HB
238

(9)

HOUSE COMMITTEE REPORT

Date referred: 7/2/87 FURTHER REFERRALS: Finance

DATE: 4-20-88

The Resources Committee has considered HB 238

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

RECOMMENDS:

[X] replace with ~~SB~~ CS HB 238 (Res) [ ] the same title [X] a new title

[ ] attached amendment(s)

[X] do pass

[ ] do not pass

[ ] no recommendation

[ ] individual recommendations

[ ] additional referral to the _____ Committee

ADOPTS: [ ] _____ letter of intent

ATTACHES NEW FISCAL NOTE(s):

[X] fiscal impact

[ ] zero fiscal note

[redacted] zero with analysis

[ ] same as previous fiscal note published _____

[ ] same as previous zero fiscal note published _____

SIGNING DO PASS:

Sam Cotten

Edmund Herrmann

Hamilton Epps

Cliff Davidson

SIGNING OTHER RECOMMENDATIONS:

Dick Shultz No Rec.

Sam Cotten
Chairman's signature

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) evaluate 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.

STATE OF ALASKA
1988 LEGISLATIVE SESSION

BILL VERSION: CSHB 238
PUBLISH DATE: _____

FISCAL NOTE

REQUEST: _____

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

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		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: 4-25-88
Agency: Commerce & Economic Development

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

5-0638L
Cramer
3/29/88

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

IN THE HOUSE

CS FOR HOUSE BILL NO. 238 ( )

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 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. 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 projected power requirements. Unless a different time is specified, a projection 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 projected 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 projected use of specific facilities, the remaining useful life of the facilities, and projected 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 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, and appliances;

(5) set out a projection of 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 demand, 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 programatic 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 projections 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 projected power demand; 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 implementation of a specific development 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.

(b) The commission shall establish by regulation a consistent reporting methodology for the integrated resource plans required under (a) of this section including the preparation and joint filing of 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) adequately addresses conserving electrical energy thrcugh cost-effective, end-use efficiency improvements;

(2) would provide consumers with the lowest reasonable cost of power over the forecast period;

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

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

(5) 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

(6) 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) The utility shall submit annual reports on the implementation of the resource plan, including (1) departures necessitated by emergency service, maintenance, or repair, and (2) significant changes in the underlying assumptions of the resource plan, on the anniversary of the plan's approval date. 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 42.05.411 is amended by adding a new subsection to read:

(d) The commission may not allow a new or revised tariff to take

effect for a utility subject to AS 42.05.294 unless the commission determines that the tariff is consistent with the utility's most recently approved integrated resource plan, as modified under AS 42.-05.296(d).

* Sec. 3. 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. 4. AS 42.05.651 is amended by adding a new subsection to read:

(c) During a proceeding or investigation under AS 42.05.294 or 42.05.296, the commission shall accept the application of an interested person who is not a public utility for compensation of some or all of the reasonable costs of participating. The commission shall award compensation if it finds that the compensation is necessary to enable the interested person to adequately participate and present a significant position that does not result in the duplication of positions. Before awarding compensation, the commission shall allow a party to the proceeding or investigation or another interested person to review the application and the commission's findings and to request

a hearing on the matter. The commission may not award the compensation until the hearing has been held.

* Sec. 5. 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. 6. 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. 7. 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, 1990.

LEAST-COST ENERGY PLANNING IN ILLINOIS:

A STATE REGULATOR'S PERSPECTIVE

Prepared by:

Paul S. Galen, Manager
Policy Analysis & Research Division
ILLINOIS COMMERCE COMMISSION

For Presentation at

"ALASKA LOOKS AT LEAST-COST ENERGY PLANNING"

October 26-27, 1987

Anchorage, Alaska

The views and opinions expressed in this paper are solely those of the author and do not necessarily represent those of the Illinois Commerce Commission.

OVERVIEW

Least-Cost Energy Planning, Integrated Utility Resource Planning, Integrated Value Based Planning or some other mixture of those words has become a topic of considerable interest in the regulatory community over the last several years. Originally least-cost energy planning was defined as a way of leveling out the playing field between conventional supply-side sources of energy services and alternatives to traditional supply. These alternatives included such things as energy conservation, load management, and cogeneration. As I understand it the basic argument for this version of least-cost planning was that utilities and their regulators had become myopic in viewing available means of meeting customer demand, i.e., they focused on choices between generating plant type and fuel mix as the only viable means of meeting future demand for energy services. This view relegated other alternatives to the fringes, such as demand side management options, that might also be effective in meeting its customers energy service needs. Thus, at the simplest level least-cost energy planning was intended as a way of simultaneously evaluating demand and supply-side options to determine what mix of these resources could bring reliable and adequate service to utility customers at the lowest possible cost.

