HB
238

(11)

HOUSE COMMITTEE REPORT

Date referred: 4/22/88

FURTHER REFERRALS:

DATE: 4/30/88

The Finance Committee has considered HB 238

"An Act requiring certain electric public utilities to prepare certain reports; and relating to costs in proceedings before the Alaska Public Utility Commission."

RECOMMENDS:

[X] replace with CSHB238(Res.) [ ] the same title

[ ] attached amendment(s) [X] a new title

[ ] do pass

[ ] do not pass

[X] no recommendation

[ ] individual recommendations

[ ] additional referral to the _____ Committee

ADOPTS: [ ] _____ letter of intent

ATTACHES NEW FISCAL NOTE(s):

[X] fiscal impact

[ ] zero fiscal note

[ ] zero with analysis

[ ] same as previous fiscal note published _____

[ ] same as previous zero fiscal note published _____

SIGNING DO PASS:

BOYER

BROWN

DAVIS

SIGNING OTHER RECOMMENDATIONS:

ADAMS

LARSON

GOLL

SWACK. NO REC

PIEGER No Recommendation

FRANK

POUKCHOUT NO REC

Chairman's signature

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB238 (RES)
PUBLISH DATE: _____

FISCAL NOTE

REQUEST:

Revision Date: 4/29/88
Title: An act requiring certain electric public utilities to prepare certain reports and relating to costs in proceedings bef the APU
Sponsor: Brown, Ellis, Davis et al
Requestor: House Finance

Agency Affected: Commerce & Econ. Development
BRU: APUC
Components: Operations

EXPENDITURES/REVENUES: (Thousands of Dollars) *

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES	0.0	86.2	86.2	86.2	86.2	86.2
TRAVEL	0.0	2.5	2.5	2.5	0.0	0.0
CONTRACTUAL	0.0	40.0	0.0	50.0	0.0	0.0
SUPPLIES	0.0	.3	.3	.3	.3	.3
EQUIPMENT	0.0	6.4	0.0	0.0	0.0	0.0
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	135.4	89.0	139.0	86.5	86.5
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND	0.0	135.4	89.0	89.0	86.5	86.5
FEDERAL FUNDS						
OTHER Prog Rcpts				50.0		
TOTAL	0.0	135.4	89.0	139.0	86.5	86.5

POSITIONS:

FULL-TIME	0	2	2	2	2	2
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

*Funding FY 89 = HB 239; Funding FY 90-93 Budget Forecast - Details on attached Fiscal Note Narrative.
(See attached for narrative concerning analysis)

Prepared by: T.S. Moninski II Executive Director
Phone: 276-6222
Division: Alaska Public Utilities Commission
Date: 4/30/88

Approved by Commissioner: _____ Date: _____
Agency: Commerce & Economic Development

Distribution (by preparer):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)

page ____ of ____

ANALYSIS CSHB 238
PAGE 2 OF 2

This Fiscal Note was developed in specific response to the changes incorporated in CSHB 238. The legislature's attention is directed at the fact that the demand for Commission resources will fluctuate depending upon which planning stage is active in any given fiscal year. This Fiscal Note attempts to accommodate those changes in resource requirements in an effort to minimize the ongoing overhead associated with administering the integrated resources planning process.

Fiscal Note Narrative Concerning HB No. 238

"An Act requiring certain electric public utilities to prepare certain reports; and relating to costs in proceedings before the Alaska Public Utilities Commission.

Listed below is a breakout of the costs which are identified on the fiscal note.

PERSONAL SERVICES:

1.	54.0	UTILITY ENGINEER III (RANGE 19A).
2.	32.2	CLERICAL SUPPORT (Range 10A)
SUBTOTAL:	86.2	PERSONAL SERVICES FY 89 - FY 93

TRAVEL:

1.	2.5	Funds for travel to utilities not located in the Anchorage area. Travel costs are projected FY 90 thru FY 91.
SUBTOTAL:	2.5	TRAVEL

CONTRACTUAL:

1.	15.0	FY 89 - Development of computerized data bases in the first year (10.0); misc costs associated with promulgating regulations such as advertising, mailing costs, etc. (4.5); and additional postage costs for FY 89 (.5) = total of 15.0
2.	25.0	FY 89 - Non-allocable Attorney Services to assist the Commission in promulgate regulations, participate in public hearings, etc.
3.	50.0	FY 91 - Technical and professional services which may be required in FY 91 to review and approve plans filed, if used. These expenses are "allocable" under AS 42.05.651 and are recoverable; therefore we are requesting that this 50.0 be funded from program receipts
SUBTOTAL:	40.0 50.0	IN FY 89 IN FY 91

COMMODITIES:

1.	0.3	Additional Costs Per Year for Paper, etc.
SUBTOTAL:	0.3	FY 89 thru FY 93

EQUIPMENT:

1.	6.0	Hewlett Packard Personal Computer with additional memory boards, basic and specialized software to operate the computer, printer, and other pc peripheral.
2.	0.4	5 Drawer Filing Cabinet to house non-computerized records.
SUBTOTAL:	6.4	Equipment for FY 89 only
GRANT TOTAL:	135.4	Fiscal Year 1989 - all GF
	89.0	Fiscal Year 1990 - all GF
	139.0	Fiscal Year 1991 - 50.0 Pr.;89.0 GF
	86.5	Fiscal Year 1992 - all GF
	86.5	Fiscal Year 1993 - all GF

MEMORANDUM

To: Hon. Kay Brown
Representative
Alaska Legislature

Date: April 29, 1988

From: Ted Moninski
Executive Director
APUC

Subject: Revised Fiscal Note CSHB238

Following my review of the most recent version of the Integrated Resource Planning bill, HB238, and discussions with your office, I have determined that it would be appropriate to restructure the APUC's fiscal note associated with this bill. A copy of the updated fiscal note along with this memorandum will be telecopied to you immediately. The original of the fiscal note will be forwarded to you and should arrive early next week.

The Commission Staff's approach in developing the revised fiscal note was to analyze the bill's impact on a "per phase of implementation" basis. This resulted in a fair amount of fluctuation in resource requirements from one fiscal year to the next. The outline which follows describes our best estimate of the activities and related resources that will be required from FY89 through FY93.

FY89: Activities -- Promulgation of Regulations
Initial Commission Planning
Database Design
Initial Utility Planning

APUC Resources -- Utility Engineer
Support Staff
One-time Attorney Expense
Miscellaneous Start-up Costs

FY90: Activities -- Active Phase of Utility Plan Development

APUC Resources -- Utility Engineer
Support Staff

FY91: Activities -- Plan Review and Approval

APUC Resources -- Utility Engineer
Support Staff
Contingency Program Receipt Appropriation for Professional Services

FY 92/3: Activities -- Approved Plan in Place
Utility Annual Reporting

APUC Resources -- Utility Engineer
Support Staff

As you can see, the revisions in the bill coupled with a restructuring of the Commission's resource forecasting has resulted in a measurable reduction in the projected fiscal impact. Even in the most active years, our revised estimate produces a funding requirement lower than anticipated in the earlier fiscal note.

Worthy of mention is the reference to the use of program receipts in FY91. Since it is impossible to predict exactly which planning issues will require specialized evaluation, it seems prudent to wait until we are analyzing a specific plan to determine what technical assistance will be required. By relying on the use of program receipts and the cost allocation process authorized by AS 42.05.651, the Commission can avoid the burden of developing and maintaining such specific expertise internally. By definition, program receipts can only be used on a case by case basis where appropriately allocable and, therefore, offers other controls in response to the concern for cost escalations associated with Commission review of the Integrated Resource Plans.

I hope this updated fiscal note adds another useful dimension to the Legislature's consideration of CSHB238. If you have any other questions, please contact me.

Offered: 4/22/88
Referred: Finance

5-0638X

Original sponsors: Brown, Ellis,
Davis, et al.

IN THE HOUSE BY THE RESOURCES COMMITTEE

CS FOR HOUSE BILL NO. 238 (Resources)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled: "An Act requiring certain electric public utilities to prepare certain plans."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 42.05 is amended by adding new sections to read:

Sec. 42.05.294. INTEGRATED RESOURCE PLANS. (a) An electric utility with annual sales that exceed 300,000,000 kilowatt hours shall file an integrated resource plan with the commission on or before January 15 every three years. The plan must show how the utility will meet forecasted power requirements. Unless a different time is specified, a forecast required by this subsection must be for the next 20 years. In the plan, the utility shall

(1) list and describe current facilities and energy supply resources of the utility;

(2) include a forecasted retirement schedule that lists the facilities that the utility expects to remove from service, discusses the assumptions used to develop the retirement schedule, and includes the forecasted use of specific facilities, the remaining useful life of the facilities, and forecasted maintenance work;

(3) describe the utility's interconnection relationships with other utilities and small power producers, and the utility's agreements for operation of joint use facilities, power exchanges, power pooling, reserve sharing, commodity displacement, and other operating arrangements;

(4) document energy end-use in the utility service area and

identify with reasonable accuracy the final physical use of electricity in the residential, commercial, and industrial sectors, including use within each sector for space heating and cooling, lighting, water heating, refrigeration, and appliances;

(5) forecast system power demand including annual, seasonal, and peak day load hourly duration curves and best estimates of anticipated peak demand of the major user classifications including residential, commercial, and industrial sectors;

(6) analyze the utility's existing ability to meet increased system requirements, including

(A) opportunities for generation, transmission, or other system efficiency improvements;

(B) potential electric power pooling;

(C) possible interconnection with qualifying cogenerators or small power producers;

(D) anticipated demand reductions in power requirements as a result of market-induced or programmatic conservation efforts; and

(E) current utility load management efforts;

(7) summarize the utility's load research programs, end-use analysis, and load management investigations, including

(A) the status of current and anticipated load research, data collection, and analysis;

(B) the status of current and anticipated end-use research, data collection, and analysis;

(C) an assessment of changes anticipated in end-use requirements from appliance and mechanical system efficiency improvements for each consumer sector;

(D) an evaluation of the effects on utility costs from

end-use efficiency changes;

(E) a description of methods including innovative rate designs available to modify, coordinate, or control end-uses to manage system loads; and

(F) cost estimates for implementation of load management programs;

(8) provide long-term forecasts, based on end-use and econometric methodologies as appropriate, including

(A) base, low, and high forecasts of the power requirements for the utility service area;

(B) a discussion of the assumptions used in developing the forecasts including reserve margin requirements, population growth or decline, employment growth or decline, economic development, service area expansion, and other factors that influence the demand for electrical energy; and

(C) a sensitivity analysis that tests the importance of specific assumptions;

(9) identify and evaluate alternative development options to meet forecasted power requirements; the options must address availability, reliability, flexibility, and cost-effectiveness;

(10) identify the development option with the lowest present value of revenue requirements over the forecast period;

(11) recommend a specific development option and an implementation plan for the option; the option must identify projected facility retirement, development of additional generating and transmission systems, load management efforts, conservation, and energy end-use efficiency improvements; and

(12) include other information considered necessary by the commission to ensure adequate evaluation of all supply-side and

demand-side alternatives; the commission may not require the utilities to provide information unless the type of information requested is consistent with the type of information required by electric utility regulatory agencies in other states.

(b) The commission shall establish by regulation a consistent plan development and reporting methodology for the integrated resource plans required under (a) of this section including the coordinated preparation and filing of individual plans by closely integrated utilities served by common facilities.

(c) The commission shall assist utilities in the development of the integrated resource plan to minimize regulatory burdens and cost.

Sec. 42.05.296. REVIEW AND APPROVAL OF INTEGRATED RESOURCE PLANS. (a) The commission shall establish by regulation a procedure for the review and approval of a plan submitted under AS 42.05.294 that includes provision for public hearings before the commission in the principal localities served by the utility submitting the plan.

(b) The commission shall approve a utility's integrated resource plan including the recommended development option if the commission finds that the plan

(1) ensures system reliability;

(2) would provide consumers with the lowest reasonable cost of power over the forecast period; cost savings identified through life-cycle cost analysis may be considered even though the cost savings will be realized after the forecast period;

(3) adequately addresses conserving electrical energy through cost-effective, end-use efficiency improvements using readily available or reliably anticipated methods or technology;

(4) documents a reasonable expectation of future load and resource requirements;

(5) uses, as appropriate, life-cycle costing and cost-effectiveness analysis and explains the criteria and assumptions on which the analysis is based;

(6) evaluates resource alternatives that would be appropriate for the service area in light of technology currently available and reliably anticipated to exist during the forecast period; and

(7) describes the utility's data collection activities, additional data requirements, and efforts to develop that additional data.

(c) Notwithstanding AS 42.05.294 and this section, a utility may, without commission approval, maintain, repair, upgrade, or rebuild existing facilities to maintain reliable service and may pursue action to alleviate an emergency situation in which service would be lost.

(d) On the anniversary of the plan's approval date, the utility shall submit annual reports on the implementation of the resource plan and the approved development option, including (1) departures necessitated by emergency service, maintenance, or repair, and (2) significant changes in the underlying assumptions of the resource plan. The report must include modifications to the plan under (c) of this section, changes to underlying assumptions, and supporting data and documentation.

(e) Commission review and approval of a utility's integrated resource plan and development option authorizes the utility to implement the plan as approved.

(f) The commission shall adopt regulations and establish policies that 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 the utility in preparing the plan and

implementing the approved plan. Expenses allowed for recovery in rates shall include those expenses reasonably expected to occur during the time the rates are in effect. The commission shall develop specific procedures for revenue requirement adjustment in lieu of a general rate adjustment filing.

* Sec. 2. AS 42.05.711(b) is amended to read:

(b) Except as otherwise provided in this subsection, public utilities owned and operated by a political subdivision of the state, or electric operating entities established as the instrumentality of two or more public utilities owned and operated by political subdivisions of the state, are exempt from this chapter, other than AS 42.05.221 - 42.05.281, 42.05.294 - 42.05.296, and 42.05.385. However,

(1) the governing body of a political subdivision may elect to be subject to this chapter; and

(2) a utility or electric operating entity that is owned and operated by a political subdivision and that directly competes with another utility or electric operating entity is subject to this chapter and any other utility or electric operating entity owned and operated by the political subdivision is also subject to this chapter.

* Sec. 3. AS 44.83 is amended by adding a new section to read:

Sec. 44.83.085. GRANTS FOR INTEGRATED RESOURCE PLANS. The authority may make a grant to a Railbelt electric utility that is required to prepare an integrated resource plan under AS 42.05.294 to assist in the cost of preparing the plan.

* Sec. 4. INITIAL PLAN DEADLINE. A public utility's first integrated resource plan required under AS 42.05.294, enacted by sec. 1 of this Act, shall be filed on or before January 15, 1991.

