailing the means by which utilities plan to acquire and implement resource options with cost-effectiveness being the key priority.

4) **Utility Responsibility for Plan Creation:** If the expertise and data for plan development originate within the utilities, utilities are likely to stand behind their plans and use them in a variety of internal and external decision making processes. By placing primary responsibility for creation and coordination of plan components within the individual utilities, successful plan implementation is more readily assured.

5) **Plan Enforcement:** Unless the regulatory process provides for an effective enforcement mechanism to ensure that utilities adequately conduct the planning process and follow through with the acquisition and implementation of resource options, the entire process becomes little more than a futile exercise. Regulatory integration of the planning process can greatly facilitate enforcement of the planning process.

## EXAMPLES OF INTEGRATED RESOURCE PLANNING AT WORK

This section provides practical examples of integrated resource planning in the Pacific Northwest and Southern California. The Northwest Power Planning Council was developed following the very expensive Washington Public Power Supply System construction "mistakes" in the late 1970s. Southern California Edison is an excellent example of one utility's creative response to state legislation requiring utility planning. These examples were chosen because each emphasizes planning for uncertainty to maximize flexibility and minimize costs. Because of the volatility of Alaska's economy, this approach to planning is especially pertinent. In addition, the Pacific Northwest has considerable surplus electrical generating capacity--similar to conditions in many Alaska communities.

## Pacific Northwest Planning

The Northwest Power Planning Council is responsible for electrical energy planning for the Northwest Region (Washington, Oregon, Idaho, and Montana) as required by the Federal Northwest Power Act.[29] The council's planning strategies are particularly relevant to the Railbelt and some other areas of Alaska, because the Northwest, like the Railbelt, currently has a large surplus of power and future demand levels are uncertain. The council utilizes an integrated resources and risk minimization planning approach. All potential demand- and supply-side options are evaluated for their ability to provide an adequate and reliable supply of electrical energy at the lowest possible cost; most efficient options are added to the region's energy portfolio. Risk minimization is accomplished through the recognition of the shifting nature of energy demand projections and addressing this uncertainty by defining the probable boundaries of potential energy growth. To do this, the council develops high, medium-high, medium-low, and low electrical growth forecasts for twenty-year periods. These forecasts are continually monitored and updated on a two-year cycle.

The range of forecasts serves two important functions. First, it is an explicit statement that the future is uncertain and that the council does not base decisions on the traditional "most likely" forecast. Rather, the council evaluates the consequences of specific actions across a wide range of possible futures. Second, the forecast range represents the council's judgment on the potential futures for which the region should plan and invest.

The council attempts to maximize flexibility by identifying options with short lead times, small sizes, and/or low capital costs. Short lead times allow for greater adaptability to unforeseen changes in demand. Smaller plant sizes make it easier to match resources to loads. Options with lower capital costs tend to reduce risk because they reduce the amount of money that has to be committed to any one project. Conservation is considered a highly flexible option in the Pacific Northwest. The region has a large supply of potential conservation measures which cost much less than building generating capacity. Conservation also helps reduce uncertainty because more energy efficient building and end uses are more resistant to changes in energy prices and are therefore less likely to contribute to fluctuations in power demand or switching to other fuels.

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[29]Chapter 12H-Pacific Northwest Electric Planning and Conservation Act, Bonneville Power Administration, U.S. Department of Energy, December 5, 1980.

The Pacific Northwest region also uses a resource options strategy to add flexibility to the scheduling of options that require a great deal of time from inception to completion. Under this strategy, an option moves through the time-consuming but relatively inexpensive siting, design, and licensing, after which it can be scheduled, placed on hold, constructed, or terminated, depending on the demand for electricity. The cost of developing resource options is typically very small compared to the costs associated with construction. Furthermore, options substantially reduce the lead time required for constructing generation capacity. By having a licensed or readily licensable power project effectively "on hold," the period over which electricity needs must be forecast can be reduced to the construction period, which is as little as half of the total time that is now needed. The objective of the effective options planning strategy is to move decisions involving the commitment of large sums of capital as close as possible to the anticipated time power will be needed. This significantly reduces the likelihood of beginning construction on a project that is not needed. The council has analyzed the value to the region of being able to option resources. It found that this two-stage decision making process could save the region $700 million across the 20-year range of future load growths.

The council's planning process consists of three steps: 1) initial determination of resource needs; 2) selection of cost-effective supply- and demand-side options; and 3) selection of the final resource portfolio and action plan. The council's planning begins with an extensive analysis to determine the range of future electrical energy growth in the region over the next 20-year horizon, based on economic and demographic projections and the price of alternative fuels. Forecasts of future electricity prices are also a key factor in forecasting future electricity use. As previously described, the forecasts characterize the range of uncertainty by providing estimates of four growth patterns for electrical demand (high, medium-high, medium-low, and low).

In the second step, the council estimates the availability, reliability, and cost of both generating and conservation resources; cost analyses include environmental impacts or costs. To most accurately estimate the costs of potential resources, their use is simulated with the existing power system to determine the actual costs to the region. This analysis also determines the compatibility of each alternative with the existing power system. The council then analyzes the lowest cost combinations of all resources to meet the entire range of potential energy needs. Nondiscretionary resources are first added into the portfolio. These are cost-effective resources whose timing cannot be scheduled or controlled by the power system. For example, the opportunity for energy savings in new residential and commercial buildings will occur when the buildings are built. In contrast, discretionary resources can be scheduled by the power system to produce energy when they are needed.

The council also identifies "lost opportunity resources." A lost opportunity resource is a potential electrical power generating or conservation option currently available to the region which, if not acquired or currently secured, will no longer be available and cost-effective. If a lost opportunity is not secured, it will have to be replaced in the future by a less cost-effective option. Conservation standards for energy efficient construction of new residential and commercial buildings are an example of a lost opportunity resource the Northwest Region is currently pursuing.

The final step in the planning process is the application of electricity costs (from the resource portfolio determined in step two) to the forecasting system. The resulting forecasts of energy needs are then used to fine tune the amount of options needed.

The council's planning strategy is based on a societal perspective. The objective of the council's plan is to minimize total system costs, whether these costs are borne by utilities--and thus reflected in electric rates--or by individuals, businesses and governments acting in their own self-interest. This approach does not necessarily result in the lowest electrical rates in the short term; but instead minimizes the long-term cost of serving all ratepayers in the region.

## Southern California Edison

As at many other utilities, resource planning at Southern California Edison (SCE) had traditionally been dominated by a single load forecast which defined the resource requirements necessary to meet the load with an adequate safety margin. This process worked quite well during decades of steady growth and few surprises. As the business environment began to change, starting in the late 1960s, the process of load forecasting and resource planning became more complicated. The SCE's initial response to this new planning environment was to develop more sophisticated forecasting models and more extensive data bases. It took some time to realize that more sophisticated forecasting methods were not the problem's cure. Planning had become more complicated not because the forecasting models were inadequate, but because frequent surprise events made their underlying assumptions inappropriate. This observation led to SCE's new resource planning philosophy: planning for uncertainty.

## ENERGY PLANNING

A review of SCE's resource plans since 1965 indicates that out of a total of 34,000 megawatts of "planned" resource additions, only 9,000 megawatts were actually built. In all cases, the cancellations took place with projects in early stages of conceptual planning or design. As a result, SCE did not incur any major engineering or construction costs in canceling these planned resources. Despite the fact that forecasts were, on average, twice as high as actual growth rates experienced, the separation of forecasting functions from planning functions--and consequent consideration of alternative scenarios and responses--allowed SCE to respond to "low" demand in time to come up with the "correct" plan of action. Learning from this experience, SCE changed the focus of their planning from predicting future events to responding efficiently to change.

The SCE analysis starts with an effort to identify how the future could unfold under a wide range of assumptions. Alternative economic conditions, growth rates, and regulatory, environmental, technological, social, political and business environments are considered. Future scenarios consisting of plausible combinations of these parameters, including many surprise events, are postulated and their potential impact on electrical service and customers are evaluated. Each scenario leads to a set of outcomes affecting economic growth, employment, income, housing, trade, financial services, industrial activity, and so on. Since demand for electrical services is a derived demand, SCE's growth rate is a function of these other variables.