Since least-cost planning was first conceptualized and subsequently in certain parts of the country, the arena in which it has been implemented is changing. That change is characterized by increasing competitive pressures in markets for utility services. Whether this is "real" competition resulting from basic structural changes in these markets; or whether the competition is only apparent and actually represents the consequences of applying antiquated regulatory tools to a non-monopoly market is currently a hotly debated question.

Least-cost energy planning as originally envisioned assumed the utility, be it electric or gas, to be the sole monopolistic provider of energy services. Changes in the national natural gas industry over the last several years have altered that assumption considerably for natural gas utilities. Whether corresponding changes will or should occur in the electric utility industry is the subject of spirited discussion within the states and at the Federal Energy Regulatory Commission. If in fact the structure of electric and natural gas utility markets has changed in such a way as to become more competitive, then I believe a planning approach that assumes a monopoly position for the local utility is sure to fail in achieving its intended objectives.

The Electric Power Research Institute (EPRI) has recently taken the position that electric and natural gas markets are in fact more competitive. EPRI contends that utilities can no longer function as monopolistic providers of service in those

markets. EPRI, therefore, has advanced the idea of Integrated Value Based Planning as a variant of least-cost energy planning. EPRI's variant accounts for and acknowledges that utilities must compete in the energy service market and proposes a conceptual framework that allows utilities to do so. I must admit, however, to not being familiar enough with the details of the Integrated Value Based Planning approach to discuss it in any detail with you today. It is, however, an interesting alternative to what has become "traditional least-cost energy planning".

If utility markets are more competitive today than they were in the past this does not necessarily mean that least-cost energy planning as originally defined and envisaged cannot be implemented successfully. What I would like to discuss with you at this conference are some of the key conceptual, methodological, operational, and policy issues which we in Illinois have identified as being significant.

As a prologue to this discussion I wish to say that the issues themselves, their interdependence and their complexity can at times become bewildering to the analyst. Past regulatory and industry practice and policy, plus existing state and federal laws, often appear to provide insurmountable barriers to developing a straightforward approach to implementing least-cost energy planning. Put simply, there is considerable "institutional inertia" behind the way we've always done things. Even when one is conscious that this inertia exists it is usually difficult to overcome it and clearly define the problems and reach viable solutions to them through implementing a least-cost planning process. Issues such as the utility's obligation to serve and the concomitant "social compact" between utilities and consumers arise. The overlap of state and federal regulatory authority in dealing with siting of plants, the transmission of electricity, or the transport of natural gas also are interwoven in the landscape of utility markets, and thus must be explicitly considered in a least-cost energy plan.

Finally, and perhaps most fundamentally, are the issues of high retail rates faced by industrial, commercial and residential customers. Equally basic are the issues of utility recovery of huge amounts of capital sunk in new powerplants; plants that either have just come on-line or are candidates for inclusion in the rate base. State regulatory commissions are charged with balancing the interest of shareholders and ratepayers. Under current conditions this balancing act can appear to be a zero sum game, i.e., to give to one one must take an equal amount from the other. This rapidly gets the regulator into such questions as defining used and useful capacity, excess capacity, treatment of canceled plant cost, etc. This is a bewildering thicket of legal, economic, policy and political questions.

With that in mind I have tried to structure my presentation today along simpler lines. Because of the rapidly increasing complexity I have categorized these issues for analyses and have not attempted to make too many explicit linkages between them. I hope, however, that during tomorrow's concurrent sessions I will have the opportunity to flesh out some of these thoughts.

I. Least Cost Planning in Illinois[1]

On January 1, 1986 a substantially revised Public Utilities Act took effect in Illinois. The revisions incorporated into the Act broadened the scope of the Commission's authority and responsibility for the regulation of public utilities. One of the key elements of the new Public Utilities Act, is Section 8-402: Least-Cost Energy Planning. By including this section in the revised statute the Illinois General Assembly acknowledged the need to modify the scope of traditional utility resource planning to encompass alternatives to conventional sources of energy supply, e.g., conservation/load management, renewable energy resources, and cogeneration/independent small power production. Section 8-402(a) states the objective of least-cost planning as:

> "The objective of this section shall be to insure the provision of adequate, efficient, reliable and environmentally safe energy services at the lowest possible cost to all Illinois consumers and users, and, in doing so to utilize the fullest extent practicable all economical means of conservation, non-conventional technologies relying on renewable resources, cogeneration and improvements in energy efficiency as initial sources of energy supply."

Section 8-402 governs the design and implementation of the energy planning process. In brief, the elements of the process as described by the Act include:

1. All utilities provide adequate, efficient, reliable and environmentally safe service which constitutes the least-cost means of meeting the utility's service obligation.

2. Preparation of a comprehensive utility energy plan for the State by the Illinois Department of Energy and Natural Resources. The plan is to be reviewed at least every two years. Every utility subject to the planning responsibility of the Act shall provide the Department with "any and all information and data necessary to the preparation of the plan."