R10 4/30/88

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB238 (RES)
PUBLISH DATE: _____

FISCAL NOTE

REQUEST:

Revision Date: 4/29/88
Title: An act requiring certain electric public utilities to prepare certain reports and relating to costs in proceedings before the APUC.
Sponsor: Brown, Ellis, Davis et al
Requestor: House Finance

Agency Affected: Commerce & Econ. Development
BRU: APUC
Components: Operations

EXPENDITURES/REVENUES: (Thousands of Dollars) *

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES	0.0	86.2	86.2	86.2	86.2	86.2
TRAVEL	0.0	2.5	2.5	2.5	0.0	0.0
CONTRACTUAL	0.0	40.0	0.0	50.0	0.0	0.0
SUPPLIES	0.0	.3	.3	.3	.3	.3
EQUIPMENT	0.0	6.4	0.0	0.0	0.0	0.0
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	135.4	89.0	139.0	86.5	86.5
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND	0.0	135.4	89.0	89.0	86.5	86.5
FEDERAL FUNDS						
OTHER Prog Rcpts				50.0		
TOTAL	0.0	135.4	89.0	139.0	86.5	86.5

POSITIONS:

FULL-TIME	0	2	2	2	2	2
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

*Funding FY 89 = HB 239; Funding FY 90-93 Budget Forecast - Details on attached Fiscal Note Narrative.
(See attached for narrative concerning analysis)

Prepared by: T.S. Moninski II Executive Director
Phone: 276-6222
Division: Alaska Public Utilities Commission
Date: _____

Approved by Commissioner: _____
Date: 5-2-88
Agency: Commerce & Economic Development

RECEIVED
MAY 2 1988
LEGISLATIVE FINANCE

Distribution (by preparer):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)

This Fiscal Note was developed in specific response to the changes incorporated in CSHB 238. The legislature's attention is directed at the fact that the demand for Commission resources will fluctuate depending upon which planning stage is active in any given fiscal year. This Fiscal Note attempts to accommodate those changes in resource requirements in an effort to minimize the ongoing overhead associated with administering the integrated resources planning process.

Fiscal Note Narrative Concerning HB No. 238

"An Act requiring certain electric public utilities to prepare certain reports; and relating to costs in proceedings before the Alaska Public Utilities Commission.

Listed below is a breakout of the costs which are identified on the fiscal note.

PERSONAL SERVICES:		
1.	54.0	UTILITY ENGINEER III (RANGE 19A).
2.	32.2	CLERICAL SUPPORT (Range 10A)
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SUBTOTAL:	2.5	TRAVEL
CONTRACTUAL:		
1.	15.0	FY 89 - Development of computerized data bases in the first year (10.0); misc costs associated with promulgating regulations such as advertising, mailing costs, etc. (4.5); and additional postage costs for FY 89 (.5) = total of 15.0
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1.	0.3	Additional Costs Per Year for Paper, etc.
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EQUIPMENT:

1.	6.0	Hewlett Packard Personal Computer with additional memory boards, basic and specialized software to operate the computer, printer, and other pc peripheral.
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SUBTOTAL:	6.4	Equipment for FY 89 only
GRANT TOTAL:	135.4	Fiscal Year 1989 - all GF
	89.0	Fiscal Year 1990 - all GF
	139.0	Fiscal Year 1991 - 50.0 Pr.;89.0 GF
	86.5	Fiscal Year 1992 - all GF
	86.5	Fiscal Year 1993 - all GF

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB 238 (Res)
PUBLISH DATE: HOUSE 2/22/88

FISCAL NOTE

REQUEST:

Revision Date: _____
Title: An act requiring certain electric public utilities to prepare certain reports and relating to costs in proceedings befor APUC.
Sponsor: Brown, Ellis, Davis et al.
Requestor: Cotten

Agency Affected: Commerce & Econ. Development
BRU: APUC
Components: Operations

319

EXPENDITURES/REVENUES: (Thousands of Dollars)

OPERATING	FY 88	FY 89	FY 90	FY 91	FY 92	FY 93
PERSONAL SERVICES		170.0	170.0	170.0	170.0	170.0
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING		170.0	170.0	170.0	170.0	170.0
CAPITAL						
REVENUE						

FUNDING: (Thousands of Dollars)

GENERAL FUND			170.0	170.0	170.0	170.0
FEDERAL FUNDS						
OTHER		170.0				
TOTAL		170.0	170.0	170.0	170.0	170.0

POSITIONS:

FULL-TIME		3	3	3	3	3
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary) HB238 creates an ongoing filing and approval process for integrated resource plans. Although HB239 provides inception year funding via direct appropriation from the Railbelt Energy Fund, subsequent year funding is forecasted to be provided by General Fund resources unless the legislature determines that further Railbelt Energy Fund support is appropriate.

Prepared by: T.S. Moninski II Executive Director Phone: 276-6222
Division: Alaska Public Utilities Commission Date: _____

Approved by Commissioner: _____ Date: _____
Agency: Commerce & Economic Development

Distribution (by preparer):
Legislative Finance
Legislative Sponsor
Requestor
Office of Management and Budget
Impacted Agency(ies)

Alaska State Legislature

HOUSE OF REPRESENTATIVES

Committee on Finance

Official Business

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

TO: Representative Al Adams

FROM: Representative Kay Brown

DATE: April 28, 1988

SUBJ: HB 238/239: Integrated Resource Planning Legislation

As you may know, the topic of integrated resource planning (also known as "least-cost" planning) was the subject of a conference held in Anchorage last fall which involved representatives of private and public utilities from aaround the nation. On the basis of that conference and an interim worksession of the Resources Committee, as well as additional discussions with utility representatives and consumer organizations, CS HB 238 (Res) has developed into the bill now before the House Finance Committee.

Fundamentally, integrated resource planning is designed to achieve the most cost-effective energy system by integrating the analysis of "demand-side" options with "supply-side" options. 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. The value of integrated resource planning is increasingly recognized throughout the country. One recent survey found that **25 states are using or developing integrated resource planning and another 7 are considering** implementation or using a similar type of methodology for facility siting or conservation programs.

The recently released energy report by the House Research Agency (*Energy Planning in Alaska: Past Efforts and A Future Direction*, February 1988) clearly reveals that integrated resource planning for Alaska is overdue. Although Alaska Power Authority statutes and regulations specify a multi-step review process for individual power projects, APA reviews are driven by specific project proposals and do not constitute a true planning process. Had integrated resource planning been in place over the past decade, many of the costly mistakes which have characterized the Energy Program for Alaska could have been avoided.

As noted by the HRA report, in urban areas of the state, the legislature appropriated **$1.3 billion 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 integrated resource planning had been in place during this period, the HRA report suggests that "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." Instead, the more traditional project-based, supply-side approach has resulted in the futile pursuit of infeasible projects (eg, Susitna) as well as to the development of expensive excess capacity (eg, Tyee Lake and Soldotna One).

The version of HB 238 reported out of the Resources Committee is significantly compromised relative to earlier versions of the legislation. CS HB 238 (Res) would require the Railbelt electric utilities to prepare integrated resource plans that adequately address both supply-side and demand-side energy development opportunities. During the evolution of HB 238 the utilities have argued that while they support integrated resource planning, they would urge an incentive-based approach. In the spirit of compromise, I have supported amendments to the bill which eliminated the enforcement mechanism originally included in the bill (ie, APUC pre-project approval). As the bill now stands, the quality of the integrated resource planning process will largely depend on the good-faith efforts of the utilities involved.

The integrated resource planning requirements proposed in **CS HB 238 (Res) would apply only to the state's larger Railbelt electric utilities** (defined as those with sales in excess of 300,000,000 kilowatt hours annually). These are utilities with the administrative and financial resources to undertake the planning efforts that would be required. These are also utilities in which the state has an enormous equity investment in the form of Bradley Lake and the Anchorage-Fairbanks Intertie. While it is anticipated that ratepayers throughout the state will ultimately benefit from the experience gained by the Railbelt utilities, the legislation has purposefully been crafted to involve only the state's larger utilities.

Finally, the proposed planning process would ensure that future development of Railbelt utility systems proceeds in a rational and deliberate fashion. Neither the ratepayers in the Railbelt, nor the state, can afford business as usual.

04/28/88 Rep. Brown

Sectional Analysis
HB 238/RESOURCES COMMITTEE SUBSTITUTE

Section 1

Integrated Resource Plans. This section establishes a requirement for utilities with annual sales greater than 300 million kilowatt hours (kwh) to prepare 20-year integrated resource plans for approval by the APUC every three years.

(Note: Utilities in Alaska with sales above the 300 million kwh sales level include Chugach Electric Association, Golden Valley Electric Association, Homer Electric Association, Matanuska Electric Association, and Municipal Light and Power - Municipality of Anchorage.)

The required integrated resource plans would:

- list and describe current facilities
- include the utility's forecasted retirement schedule
- describe the utility's interconnection relationships
- document energy end-use in the service area
- forecast system power demand (load duration curves)
- analyze the utility's existing ability to meet demand
- summarize load research
- provide long term forecasts (base, high, low) including assumptions used to develop the forecasts
- identify and evaluate alternative development options with consideration given to availability, reliability, flexibility and cost-effectiveness
- identify the development option with the lowest present value of revenue requirement
- recommend implementation of a specific option
- include other information necessary to ensure adequate evaluation of all supply-side and demand-side alternatives

The Commission is directed to develop a consistent reporting methodology and assist utilities in the development of the plans including coordinated filing of plans by closely integrated utilities.

LEAST-COST PLANNING

Least-cost planning is a process that allows utilities to evaluate and consider supply and demand side options on an equivalent basis. It presents a "level playing field" approach to objectively evaluating energy conservation, power plant construction, improved performance of existing systems, use of alternative energy services and purchased power based upon their cost and reliability. Least-cost planning is also known as integrated resource planning and value-based integrated resource planning.

Whatever it is called, the process expands a utility frame of reference to include providing energy services: the heat, the light, the power needed to operate homes and buildings. This strategy enables utilities to consider programs which promote energy efficiency on an equal basis with increased capacity. Thus utility conservation programs can be viewed as new electrical sources just as new power plants are.

Interest in least-cost planning is the result of the uncertainties in the utility market and the increased penetration into the market of demand-side management technologies. Utilities understand how to evaluate and rank supply-side options. Demand-side options have, however, developed rather recently and there is not a lot of experience in incorporating these considerations into utility plans. One of the goals of least-cost planning is to expand the historically supply oriented utility by encouraging the development of a demand-side analytical and experience base.

Utilities from Alabama to Wisconsin have undertaken demand side strategies through a least-cost planning process. The American Public Power Association supports the concept of this process, calling it "energy services planning", and stating that it helps "reduce the adverse impact of long lead-times and costly construction of large generating facilities... and encourages optimum utilization of existing equipment." Examples of utility programs include the Snohomish Public Utility in Everett, Washington that has incorporated least-cost strategies into its planning process, and Navopache Electric Cooperative in Arizona that is involved in innovative load management programs including budget billing, off-peak rates, and heat pump and weatherization loans.

State governments have also been actively involved in least cost planning. In 1984 the National Association of Regulatory Utility Commissioners unanimously passed a resolution urging all state and federal regulatory commissioners to adopt a "policy mandating electric and gas utilities to develop and submit for approval least-cost plans." The two states that are recognized as playing leading roles in least-cost planning are Nevada and

The Commission is directed to 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:

1) ensures system reliability;
2) would provide consumers with the lowest reasonable cost of power;
3) adequately addresses conserving electrical energy;
4) documents a reasonable expectation of future power requirements;
5) uses appropriate methodology for the evaluation of options;
6) adequately evaluates resource alternatives currently available or reliably anticipated to exist in the forecast period; and
7) describes the utility's data collection activities and on-going data collection efforts.

The legislation provides that, notwithstanding the requirement for preparation of an integrated resource plan, a utility may, without commission approval, maintain or repair facilities in order to maintain reliable service, including emergency repairs.

The legislation calls for the submission of annual reports on the implementation of the resource plans which include any departures necessitated by emergency service and any significant changes to the underlying assumptions used in the plan. Commission review and approval of a plan authorizes the utility to implement the plan as approved.

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.

Section 2

Clarifies that municipal utilities with sales in excess of 300,000,000 kwh are not exempt from the integrated resource plan requirement.

Section 3

Amends APA statutes to provide specific authority to make grants for the purpose of preparing integrated resource plans.

Section 4

Establishes the due date for the first plan as January 15, 1991.

Wisconsin. Nevada requires regulated utilities to consider demand and supply options in developing an integrated resource plan. In order for a utility to receive approval for a new generation or transmission facility, the proposed must be included in the utility's least-cost plan. Wisconsin mandates that utilities submit biennial plans for new power projects, and that least-cost analyses of both supply and demand-side options be included as part of the framework of the plan.

This issue has also grabbed the attention of national and state legislatures. Congress has appropriated funds to the U.S. Department of Energy for research, technology transfer, and analytical activities to promote least-cost planning. State legislatures in California, Wisconsin, Florida and Iowa have passed legislation mandating some form of least-cost planning regulation. In the last session of the Alaska Legislature, H.B. 238 was introduced by Representative Kay Brown. This bill would incorporate least-cost planning into the planning process of Alaskan utilities regulated by the Alaska Public Utilities Commission.

Least-cost planning is not a panacea for all of the current uncertainties in electrical planning but it does offer a process that allows demand-side options to compete equally with supply side options. As more utilities and states begin to look at this type of planning strategy they find they must grapple with several important questions: How will they define and determine least-cost? Least-cost to whom, and at what point in the planning strategy? What are the most effective methods of implementing least-cost planning - through voluntary utility initiative or state mandate? There is also a question of what aspects of least-cost planning are applicable to Alaska, with its relatively small utilities, unique distribution system, and currently, in many places, a surplus of power.

In order to explore these issues, the Department of Community and Regional Affairs, in conjunction with the Alaska Rural Electric Cooperative Association, Alaska Public Interest Research Group, Alaska Public Utility Commission, and Chugach Electric Association, is sponsoring a conference on least-cost planning in Anchorage on October 26-27, 1987. Representatives of utilities and regulatory agencies as well as nationally recognized energy analysts who have been involved in least-cost planning have been invited to share their experiences and concerns. In addition their Alaskan counterparts will discuss what applications there could be for Alaska.

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THE LEAST-COST ALTERNATIVE TO NEW POWER PLANT CONSTRUCTION

A Strategy for Ensuring Utility Investments in Conservation and Renewable Energy Resources

OCTOBER 1985

BY PAUL MARKOWITZ

AN INTRODUCTION

In the past decade, energy price shocks, supply disruptions, and a major nuclear accident have made it increasingly clear that America depends upon an unnecessarily high-cost and high-risk energy system. The sweeping changes affecting the energy field over the past ten years have perhaps been most profound in the electrical utility industry. Since 1973, electrical demand has declined drastically, fuel prices have escalated, and power plant construction costs have increased exponentially. Rate increases caused by power plant cost overruns have significantly raised electric rates and threaten to add thousands of people to the ranks of the poor and unemployed.

The concept of a "least-cost energy strategy" is emerging among consumer advocates, regulatory commissions, and utilities in response to the radical changes affecting the economics of electricity production. The first step towards implementing such a strategy requires that utilities shift their focus from selling electricity to providing electrical services: the heat, light and power needed to operate the buildings and industries in their service area.[1] This strategy enables utilities to consider programs which promote electrical efficiency on an equal basis with the construction of new electrical generating facilities. Thus, utility conservation programs (such as providing low-interest loans for home weatherization or cash rebates for the purchase of energy-efficient appliances) can be viewed as new electrical sources just as assuredly as a new nuclear or coal-fired power plant.

Since 1973, electricity prices have tripled and utilities have cancelled 180 proposed or partially constructed power plants that have cost consumers over $16 billion dollars to date.