In the early stages of SCE's analysis, it became clear that many alternative scenarios result in similar consequences relative to the need for new resources. That is, even though they were caused by different factors, their impact on SCE's resource requirements would be similar. This reinforced the importance of focusing on the consequence of scenarios as opposed to the events or scenarios themselves. Subsequently, the scenarios were grouped based on their consequences. In 1986, the outcome of this consolidation process was 12 sets of scenarios or consequences which encompassed a wide range of potential futures. These consequences formed the boundaries of a forecast range similar to the council's forecast range previously described.

Since there is no way of knowing which one, if any, of the scenarios will occur, SCE's resource planning process focuses on developing a flexible action plan which covers the entire set of possible outcomes. To achieve this objective, the resource plan consists of a number of strategic elements that can be rearranged in a variety of ways to accommodate any plausible scenario. Using these strategic "building blocks," SCE can accommodate a range of growth outcomes from four percent annual growth to one-half of one percent annual decline during the next ten-year period. The strategic elements in SCE's plan include:

- Extended or Shortened Use of Oil and Gas Units--This offers a number of options that may be exercised in relatively short order depending on the need for capacity and the type of load. The useful life of many aging plants may be extended or plants may be mothballed as needed. In addition, units can be modified to meet base, intermediate, or peaking load requirements.

- Transmission Network--The availability of excess capacity at other utilities allows SCE to use their existing and planned transmission network for purchases of economy energy. In recent years, this has saved SCE customers billions of dollars.

- Qualifying Facility Resources--Power generated by independent entities and sold to SCE under PURPA-type contracts has grown in significance during the past several years. Qualifying facility (QF) projects are generally nonutility financed and have short development times. Managing QF development to conform to changing requirements through appropriate price signals provides an additional element of flexibility to SCE's resource planning process.

- Energy Management--During decades of demand-driven, generation-focused planning, customer demand was considered as a "given" and supplies were planned to meet it no matter what the cost. The SCE is increasingly focusing its attention on managing and modifying its load with a variety of load management options. The SCE believes that the key to customer-side load management is time-of-use differentiated pricing and marketing strategies which provide sufficient incentives for customers to modify their consumption patterns.

- New Resources--In addition to the above-mentioned options, SCE maintains a number of conventional and nonconventional new resources in its inventory. Many are modular in nature and can be brought on line in a relatively short period of time. These include all types of capacity: base load, intermediate, and peaking.

The use of strategic elements to develop alternatives provides the basic ingredients of SCE's flexible integrated resource plan. The success of SCE's planning process is evident in its ability to respond to a wide range of possible growth scenarios in the future. The SCE's planning methods have been widely acclaimed and emulated by other utilities.

## CONCLUSION

In theory, integrated resource planning is a framework within which all reasonable options for meeting electrical power demand are considered to provide the most cost effective system. In practice, states and utilities are finding that IRP maximizes flexibility in addressing the uncertainties of future power needs in the late 1980s and beyond. Integrated resource planning is worthy of consideration in Alaska's energy future. Alaska's economy and its dependence on natural resource development and extraction makes the demand for electricity particularly subject to volatility. Therefore, an energy program that plans for uncertainty and maximizes flexibility is likely to provide maximum benefits to all consumers of electricity in Alaska.

In the following chapters, the history of energy planning in urban (Chapter Two) and rural (Chapter Three) Alaska is reviewed. Then, the current energy situation and programs are assessed from an IRP perspective and suggestions are offered for near-term efforts. The final chapter explores the implementation of IRP for future energy planning in Alaska.

THE FOLLOWING DOCUMENT HAS
NOT BEEN FILMED BUT IS
AVAILABLE IN THE ORIGINAL
FILE

# ENERGY PLANNING IN ALASKA: PAST EFFORTS AND A FUTURE DIRECTION

House Research Agency
Alaska State Legislature
February 1988

House Research Agency Report 88-B

**EPRI**
Electric Power
Research Institute

Topics:
Demand-side planning
Demand-side management
Planning
Financial planning
Least-cost planning
Integrated value-based planning

EPRI EM-6133
Project 2982-2
Final Report
December 1988

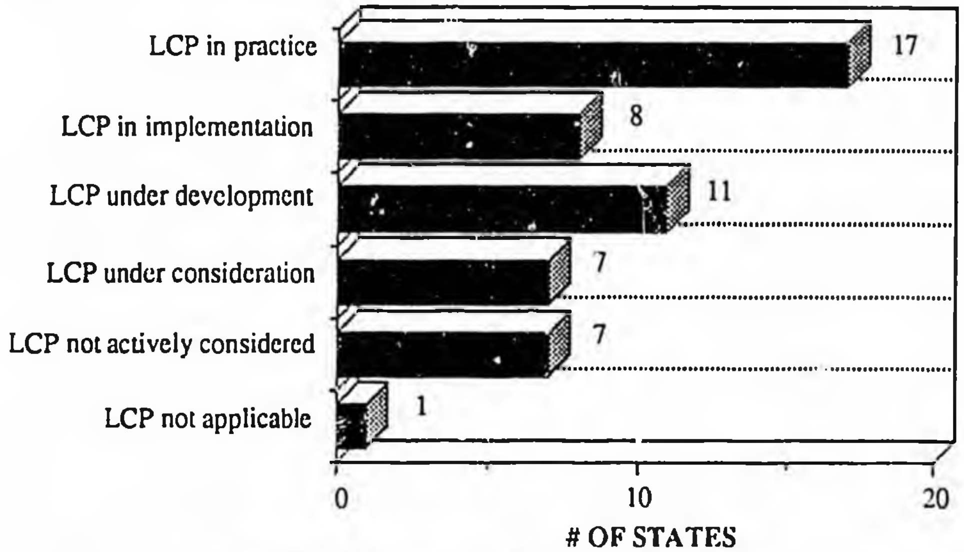
# Status of Least-Cost Planning in the United States

Prepared by
Barakat, Howard & Chamberlin, Inc.
Oakland, California

Electrical resource planners in nearly every state either use or are considering least-cost planning (LCP). At least 43 states have functioning LCP strategies or are considering, developing, or implementing a planning process that will ensure the most cost-effective mix of new generating facilities and demand-side management (DSM). In most of these states, regulatory commissions or legislative bodies lead the development of LCP procedures through mandate or through active encouragement of nascent utility LCP processes.

At least 17 states have functional LCP strategies (see Figure 1). Commissions in many of these states enforce least-cost planning through a variety of regulations and filing requirements, often using plant authorization or rate cases as the forum. Legislatures in at least 12 of these states have supported the process either by passing LCP laws or by giving authority to the commissions to establish and enforce regulations. Utilities in a few of these 17 states practice LCP without regulatory or legislative mandates.

**Figure 1**
NATIONWIDE STATUS OF LEAST-COST PLANNING




An additional 8 states are beginning to implement LCP strategies through legislative, regulatory, or utility action. Regulatory planners are developing or actively considering LCP in 18 more states. Eleven of these 18 states are preparing LCP rules for regulatory or legislative review. The other 7 states are examining LCP through commission studies or legislative task forces. Seven states are not actively considering LCP.

Los Angeles Times Oct. 14, 1990

# Seeing the Light on Energy

*Why would a utility company give away light bulbs?*

The state Public Utilities Commission recently guided California's four biggest private power companies back into energy conservation by letting them count as profits some of the power they saved.

But the law says the commission can't tell municipal utilities what to do, so it was obviously on its own initiative that the Los Angeles Department of Water and Power decided to give away energy-saving light bulbs. Talk about seeing the light.

The goals are the same—reducing the need to build new generating plants. Four of the biggest private utilities expect to spend $560 million over five years on conservation. That will save enough energy to eliminate the need for a new 300-megawatt power plant. DWP will spend $80 million a year on its own programs, among them dispensing bulbs that use about one-fourth as much power as standard bulbs.

Not entirely by coincidence, the Natural Resources Defense Council, which helped write the PUC's conservation formula, helped the department find an Oregon consultant to help with its bulb deal.

DWP crews will start calling the utility's 1.3 million customers shortly after the first of the year to promote the program. They plan to give between four and eight bulbs to each household, and even show up at houses and apartments to screw the bulbs in. The brightest bulb is 100 watts, which burns on only 27 watts of power. DWP says the bulbs will go in sockets that are used the most, not in closets and basements.

Promoting these bulbs has taken off in recent years. Southern California Edison Co. will soon give away its millionth low-energy bulb to low-income customers.

But there is a catch. Utilities probably cannot give bulbs away indefinitely, and even though the energy-savers last up to 10 times longer than standard bulbs, the initial cost runs between $8 and $10.

Retailers so far hesitate to stock bulbs costing that much more than others. Stores are the next hurdle, says NRDC. Based on its record so far, it will find a way.

The Wall Street Journal 11/5/90

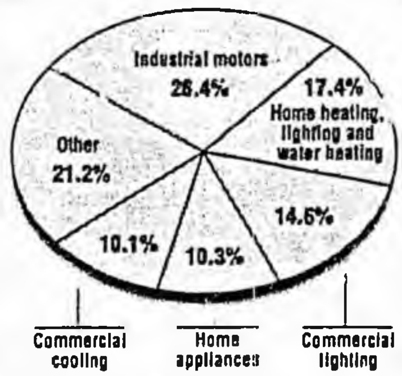
# Utilities Rush to Profit From Selling Less

By David Stipp
*Staff Reporter of* The Wall Street Journal

## The Power of Conservation

### Energy-Saving Technologies

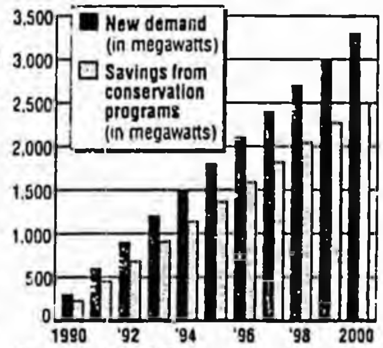
Replacing existing devices with more efficient ones could cut U.S. electricity consumption over time by 31.3%, according to a utility group. Here are the group's estimates of which areas the savings would come from:




*Source: Electric Power Research Institute*

### Meeting Demand With Efficiency

Pacific Gas & Electric, the nation's largest utility, expects conservation programs to meet three-quarters of its new demand for electricity by 2000. How its electricity savings will grow along with rising demand to offset the need for power plants:




*Source: Pacific Gas & Electric*

Perhaps the most radical recent change on America's energy horizon started not in the Middle East but in Rhode Island.

Last December, regulators there were the first to give profit incentives to utilities for investing in energy conservation. Regulators in New Hampshire, Massachusetts, New York and California recently adopted similar rules, and those in several other states are expected to follow soon.

The new rules foster a strange logic: Utilities now can boost earnings by paying customers not to buy their main product.

The companies once simply built power plants to make megawatts and money. Now they're rushing to invest in the "negawatt" business: handing out or helping customers buy high-efficiency light bulbs, air conditioners and electric motors, and sharing in the savings by charging higher rates.

That has sparked the economic equivalent of war on electricity waste. Utility investment in negawatts "has gone ballistic in the past 18 months, from a million-dollar business to a billion-dollar one," says Thomas Feiler, an energy analyst at Cambridge Energy Research Associates in Cambridge, Mass. In the Northeast, where dire power shortages were foretold a few years ago, some utilities now project "flattening demand [for power] or a downturn in demand," largely due to conservation.

The change is being fostered by some odd couples. Utilities and environmental groups—after years of tangling over nuclear power, acid rain and other issues—have teamed up to push through the new rate rules. This blossoming "collaborative"—a utility industry buzzword—has become "very significant to utilities and to national energy policy," says John Bryson, chief executive of SCEcorp, parent of Southern California Edison Co.

The breakthrough alliance was formed by the Conservation Law Foundation, a Boston environmental group, and New England Electric System, Westboro, Mass., which serves customers in three New England states. They jointly drafted the first of the new rate rules and ushered them through state regulatory channels.

Meanwhile, California's version of the incentives was being formulated by the Natural Resources Defense Council, an environmental group, that state's utilities and some other organizations. The NRDC also recently joined with Pacific Gas & Electric Co., San Francisco, to push the federal Energy Department to make conservation the cornerstone of its forthcoming national energy strategy.

"There's been a major philosophical and cultural shift toward conservation" among utilities, says Douglas Foy, executive director of the Conservation Law Foundation.

Regulators "for a long time have been telling utilities to go forth and spend money on conservation, [but the companies] weren't responding aggressively" before the incentives, says Susan Tierney, a Massachusetts utility commissioner. The problem, says John W. Rowe, New England Electric's chief executive, "was that we didn't see how we could afford to spend much money on something that both added costs and lowered revenues." Utilities traditionally have been allowed to charge customers for the costs of conservation programs. But that didn't offset the lost revenues from the programs, he adds, so "there was no way we could make money on them. The rat has to smell the cheese."

The cheese that regulators are beginning to offer utilities is a return on energy-saving outlays that is roughly equivalent to the returns they've traditionally made by investing in power plants. This year, New England Electric will spend \$66 million on conservation, says Lawrence J. Reilly, the utility's director of rates.

The program will save customers an estimated \$154 million; stringent monitoring overseen by regulators will verify the savings. The utility expects to get back its \$66 million of costs plus a \$7.4 million profit incentive awarded under the new rules.

Overall, the rules "have turned conservation from being the most controversial expenditure I have to deal with to being the most profitable investment I make," says Mr. Rowe.

The California Energy Commission, which sets state energy policy, recently projected that such programs and other efficiency measures will meet three-fourths of the state's increased demand for electricity between now and 2001. PG&E alone says it expects to spend up to \$2 billion on conservation programs over the next 10 years. Consolidated Edison Co. of New York recently announced plans to spend \$4.1 billion on conservation by 2008. New England utilities are committed to spending \$1 billion to \$2 billion on "collaborative" conservation programs between 1990 and 1994, according to the Conservation Law Foundation. That will displace the need for at least several new power plants, at one-half to two-thirds of the cost of building them.

The programs—and the incentives behind them—are popular with environmentalists because they will lower power-plant emissions that contribute to acid rain, urban smog and suspected global warming. Utilities, for example, contribute about 35% of U.S. emissions of carbon dioxide, the main "greenhouse" gas, says Armond Cohen, an energy expert at the Conservation Law Foundation. As energy demand grows world-wide, he adds, conservation precedents set now by U.S. utilities "will be copied elsewhere and leveraged into enormous future benefits." Even Sweden, known for its energy-efficient ways, recently sent officials to New England to study its conservation programs.