While energy efficiency (or conservation) measures are the most cost-effective of all resource options, and therefore the cornerstone of a least-cost investment strategy, the concept really involves utilizing *all* resources which provide the least-cost means of meeting future electrical demand. Thus, *load management*, the shifting of energy consumption from peak periods of the day into slack demand periods; *cogeneration*, the simultaneous production of electricity from industrial heat processes; and *renewable energy resources* such as solar, wind, biomass, and water become integral components of utilities' least-cost energy investment strategies.

For varying reasons, many electric utilities are reluctant to consider many of the investments which are part of a least-cost investment strategy, particularly conservation, and it is left to legislatures and regulatory commissions to enact least-cost energy planning laws and regulations. These require utilities to comprehensively assess the potential of *all resources options* available for meeting new electrical demand, and to invest in these options based upon their cost-effectiveness.

ELECTRICAL UTILITIES: AN INDUSTRY IN TRANSITION

The changes affecting electric utilities have been dramatic and swift. From 1945 to 1970, the demand for electricity grew at an average annual rate of 8 percent, and utilities met new demand by constructing new fossil and nuclear-fueled power plants. Economies of scale achieved in power plant size, improvements in power plant productivity, and decreasing fuel costs resulted in declining electrical rates and contributed to electric utilities becoming one of the most sound financial investments in the marketplace.

Then the 1973 oil embargo struck, and the world of the electric utility planner turned upside down. With the astronomical increases in oil prices (and their consequent price effect on oil-fired electrical generation), demand growth for electricity slumped to near zero and continued to grow only a modest two percent annually for the next ten years. At the same time, the long term trend of declining marginal costs associated with larger power plants came to an abrupt halt. From 1971-1981, the real costs (above inflation) for constructing nuclear and coal power plants increased *each year* by 14 percent and 8 percent, respectively.[2]

A myriad of factors contributed to the escalation of power plant construction costs, including: higher interest rates, new safety and environmental regulations, mismanagement, and technological difficulties resulting from the rapid escalation in power plant size. As a result, since 1973, electricity prices have tripled and utilities have cancelled 180 proposed or partially constructed power plants that have cost consumers over $16 billion dollars to date.[3] Utilities across the country are struggling to pay for power plants whose electricity is neither needed nor affordable.

The impact on utility ratepayers from these power plant cost escalations is devasting. Many of the power plants ordered in the early 1970's have recently started (or soon will

be) producing power. The rate shock resulting from the inclusion of these power plant construction costs in electrical rates (construction costs are generally not passed on to ratepayers until plants are completed or officially cancelled) is expected to increase consumers' rates 50—180 percent in many utility service areas, and impact 35 million families in 25 states.[4] The employment and economic repercussions resulting from these rate shocks threaten to be equally disastrous. In a report commissioned by Suffolk County in Long Island, New York, rate increases necessary to pay for the Shoreham Nuclear Power Plant are expected to eliminate 35,000 jobs, disqualify 37,000 families from the mortgage market, increase foreclosures and home abandonment by up to 2000 per year, and push 11,000 households below the poverty line.[5]

LEAST-COST ENERGY OPTIONS

A quiet revolution in the energy field has been manifested in the rapid movement toward least-cost energy efficiency and renewable energy investments. According to energy conservation advocate Amory Lovins, since 1979, the United States has obtained more than one hundred times as much new energy from efficiency improvements as from all net expansions of energy supply. Technological developments have spurred extensive design improvements in America's electricity consuming buildings and devices. As a result, the efficiency of the best available commercially-available motors has doubled, lighting systems tripled, major appliances quadrupled, and the efficiency of building space conditioning (heating and cooling) has improved by a factor of ten.[6]

For example, Norelco has developed its SL-18 light bulb which uses only 18 watts of electricity, yet produces the same amount of light as a 75-watt incandescent bulb. The bulb lasts more than 13 times longer, provides light of better quality, and uses a high-frequency solid-state ballast which eliminates flicker and hum. By replacing 75 watts with 18 watts, an individual is essentially installing a 57-watt power plant in their home. The SL-18 repays its high retail cost ($15-$20) two-three times over by saving $40 worth of electricity plus $10 for a dozen replacement bulbs. When universally used, SL light bulbs and other equally efficient bulbs, will displace (at one-to-two cents/kilo-watt hour (KW-h)) the need for thirty 1000 mega-watt power plants (at seven cents/KW-h.). Savings of similar magnitude exist for appliances, industrial processes, and other electrical end-uses, as well.[7]

In an era of uncertain demand, utilities find that conservation and load management investments offer a unique opportunity to reduce high capital costs and the financial risks associated with excess generating capacity.

Renewable energy technologies such as photovoltaics (solar electric cells), wind energy systems, passive solar applications, solar flat plate collectors (for hot water and space heating), and biomass conversion (wood, alcohol fuels, etc.) have also become increasingly cost-competitive. The Public Utilities Regulatory Policy Act (PURPA) has played a significant role in this recent transition towards renewable energy resources. PURPA requires electric utilities to purchase electricity from small-power (renewables and cogeneration) producers up to the utility's cost of producing electricity from conventional most dramatic example of this shift toward renewables is found in California, where by mid-1984 over 10,000 megawatts of small, independent sources were planned or under construction, enough to supply over 20 percent of the state's power by 1990.[8]

In addition to their cost-effectiveness, energy efficient and renewable energy technologies create several times as many jobs per dollar as their conventional counterparts. They also represent the best energy supplies for abating the long-term problems of acid rain, carbon-dioxide build-up, and the proliferation of fissionable materials that are posed by continued dependence on conventional energy sources.

UTILITY SUPPORT FOR LEAST-COST OPTIONS

A few utilities have heeded the changing economics of electrical generation, and begun developing programs which promote least-cost electrical investments. Utilities, such as Pacific Power and Light, Northern States Power Co., and New England Electric Systems are finding that least-cost investment options are not only much cheaper than conventional generating sources, but also improve their own financial well-being. South California Edison, one of the nation's largest utilities, announced a change in its 1981 corporate policy which involved "devoting corporate resources to the accelerated development of a wide variety of renewable resources, cogeneration, conservation, and load management."[9]

Demand-side options (efficiency and load management), cogeneration, and renewable energy resources reduce utility planning uncertainty and risk. These investment options are small, modular, and incremental in nature. Compared to conventional coal and nuclear-fired power plants, they have shorter production lead times, low capital requirements, and

MODEL CONSERVATION PROGRAMS

Pacific Gas and Electric Company (California), the nation's largest private utility, recently embarked on its Great Energy Rebate Program. As part of this program, commercial, industrial and agricultural electric customers are paid up to $150,000 per customer account to convert to energy-saving equipment and products. Rebates are offered for such equipment as lighting conversions, air conditioners, industrial motors, refrigerators and freezers, heating system conversions and modifications, and load management controls. Customers can obtain rebates which defray 25% to 40% of the purchase and conversion costs for efficient products, and rebates are paid on the basis of up to $250/KW for saved electrical capacity and $.06/KW-h for saved energy. Similar rebates are also available for residential customers.[10]

General Public Utilities (of Pennsylvania and New Jersey) has developed an alternative financing program for home weatherization through its Residential Energy Conservation Action Program (RECAP). Under RECAP, contractors install cost-effective conservation measures free of charge to individual residences. The utility pays the contractor for the actual, measured long-term reductions in energy consumption over a period of years at an agreed upon rate. Energy savings from the program are expected to exceed costs by a ratio of five to one over a 10 year period, and General Public Utilities has already completed weatherization for over 5,000 homes.[11]

offer the utility a quick return on its investment. In an era of highly uncertain demand, utilities are finding that conservation and load management investments offer a unique opportunity to improve load factors, increase velocity of cash flow, reduce high capital costs, and reduce the financial risks associated with excess generating capacity.

Untapped investments in energy efficiency and load management offer enormous potential for meeting new electrical demand and remain the most cost-effective of all resource options. Utilities, regulators, and consumer advocates have developed programs designed to increase the efficiency of America's electrical consumption.

Most utilities offer some type of program promoting efficiency investments, ranging from simple bill inserts on conservation tips and school education programs to innovative financing programs like those cited above. However, very few utilities have begun to comprehensively investigate the full potential for improving the efficiency of their customers' energy consumption or to implement incentive programs which are designed to promote efficiency investments.

UTILITY OPPOSITION TO LEAST-COST OPTIONS

The majority of utilities are still planning for high electrical demand growth in the future, despite the drastic decline in the rate of electrical demand growth over the past decade. And they are planning on meeting this demand primarily by building large coal-fired electrical generating plants (and to a lesser extent nuclear power), despite the radical changes in the economics of central power generation. Most utilities are reluctant to shift to a least-cost investment strategy for a variety of reasons, including:

- Utilities have traditionally seen themselves as suppliers of a commodity (electricity), and like most other private enterprises, strive toward increasing profits by increasing sales of their commodity. This has been historically accomplished by constructing large power plants.
- Most utility executives wait for positive signs from their commissioners that least-cost investments will receive preferential rate treatment.
- The revenue formulas established by public utility commissions, which are used to determine return on investment, are often based on total capital investment. Utilities have a built-in incentive to overinvest in capital-intensive plant and equipment.
- Efficiency measures, programs, and technologies for saving energy and electricity are still relatively unfamiliar to the utility industry, and are viewed as risky until proven over a long period.[12]

Because of this reluctance, a few state legislators and regulators have begun to adopt statutes and regulations which assure that utilities will comprehensively examine all resource options, and invest in these on a cost-effective basis.

STATE REGULATORY COMMISSIONS CAN ENSURE LEAST-COST INVESTMENTS

The least-cost concept has garnered strong support from some impressive official bodies, including the American Public Power Association, the American Gas Association, and the National Association of Regulatory Utility Commissioners (NARUC). At its 1984 annual convention, NARUC unanimously passed a resolution urging all state and federal regulatory commissions to adopt a "policy mandating electric and gas utilities to develop and submit for approval least-cost resource plans".[13]

Legislators and commissioners have begun to develop laws and regulations to compel utility investment in demand-side options and renewables due to many utilities' reluctance to pursue least-cost planning on their own initiative. Several states, including California, Wisconsin, Florida, Iowa, and Nevada have now adopted some form of least-cost electrical planning regulations.

The state of Nevada has developed one of the most comprehensive least-cost planning regulations in the country. The

Citizen-based organizations and public interest intervenors have been the primary motivating force behind the adoption of many current least-cost planning laws and regulations.

Nevada Utility Resource Planning Act of 1983, authored by the state's Office of Consumer Advocate, requires electric utilities to submit to the Nevada Public Service Commission a fully integrated, long-range resource plan every two years. These plans must demonstrate that *all* aspects of a utility's future energy needs and resource options have been considered.

Nevada utilities are required to conduct assessments of the cost-effective potential for each resource option, including efficiency, load management, cogeneration, and renewables, and then integrate and prioritize those options according to their cost-effectiveness. Perhaps most importantly, utilities cannot receive approval for a new power plant unless the plant has been previously approved as part of the utility's least-cost resource mix. The Nevada model includes provisions which assure that:

- Demand forecasts are based upon inventories of electrical end-uses such as lighting, heating, and cooling.
- Utilities must also submit a two-year implementation plan that specifies which least-cost resources will be utilized over the next two years.
- Standardized planning methodologies and models are used by all utilities to assure long-term consistency.
- Utilities are held responsible for the creation and coordination of all plan components.
- Enforcement mechanisms are developed to assure utility compliance with their resource plans.[14]

Most states have adopted only individual components of comprehensive least-cost planning regulations, and consequently lack the ability to ensure utility investments on a least-cost basis. For example, many public utility commissions have specific statutory authority to require utility investments in conservation and load management but lack the capability to adequately evaluate utility assessments of conservation potential or program proposals. Other commissions require utilities to file conservation plans which must evaluate all resource options available for meeting new electrical demand yet lack the authority (or initiative) to deny approval of the plan or to require that utilities invest in all cost-effective conservation investments prior to new supply resources.

Unfortunately, very few commissions have adopted comprehensive least-cost regulations which ensure that utilities

invest in the most cost-effective resources to meet new electrical demand.[15] This is due to a variety of reasons. Some state commissions lack adequate information and analytic planning tools, while others are awaiting the results of those states which have enthusiastically promoted conservation. Still, other commissions believe that utilities should decide how to meet demand for electricity or that existing regulations are sufficient in promoting utility conservation investments. However, a truly integrated and comprehensive least-cost planning model, such as Nevada's, is vital to assure utility investments in least-cost energy resources.

A FRAMEWORK FOR CITIZEN ACTION

A well-informed and organized consumer-based coalition can significantly influence its state regulatory and legislative bodies to adopt least-cost planning laws and regulations. Citizen-based organizations and public interest intervenors have been the primary motivating force behind the adoption of many current least-cost planning laws and regulations. The following are specific actions that public policy organizations and citizen-based groups can take to promote least-cost energy planning in their state:

1. Review Existing Statutes and Regulations Regarding Utility Investments in Least-Cost Energy Resources. Utility statutes and regulations vary from state to state. Thus, a crucial first step involves reviewing existing statutes and regulations to reveal possible gaps in a comprehensive least-cost planning process. Some of the more pertinent questions to pursue, include:

- Does your public utility commission have the regulatory authority to require utility investments in customer efficiency improvements?
- Are utilities required to undertake a comprehensive assessment of the conservation potential in their service districts?
- Are utilities required to file long-range resource or conservation plans? If yes, do these plans include assessments of demand-side and supply-side options and do they require these options to be integrated according to their cost-effective?
- Does your commission have an adequate enforcement mechanism which ensures that utilities invest on a least-cost basis, i.e. denial of a power plant permit due to lack of consideration of alternatives?
- Has the state adopted favorable buyback regulations to require utilities to purchase electricity from small-power producers, including cogeneration and renewables?

2. Develop an Independent Conservation Potential Assessment. Universities offer an ideal base for the development of independent assessments of the potential for energy conservation in a utility service district or the state as a whole. For example, the Center for Energy Studies at the University of Texas, in conjunction with Lawrence Berkeley Laboratories, has recently developed an assessment of the conservation supply potential for residential and commercial buildings in the state of Texas.[16]

University departments with experience in quantitative analysis, computer modeling, or electrical planning issues can be solicited to develop specific information:

- An inventory of available efficiency measures, methods, and technologies capable of cheaply and reliably supplying or saving energy and power.
- A detailed inventory of energy use, indicating how much electricity is consumed for what purposes within the state.
- An assessment of the potential for efficiency improvements in the residential, commercial, and industrial sectors.
- A survey of information on state commission orders, regulations, rate treatments and case histories of efficiency programs.

3. Form a Coalition. A successful strategy will be based on linking least-cost planning with other utility issues that are affecting ratepayers. Least-cost planning offers a long-term, comprehensive process for assuring the most cost-effective implementation of electrical resources as well as an ideal complement to shorter-term and single focus, and sometimes adversarial, utility issues.

For instance, "rate shock" (the rate impacts from the cost of new power plants) is an excellent organizing issue because the inclusion of expensive, new power plants costs in the rate base directly result in higher utility bills. While citizen groups argue against the inclusion of imprudent power plant construction costs in the rate base, rate shock also presents an excellent opportunity for consumers to press their regulators with the question of, "How are you going to prevent these astronomical rate increases from occurring in the future?"

Least-cost planning can be used to address other utility issues, such as utility proposals for the construction of new coal or nuclear plants, the inclusion of construction work-in-progress (CWIP) costs in the rate base, and the impacts of rate increases on low-income households. Least-cost electrical planning offers an ideal issue for forging statewide coalitions which can bring together diverse organizations, including low-income, senior citizen, safe energy, and consumer groups.