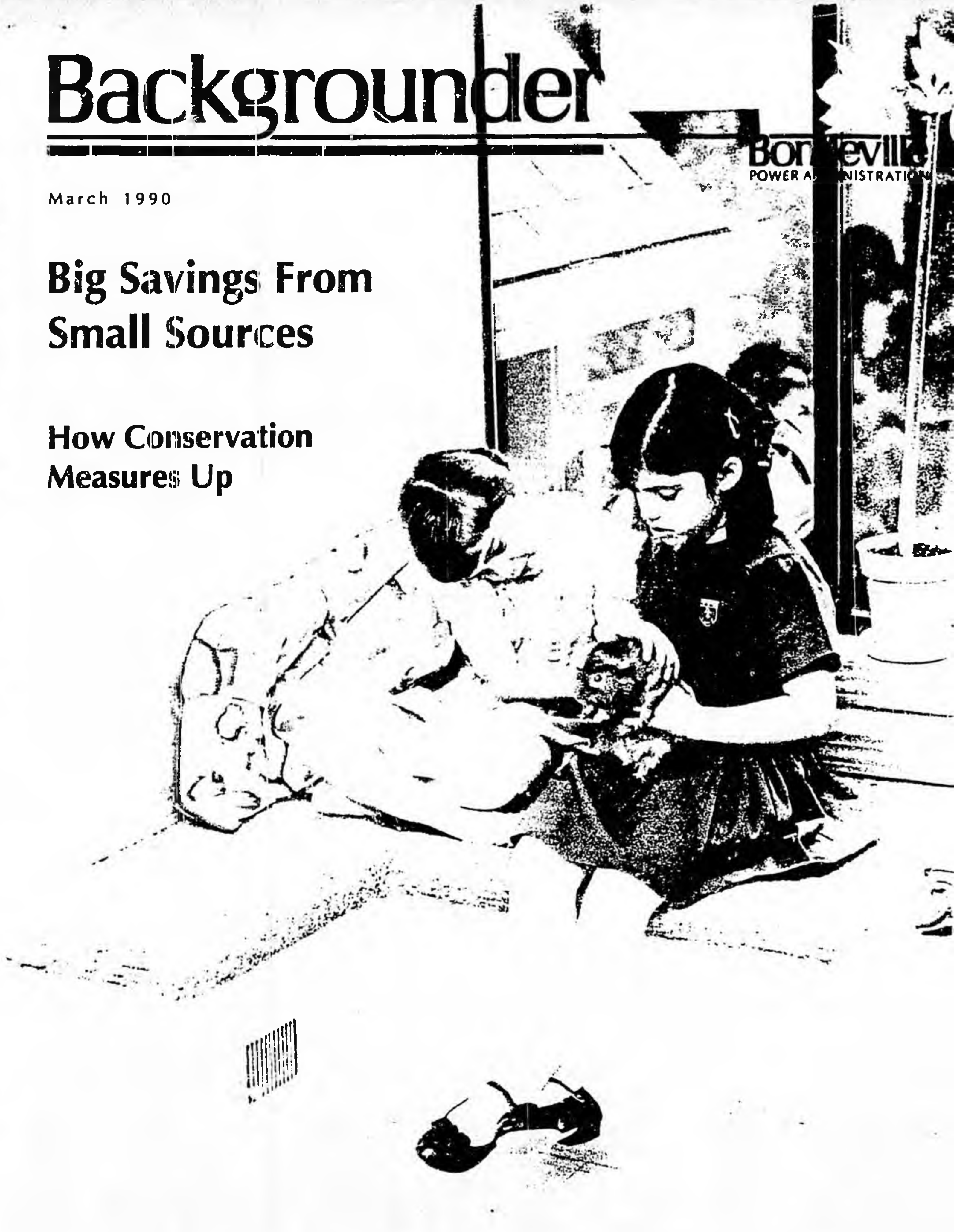
# Backgrounder

Bonneville POWER ADMINISTRATION

March 1990

## Big Savings From Small Sources

### How Conservation Measures Up



## Payback on the Conservation Investment

**BPA Conservation Spending and Savings as of Sept. 30, 1989**

Includes Budget Obligations and Contractual Commitments

| Activity | Purpose | Savings (megawatts) | Cost to BPA ($millions) | Life-cycle cost/kWh to BPA (1988 $) |
|---|---|---|---|---|
| **Direct-Savings Programs** | | | | |
| RESIDENTIAL SECTOR | | | | |
| Residential Weatherization | Install weatherization measures in existing electrically heated homes. | 87 MW | $393 | 2.7¢/kWh |
| Residential Hot Water | Wrap electric water heaters in homes. | 37 MW | $ 34 | 2.6¢/kWh |
| COMMERCIAL SECTOR | | | | |
| Street and Area Lighting | Convert to lighting systems that are more energy efficient. | 16 MW | $ 49 | 2.3¢/kWh |
| INDUSTRIAL SECTOR | | | | |
| Conservation/Modernization | Modernize aluminum smelters to increase their energy efficiency. | 95 MW | $ 46 | 0.6¢/kWh |
| Energy Savings Plan | Make energy efficiency improvements in manufacturing processes. | 3 MW | $ 3 | 0.4¢/kWh |
| AGRICULTURAL SECTOR | | | | |
| Irrigated Agriculture | Convert to lower-pressure sprinkler systems. | 3 MW | $ 2 | 0.4¢/kWh |
| | Total — Evaluated Programs, measured | 241 MW | $527 | 1.8¢/kWh avg. |
| | Total — Unevaluated Programs, estimated | 50 MW* | $ 75 | 3.0¢/kWh est. |
| | Total — All Direct-Savings Programs | 291 MW | $602 | 2.0¢/kWh |
| **Codes and Standards Support** | | | | |
| | Improve energy-efficiency of new buildings and appliances. Includes savings by 2010 from actions taken through Sept. 30, 1989, in code adoption, through Super Good Cents, Blue Clue, and related programs. | 100-400 MW | $129 | N/A |
| **Technical Support Activities** | | | | |
| | Develop regional infrastructure energy conservation; improve conservation technology; develop techniques to measure program savings. Includes program evaluation, research, state and local government support. | N/A | $139 | N/A |
| | Total Conservation Investment | | $870 million | |

*41 MW and $66 million are in the commercial sector; 9 MW and $9 million are industrial.

3/18/91

# AMENDMENT

by BROWN

IN THE HOUSE
TO HB 121

Page 4, line 10: after "commission"

delete "shall"
insert "may"

Page 4, line 14-16:

Delete: "(c) After consulting with the Alaska Energy Authority, the Commission shall assist utilities in the development of the integrated resource plan to minimize regulatory burdens and costs."

Page 5, lines 10-11:

Delete all material.

Insert: "If the Commission finds that a utility's integrated resource plan and recommended system development option does not meet the criteria set out in AS 42.05.293(b)(1)-(7), the Commission may reject the plan or approve a modified plan and system development option that meets the criteria. Commission approval of a plan and system development option authorizes the utility to implement the plan as approved."

Page 5, lines 12-18:

Delete all material.

Insert: "The Commission shall set rates for utility services and revenue requirements at a level sufficient for a utility to recover all reasonable expenses and capital expenditures incurred by a utility in preparing the plan and implementing the approved plan."

Page 5, lines 19-24:

Delete all material.

Insert: "Sec. 42.05.294 COMPLIANCE WITH INTEGRATED RESOURCE PLAN. An electric utility that is subject to the requirements of AS 42.05.292 and 42.05.293 may not participate in the use of an electrical generation or transmission system project authorized by the legislature after January 15, 1993 whose construction or acquisition was financed in whole or in part by state appropriations unless the project is consistent with the utilities approved integrated resource plan under AS 42.05.292 and 42.05.293."

# Alaska State Legislature

## HOUSE OF REPRESENTATIVES

Official Business

P.O. Box V
State Capitol
Juneau, Alaska 99811

TO: Representative Jerry Mackie, Chair
House Community and Regional Affairs Committee

FROM: Representative Kay Brown

DATE: February 26, 1991

SUBJ: HB 121 — Least-Cost Planning/Energy Efficiency Legislation

The purpose of this memorandum is to request that you schedule HB 121, integrated resource planning for large electric utilities, at your earliest possible convenience. For your reference, please find attached a copy of HB 121, together with a sectional analysis.

Briefly, the legislation establishes an integrated resource planning requirement for the state's largest utilities (ie, those with yearly sales in excess of 300 million kilowatt hours). Integrated resource planning, also referred to as "least-cost planning" is designed to achieve the most cost-effective energy system by integrating the analysis of "demand-side" energy options with "supply-side" options. The legislation also directs the Department of Community and Regional Affairs to prepare a report for the legislature concerning the implications of a major energy supply disruption.

The value of the integrated resource planning approach is recognized throughout the nation. A 1988 report by the Electric Power Research Institute found that "[a]t least 43 states have functioning LCP [least cost planning] strategies or are considering, developing or implementing a planning process that will ensure the most cost-effective mix of new generating facilities and demand-side management (DSM). In most of these states, regulatory commissions or legislative bodies lead the development of LCP procedures...." (*Status of Least Cost Planning in the United States*, EPRI Project 2982-2, December 1988).

The state has invested hundreds of millions of dollars in electrical energy generating and distribution facilities and there is a compelling public interest in the efficient and cost-effective utilization of these facilities. As part of the Railbelt energy alternatives reconnaissance study process, the AEA identified a substantial number of cost-effective energy efficiency/conservation investments. In fact, the AEA studies documented that conservation (demand-side) investments have a higher cost-benefit ratio than virtually any of the power project (supply-side) options considered. HB 121 would ensure a much needed planning process to provide on-going evaluation of cost-effective energy efficiency and conservation improvements as a condition of using state subsidized power facilities and access to future state financing.

**Integrated resource planning enables utilities to consider conservation options (or "end-use" technologies that conserve electricity) on an equal basis with the construction of new power generation facilities.** A 1988 House Research Agency (HRA) report, indicates that integrated resource planning for Alaska is long overdue (*Energy Planning in Alaska: Past Efforts and A Future Direction* , February 1988). As noted by the House Research Agency, in urban areas of the state, $1.3 billion was appropriated between FY 77 and FY 88. Over 99 percent of these appropriations were spent on supply-side projects (89 percent on hydroelectric projects) and less than one percent on demand-side investments. If a true integrated resource planning process had been in place during this period, the study concluded, "a comprehensive analysis would have revealed residential and commercial building standards, commercial ventilation and lighting technical improvements, energy efficient appliances, and load management as feasible or more cost effective alternatives to new generating capacity."

**The planning requirements proposed in HB 121 would only apply to the state's larger Railbelt electric utilities (ie, those utilities served by state-owned or financed power facilities and having annual sales in excess of 300,000,000 kilowatt hours).** These are utilities with the administrative and financial resources to undertake the planning efforts that would be required. The proposed planning process would ensure that future development of Railbelt utility systems proceeds in a balanced fashion with appropriate consideration given to both supply-side and demand-side alternatives.

**War in the Middle East makes the strongest possible case regarding the need for us all to make a serious and aggressive commitment to energy efficiency and energy conservation.** HB 121 would establish a clear process that would ensure that future state financial assistance to power utilities is consistent with cost-effective energy efficiency and energy conservation investments.

If you have questions or comments regarding this legislation, please contact Eric Myers of my staff at 465-4998.

attachments

2/7/91
Rep. Kay Brown

# Sectional Analysis

## HB 121 — Energy Efficiency and Security Act

Section 1

Findings

Section 2

Short Title: "Energy Efficiency and Security Act"

Section 3

Requires utilities served by state-owned or financed power facilities with annual sales greater than 300 million kilowatt hours (kwh) to prepare 20-year **integrated resource plans.** The plans would evaluate "demand-side" and "supply-side" energy alternatives available to the utility to meet forecasted power requirements. The first plan would be prepared on or before January 15, 1993, and every 4 years thereafter.

Plans would approved by the Alaska Public Utilities Commission (APUC), in consultation with the Alaska Energy Authority (AEA). Major elements of the integrated resource plans would:

- identify a utility's current facilities and forecasted retirement schedule;
- document energy end-use in the service area;
- provide 20-year power demand forecasts (base, high, low);
- evaluate alternative development options with consideration given to availability, reliability, flexibility and cost effectiveness;
- identify the system option with the lowest cost ;
- evaluate demand-side and supply-side alternatives; and
- recommend a specific system development option.

The APUC is directed to develop a consistent reporting methodology and, in consultation with the Alaska Energy Authority, provide assistance to utilities in the development of plans, including coordinated filing of plans by closely integrated utilities.

The APUC shall establish by regulation a public process for the review and approval of integrated resource plans. The Commission is directed to approve a plan upon a finding that the plan would:

- ensure system reliability;
- provide consumers with the lowest reasonable cost of power;

- adequately address the conservation of electrical energy;
- documents a reasonable expectation of future power requirements;
- uses appropriate methodology for the evaluation of options;
- adequately evaluates resource alternatives currently available or reliably anticipated to exist in the forecast period; and
- describes the utility's data collection activities and on-going data collection efforts.

The Commission is directed to adopt regulations and policies that set rates and revenue requirements at a level sufficient to recover costs incurred by a utility in preparing and implementing an approved plan.

Effective January 15, 1993, state agencies or corporations of the state may not participate in the financing, acquisition or construction of an electrical generation or transmission system project or improvement intended to provide electricity to a utility subject to the integrated resource planning requirements unless the project or improvement is consistent with a utility's approved integrated resource plan.

Section 4

Establishes authority for the Alaska Energy Authority to make grants to utilities for the purpose of preparing integrated resource plans.

Section 5

The Department of Community and Regional Affairs, in consultation with the Alaska Energy Authority and Department of Military and Veterans Affairs, shall prepare a report investigating the implications of a major energy supply disruption to the State of Alaska. The report shall be submitted to the Alaska Legislature by January 15, 1992.

TABLE 5
EXPECTED COSTS AND BENEFITS FOR RAILBELT INTERTIE RECONNAISSANCE STUDY PROJECTS
(in millions of 1987 dollars)

| | Est. Expected Costs $ | Est. Expected Benefits $ | Est. Net Bens. $ | Benefit to Cost Ratio | Source of Benefits and Costs | Prob. that Net Benefits are Postive |
|---|---|---|---|---|---|---|
| *Projects that are economically efficient* | | | | | | |
| Limited Upgrade of Anch-Frbks Intertie | 10 | 40 | 30 | 4.0 | 3,5 | 1.00 |
| Gas Pipeline Between Cook Inlet & Fbks. | 284 | 527 | 243 | 1.86 | 2,3,& 4,5 | 1.00 |
| Top Three End-Use Conservation Programs | 16 | 28 | 12 | 1.75 | 3,4,5 | 1.00 |
| Top Eight End-Use Conservation Programs | 44 | 61 | 17 | 1.39 | 3,4,5 | 1.00 |
| *Projects that are economically inefficient* | | | | | | |
| Northeast Intertie | 188 | 159 | -29 | .85 | 2,3,5 | 0.08 |
| Full Upgrade of Anch-Fbks. Intertie | 134 | 96 | -38 | .72 | 2,3,& 4,5 | 0.00 |
| 50-MW Coal-Fired Power Plant | 177 | 108 | -69 | .61 | 3,4,5 | 0.00 |
| New Kenai-Anchorage Intertie | 103 | 49 | -54 | .48 | 1,2,& 3,4,5,6 | 0.00 |

Notes:

1: All values are in 1987 million (present value for 1994 through 2028 discounted at 4.5 percent per year).

2: Estimated Net Benefits = Estimated Expected Benefits - Estimated Expected Costs.

3: Benefit to Cost ratio is a number, rather than a dollar figure, and are always greater than zero.

4: Economically efficient projects are those that lead to a net increase in the value of goods and services produced within the economy. Economically efficient projects have net benefits (benefits - costs) that are positive and benefit-cost ratios greater than one. The term "economically efficient" and "financially feasible" are not the same thing and one does not always imply the other.

Source: Decision Focus Inc., *Railbelt Intertie Reconnaissance Study*, prepared for the Alaska Power Authority, June 1989.

Alaska
League of Women Voters

March 18, 1991

House Committee on Community and Regional Affairs
c/o Representative Jerry Mackie, Chair
Alaska State Legislature
P.O. Box V
Juneau, AK 99811-1800

To the Members of the Committee:

I write on behalf of the League of Women Voters of Alaska to express our support of House Bill 121. The League favors energy conservation as an energy source above all others, and supports government policies to minimize the need for new generating capacity through techniques such as marginal cost and demand management programs.