FOOTNOTES

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[5] *Operation Va Abandonment of the Shoreham Nuclear Plant The Effect on Long Island Unemployment*. 1984. Greg Palast. Union Associates. New York, NY.

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[11] "Don't Pay for Insulation... Buy Conservation." 1983. Slide show presentation explaining General Public Utilities RECAP Progam. Richard Esteves, Manager of Conservation Communications, General Public Utilities. Parsippany, NJ.

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[13] Resolution on gas and electric utility least-cost resource plans. 1984. Proposed by the Ad Hoc Committee on Energy Conservation of the National Association of Regulatory Utility Commissions (NARUC). Adopted by NARUC at their 1984 Annual National Convention. NARUC. Washington, DC.

[14] "Utility Resource Planning: The State of Nevada Adopts an Integrated Planning Model". 1984. Jon Wellinghoff and Cynthia Mitchell. Nevada Office of Consumer Advocate. Carson City, NV.

[15] "Results of Survey of Regulatory Utility Commission's Electric Resource Planning and Conservation Activities". November 1985. Conducted by Congresswoman Claudine Schneider's office for hearings on the Least-Cost Planning Initiative. Hearings held before the House Energy Development and Applications Subcommittee. September 26, 1985.

[16] *Electrical Energy Conservation Supply Potential in the Texas Building Sector*. December 1985 (expected date). Center for Energy Studies. University of Texas. Austin, TX. and Energy Efficient Buildings Program. Lawrence Berkeley Labs. Berkeley, CA. Commissioned by the Texas Public Utility Commission. Austin, TX.

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ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
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March 29, 1988

MEMORANDUM

TO: Representative Kay Brown

ATTN: Eric Meyers

FROM: Ginny Fay
Legislative Analyst

RE: **Regulation of Cooperative and Publicly-Owned Electric Utilities**
Research Request 88.227

You requested information on the regulation of electric utilities in other states. You are interested in the number of states that: (1) regulate cooperative and publicly-owned electric utilities and (2) require advanced siting approval for new utility construction projects.

Based on the "1985 Annual Report on Utility and Carrier Regulation," by the National Association of Regulatory Utility Commissioners, forty-five of the fifty states have electric cooperatives. Coincidentally, forty-five states also have public utilities such as municipal utilities. Twenty-five of the forty-five states with cooperatives (fifty-six percent) regulate their rates. Of the twenty states that do not regulate cooperatives, one (Minnesota) allows for members to elect to be regulated, another (Nevada) exempts cooperatives only if all their sales are to members, and a third (Wisconsin) regulates a cooperative if its activities include functions that make it a public utility under Wisconsin statute (Attachment A). In twenty-three of the forty-five states with publicly-owned electric utilities (fifty-one percent), electric rates are subject to regulation (Attachment A).

Eighteen states require advance approval or certification for construction of additional generation facilities by investor-owned electric utilities. Twelve require advanced approval for electric cooperatives and nine for publicly-owned electric utilities (Attachment B). Twenty-two states required advance approval for construction of distribution lines by investor-owned electric utilities. Fourteen states require approval for cooperatives and ten for publicly-owned utilites (Attachment B).

I hope this information is useful. Please do not hesitate to call if you have additional questions.

Attachments

ATTACHMENT A
Regulation of Rates: Electric, Gas and
Telephone Utilities

TABLE 3 - REGULATION OF RATES: ELECTRIC, GAS AND TELEPHONE UTILITIES

AGENCY	The Agency has authority to regulate or control Rates on sales to -																			
	Ultimate Consumers						Indus. Customers of		Public Authorities for public use (not resale)						US Government - not for resale					
	Electric			Gas			Inter state pipe-line comp-anies	Nat-ural Gas Pro-duc-ers	Electric			Gas			Electric			Gas	
	Pri-vate	Pub-lic	Coop-era-tive	Pri-vate	Pub-lic	Tele-phone			Pri-vate	Pub-lic	Coop-era-ting	Pri-vate	Pub-lic	Tele-phone	Pri-vate	Pub-lic	Coop-era-tive	Pri-vate	Pub-lic
FCC						X 16/								X 16/					
FERC		1/					17/	17/		1/						1/			
ALABAMA PSC	X			X		X			X			X		X	X			X	
ALASKA PUC	X	X 2/	X 66/	X	X	X			X	X 2/	X 66/	X	X	X	X	X 2/	X 66/	X	X
ALBERTA PUB	X	53/		X	54/	X		X 51/	X	53/		X	52/	X					
ARIZONA CC	X		X	X		X		X	X		X	X		X	X		X	X	
ARKANSAS PSC	X		X	X	X 3/	X		X	X		X	X		X	X		X	X	
CALIFORNIA PUC	X			X		X			X			X		3	X			X	
CANADIAN RTC						X													
COLORADO PUC	X		X	X		X			X		X	X			X		X	X	
CONNECTICUT DPUC	X			X		X			X			X		X	X			X	
DELAWARE PSC	X		X	X		X			X		X	X		X	X		X	X	
D.C. PSC	X		X	X		X			X		X	X		X	X		X	X	
FLORIDA PSC	X	X 43/	X 43/	X		X			X	X 43/	X 43/	X		X	X	X 43/	X 43/	X	
GEORGIA PSC	X			X		X			X			X		X	X			X	
HAWAII PUC	X			X		X			X			X		X	X			X	
IDAHO PUC	X			X		X			X			X		X	X			X	
ILLINOIS CC	X			X		X	X		X			X		X	X			X	
INDIANA PSC	X	X	X	X	X	X			X	X	X	X	X		X	X	X	X	X
IOWA SCC	X		X	X		X 35/	X		X		X	X		X 35/	X		X	X	
KANSAS SCC	X	4/	X	X	4/	X			X	4/	X	X	4/	X	X	4/	X	X	4/
KENTUCKY PSC	X		X	X		X		X	X		X	X		X	X		X	X	
LOUISIANA PSC	X		X 56/	X 41/		X			X			X		X	X			X	
MAINE PUC	X	X	X	X	X 12/	X			X	X	X	X	X 12/	X	X	X	X	X	X 12/
MARYLAND PSC	X	X	X	X	X	X			X	X	X	X		X	X	X	X	X	X
MASSACHUSETTS DPU	X	5/		X	5/	X			X	5/		X	5/	X	X	5/		X	5/
MICHIGAN PSC	X		X	X		X	X		X 20/		X 20/	X 20/		X 67/	X		X	X	
MINNESOTA PUC	X		56/	X 68/		X 72/			X		56/	X		X	X			X	
MISSISSIPPI PSC	X	64/		X	64/	X			X	64/		X	64/	X	X	64/		X	64/
MISSOURI PSC	X			X		X			X			X		X				X	
MONTANA PSC	X	X		X	X	X	X	X	X	X		X	X	X	X	X		X	X
NEBRASKA PSC 42/						X									X	6/	65/	X	6/
NEVADA PSC	X	6/	65/	X	6/	X			X	6/	65/	X	6/		X	X 3/	X	X	
NEW HAMPSHIRE PUC	X	X 3/	X	X		X			X	X 3/	X	X		X	X			X	
NEW JERSEY BPU	X	7/		X		X			X			X			X	8/	X	X	
NEW MEXICO PSC	X	8/	X	X			X 18/		X	8/	X	X							
NEW MEXICO SCC						X													
NEW YORK PSC	X	X 9/		X	X	X			X 21/	X 21/		X 21/	X 21/	X 21/	X 21/	X 21/		X 21/	X 21/
NORTH CAROLINA UC	X			X		X	X		X			X		X	X			X	
NORTH DAKOTA PSC	X			X		X			X			X		X				X	
NOVA SCOTIA PUB	X	X	X	X 12/	X 12/	X			X	X	X	X 12/	X 12/	X	X			X	
OHIO PUC	X			X		X			X			X							
OKLAHOMA CC	X		X	X		X			X		X	X		X	X		X	X	
ONTARIO EB				X										X					
ONTARIO TSC						X								X					
OREGON PUC	X			X	12/	X			X			X	12/	X	X			X	12/
PENNSYLVANIA PUC	X	X 11/		X	X 11/	X			X	X 11/		X	X 11/	X	X	X		X	X 11/
PUERTO RICO PSC				X		19/		10/						19/					
QUEBEC EGB	X			X					X			X		X					
QUEBEC RSP						X								X					
RHODE ISLAND PUC	X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X
SASKATCHEWAN PUBC	X	X		X	X	X		X		X			X	X					
SOUTH CAROLINA PSC	X			X		X			X			X		X					
SOUTH DAKOTA PUC	X			X		X 58/	X	X	X-X			X		X	X			X	
TENNESSEE PSC	X			X		X	X		X			X		X	X			X	
TEXAS PUC	X	X 48/	X			X			X	X 48/	X			X	X	X 48/	X		X
TEXAS RC				X	X 8/								X 8/					X	X 8/
UTAH PSC	X		X	X	X	X			X	X	X	X	X	X	X	X	X	X	X
VERMONT PSB	X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X
VIRGIN ISLANDS PSC		X				X				X				X		X			
VIRGINIA SCC	X		X	X		X 73/						X		X	X			X	
WASHINGTON UTC	X			X		X		X	X					X					
WEST VIRGINIA PSC	X	X 59/	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X
WISCONSIN PSC	X	X	14/	X	X	X	12/	12/	X	X	14/	X	X		X	X	14/	X	X
WYOMING PSC	X	X 45/	X	X	X 45/	X	X 50/		X	X 45/	X	X	X 45		X	X 45/	X	X	X 45/

FOOTNOTES - TABLE 3
REGULATION OF RATES: ELECTRIC, GAS AND TELEPHONE UTILITIES

1/ The FERC has statutory jurisdiction over the power and transmission rates of the Bonneville Power Administration and jurisdiction over power and transmission rates of DOE's other power marketing agencies as delegated by the Secretary of Energy. Rates for the transmission of non-Federal electric power over the Federal Columbia River Transmission System became effective upon confirmation and approval by FERC under the Federal Columbia River Transmission System Act.
2/ Publicly owned utilities are regulated as to service area. Full regulation is imposed when competition exists between municipal and similar utility.
3/ Public utilities regulated when outside of municipal boundary only.
4/ Same as for private utilities and co-ops for facilities outside of 3 miles from the corporate limits of municipalities. Commission has no jurisdiction within the 3 mile limit.
5/ Only if earnings exceed 8 percent of original cost of plant in service or if discrimination between class of customers.
6/ Municipal utilities exempt from State regulation.
7/ Authority limited in individual cases by legislation or court decision.
8/ Municipally owned utilities are fully regulated with respect to service beyond five miles of municipal boundary.
9/ Not over publicly owned electric utilities served by NYS Power Authority. Publicly owned gas or electric utilities need not decrease rates unless investigation was based upon complaint of 25 or more active customers.
10/ No natural gas in Puerto Rico.
11/ Only when service extends beyond the corporate limits of a publicly owned utility company.
12/ None in state.
13/ Seven months after filing, utility may place a portion of the increase in effect not to exceed 15% of their gross intrastate operating revenue.
14/ Not unless co-op extends activities to include functions that make it a public utility under the statutes (except to portion of co-op service within incorporated municipality as a result of annexation).
15/ Plus 60 days notice.
16/ Authority to regulate rates for interstate and foreign services of telephone and telegraph carriers.
17/ FERC reviews rates by interstate pipelines to mainline industrial customers in certificate proceedings.
18/ Authority not exercised.
19/ The Puerto Rico Telephone Authority, a state public corporation created by Law 25 (May 6, 1974) purchased the Puerto Rico Telephone Company.
20/ Commission jurisdiction excluded from rates covered by special agreements with municipalities.
21/ Jurisdiction over all rates either by tariff or contract.
22/ Commission jurisdiction excluded from rates for intrastate service covered by special agreements with municipalities and rates for interstate services subject to the Federal Energy Regulatory Commission.
23/ Authority limited to rate charged and manner of delivery.
24/ Primarily Federal Energy Regulatory Commission jurisdiction.
25/ No specific statutory authority.
26/ May fix temporary rates, but practice is not followed.
27/ Interim rates must be approved and are collected under bond subject to refund.
28/ Commission has authority to grant partial and immediate rate relief during pendency of final order, after statutory requirements are met.
29/ May permit rates to go into effect, subject to refund.
30/ Interim rates may be prescribed after a hearing.
31/ Required to advertise 30 days prior to change.
32/ Rates for interstate service subject to FERC.
33/ When not subject to FERC.
34/ Specific authority required to change rates. Rates do not become effective after a specified period, consequently, no suspension is required.
35/ Mutual telephone companies in which at least 50% of the users are owners, cooperative telephone corporations or associations, and telephone companies having less than 15,000 customers and less than 15,000 access lines are not subject to rate regulation.
36/ Hawaii law provides that rate increases may not go into effect until approved by the Commission.
37/ Effective July 1, 1978 for electric and gas private utilities. Effective July 1, 1982 for telephone utilities.
38/ Emergency only.
39/ 90 days at a time; up to a total of 6 months.
40/ Can investigate co-op rates for discriminatory practices.
41/ Except no authority over rates charged to industrial customers by any gas company.
42/ Telephone is the only regulated utility. Electric service is supplied by political subdivisions called public power districts, electric cooperatives and municipal electric systems. Nebraska is unique among the states in having no private power companies; all electric facilities are publicly-owned or member-owned. Natural gas is provided by private companies through franchise granted by each city, town or village.
43/ Basic rate structure regulation only.
44/ Rates for interstate sales are subject to the jurisdiction of the FERC; intrastate rates are subject to State regulation.
45/ Public utilities regulated insofar as they are owned and operated outside corporate limits.
46/ Municipals can put rates into effect after 45 days. The Board can order an investigation and rates may be subject to rebate.
47/ The Commission may extend the ten-month suspension period for periods of time and for reasons established by statute.

FOOTNOTES - TABLE 3
REGULATION OF RATES: ELECTRIC, GAS AND TELEPHONE UTILITIES

48/ If municipality, appellate jurisdiction only. This Commission has original jurisdiction over two public authorities (River Authority).
49/ Wyoming Supreme Court decision to effect PSC cannot regulate gas sale for resale.
50/ To extent not Federally preempted.
51/ Only if authorized by Lieutenant Governor in Council.
52/ Alberta PMC may determine what amounts are eligible for inclusion in cost of service.
53/ If for resale outside municipal boundaries. Pursuant to the Electric Energy Marketing Act the Alberta PUB has jurisdiction to fix the price at which one publicly (municipal) owned utility sells to the Alberta Electric Energy Marketing Agency.
54/ Only if the municipality has passed a by-law approved by the Lieutenant Governor in Council, bringing itself under the Alberta PUB or if the public body is the Government of the Province of Alberta.
55/ Rates must be filed 30 days before final adoption by the utility; however, the rates become effective regardless of whether the PSC issues a comment to the utility on some aspect of its rate structure.
56/ Has authority only at the election of the cooperative.
57/ Rates cannot be increased without hearings and a subsequent order of the Commission, consequently, no suspension is required.
58/ PUC does not regulate rates of rural telephone cooperatives or of thirteen independents and three municipals.
59/ Commission has limited review authority over rate changes by municipally owned utilities.
60/ One hundred and fifty days beyond automatic 35 days and two additional days for each day of hearings on merit beyond 15 days.
61/ One year for utilities with $3 million or less annual gross revenues; indefinite for utilities with over $3 million in annual gross revenues. Interim rates must be acted upon within five months for utilities with $3 million or less annual gross revenues; no statutory requirements for large utilities.
62/ Rates become effective after seven months if Commission does not take action.
63/ May be extended to nine months if just cause is shown in the Record.
64/ Only with that service which extends one mile beyond the corporate limits.
65/ Rates of cooperatives providing services to members only are not regulated.
66/ May become deregulated upon majority vote of at least 15 percent of eligible members.
67/ Only intrastate WATS.
68/ Rates are not regulated for gas utilities serving fewer than 650 customers.
69/ PSC has state authority to require investor-owned, municipal and cooperative utilities to wheel. PSC is pre-empted by FERC from setting wheeling rates for investor-owned utilities, but may regulate wheeling rates for municipal and cooperative utilities.
70/ Investor-owned gas distribution companies only.
71/ Commission's alternate energy production rules, adopted pursuant to Iowa Code Sec. 476.43, set wheeling rates.
72/ Five local exchange companies must receive approval prior to changing rates; all other 89 companies must give notice but do not need PUC approval.
73/ The Commission has authority to regulate rates for certificated interexchange carriers but allows these rates to be set competitively.

ATTACHMENT B
Certificates, Licenses and Permits

TABLE 42 - CERTIFICATES, LICENSES AND PERMITS - PART I (CONTINUED)

AGENCY	The Agency has authority to require certificates of convenience and necessity for - Constructing Major Additions - Distribution Lines: ELECTRIC: Private	Public	Co-op	GAS: Private	Public	Telephone	Other Plant: ELECTRIC: Private	Public	Co-op	GAS: Private	Public	Telephone	Abandonment of Facilities or Service: ELECTRIC: Private	Public	Co-op	GAS: Private	Public	Telephone
FCC						X												X
FERC										X 39/			X38/49/	X 38/	X 38/	X		
ALABAMA PSC							X			X		X	X			X		X
ALASKA PUC													X	X	X	X	X	X
ALBERTA PUB 45/																		
ARIZONA CC													X		X	X		X
ARKANSAS PSC	X		X	X		X	X		X	X		X	X		X	X		X
CALIFORNIA PUC							X			X			X		X	X		X
COLORADO PUC 27/	9/		9/	9/		9/	9/		9/	9/		9/	X		X	X		X
CONNECTICUT DPUC													X					
DELAWARE PSC													X		X	X		X
DC PSC																		
FLORIDA PSC 40/																		
GEORGIA PSC				X		14/										X		X
HAWAII PUC	10/			10/		10/	10/			10/		10/						
IDAHO PUC	X			X		X	X			X		X	X			X		X
ILLINOIS CC	X			X		X 14/	X			X		X 14/	X		X	X		X
INDIANA PSC													X	X	X	X		X
IOWA SCC	X	X	X	X	X		X	X	X				X	X	X	X	X	X
KANSAS SCC	X	5/	X					5/	X				X	5/	X	X	5/	X
KENTUCKY PSC	X		X	X		X	X		X	X		X	X		X	X		X
LOUISIANA PSC 29/																		
MAINE PUC													30/	30/	30/	30/	30/	30/
MARYLAND PSC													X	X	X	X	X	X
MASSACHUSETTS DPU													X	X		X	X	X
MICHIGAN PSC										X			X		X	X		X
MINNESOTA PUC										X			X	X	X	X	X	X
MISSISSIPPI PSC	X	X	X	X	X	X	X		X	X		X	X	X	X	X	X	X
MISSOURI PSC	X 54/			X		X	X 54/			X		X	X			X		X
MONTANA PSC 31/																		
NEBRASKA PSC		X																X
NEVADA PSC	X		X	X		X				X			X		X	X		X
NEW HAMPSHIRE PUC													X	19/	X	X		X
NEW JERSEY BPU 32/																		
NEW MEXICO PSC	18/	18/	18/	18/	18/		18/	18/	18/	18/	18/		X		X	X		
NEW MEXICO SCC																		X
NEW YORK PSC	11/	6/11/		11/	6/11/	11/	11/	6/11/		11/	6/11/	11/	X	X		X	X	X
NORTH CAROLINA UC													X			X		X
NORTH DAKOTA PSC	X			X		X							X			X		X
NOVA SCOTIA PUB 48/																		
OHIO PUC													X 41/			X 41/		X 41/
OKLAHOMA CC													X			X		X
ONTARIO EB				X						X						X		
ONTARIO TSC 46/																		
OREGON PUC 33/																		
PENNSYLVANIA PUC	X			X		X							X			X		X
PUERTO RICO PSC				X						X						X		
QUEBEC EGB	X			X			X			X			X			X		
QUEBEC RSP 42/						X						X						X 43/
RHODE ISLAND PUC	X	X	X	X		X	X	X	X	X		X						
SOUTH CAROLINA PSC				X						X			X			X		X
SOUTH DAKOTA PUC						X	X	X	X				X			X		X
TENNESSEE PSC													X			X		X
TEXAS PUC	X		X			X	X		X			X	X		X			X
TEXAS RC																X 7/		
UTAH PSC	X		X			X	X		X	X		X	X		X	X		X
VERMONT PSB	X	X	X	X		X	X 34/	X 34/	X 34/	X 34/	X 34/	X 34/	X	X	X	X		X
VIRGIN ISLANDS PSC 35/																		
VIRGINIA SCC 32/	X		X	X		X							X		X			
WASHINGTON UTC																		
WEST VIRGINIA PSC	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
WISCONSIN PSC	X	X		X	X	X	X	X		X	X	X	X	X		X	X	X
WYOMING PSC	X	19/	X	X	19/	X	X	19/	X	X	19/	X	X	19/	X	X	19/	X

FOOTNOTES - TABLE 42 - CERTIFICATES, LICENSES AND PERMITS - PART I

1/ Finding of public convenience and necessity required if another utility is already offered or is authorized to offer a comparable service in the same area. 35 MRSA 13-A.
2/ Authorize exercise of franchise rather than issue certificate of Public Convenience and Necessity.
3/ Present certificate authority limited to gas transmission pipelines, gas storage fields, telephone companies and, in the case of gas and electric companies, to situations where one utility proposes to extend service into a municipality presently receiving like and contemporaneous service from another utility.
4/ Answered with "private" meaning investor-owned and "public" meaning municipal or governmental.
5/ Same as for private utilities and cooperatives for facilities outside of 3 miles from the corporate limits of municipalities - commission has no jurisdiction within the 3-mile limit.
6/ No, except for service outside the municipality. General Municipal Law, Sec. 361, 364; Public Service Law, Sec. 68.
7/ Implied authority from statute.
8/ Generating plants in excess of 50 MW.
9/ Not necessary to obtain certificate for extension of its line, plant or system if contiguous to its existing system and if such extension is not into area of another utility of like character, and if extension is necessary in the ordinary course of its business.
10/ Although certification is not required, all capital expenditures in excess of $500,000 or 10% of the total plant in service must be submitted to the Commission for review.
11/ The certificates of public convenience and necessity heretofore issued by the Commission for the most part authorize construction of minor electric, gas and telephone plant of all sorts, without time limit, within specified municipalities. Therefore, a utility needs no additional certificate, other than for a major steam electric generating facility or an electric or gas transmission line to construct additional plant within its previously certified area. For any construction outside its previously certified area, approval of the Public Service Commission is required. Non-retail gas transmission by exploration companies needs no franchise, but must meet safety standards and may require an Article VII certificate.
12/ Participates through membership on Power Siting Commission, which has authority as indicated. Note: Power siting now part of PUCO.
13/ Transmission lines in excess of 200 KV.
14/ Certificates are required if new areas are to be served by the facilities. The state is completely covered for telephone service.
15/ Department has power to rezone property for construction of utility facilities and make takings in Eminent Domain Proceedings.
16/ Limited to when condemnation is required.
17/ Once a utility has been certified by the Commission, the general policy followed by the Commission is to not require further certification for major additions within the service area of the utility.
18/ Certificate needed for extensions into new territory not contiguous to existing service or being served by another utility.
19/ Only outside municipal limits.
20/ Indeterminate permits in Wisconsin come into existence by operation of law resulting from any grant from the State for a municipality to any public utility to own, operate, manage or control any plant for the furnishing of a public utility service. Whether an indeterminate permit exists in any given situation depends essentially upon the existence of such underlying grant.
21/ To the extent that is not in conflict with interstate commerce (Federal Energy Regulatory Commission [FERC]).
22/ Only electricity generated by water power.
23/ All territory is incorporated.
24/ Upon proper application.
25/ No, except where duplicate franchises may have been granted to more than one utility.
26/ Unless the territory is contiguous to another public utility.
27/ Colorado PUC has no jurisdiction over municipally-owned utilities operating inside corporate limits except as to gas safety.
28/ To extent a municipality generates power for resale.
29/ Louisiana Constitution of 1974 grants wide and plenary authority to "regulate" but no specific certification authority is provided except by statute to radio common carriers. Authority may be implied. Allocation of territory has been undertaken by General Order as well as RS 45:121 et seq.
30/ 35 MRSA, Sec. 212.
31/ Certificates, Permits and Licenses - None in Montana.
32/ The key word here is authority. The Commission can do all these things on the basis that utilities must provide safe, adequate and proper service.
33/ Utilities, at their option, may request exclusive territories.
34/ If significant environmental impact.
35/ Electric facilities owned and operated by the government and are regulated by the Commission only for rate increases. No natural gas service in the Virgin Islands other than "bottled gas" which is not regulated by the Commission.
36/ The term "certificates of convenience and necessity" does not apply for construction, but the agency does approve major additions of all regulated utilities.
37/ Cannot be exclusive territory.
38/ Yes, for licenses hydro-electric projects only.
39/ Compression, underground storage and LNG plant.
40/ The 1974 legislature gave territory authority to the PSC over all electrics, including municipal and REAs to settle disputes among utilities.
41/ Limited authority.

FOOTNOTES - TABLE 42 - CERTIFICATES, LICENSES AND PERMITS - PART I (CONTINUED)

42/ The Regie has exclusive jurisdiction to decide the location and conditions for connecting the installations necessary for the operation of a public service. It may also order the sharing of the utilization of a public service installation (for distribution lines). Finally, an undertaking must also obtain the Regie's authorization to extend or amend service.
43/ The Regie's authorization is needed to abandon service.
44/ Have authority, but no public gas companies in Vermont.
45/ Authority rests with Energy Resources Conservation Board for electric and gas.
46/ Certificates are not applicable to telephone companies and systems under the Ontario TSC jurisdiction.
47/ Participates through membership on Connecticut Siting Council which has authority indicated.
48/ The Board has power to grant franchises but not certificates of convenience except where territory already served by a public utility. Board's approval is required for expenditures to construct major additions. Consent of Board is required for any abandonment of lines or works.
49/ Notice of abandonment must be filed as a change in rates and the effectiveness may be suspended for five months.
50/ There are no public gas utilities in Oregon.
51/ All electric and telephone utilities, including cooperatives and municipals, must have Commission approval to serve outside assigned service areas. Gas utilities serve on a local franchise basis.
52/ MPUC approval required for construction of electric generating and transmission facilities under 35 MRSA Section 13-A.
53/ The utilities are owned and operated by the government; the Commission has authority over rates only.
54/ Only if outside of certificated service area.
55/ Generating plants with capacity of 12 MW or greater.
56/ Transmission lines rated 100 KV or greater.
57/ Only upon the request of the appropriate utility.
58/ Article VIII of the State's Public Service Law establishes within the Department of Public Service a Board on Electric Generation Siting and the Environment intended to have one-stop siting jurisdiction. The Chairman of the Public Service Commission acts as Chairman of the Board. The other members are the Commissioners of Environmental Conservation, State Energy Office, Health and Commerce, an ad hoc member appointed by the Governor, who shall be a resident of the judicial district in which the facility as primarily proposed is to be located, and an ad hoc member appointed by the Governor, who shall be a resident of the county in which the facility as primarily proposed is to be located.
59/ Article VII of the Public Service Law requires a certificate for major electric and gas transmission lines. It does not apply to telephone lines.

INTRODUCTION

In the midst of substantial controversy, the Fifteenth Legislature has spent a great deal of time discussing numerous state energy issues. Topics include the financing and regulation of the Bradley Lake Hydroelectric Project and the broader question of regulatory jurisdiction over state-owned wholesale power; the disposition of the Railbelt Energy Fund; state construction and upgrade of Railbelt interties; state construction of a natural gas pipeline to the Interior; and proposals for the future financing of energy loans, the Alaska Power Authority (APA) and the Power Cost Equalization (PCE) program.

Previously, the Cowper Administration Budget Transition Team recommended that the energy functions provided by the Alaska Power Authority and the Department of Community and Regional Affairs (DCRA) be examined closely, with strong consideration being given to their consolidation in a single energy division. In mid-1987, Governor Cowper appointed an Energy Policy Task Force and charged them with the task of examining the state's energy programs and recommending ways to make them as efficient and affordable as possible.

These legislative and executive deliberations are occurring at a time when urban utilities are facing surplus capacity and declining sales and when rural utilities have become heavily dependent on a state rate subsidy. Utilities, municipalities and individuals statewide are feeling the effects of an economic downturn. The need to maximize flexibility and minimize uncertainty in the delivery of energy services is underscored by the economic uncertainties facing Alaska today and in the future. With state and local governments, utilities and individuals facing tough budget decisions, securing lowest cost energy options in the short- and long-term future is desirable.

This agency was asked to examine Alaska's energy planning, programs and policies from a perspective which seeks to minimize costs of energy services--to the consumer, the utilities and the state. This report begins with a general discussion of energy planning; a least cost planning perspective is the current focus across the nation with 25 states actively using this approach. We assess Alaska's current energy programs--what we are doing and where the public funds are going. Specific suggestions are made to reorient state programs in the near future toward efforts which more effectively address current energy needs statewide. In addition, the

report presents legislators with an outline of a future direction for Alaska's energy programs. Following a transition period, state decision making would be anchored to a deliberate, planned process that identifies the best and lowest cost options for meeting Alaska's future energy needs.

Chapter One describes the evolution of energy planning nationwide, particularly during the last decade as load growth, capital costs and fuel prices have become more unpredictable. We review state and utility energy planning nationwide in order to present a view of where the leaders are and the methods they are employing. We explain the convergence of society-based least cost planning and utility-based demand-side management into the state-of-the-art approach of integrated resource planning under which all reasonable supply- and demand-side options are considered on an equal basis. Specific information about current energy planning in other states, the Pacific Northwest, and one utility is presented.

In **Chapter Two**, we examine past energy planning in urban Alaska and suggest what might have happened differently had an integrated resource planning process been in place. Second, an integrated resource planning perspective is applied to today's urban energy programs in order to assess current strategies, options and levels of spending in light of the current energy situation in urban Alaska. A number of suggestions are made which would address urban energy problems in the near future more effectively than some of the current programs.

Chapter Three presents an overview of past energy planning and programs in rural Alaska and also suggests what the state might have done differently if integrated resource planning had occurred. The myriad rural energy programs today are examined within an integrated resource planning framework which defines strategies and looks at where the public funds are being spent. Based on an assessment of the effectiveness of current rural energy programs, several specific suggestions for reorienting state efforts are offered for action in the near future.