The state of Alaska has a history of spending a great deal of money on inefficient power projects that in their initial design did not incorporate energy conservation strategies, even though energy conservation investments often have a higher cost-benefit ratio. Now is the time to change that pattern by requiring large utilities to develop integrated resource plans, and by making state funding of energy projects contingent on their inclusion of applicable cost-effective energy efficiency and energy conservation strategies.

The League encourages the members of the Committee on Community and Regional Affairs to support HB 121. We are pleased to see the Legislature take positive action to direct Alaska's limited public funds towards responsible, cost-effective energy use.

Thank you for considering these comments.

Sincerely,

Karen Wood

Karen Wood
Natural Resources Director
1237 W. 11th Ave
Anchorage, AK 99501

cc: Representative Kay Brown

FISCAL NOTE

STATE OF ALASKA
1991 LEGISLATIVE SESSION

BILL NO. CS HB 128

Revision Date: ____

Department Affected: Community & Regional Affairs

Title: Office of Municipal Clerk/ Clerk-Treasurer

BRU: State Assessor

Component: ____

Sponsor: Rep. C. Davis

Requestor: House C&RA

COMPONENT SERIAL NO.

Expenditures/Revenues: (Thousands of Dollars)

| OPERATING | FY 92 | FY 93 | FY 94 | FY 95 | FY 96 | FY 97 |
|---|---|---|---|---|---|---|
| PERSONAL SERVICES | | | | | | |
| TRAVEL | | | | | | |
| CONTRACTUAL | | | | | | |
| SUPPLIES | | | | | | |
| EQUIPMENT | | | | | | |
| LAND & STRUCTURES | | | | | | |
| GRANTS, CLAIMS | | | | | | |
| MISCELLANEOUS | | | | | | |
| **TOTAL OPERATING** | -0- | -0- | -0- | -0- | -0- | -0- |
| **CAPITAL** | | | | | | |
| **REVENUE** | | | | | | |

FUNDING: (Thousands of Dollars)

| | | | | | | |
|---|---|---|---|---|---|---|
| GENERAL FUND | -0- | -0- | -0- | -0- | -0- | -0- |
| FEDERAL FUNDS | | | | | | |
| OTHER | | | | | | |
| **TOTAL** | -0- | -0- | -0- | -0- | -0- | -0- |

POSITIONS:

| | | | | | | |
|---|---|---|---|---|---|---|
| FULL-TIME | -0- | -0- | -0- | -0- | -0- | -0- |
| PART-TIME | | | | | | |
| TEMPORARY | | | | | | |

Estimate of current year impact: ____

ANALYSIS: (Attach a separate page if necessary.)

Prepared By: Remond Henderson, Director Remond Henderson

Phone: 465-4708

Division: Administrative Services

Date: 4/10/91

Approved by Commissioner: Edgar Blatchford

Agency: Community & Regional Affairs

Date: 4/10/91

Distribution (by preparer): Legislative Finance, Legislative Sponsor, Requestor, OMB, & Impacted Agency(ies).

# HOUSE COMMITTEE REPORT

(7)

Date Referred: February 8, 1991 FURTHER REFERRALS: Judiciary

Date of Committee Action: 4-10-91

The COMMUNITY AND REGIONAL AFFAIRS Committee considered: HB 128

HOUSE BILL NO. 128 OFFICE OF MUNICIPAL CLK & CLK/TREASURER

"An Act relating to the offices of municipal clerk and clerk-treasurer."

RECOMMENDATIONS:
be replaced with CSHB 128 [X] the same title [ ] a new title

[ ] have attached amendments(s)
[X] do pass
[ ] do not pass
[ ] no recommendations
[ ] individual recommendations
[ ] additional referral to the ______ ______ Committee

ADOPTS: ______ letter of Intent

ATTACHES NEW FISCAL NOTE(s): (Dept) APPROVES PREVIOUS: (Dept/Date)

[ ] fiscal impact ______ [ ] fiscal note(s) ______

[X] zero fiscal note DCRA [ ] zero fiscal note(s) ______

SIGNING DO PASS: SIGNING OTHER RECOMMENDATIONS:

| | Check appropriate column: | Do Not Pass | No Rec | Amend |
|---|---|---|---|---|
| Gail Phillips | | | | |
| Richard Foley Foster | | | | |
| BAKER | | | | |
| Cheri Davis | | | | |
| [illegible] | | | | |
| Mackie | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

Mackie

Chairman's Signature

STATE OF ALASKA

OFFICE OF THE GOVERNOR

# BILL ANALYSIS

| DEPARTMENT | DIVISION | BILL NUMBER | SPONSOR |
|---|---|---|---|
| DCRA | MRAD | HB 128 | Reps C.Davis, Ellis etc |

SHORT TITLE OF BILL

Offices of municipal clerk and clerk-treasurer.

DEPARTMENT POSITION

None.

| PREPARED BY | DATE | COMMISSIONER'S SIGNATURE | DATE |
|---|---|---|---|
| Mike Worley | 3/26/91 | Edgar Blatchford | 3/26/91 |

## SUMMARY

OTHER AGENCIES AFFECTED BY BILL

CONSTITUENT GROUP(S) AFFECTED BY BILL

ORGANIZATIONAL SUPPORT FOR BILL

ORGANIZATIONAL OPPOSITION TO BILL

FISCAL IMPACT: ☒ NONE ☐ FISCAL NOTE ATTACHED

BACKGROUND/LEGISLATIVE INTENT

ANALYSIS OF BILL/PROGRAM EFFECTS

Does not affect this department.

AMENDMENTS PROPOSED

PLEASE ATTACH A SEPARATE SHEET FOR ADDITIONAL COMMENTS OR ANALYSIS.

01-009 (Rev. 12/83)

# FISCAL NOTE

STATE OF ALASKA
1991 LEGISLATIVE SESSION

BILL NO. HB 128

Revision Date: ____________ Department Affected: DCRA

Title: Office of Municipal Clerk/ Clerk-Treasurer BRU: State Assessor

Component: ____________

Sponsor: Rep. C. Davis

Requestor: House CRA COMPONENT SERIAL NO.

Expenditures/Revenues: (Thousands of Dollars)

| OPERATING | FY 92 | FY 93 | FY 94 | FY 95 | FY 96 | FY 97 |
|---|---|---|---|---|---|---|
| PERSONAL SERVICES | | | | | | |
| TRAVEL | | | | | | |
| CONTRACTUAL | | | | | | |
| SUPPLIES | | | | | | |
| EQUIPMENT | | | | | | |
| LAND & STRUCTURES | | | | | | |
| GRANTS, CLAIMS | | | | | | |
| MISCELLANEOUS | | | | | | |
| TOTAL OPERATING | -0- | -0- | -0- | -0- | -0- | -0- |
| CAPITAL | | | | | | |
| REVENUE | | | | | | |

FUNDING: (Thousands of Dollars)

| | | | | | | |
|---|---|---|---|---|---|---|
| GENERAL FUND | -0- | -0- | -0- | -0- | -0- | -0- |
| FEDERAL FUNDS | | | | | | |
| OTHER | | | | | | |
| TOTAL | -0- | -0- | -0- | -0- | -0- | -0- |

POSITIONS:

| | | | | | | |
|---|---|---|---|---|---|---|
| FULL-TIME | -0- | -0- | -0- | -0- | -0- | -0- |
| PART-TIME | | | | | | |
| TEMPORARY | | | | | | |

Estimate of current year impact: ____________

ANALYSIS: (Attach a separate page if necessary.)

Prepared By: Remond Henderson Phone: 465-4708

Division: Administrative Services Date: 3/26/91

Approved by Commissioner: Ed. Back

Agency: Community & Regional Affairs Date: 3-26-91.

Distribution (by preparer): Legislative Finance, Legislative Sponsor, Requestor, OMB, & Impacted Agency(ies).

Rev 10/90 Page ____ of ____

# Alaska State Legislature

Please enter into the record my testimony to the House CRA
committee name

committee on HB 128, dated 2/08/91.
bill/subject

I'm Clerk of the Kodiak Island Borough and I'm Chairman of the AAMC Legislative Committee and chair of AML's Legislative Comm on Education, Elections and Local Govt. Powers. I have been a municipal clerk in Alaska for over 12 years.