In **Chapter Four**, we discuss the implementation of integrated resource planning statewide during the next few years. The state's future role in energy affairs--particularly energy planning--is considered. An integrated resource planning approach in Alaska, which blends both utility-directed and state-directed planning, is suggested. We describe specific elements of the planning process itself and outline an appropriate organization of energy functions and programs. Finally, we offer a means to initiate an integrated resource planning process in Alaska's immediate future.

This report analyzes Alaska's energy efforts separately for the urban and rural regions of the state. The primary reasons for this division are: 1) some distinct differences in the production and cost of urban and rural energy; and 2) the differences in makeup and focus of most past and present energy programs in urban and rural Alaska. For the purposes of this energy report, we have defined urban and rural Alaska, as follows:

Urban Alaska - the more populated communities which are also serviced primarily by an interconnected power grid or major hydroelectric projects. The urban communities include: Anchorage, Fairbanks, Homer, Juneau, Kenai, Ketchikan, Kodiak, Palmer, Petersburg, Seward, Sitka, Soldotna, Valdez, Wasilla and Wrangell.

Rural Alaska - the less populated communities, which in general have isolated power generation systems serving only the immediate area, or other scattered settlements which experience high energy costs relative to urban Alaska.

Based on the most recent population figures available from the Alaska Department of Labor, we estimate an urban population of about 394,000 (73 percent) and a rural population of about 146,000 (27 percent) as of July 1, 1986.

EXECUTIVE SUMMARY

CHAPTER ONE: ENERGY PLANNING

Introduction

Until the mid-1970s, nationwide annual demand for electrical power increased steadily and fuel prices and interest rates were relatively stable. In this more predictable environment, the primary role of electric utility planning was to assure that long construction lead times did not interfere with utilities' ability to meet demand with supply-side options. Utility supply planners used historic demand growth to project future load growth and built power plants based on those projections.

Nationally, the 1973 oil embargo radically altered the energy planning environment. Load growth, capital costs, and fuel prices increased rapidly during the 1970s, causing real electricity prices to increase dramatically compared to prior decades. This dramatic increase in real electricity prices, coupled with a recession and the emergence of cost-effective energy efficiency technology caused load growth to slow substantially in the early 1980s.

As load growth, capital costs, fuel prices and competition have become more unpredictable, utility planning methods became more sophisticated. In recent years, there has been interest in planning methods that focus on alternatives to supply-side options. Two such approaches, **Demand-Side Management** and **Least-Cost Planning**, address opportunities to modify the way in which energy (especially electricity) is used in order to reduce the need for new generation sources. The term "least-cost planning" is sometimes used to describe the balancing of a mix of supply- and demand-side alternatives to meet society's energy needs at the "least-cost." A more descriptive and accurate term for this balancing is **Integrated Resource Planning (IRP)**.

Demand-Side Management

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/or magnitude of a utility's load. Demand-side management is a planning process developed by utilities and their research institutions to address demand growth uncertainties and financial vulnerabilities faced by utilities during the past decade. Initial research and implementation of demand and load management programs were conducted by innovative utilities without any regulations requiring them to do so.

Utility demand-side management programs include: load management, new uses, strategic conservation, electrification, power customer self-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.

Least-Cost Planning

At the same time that utilities and regulators were grappling with the shifting energy environment, there was a growing interest among government energy planners and research institution analysts to develop a new framework for meeting energy users' needs. The framework for these analyses conveyed a new societal perspective of minimizing the societal costs and risks of meeting energy needs. Least-cost planning appeared in situations where government and the public perceived there was a failure of regulatory and market mechanisms to achieve a "least-cost societal solution" to the delivery of energy services. When speaking about least-cost planning today, it is important to recognize the evolution of the scope of energy sources and functions included. Today, least-cost planning is often interpreted to mean any process which integrates supply- and demand-side planning by comparing the costs of each alternative. In contrast, early least-cost analyses focussed on the technical potential of demand-side alternatives to replace supply-side options.

Integrated Resource Planning

Integrated resource planning, as it has evolved from demand-side and least-cost planning, is a process through which all reasonable options for both supply and demand are assessed against an array of cost and benefit considerations which are defined as broadly as possible. This approach does not segregate suppy-side options from demand-side options but instead seeks to evaluate all options on an integrated, equivalent basis.

Integrated resource planning evaluates programs from the perspective of the participant in the program, the nonparticipant, the average ratepayer, the utility, and society-at-large. The convergence of least-cost planning and demand-side management is occurring through the development of a process which combines the societal and customer perspective of least-cost planning and the utility and individual ratepayer perspective of demand-side management.

In order to achieve an integrated resource planning process that addresses all these perspectives, it has been necessary for states to pass legislation requiring planning and to write specific rules. Utilities and consumers have actively participated in the rulemaking process to assure that the planning process would be workable for all parties involved. It is unrealistic to expect that utilities will engage in integrated resource planning unless required because they cannot be expected to assess benefits and costs from a societal rather than utility perspective.

Approaches to Integrated Resource Planning in Other States

The predominant mechanism for establishing an integrated resource planning process by states has been through legislation that provides the state public utilities commission with the authority to require utilities to conduct planning. The 25 states that are using or developing IRP vary considerably in their scope of planning. All consider electricity on a utility by utility basis but some also consider electricity on a statewide basis. Some include natural gas in their planning review. The level of state resource commitment varies with the purpose and scope of planning efforts and with the level of state involvement in the planning process. Current levels of annual effort range from less than one person year to at least 14-person years. There are three general state prototypes of integrated resource planning approaches--utility planning, statewide overview, and countervailing recommendation.

Several key components have been identified to be important to the integrated resource planning process:

- **Integration of the Planning Process.** On a substantive level, demand forecasts and the demand- and supply-side options are integrated to derive the "least-cost" resource plan. In addition, regulators strive for integration of utility rate making and construction permit proceedings to ensure that the planning process takes hold.

- **Sufficient Methodological Specification.** Specification of the methodology and models to be used by utilities is necessary, but must not be so rigorous as to thwart innovation by utility planners.

- **Required Implementation.** Action plans which specify how utilities plan to acquire and implement resource options are necessary.

- **Utility Responsibility for Plan Creation.** If utilities have primary responsibility for creation of resource plans, they are more likely to use them in internal and external decision making.

- **Plan Enforcement.** The regulatory process must provide for an enforcement mechanism to ensure that utilities adequately conduct the planning and follow through with implementation of the "least-cost" resource options.

Examples of Integrated Resource Planning At Work

Examples of planning in the Pacific Northwest and Southern California were selected because each emphasizes planning for uncertainty to maximize flexibility and minimize costs. Because of the natural volatility of Alaska's economy, this approach to planning is especially pertinent.

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. The council's planning strategies are particularly relevant to the Railbelt and some other areas of Alaska, because the Pacific Northwest, like the Railbelt, currently has a large surplus of power and future demand levels are uncertain. The council utilizes an integrated resource and risk minimization planning approach. The council attempts to maximize flexibility by identifying options with short lead times, small sizes, and/or low capital costs. Conservation is considered a highly flexible option in the Pacific Northwest.

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. An option moves through the time-consuming but relatively inexpensive siting, design, and licensing steps, after which it can be scheduled, placed on hold, constructed, or terminated, depending on the demand for electricity. The objective of the resource options 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. The value to the region of this two-stage decision making process is estimated to be $700 million during the 20-year planning horizon.

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 implemented, will no longer be available and cost-effective. Conservation standards for new residential and commercial buildings for energy efficient construction is an example of a lost opportunity resource the Northwest Region is currently pursuing.

The council's planning strategy is based on a societal perspective. The objective 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 result 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. As the business environment began to change, starting in the late 1960s, the process of load forecasting and resource planning became more complicated. 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.

The SCE scenario 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. The SCE has discovered that many alternative scenarios result in similar consequences relative to the need for new resources, thus reinforcing the importance of focusing on the consequences of scenarios as opposed to the events or scenarios themselves.

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. 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 SCE's planning methods have been widely acclaimed and emulated by other utilities.

CHAPTER TWO: APPLICATION OF INTEGRATED RESOURCE PLANNING TO URBAN ALASKA

History

In the mid-1970s, the major energy concern identified for urban Alaska was the ability of utilities to finance and build generation capacity to meet rapidly growing demand. Based on expected growth rates, the Institute of Social and Economic Research (ISER) identified utilities' ability to finance generation capacity as a major obstacle to low electrical rates in urban Alaska. The ISER suggested several alternatives to lower the cost of construction financing. One alternative was the establishment of a state-owned power authority that "would be able to borrow in the tax-free municipal bond market and provide interim construction financing." By serving as a financing agency to lower the cost of money, the public corporation could indirectly lower electric rates. To this end, the Alaska Power Authority (APA) was established in 1976 as a quasi-independent public corporation.

Drawing upon a windfall of oil revenues, the state appropriated $1.3 billion for urban energy programs between FY 77 and FY 88. This amounts to approximately $3,359 per urban resident. This appropriation frenzy did not allow adequate opportunity for a thorough evaluation of energy projects or alternatives. As a result, urban energy dollars were probably not spent as efficiently or equitably as possible. In urban Alaska, for example, the cost per installed kilowatt of state built and owned hydroelectric capacity ranges from $4,420 to $10,499. Similarly, the per capita state appropriations for urban energy projects range from approximately $900 in one community to $25,000 in another.

Within urban Alaska, over 99 percent of the energy appropriations was spent on supply-side projects; approximately 89 percent was spent on hydroelectric projects. Less than one percent of urban energy expenditures was spent on demand-side projects. Most of the demand-side appropriations were federal weatherization program dollars.

What would have happened had integrated resource planning (IRP) been in place during the last decade? If supply- and demand-side options had been considered equally, more state money would most likely have been directed to demand-side options. On the supply-side, regularly updated forecasts and monitoring of electrical demand growth would have made apparent the inaccuracy of ISER's 1976 forecast of electrical demand. Recognition of this trend could have resulted in lower expenditures on the Susitna hydroelectric project. Additionally, the high load forecast and the state's zealous construction of large projects created an environment in the early 1980s that focussed on supply-side growth. Under an IRP process, utilities would now be in a more flexible position to ease the adjustment to a declining economy.

Rather than requiring projects merely to be feasible, IRP would have also required projects to be cost-effective and the lowest cost alternative. More extensive analysis of the Four Dam Pool projects from a cost-effectiveness perspective probably would have resulted in the scaling back of some projects or, for example, the construction of one dam and an intertie system between the communities of Wrangell, Petersburg, and Ketchikan.

Given the strength of the political momentum in the early 1980s to fund large power projects to create construction jobs and encourage economic development, it is unlikely that IRP could have completely redirected the momentum as state revenues soared. Planning, however, could have made the economic development versus energy production objectives more explicit.

An Integrated Resource Planning Assessment of Current Urban Energy Programs

The general energy problem in urban Alaska today is that the energy systems were developed in anticipation of higher and unabated demand growth. The focus has been on increasing installed generation capacity to meet this anticipated demand. As a result of Alaska's economic recession, most of urban Alaska is experiencing large surplus capacity while population and economic activity have declined, i.e., the revenue base has fallen.

A number of conclusions can be drawn from the examination of current urban energy programs:

1) Approximately $9.7 million of state and federal funds is being spent in FY 88 on urban energy (electrical and space heating) programs. This is about 21 percent of the total public funds ($47.1 million) currently directed toward energy programs and projects statewide.

2) Approximately 45 percent of the public's current urban energy expenditures is directed toward electrical services; 55 percent is for space heating. The state, however, directs 98 percent of its energy dollars to electrical services while 93 percent of federal funding is allocated to space heating. Federal energy assistance and weatherization programs are income-based.

3) As in previous years, the majority (94 percent) of state electric program dollars are being spent on supply-side options. Almost all state demand-side dollars are to match federal funds; the state has initiated no demand-side programs in urban Alaska. Almost all federal energy dollars are for demand-side programs.

4) Approximately 94 percent ($4.1 million) of the state's current electrical funding is for analyses of supply-side alternatives for the use of the Railbelt Energy Fund. Given the Railbelt's excess capacity until after the year 2000, these expenditures appear to be driven by the availability of funding rather than a need to increase capacity. These expenditures are also being made to determine the feasibility of individual projects without a long-range assessment of supply- and demand-side energy needs of the Railbelt.

Viewed as a whole, it is apparent that urban energy programs and expenditures are not well matched to evolving state policy or the current situation in urban Alaska. Relatively little is being done to address the near-term (0 to five years) energy problems in urban Alaska.

Short-term Reorientation of Urban Energy Programs

In the short term, there are a number of alternatives that address the urban energy problem more effectively than some of the current state programs. Suggested programs options are designed to either lower power system costs and improve utility financial conditions or improve end-use efficiency.

Utility Financing. Two of the program options are directed at lowering the cost of utility debt. The first provides increased funding through the Power Project Loan Fund to finance capital expenses of electric utilities in the near-term. The other, to refinance high-cost debt. If the Railbelt Energy Fund financed both of these programs, the fund would provide short-term rate relief to customers while assuring use of the Railbelt Energy Fund for Railbelt energy needs. From a planning perspective, the options are attractive because they offer a practical solution to a political debate during a period when the region has excess capacity. The existing and projected excess capacity make additional investment difficult to justify on a strictly economic basis.

Regulatory Review. Another program area that could provide indirect rate relief is modifications to the regulatory review system. Increased funding to the APUC would allow them to more effectively conduct their responsibilities. One method to provide funding is to incorporate a "users' fee" into the rates of regulated industries. This is a common practice in other states. The other suggestion is a prioritization and subsequent reduction of APUC responsibilities to match their available funding.

Load/Demand Management Pilot Projects. Despite the benefits of increased demand and load management in urban Alaska, these strategies are relatively new and untested and require financial and time commitments to develop. In most of urban Alaska, the financial status of utilities today is not conducive to project testing and experimentation. A state program to support demand and load management pilot projects would overcome this obstacle.

Improve End-Use Efficiency. Given the current surplus in urban generating capacity, there are limitations to short-term improvements in end-use efficiencies that would not have a detrimental effect on electrical rates. Therefore, although it is inevitable that some electric customers will attempt to increase end-use efficiencies, in the short-term it is unrealistic to expect utilities facing falling demand to actively encourage programs that will further reduce their declining revenues.

There are improvements in end-use efficiencies, however, that should be encouraged even if demand is declining. These include programs such as residential and commercial building energy standards and appliance efficiency standards. The cost to retrofit buildings is much greater than the cost to efficiently construct them in the first place. Similarly, the stock of electric appliances takes many years to be replaced by more efficient models. To initially install an efficient appliance is also more cost-effective than later developing rebate programs to encourage the purchase of more efficient models.

Improvements in energy efficiency--especially in public buildings such as schools--is another area identified for short-term, as well as mid- and long-term, potential energy programs. From a fiscal standpoint, it makes sense for public buildings to be operated and maintained as efficiently as possible to maximize the social benefits of state funds. Therefore, despite the potential effects on utilities and ratepayers, who are also beneficiaries of state programs such as education, opportunities to improve end-use efficiencies in public buildings should be explored even in the short-term because their social benefits may outweigh individual ratepayer or utility costs.