This bill was introduced at the request of the AAMC and I'd like to thank Rep. Chair Davis and the co-sponsors for introducing it.

AAMC will support a substitute bill which will delete sections 1 and 2 and amend section 3.

AAMC feels that the duties listed belong in the clerk's office. In most municipalities they are currently being done by the clerk.

Again, we support a substitution and urge "Do Pass".

Thank you.

Signed: Gay Vaughan
Testifier

Kodiak Island Borough / Alaska Assn. of Municipal Clerks
Representing (Optional)

710 Mill Bay Rd. Kodiak
Address

486-5736
Phone No.

March 19, 1991

Honorable Jerry Mackie
Chair Community & Regional Affairs Committee
House of Representatives
P. O. Box V
Juneau, Alaska 99811

RE: Support of House Bill 128

Dear Representative Mackie;

My name is Susan Bethel. I live at 718 Deermount, Ketchikan, Alaska. I have approximatly 5 and 1/2 years experience as a municipal clerk in the State of Alaska. I am writing in favor of HB 128, relating to the offices of municipal clerk and clerk-treasurer, and would like to explain why.

I was the City Clerk for the City of Thorne Bay for approximately four years. This was a new 2nd class city with an administrator. Not a manager or a strong mayor form of government. The only direction I had was Alaska Statute Title 29. During the time I worked there, there were 8 administrators. One lasted 11 months. So you can see the government wasn't stable. Many times I was alone, a new clerk, with no training.

I have now worked as the Deputy Borough Clerk for the Ketchikan Gateway Borough for a year and a half. I feel these changes are needed to maintain ethics and competence in local government. There may not always be an ethical and competent manager/mayor in a municipality. Normally in municipalities the Clerk has no experience. This outline of duties needs to be written down and easily assessable.

If it hadn't been for the Department of Community and Regional Affairs staff, the Alaska Association of Municipal Clerk's, AML and the other clerks in Southeast Alaska I would have been completely lost. As it was I called for advice in all areas of government for the municipality. I've been able to learn from experienced clerks and have become aware of the "Municipal" laws of the State.

Checks and balances are needed in government. If it is left to only the "manager or Mayor" to run the day to day operations in the municipality there is a great chance of malfeasants. You would never write a check in a municipality with only one signature. There has to be checks and balances in government.

We are public servants and we handle the "peoples" business in local government. We have to be honest and prepared to help the people we work for and represent in all areas of our position. I think you know what I mean being a representative in the State House. As a Clerk we don't play favorites.

Please pass HB128 to help insure local government has guidelines for duties of the Municipal Clerk, for the assemblies, councils, mayors and administrators in our State. If we have one **"higher power"** be it a Mayor/Manager or Administrator, to run the municipalities we are not a democratic government we are becoming a dictatorship.

Local ordinances are not enough. They are easily changed. We may not always have ethical competent people in charge. We need the checks and balances to insure government is fair and equitable in our municipalities and the history of our great state is recorded properly.

Susan Bethel

Susan L. Bethel
718 Deermount
Ketchikan, Alaska 99901

312 Front Street
Ketchikan, AK 99901
March 15, 1991

The Honorable Jerry Mackie
House of Representatives
P.O. Box V
Juneau, Ak 99801

Dear Jerry:

Representative Davis' bill relating to municipal clerks, HB 128, has my support as a former Assemblyman of the Ketchikan Gateway Borough. As you and I both know, I have a long-standing involvement in local, state and federal government both as an interested Alaskan and member of the business community. I personally know all four municipal clerks in Ketchikan and have a lot of respect for the jobs that they do.

A long time ago I too was one of the many people who didn't realize the many hats and capabilities of the municipal clerk. Most of all, the safeguard of the checks and balance system is important to the taxpayers. I support having the manager, attorney, and clerk responsible to the Assembly.

Sincerely,

Elkins

James B. Elkins

P.O. Box 188
Barrow, Alaska 99723
March 1, 1991

Honorable Eileen P. MacLean
Alaska State Legislature
Box V
Juneau, Alaska 99811

Dear Representative MacLean:

I am writing in reference to HB 128, a Title 29 bill that would transfer the appointment of the municipal clerk from the mayor of a municipality to the governing body of said municipality.

While I do like the concept of this bill and the spelling out the duties of the municipal clerk, there are some questions that I have should this bill be passed and made into law. I would like to expound upon my experience regarding this matter.

The Alaska Municipal League supports this bill and did specifically include it into their 1991 policy statement (1991 PS, VII B 2). However, I as a Barrow City Councilman, introduced an ordinance (see enclosed Ordinance 91-01) to reflect the AML policy statement. The mayor, Donald Long, was opposed to this because he said that it would hinder the normal course of city business where if he needed something with the official seal of the city affixed to it, he would have to wait until the council gave approval for it at their next regular meeting, or call a special meeting for the simple task of getting approval for a document that may not need council approval (i.e. proclamations, licenses, deeds, etc.). There were also other considerations such as evaluating employee performance, discipline and the immediate supervisor of the city clerk.

These matters were expressed by the mayor at a workshop of the council on February 6, 1991 and was reiterated during the public hearing of regular council meeting the following evening. Because I had very little argument on behalf of the ordinance, the ordinance failed to pass the council upon voting on it.

While HB 128 is now in the Community and Regional Affairs committee and will enter the Judiciary committee at a later date, I feel that more work needs to be done to improve this bill and make it more applicable for small municipalities where the mayor is the chief administrator for the municipality, otherwise those municipalities will suffer the same scenarios as was brought up before the Barrow City Council.

I hope that you may pass this information on the Community and Regional Affairs chairman and the Judiciary chairman so that a committee substitute may be introduced.

If you have any questions regarding this matter, or would like more information, please do not hesitate to contact me at 852-7181.

Sincerely,

Michael D. McDermott, Councilmember
City of Barrow

MDMc:ss
Enclosure

cc: Hon. Jerry Mackie, Chairman; House Committee on Community and Regional Affairs
Hon. Dave Donley, Chairman; House Judiciary Committee
Scott Burgess, Executive Director; Alaska Municipal League
Hon. Don Long, Mayor; City of Barrow
Hon. Johnny Leavitt, Councilmember
Hon. Miranda Rexford, Councilmember
Hon. Rosabelle Rexford, Councilmember
Hon. William F. Brown, Councilmember
Hon. Lucy Brown, Councilmember

# ORDINANCE 91-01

AN ORDINANCE AMENDING SECTIONS 2.20.020 AND 2.20.030 OF THE BARROW CODE OF ORDINANCES, RELATING TO THE APPOINTMENT OF THE CITY CLERK BY THE CITY COUNCIL.

Section I. CLASSIFICATION. This ordinance is of a general and permanent nature and shall become apart of the City of Barrow Code of Ordinances.

Section II. EFFECTIVE DATE. This Ordinance shall become effective upon adoption by the City Council.

Section III. AMENDMENTS. Section 2.20.020 and 2.20.030 of the Barrow Code of Ordinances is amended as follows: (material to be added is typed in **boldface** and material to be deleted is typed in [brackets].)

2.20.020 Appointment. **A.** The [city clerk,] finance director and city attorney are appointed by the mayor acting as the chief administrative officer of the city. [Officers] **The finance director and the city attorney** serve at the pleasure of the mayor, subject to ordinance. Appointments by the mayor are subject to confirmation by the city council.

**B. The city clerk is appointed by the city council acting as the legislative body for the city. The city clerk shall serve at the pleasure of the city council, subject to ordinance. Appointments by the city council shall require a two-thirds majority vote.**

2.20.030 City Clerk. There shall be a city clerk, who shall be an officer of the city appointed by the [mayor] **city council** subject to [council approval] **two-thirds majority vote of council to serve** for an indefinite term. The city clerk shall serve as the clerical officer of the council. He shall maintain the journal of the proceedings of the council, and shall enroll in a book or books kept for that purpose all ordinances and resolutions passed by it. He shall be the custodian of such documents and records as may be provided by law or ordinance, shall keep a correct record of city boundaries and changes therein, and shall have such powers and duties relating to elections as this chapter and council may prescribe. He shall have such other powers, duties and functions as may be prescribed by applicable law or by ordinance.