CHAPTER THREE: APPLICATION OF INTEGRATED RESOURCE PLANNING TO RURAL ALASKA

History

Prior to the 1970s, the state did not put a great deal of time or money into the electrification of rural Alaska. The federal Rural Electrification Administration (REA) was a primary source of financing for several rural utilities established in the 1960s and early 1970s.

Several studies assessing rural power systems in the mid-1970s reflected Alaska's preoccupation with new power development throughout the state as well as the gathering momentum to more adequately electrify rural Alaska. A 1979 study on rural energy options noted, however, that the lack of a comprehensive rural energy policy lead to a reactive and piecemeal approach by the state in addressing the problems of rural power systems throughout the 1970s.

Major energy legislation in 1980 and 1981 established several rural programs, including village and regional studies which investigated various supply-side options to meet present and future energy needs. Individually, these programs addressed different aspects of the rural power picture, but it is difficult to find an overall set of objectives which guided their development. However, the intent of such legislation was quite clear The interests of the people would be served through the provisions of adequate, safe and reliable power at affordable rates.

A flood of state electrification grants to rural communities commenced in FY 80 and continued unabated through FY 85. Many projects received no technical oversight by the state. The unfortunate legacy of this electrification spending spree is many oversized power plants operating at inefficient loads and a constant stream of requests to the APA staff for technical fixes to these systems--because many of these systems have not worked very well.

The Power Production Cost Assistance (PPCA) program, which subsidized the high cost of rural power, was created in 1980 and was viewed as an interim measure until lower cost alternatives to diesel generation could be devised. Over the years, the subsidy (now called the Power Cost Equalization Program) has increased generally to keep pace with the sizable grants and loans for urban power projects and as the lack of alternative technology "fixes" for rural power became apparent.

During the period FY 77 to FY 88, the state appropriated roughly $276 million specifically to rural energy programs--or about $1,890 per rural resident. About 87 percent of these funds was directed toward supply-side programs, with the remaining 13 percent for demand-side efforts. Currently, most of the state's rural energy capital is being spent on a power rate subsidy which provides short-term relief to the underlying problem of a cash-poor economy more than it addresses the costs of providing power or keeping warm.

What would the state have done differently had integrated resource planning (IRP) been in place during the past decade? If supply- and demand-side options had been considered equally, it appears likely that more state funds would have been directed at demand-side programs, particularly those programs which addressed the high cost of thermal energy to heat inadequate rural homes. Under IRP, the state might have retained considerable design review and technical oversight once rural electrification grants were given to communities. Many of the oversized power systems that exist today might have been avoided. In addition, the power rate subsidy might have retained its original design to alleviate the high electric costs for only a minimal amount of consumption (e.g., 200 to 300 kwh/month per customer) because an IRP approach would have been able to clearly identify other supply- or demand-side alternatives which were more cost-effective in the long run and which therefore warranted state funding.

An Integrated Resource Planning Assessment of Current Rural Energy Programs

The overall energy problem in rural Alaska today continues to be high cost energy (both on a unit and total cost basis) in a rural economy with scarce cash. Rural households spend roughly 30 percent of their income on energy purchases. Over two-thirds of those energy dollars are spent for space heating, 20 percent for electricity, and the remainder on fuels for transportation, cooking, etc. Rural residents need safe, reliable power and improvements in housing, heating systems, appliances and lighting in order to use both electricity and thermal energy efficiently.

Several conclusions can be drawn from an assessment of current rural energy programs:

1) About $37.4 million in state and federal funds is being spent annually on rural energy needs. This represents roughly 79 percent of the estimated $47.1 million being directed toward energy programs and projects statewide.

2) The various programs address, to some degree, a broad range of strategies. However, the current orientation in Alaska's rural energy efforts is heavily weighted toward funding of programs which address rural electric services (about 76 percent), despite the fact that space heating expenses are generally more substantial for rural households.

3) Supply-side options clearly command the lion's share (89 percent) of the public funds directed toward rural energy problems. However, just over one-fourth of this supply-side funding is being spent on long-term solutions of power system improvements, technical training and bulk fuel handling. Most of the supply-side funds are going into short-term cash assistance programs--Power Cost Equalization (PCE) and Low Income Home Energy Assistance.

4) Virtually all of the funds being spent on demand-side options are federal money--primarily in the Low Income Weatherization program. Only one percent of the total state funds are committed to demand-side options.

An evaluation of the effectiveness of current rural energy programs at meeting several energy-related and public funding criteria provides the following conclusions:

1) In general, the supply-side programs which improve utility or municipal finances and/or power system efficiency and reliability have--at best--a moderate direct effect on the consumers' energy costs, living conditions and energy savings. On the other hand, several of the demand-side programs which lower consumer costs, improve living standards and save energy are deemed to have little direct effect on utilities and municipalities and their power systems.

2) One program--Power Cost Equalization--stands out by having negative effects on energy savings and power system efficiency. This subsidy encourages energy consumption by artificially lowering rural power rates. Furthermore, the subsidy, which covers most utility expenses, discourages local efforts to improve power system efficiency or reduce fuel costs. The PCE program also undermines other programs geared toward minimizing rural energy costs through fundamental improvements in power systems and end-use efficiencies.

3) Of the **programs funded solely by the state,** Rural Technical Assistance (RTA) is currently a low-cost effort judged to be fairly effective at helping utilities improve systems. The various bulk fuel programs, funded by the state at relatively low levels, yield moderate results with respect to lowering customer energy costs and improving the utility and municipal fiscal picture. The Rural Electrification Grants and Loan programs are fairly effective at meeting the needs of rural utilities, but at a higher cost to the state. Finally, the PCE program is highly effective at lowering customers' costs and improving the utility/municipality fiscal condition--but at a tremendous cost in state funds as well as the cost of lost opportunities for more efficient power systems and energy savings.

4) Most programs provide **mid- or long-term benefits.** The short-term exceptions are: 1) the cash subsidies programs (PCE and Low Income Home Energy Assistance); and 2) the Bulk Fuel Revolving Loan program which provides municipalities loans for annual fuel purchases. The benefits of several training programs may be only mid-term in duration because of the turnover in local people trained to operate and maintain the equipment.

When current rural programs are ranked, a supply-side option--Waste Heat Recovery--is considered to be the most effective overall. A demand- side program, the Low-Income Weatherization Program, is ranked second in terms of overall effectiveness. The ranking strongly suggests that the level of funding, particularly state funds, directed at some of the energy programs is inappropriate. Several programs--including waste heat recovery, weatherization, electrification grants, rural technical assistance, efficient lighting and energy conservation planning--appear to be underfunded in light of their relatively high overall effectiveness. Despite its effectiveness at lowering consumer cost and improving utility finances, PCE ranks as least effective overall, and yet, it garners about 66 percent of state funds spent on rural energy.

A Reorientation of Rural Energy Programs

Most would agree that a need for power system improvements still exists and that some sort of state assistance to help rural residents pay electric bills is appropriate. At this time, however, a significant shift in emphasis toward programs that foster efficient energy production and consumption appears essential if the state is to maximize the use of available public funds in alleviating long-term energy needs in rural Alaska. In general, rural needs exceed the state's ability to pay, therefore, the focus must be on efficient, long-term solutions. The following suggestions would reorient rural energy programs toward this goal and could be implemented in the near future while the state considers longer range changes to its entire energy efforts statewide.

Funding and Administration of Electrification Projects. At this time, the statutes should be amended to require technical oversight of electrification grants to municipalities (AS 37.05.315) and unincorporated communities (AS 37.05.317) in order to maximize the construction of efficient power systems. Funds appropriated directly to the APA for various electrification projects are, of course, subject to the state's contracting and procurement procedures. The cumbersome nature of these procedures--coupled with a project's remoteness, tight shipping schedules and relatively short building seasons--can delay power system improvements considerably. At this time, the APA should review and streamline internal contracting and procurement procedures (to the extent possible) in order to maximize delivery of staff services on these rural projects. Furthermore, we believe that the APA should investigate the procurement and accounting system established by the Department of Environmental Conservation (DEC) for rural sanitation projects under the Village Safe Water Program (VSWP) as a possible model for accounting flexibility which could be applied to the Rural Energy Construction Assistance program.

Waste Heat Recovery Program. Emphasis by the APA should be placed on arranging heat sales contracts among the school districts, municipalities and utilities as well as getting the inoperative waste heat systems working. Other systems constructed with state funding over the years should be encouraged to (or required to) establish heat sales contracts within the next year, if not already in place, so that the utilities can increase revenues and the state can reduce PCE payments. **Future waste heat recovery projects which receive state technical or financial assistance should routinely require firm heat sales contracts prior to construction.**

Rural Technical Assistance (RTA). During the course of their field work, RTA staff may identify circumstances where relatively low-cost modifications, equipment or materials would provide immediate efficiency improvements to the rural power systems. On occasion, the APA has rectified problems using funds available under the Rural Electrification program, the remaining portion of which will be expended during the current fiscal year. **Strong consideration should be given to the replenishment of these rural electrification funds in the FY 89 budget and to specifically earmark a portion as "on hand" funds for minor system improvements or modifications.** The alternative, for many communities, will likely be "making do" with an inefficiently functioning power system until funds are secured via a legislative appropriation.

At this time, the APA should also investigate the establishment of a **regionalized "circuit rider" program as a component of the RTA program in FY 89**--similar to the Remote Maintenance Worker program administered by DEC for rural sanitation systems. Rather than strictly a troubleshooting and emergency assistance program, the DEC program is designed to provide routine checkups and critical pre-winter system tune-up reviews. Not only would these efforts provide routine help to rural utility operators, but they would also provide useful administrative and operational experience and cost information with which the state and local utilities could investigate the possibility of establishing additional regionalized utilities in the future.

Power Cost Equalization. As a near-term strategy for the program, a starting point could be the imposition of a funding ceiling at, for example, $19 million in FY 89. Funding at this level would necessitate some adjustments to the program in order to reduce projected costs in FY 89. Several adjustments to the PCE program are considered, with varying effects on different user categories. The adjustments would send modest energy conservation signals to the consumers, while at the same time free up money for other, more effective programs.

Two suggestions have been made that represent a more fundamental overhaul of the PCE program to encourage long-term efficiencies. One of these suggestions is to establish standards for maximum operating and fuel costs that would be eligible for PCE payments for utilities of varying sizes in different regions of the state. The other proposal would change the current consumption-based monthly PCE subsidy into a fixed payment formula-based subsidy. The payment would be calculated based on a formula which takes into consideration the size of the utility (i.e., the number of customers) and fuel costs. Both appear to require more thorough analysis because of the fundamental changes they propose. **Funding should be provided in FY 89 to study these alternatives and make specific recommendations for implementation in FY 90.**

Ultimately, it would be desirable to determine an acceptable level of longer term funding for a rate subsidy to be provided to rural residents. Following an adjustment to reduce costs under the current PCE program, a schedule should be devised for lowering costs gradually to a sustainable level of funding. As PCE costs are reduced, the funds can be directed at more productive and effective rural energy programs. In the long run, the large fuel savings and efficiencies gained under other rural energy programs will offset a significant reduction into PCE subsidy on monthly power bills.

Energy Conservation Standards for Residential Buildings. The state should implement the standards developed by the Department of Community and Regional Affairs (DCRA) for the construction of reasonable energy-efficient housing in Alaska. More rigorous, optimal standards have been in place in many other states for years.

Low-Income Weatherization Program. The DCRA should place a high priority on convincing the federal Department of Energy to allow for the purchase and installation of wood stoves, as has been done in the case of high-efficency oil heaters. A wood stove option would provide additional flexibility to contractors--particularly those operating in Southeast and Interior Alaska villages where wood space heating is common. Furthermore, within the limitations imposed by federal regulations, the state should emphasize the most cost-effective weatherization measures. By targeting measures that maximize energy savings (such as attic insulation, caulking or metal insulated doors), the program results in more cash-on-hand in rural households--available for other essentials, including home repairs.

Space Heating Initiative. The replacement of inefficient oil heaters or wood stoves provides an avenue for significantly lowering household fuel consumption. The state could have an immediate, positive impact on rural families' cash flow if it addressed space heating--the major component of household energy expenses. The estimated cost of efficient oil heaters or wood stoves is roughly $1,200/unit (including freight and installation). At reported fuel savings of 30 percent, these units would pay for themselves in two to five years. The lack of capital, however, presents a virtually insurmountable barrier to the purchase of these units in many rural households. Under a space heating initiative, each household could be offered an efficient oil heater or wood stove. For households in which new heating systems are inappropriate, the homeowner could choose the equivalent value in installed weatherization measures. The state could: 1) provide a rebate paid to state-approved vendors for households which purchase units; 2) offer a low interest loan; or 3) provide a grant.

CHAPTER FOUR: IMPLEMENTING INTEGRATED RESOURCE PLANNING IN ALASKA

The State's Role in Energy Planning

The degree of state involvement in the IRP process in Alaska depends upon the broader role(s) policymakers decide that the state will play in the future energy affairs of Alaska. The long-term thrust of the policies developed by the Governor's Energy Policy Task Force is to get the state out of the business of building and owning additional urban power projects and limit its involvement primarily to regulation, planning, and financing. In contrast to the limited state role in energy planning recommended by the task force, the IRP approach to energy planning is based on the state playing a central role in the planning undertaken by all utilities.

An Integrated Resource Planning Process for Alaska

To evaluate various supply- and demand-side IRP options, states utilizing IRP use one of three approaches: utility planning approach, statewide overview approach, or countervailing recommendation approach. Alaska's characteristics--particularly its diverse geography, small population size, mixture of interconnected urban energy systems and isolated communities with independent energy systems, and state ownership of several power production and transmission facilities--makes the selection of a single IRP approach inappropriate. Energy planning in Alaska should include elements of both the utility planning and statewide overview approaches. Furthermore, the use of natural gas for both space heating and electric power generation in the Railbelt as well as the high costs of space heating for rural households necessitate that IRP in Alaska be broadened to include a thermal energy component in the overall energy planning process.

For Alaska's urban communities, the utility planning approach is more suitable--particularly because it provides utilities with the greatest amount of control and participation using their existing planning capabilities. In general, the state's role in the IRP process for urban areas should be that of a reviewer of utility-developed plans. However, as long as the state continues to conduct feasibility studies and consider the construction of additional energy facilities, it will have to be an active participant in the planning process. State projects should be subject to the same planning criteria as the urban utility projects.

In rural areas of the state, most utilities and communities do not have the financial resources or expertise to conduct energy planning. In addition, the state acts as the key source of assistance through its grants and loans to rural utilities and its Power Cost Equalization program. As a result of the state's primary role in rural energy, a statewide planning approach makes more sense. In fact, the state's involvement in the IRP process would extend beyond the typical statewide approach taken in other states. In Alaska's rural areas, it will be necessary for the state to act as the lead planner developing the strategic plans in order to maximize the effectiveness of state funds.

As a starting point in undertaking an IRP process in Alaska, the state should take the lead by reviewing the numerous energy studies that have been conducted during the past several years or which are currently underway. The effort would concentrate on extracting usable information on: 1) demand forecasts; 2) supply-side alternatives; and 3) demand-side management and conservation measures. While this review and data compilation are underway, the state could commence specification of the methodology to be used in developing the strategic resource plans. The specification of methodology is likely to take time, particularly if the state develops these guidelines within a public forum. Utilities and other interested parties must be involved in the process to ensure that the ensuing methodologies are acceptable and workable. Once the methodology is in place, the urban utilities would use these guidelines for their resource plans while at the same time the state would use them to develop an integrated resource plan for rural Alaska.