Introduced:____________________

Public Hearing:_______________

Position Statement - CS for HB 128

## Introduction

This position statement is made with all due respect to the Alaska State Legislature and to the Alaska Association of Municipal Clerks (AAMC). None of the points contained herein should be construed to question the motives or integrity of either of these groups.

## Description

House Bill 128, as originally introduced, would have mandated that the clerk in all non-home rule municipalities be hired by the local legislative body and would have provided for the combining of the clerk with the treasurer. Title 29 now gives the local legislative bodies the right to delegate the hiring of this position to the mayor or to the manager, depending on the locality's form of government. The original bill also mandated certain duties to be performed by the clerk and seemed to require all municipalities to hire a clerk. Currently, Title 29 contains a short and broad definition of the general duties of the position.

A substitute for HB 128 was introduced on April 4th. This bill deletes the hiring requirements for the clerk and the language regarding the combining of that office with that of the treasurer. However, it retains all of the mandated duties of the original bill, plus adding an additional duty for the clerk to perform.

## Background

The AAMC developed and presented to the Alaska Municipal League a "policy statement" regarding the hiring and the duties of clerks. This statement was incorporated into the 59 page "Alaska Municipal League Policy Statement 1991" adopted by the AML at its Annual Meeting last November in Anchorage. The clerks then subsequently drafted what was to become HB 128. As indicated, the bill has since been amended and reintroduced as CSHB 128. It should be noted, however, that while the AML "supports legislation that would update and clarify the powers and duties of the municipal clerk", it has not endorsed the specific list of duties contained in CSHB 128.

## The "Philosophy" of CSHB 128

While the revised bill drops the requirement that the clerk be hired by the local governing body, it still involves the state legislature in what should be strictly a local government's decision: what duties a particular employee shall perform on behalf of the local government. It could thereby set an inadvisable precedent. If the legislature decides to determine job duties for the clerk, why not for the planning director, or the finance director, or the superintendent of schools? A local governing body is in a much better position than the legislature to determine what a particular local government official's job duties should and should not be.

Even though some principles in support of the bill are contained in the AML's Policy Statement, they run against the AML's more fundamental position on the State of Alaska's relationship with local government: Home rule, and maximum flexibility and independence for local governments. Page 45 of the Policy Statement, for example, provides as one of AML's basic policies that of "Local Autonomy":

"The League supports legislation that would promote more effective and independent local government in all organized boroughs and cities and opposes any legislation that unduly restricts local government operations. [Underlining added.]

The underlying philosophy of CSHB 128 seems to be that the legislature is more qualified than local governments in determining what duties the municipal clerk should perform. Furthermore, the clerk is being singled out for this special legislation. No other position in local government is given this "privilege" in Title 29 of having the state mandate such a specific list of duties, except perhaps the manager in a manager form of government. (While Title 29 does delineate duties of the manager, it should be remembered that the manager plan must be approved by the local government's voters.) Even in its amended form, this is not merely an "updating" or a minor "housekeeping" bill. It goes against the basic principles of Title 29 and could, in fact, "break the mold" of this carefully crafted state law, which skillfully delineates the role separation of local and state governments.

The AAMC's stated reason for advocating this legislation is to improve the professionalism and image of clerks in Alaska. This is certainly a worthwhile and well intentioned goal. However, the appropriateness of trying to achieve this goal through requiring a clerk's employer to assign certain job duties by state mandate is, at best, questionable.

Usually, there are two basic reason why uniformity in local government practices or procedures is required by the state. Either there is strong evidence of abuse at the local level or there are pervading arguments of a need for state wide uniformity. Neither of these two conditions exist, at least to the degree that would necessitate mandating this rather lengthy and detailed list of duties for the municipal clerk. Each municipality has its own unique needs and its own policies regarding its organization and the proper role of each of its employees. The stature of a local position, its professionalism, and even its place within the local organization should not be determined by state mandate.

The contents of this bill also seem to indicate a lack of trust and confidence by the clerks in local government and in the local government process. All of the issues addressed in the bill can easily be dealt with at the local level. It could be interpreted that the clerks wish to "bypass" the very government they state they are supporting and to force local governments, through state legislation, to assign certain duties that should rightly be determined by each local governing body, based upon its on unique needs and resources.

A Reply to "Position Statement" by Clerks on this Bill

On March 15, the AAMC issued a "Policy Statement in Support of House Bill 128". This Statement addresses the "image" of the clerk's office. "In order to create a better image of the clerk's position, AAMC is undertaking a positive approach to sell...our skills, our caring, our self-esteem, our attitude and continuing education to create an image that is believable and trusted. Updating the `powers and duties of the municipal clerk' or the `legal mandates' of the clerk's office is one step in that process".

While the improving of a position's "image" may be a worthwhile goal, mandating the duties of the position through state law is not the proper way to do it. Is the prestige of the position and its positive image only achievable if local governments are forced to assign certain duties to the clerk? Professionalism in the performance of duties at the local level is the more proper way to improve the "image" of a position. If the "image" of the clerks is not satisfactory to the AAMC, then it should address the real reasons for this less than satisfactory image, rather than trying to overcome it through a legislative mandate. Why are no other municipal officers demanding this type of legislation to improve their own professional "image"? Why are the clerks the only identifiable group that sees the "need" for this type of legislation? Title 29 is not the place to improve the "image" of a municipal official's position.

Great exception is also taken to the statement that "The municipal clerk plays a unique role in the balance of powers in local government". It could be said that "balance of powers" at the local level is actually another term for inefficiency. The local government is directly responsible to its constituents and is directly accessible by the voters of the community. "Balance of powers" is an irrelevant concept for the relatively small local governments in Alaska. It is also historically been proven to often lead to inefficiency and conflict, rather than to better and more responsive local government. The real "balance of power" at the local level is the balance between local authority and state and federal authority. CSHB 128 could be a precedent in starting to "unbalance" the roles of the state and local governments so carefully structured under the present Title 29.

The statement, "The governing body/manager form of government ...is based on a philosophy of separation of powers that establishes separate legislative and administrative branches" is simply not true, and demonstrates a fundamental misunderstanding of the manager form of government. That form has never been based on a "balance of powers" concept. In fact, its fundamental concepts are just the opposite of "balance of powers". They involve unity of power, accountability, cooperation, and teamwork. It was established for efficiency and effectiveness rather than for a brokerage of power. All power in the manager form of government is assigned to the legislative body. (Ironically, CSHB 128 would take away some of that power--specifically the power to determine the job duties of a particular employee.) There is no separation of powers. The manager is directly accountable to the governing body. A separation of powers weakens the elected legislative body and anticipates conflict, rather than cooperation and teamwork.

The manager form was modeled after the structure of most private corporations: The stockholders (voters) elect a board of directors (council or assembly) which, in turn, hires a chief administrative officer (manager) to administer the company (government) on its behalf. The manager works at the pleasure of the council or assembly, and exercises power only at the behest of the duly elected body.

The manager plan for local government evolved out of the old commission form, popular in the early part of this century, in which each department head was elected and served as a member of the council (commission). That form, which was based upon "separation of powers", soon proved so inefficient and unwieldy that the "structure of choice" rapidly changed to the manager form of government. The "heart and soul" of the manager plan is efficient and responsive management by and accountability of an appointed professional administrator, serving at the pleasure of the elected body.

The AAMC statement that "The role of the municipal clerk appropriately becomes the link between the legislative and administrative branches" thereby becomes irrelevant, especially in a manager form of government. If the manager works at the pleasure of the council or assembly and is directly accountable to that body, with no "separation of powers", why is there a need for a "link" between the manager and the legislative body?