Integrated resource planning must be accompanied by the implementation of the identified lowest cost options. The planning process must include the submission of an action plan for regulatory review. The plan must provide details concerning the means by which the utility intends to implement demand- and supply-side options.

Although the action plan provides the vehicle to implement the long-term plan, state enforcement authority ensures implementation. The regulatory agency must have the authority to reject or accept plans. To the benefit of utilities, any option that has received advance approval and has been acquired, built, or implemented under sound management practices is assured cost recovery.

The Functions and Organization of Alaska's Energy Programs

In order to determine an appropriate organization of Alaska's energy programs based on an integrated resource planning approach, we identified the necessary energy program functions. The functions identified are planning, technical assistance, energy conservation, state facility maintenance, financing, and regulation. Based on these identified functions, the Governor's Energy Task Force's deliberation on program organization and consolidation, and a review of energy programs in other

states, we conclude that a single division within an executive branch department is the most appropriate organizational structure. Reasons include:

- an autonomous bonding authority will no longer be necessary once the state ceases development and construction of additional power projects; and

- a division within a department is more directly linked to state policy, thereby facilitating program implementation and increasing accountability.

In the short term, the division of energy would conduct planning, technical assistance, energy conservation, facility maintenance and their related activities. The division would also administer grants and loans and review project financing. Because bonding would no longer be the energy agency's principal function, this responsibility is transferred to the Alaska Industrial Development and Export Authority. The Alaska Public Utilities Commission (APUC) would continue to be responsible for rate review and regulation. The administration of the Power Cost Equalization program is consolidated in the APUC. Over time, planning would shift to the APUC.

Initiating Integrated Resource Planning in Alaska

Using an integrated resource planning process as the framework for meeting Alaska's energy needs represents a fundamental change from the past and present modes of operation in the delivery of state energy services. As recently noted by the Governor's Energy Policy Task Force, energy has tended to be used as a proxy for nonenergy issues or as a tool for social purposes during the last decade. Political interest in job creation, economic development, wealth distribution, and community stability have, to a considerable degree, dictated the organization and makeup of energy programs in Alaska. The legacy of past energy practices--excess power capacity in several urban communities, oversized power systems and an expensive rate subsidy in rural areas, and a general dependence on state government to solve energy problems--strongly suggests that we should do things differently in the future.

In most other states which have undertaken an integrated resource planning approach, the effort has emanated from within the executive branch. The legislature provides the fiscal resources necessary for an IRP effort through the annual budget process. In practical terms, a staff effort to orchestrate the development of IRP in Alaska needs to be initiated in the near future. We suggest that a "working group" be established in FY 89 and chaired by staff reporting to the Governor's Office. The group should consist of technical-level staff of the APUC, APA and DCRA who are temporarily assigned to work directly for, and be accountable to, the Governor's Office. Limiting the composition of the working group to agency individuals at the technical level is intended to minimize the politics and maximize the practical "workability" of their results.

Integrated resource planning has evolved across the nation specifically as a method for minimizing uncertainty in planning for future energy needs. By fully integrating supply- and demand-side options at the planning stage, utilities maximize their flexibility in meeting future energy needs at the lowest possible cost. Also, positioning energy planning and regulation in the same agency provides a level of coordination and predictability currently unattainable in Alaska's rate review process. Ultimately, the Alaska customer benefits from reasonably stable rates because we avoid the "big mistakes." Given the uncertainties about Alaska's economic future in general, it is essential that the state initiate a planning process geared toward minimizing uncertainty in the delivery of energy services which are a prerequisite for economic development.

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House of Representatives
P.O. Box V
Juneau, Alaska 99811

Dear Representative Cotten:

Municipal Light and Power and the Municipality of Anchorage are opposed to the passage of HB 238, "An Act requiring certain electric public utilities to prepare certain reports; and relating to costs in proceedings before the Alaska Public Utilities Commission."

If this bill were to be approved by the Legislature, the cost of operations of this utility could increase substantially.

The legislation has the potential for significant financial impact on ML & P. The impacts center on the number of comprehensive planning and technical reports which must be prepared and submitted to the APUC. In addition, the cost of procuring permits from the APUC for plant or transmission line expansion would be very high in terms of meeting new requirements which add nothing to the already burdensome current State and Federal permitting process. Finally, this bill contains provisions which allow the Commission to recover costs from the utility for holding hearings or conducting investigation on these new activities, The costs recovered include the costs of any time devoted to investigation or hired consultants, whether or not the consultants appears as witnesses, expenses incurred by the Commission and the costs of compensating an interested person for all of their reasonable costs of participating in a proceeding or investigation.

The sum of the new regulatory burdens, plus the proposed reimbursement costs would be significant, most likely necessitating a substantial rate increase request. From our perspective, these added new costs and burdens would do little to provide electric power to our customers at a reasonable price.

For these reasons, we oppose the passage of HB 238.

Sincerely,

Tom Stahr
General Manager

HB 238 Ltr.

Alaska Consumer Advocacy Program

513 West Seventh Avenue • P.O. Box 103111 • Anchorage, Alaska 99510 • (907) 272-6355 or 278-3663

Rep. Sam Cotten, Co-Chair
House Resources Committee
Pouch V
Juneau, AK 99811

March 31, 1988

Dear Rep. Cotten:

This letter is written in reference to discussions during the 3/31/88, House Resources Committee hearings on HB 238/9. During the discussion pertaining to intervenor funding, you questioned its relationship to the Alaska Consumer Advocacy Program and ACAP's funding. I would like to clarify the ACAP funding mechanism and stress the importance of the separate intervenor funding provided in HB 238.

ACAP is currently operating under a competitively awarded contract with the State of Alaska, Dept. of Commerce and we are charged with representing consumers' interests in gas, electric and telephone utility issues. ACAP receives no other funding to conduct this state-solicited function. It is interesting to note that some 40+ states currently have funded consumer representation on utility issues. Alaska is unique in having chosen this contractual method as opposed to incorporating the function within some appropriate branch of government. Alaska's choice, through contracting, has brought it the best of both worlds--providing the necessary function while taking advantage of the cost-savings through competitive contracting.

It is unlikely that the provision of intervenor funding contained in HB 238 would have much applicability to ACAP since ACAP's contract contains a specific provision within its funding for intervention in dockets before the APUC. At most, ACAP might seek reimbursement for costs of expert witnesses in select situations where its budget would not cover those special costs. We regard the intervenor funding as a critical source of support to enable individual utility customers, who might have a specific concern too narrow to warrant the involvement of ACAP's class-action level of representation, to effectively present their legitimate concerns. Keep in mind that this, or any other intervention, would only receive funding support if it met the criteria of being substantive, unique and of important significance to the case being heard.

As a normal part of its consumer representation, ACAP has concluded that this least-cost legislation is in the consumers', utilities' and the states' best interests. ACAP is merely fulfilling its prescribed responsibilities by advocating for the passage of this bill. However, as outlined in our testimony, we do so with some apprehension, due to the deletion of Public Utility Commission preview and approval of power projects. We feel strongly that there should be greater oversight of

construction projects prior to construction. As you know, given the cooperative or municipal status of Alaska's utilities, the APUC has little recourse but to pass construction costs on to consumers, even if the additional capacity is expensive and excessive. The Soldotna 1 gas fired generator on the Kenai Peninsula is an example of what can occur without prior construction oversight.

I hope that this letter clarifies the relationship between ACAP and its promotion of HB 238/9. Please contact ACAP if you have any questions or comments.

ACAP is strongly in favor of the enactment of this important and progressive piece of energy legislation. We urge the prompt passage of this bill from the Resources Committee and the House. All Alaskans will benefit!

Sincerely,

J. Hines

John D. Hines
Staff Economist
Alaska Consumer Advocacy Program

Offered: 7/2/87
Referred: Resources and Finance

5-0638B

Original sponsors: Brown, Ellis, Davis, et al.

IN THE HOUSE

BY THE LABOR AND COMMERCE COMMITTEE

CS FOR HOUSE BILL NO. 238 (L&C)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act requiring certain electric public utilities to prepare certain reports; and relating to costs in proceedings before the Alaska Public Utilities Commission."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 42.05 is amended by adding new sections to read:

Sec. 42.05.294. ADVANCE RESOURCE PLANS. (a) An electric utility with annual sales that exceed 300,000,000 kilowatt hours shall file an advance resource plan with the commission on or before January 15, 1989, and every four years thereafter. The plan shall

(1) include a long-term demand forecast, including base, low, and high projections, that projects the power requirements for the utility service area;

(2) list and describe the facilities and energy supply resources of the utility and project future requirements;

(3) list the facilities that the utility expects to remove from service;

(4) include an annual load duration curve and a forecast of anticipated peak loads and reserve margins for the residential, commercial, and industrial sectors;

(5) describe the projected population growth or decline, urban development, industrial expansion, and other factors influencing demand for electrical energy and describe the bases for the projections;

(6) describe additional system capacity that could be achieved by improvements in generating or transmission efficiency, load management, power pooling, interconnection of qualifying co-generation and small power producers, conservation, and reductions in demand through end-use efficiency improvements;

(7) describe the utility's relationship to other utilities and to regional associations, power pools, or networks;

(8) summarize the relevant load management efforts, load research, and energy end-use analysis efforts made by the utility under AS 42.05.415;

(9) recommend an electrical energy resource supply plan that identifies projected plant retirement, development of additional generating capacity and transmission systems, load management efforts, conservation, and cost-effective end-use efficiency improvements, and include a proposal for implementation of the plan; and

(10) include other information considered necessary by the commission to ensure adequate consideration of all supply-side and demand-side alternatives.

(b) A forecast or projection required under (a) of this section must be for the next 20 years.

(c) The commission shall establish by regulation a consistent reporting methodology for advance resource plans required under (a) of this section and shall encourage closely integrated utilities to prepare the plans jointly.

(d) The commission shall review each advance resource plan and may propose modifications to the plan. The commission shall hold a public hearing before approving or proposing modifications to a utility's plan. The commission shall approve the plan if it finds that the plan adequately addresses conserving electrical energy supply

resources through available cost-effective end-use efficiency improvements.

Sec. 42.05.296. PERMITS FOR CERTAIN ELECTRICAL UTILITY CONSTRUCTION. (a) An electric utility with annual sales that exceed 300,000,000 kilowatt hours may not construct or expand a plant or transmission system to increase its capacity by more than five megawatts unless the utility has obtained a permit from the commission.

(b) The commission may not issue a permit unless it finds that the project is necessary to meet future demand that cannot be met by cost-effective load management alternatives, including conservation and energy end-use efficiency improvements.

* Sec. 2. AS 42.05.411 is amended by adding a new subsection to read:

(d) The commission may not allow a rate revision to take effect for an electrical utility subject to AS 42.05.415 unless the commission determines that the new rate is consistent with the development or maintenance of the lowest cost electrical energy supply system for the utility under the utility's most recent load management report.

* Sec. 3. AS 42.05 is amended by adding a new section to read:

Sec. 42.05.415. LOAD MANAGEMENT REPORT. (a) An electric utility with annual sales that exceed 300,000,000 kilowatt hours shall file a load management report with the commission on or before October 1, each even-numbered year. The commission shall establish guidelines for the report by regulation. The report shall

(1) identify the cost of service for specific classes of customers;

(2) assess the opportunities for improved load management;

(3) evaluate the potential for reducing system costs by reducing demand as a result of end-use efficiency improvements;

(4) document the current load and the load projected for

the next 10 years;

(5) analyze energy end-use in the utility service area and identify as precisely as possible the final, physical use of electricity in the residential, commercial, and industrial sectors, including use within each sector for space heating and cooling, lighting, water heating, refrigeration, office appliances, and shaft power;

(6) review current and anticipated load research activities; and

(7) analyze opportunities to lower total utility system costs through improved generation and transmission efficiencies, including innovative rate designs, increased load factors, reduced demand, and deferral of additional capacity requirements.

(b) The commission shall assist the utilities to coordinate preparation of the report to minimize cost.

* Sec. 4. AS 42.05.651(a) is amended to read:

(a) After completion of a hearing or investigation held under this chapter, the commission shall allocate the costs of the hearing or investigation among the parties, including the commission, as is just under the circumstances. In allocating costs, the commission may consider the results, ability to pay, evidence of good faith, other relevant factors and mitigating circumstances. The costs allocated may include the costs of any time devoted to the investigation or hearing by hired consultants, whether or not the consultants appear as witnesses or participants. The costs allocated may also include <u>costs paid by the commission under (c) of this section and</u> any out-of-pocket expenses incurred by the commission in the particular meeting. The commission shall provide an opportunity for any person objecting to an allocation to be heard before the allocation becomes final.

* Sec. 5. AS 42.05.651 is amended by adding a new subsection to read:

(c) During a proceeding or investigation under this chapter, the commission may compensate an interested person who is not a public utility for some or all of the reasonable costs of participating if the compensation is necessary to enable the interested person to adequately participate and if the participation is necessary to adequately present a significant position in which the person has a substantial interest. After completion of a hearing or investigation under this chapter, the commission may compensate an interested person who is not a public utility for some or all of the reasonable costs of participation in the proceeding or investigation if the commission finds that the participation was significant and has caused a substantial financial hardship to the interested person.

Introduced: 4/1/87
Referred: Labor & Commerce,
Resources and Finance

5-0638A

IN THE HOUSE

BY BROWN, ELLIS, DAVIS, SUND, KOPONEN AND BOYER

HOUSE BILL NO. 238

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

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(1) include a demand forecast that projects the power requirements for the utility service area;

(2) list and describe the facilities and energy supply resources of the utility and project future requirements;

(3) list the facilities that the utility expects to remove from service;

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(5) describe the projected population growth or decline, urban development, industrial expansion, and other factors influencing demand for electrical energy and describe the bases for the

projections;

(6) describe additional system capacity that could be achieved by improvements in generating or transmission efficiency, power pooling, interconnection of qualifying small power producers, conservation, and reductions in demand through end-use efficiency improvements;

(7) describe the utility's relationship to other utilities and to regional associations, power pools, or networks;

(8) summarize the relevant load management efforts, load research, and energy end-use analysis efforts made by the utility; and

(9) recommend an electrical energy resource supply plan that identifies projected plant retirement, development of additional generating capacity and transmission systems, load management efforts, conservation, and cost-effective end-use efficiency improvements.

(b) The commission shall establish by regulation a consistent reporting methodology for advance resource plans required under (a) of this section and shall encourage closely integrated utilities to prepare the plans jointly.

(c) The commission shall hold a public hearing before approving a utility's advance resource plan. The commission may not approve the plan unless it finds that the plan adequately addresses conserving electrical energy supply resources through available cost-effective end-use efficiency improvements.

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meet future demand that cannot be met by cost-effective load management alternatives, including conservation and energy end-use efficiency improvements.

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(5) analyze energy end-use in the utility service area and identify as precisely as possible the final, physical use of electricity in the residential, commercial, and industrial sectors, including use within each sector for space heating and cooling, lighting, water heating, refrigeration, office appliances, and shaft power;

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activities; and

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under this chapter, the commission may compensate an interested person who is not a public utility for some or all of the reasonable costs of participation in the proceeding or investigation if the commission finds that the participation was significant and has caused a substantial financial hardship to the interested person.