3. Preparation of plans by each utility for its service territory. These utility plans shall include:

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1. Please note portions of this paper have been excerpted from the Staff NOI Phase I Report, submitted to the Illinois Commerce Commission in May 1987.

a. 20-year demand projections for electric utilities and 10-year demand projections for natural gas utilities;

b. Examination of possible alternative levels of demand;

c. Identification and analysis of actual and forecasted impacts of conservation, renewable resources, cogeneration, etc.;

d. Year-by-year projections of all available sources of supply including cogeneration, renewable resources, and conventional resources;

e. A discussion of existing and proposed programs to promote the full utilization of practical and economical energy conservation.

4. Demonstration by the utilities that their plans represent the least-cost means of satisfying energy service needs.

5. Demonstration by utilities that their plans fully consider and utilize all economical energy conservation, renewable resources, and cogeneration.

6. The discussion of the types of conventional facilities planned.

7. Demonstration that a utility's rate design accurately reflects the long-term cost-of-service for each customer class.

8. Evidentiary hearings on both a statewide and utility plans will be conducted. The Department and each utility shall automatically be made parties to these proceedings.

9. Following hearings the Commission shall issue an order adopting a plan for each utility and for the state. The plans selected shall be those which if implemented have the greatest likelihood of providing adequate, efficient, reliable, and environmentally safe energy services at the least-cost to consumers; and which utilize to the fullest extent practical all economical sources of conservation, renewable resources, cogeneration, and improvements in energy efficiency.

10. The plans adopted by the Commission for each utility shall, to the fullest extent possible, be consistent with the statewide energy plan adopted by the Commission.

11. The most recent plans (utility and statewide) adopted by the Commission after appropriate updating shall serve as the basis for demonstrating the need for a new facility and any proceedings where a certificate of convenience and public necessity is being requested.

This planning process represented a major new responsibility for the Commission, and the elements of the process as described in the Act raised many complex, conceptual, methodological, procedural and policy issues. Although the Act is specific with respect to the issues to be addressed in the course of the process, it is generally silent on how certain key concepts are to be defined and how particular technical issues are to be addressed. Moreover, the Act describes a particular procedural approach to planning which, while clear, is not sufficiently detailed to enable immediate implementation of the process.

The manner in which particular issues are resolved, the nature of the plans ultimately approved, and the clear and implied links between planning and other responsibilities of the Commission will have a substantial effect on the delivery of service to utility customers for many years to come. For this reason, and because other parties including the Department of Energy and Natural Resources are directly affected by the requirements of the process, it seemed appropriate for the Commission to have the benefit of concerned parties views prior to taking action to implement the planning process. Toward this end, the Commission, in conjunction with its sister agency, the Department of Energy and Natural Resources, initiated 86 NOI-2 a Notice of Inquiry regarding implementation of Section 8-402 of the Public Utilities Act.

The purpose of this NOI was to solicit the views of interested parties on issues considered critical to the successful implementation of the planning process. Paragraph d(iv) of Section 8-402 gives the Commission the authority to determine the precise form, scope, and contents of the plans consistent with the requirements of paragraph (d). The NOI was conducted between December 1986 and May 1987. The Commission used the information gathered during the NOI to assist it in fashioning the procedural tool for the implementation of the planning process.

Eighteen (18) parties filed initial comments during the NOI. Nine (9) parties filed reply comments. It was evident from the initial and reply comments that parties devoted substantial time and effort to their responses. Review of these comments provided

valuable information for the Commission. Based upon the recommendations contained in the NOI Final Report, the Commission initiated a Rulemaking in late May. The Commission directed that workshops be held within this Rulemaking in an attempt to reach a fully stipulated agreement by all affected parties on rules governing the statewide and utility plans.

At the Commission's direction, Commission staff, in cooperation with the Illinois Department of Energy and Natural Resources, prepared draft rules to be used as discussion documents in the workshops. These drafts were circulated at the beginning of July. To date, fourteen workshops have been held, each dealing with different topics addressed by the draft proposal. Additional workshops will be held regarding a Rule for natural gas utilities. These workshops will most likely continue through early next year. In November the Commission will assess the likelihood of reaching a full stipulation on rules to implement least-cost planning for electric utilities in Illinois. If additional workshops appear to be useful to reaching a full stipulation the workshop process may be continued. If the workshop process has not led to full stipulation amongst all parties, or it does not reasonably appear that further workshops will result in a stipulation, then the Commission intends to initiate evidentiary hearings to adopt a rule for implementation of Least-Cost Planning in Illinois.

II. Major Issues Identified with Implementing LCEP in Illinois

Illinois has identified many issues in connection with implementing Least-Cost Energy Planning. Some of the major issues to emerge are:

1. Operative definition of Least-Cost
2. Consistency in filing sequence of statewide and individual energy plans.
3. Treatment of uncertainty.
4. Linkages between LCEP and other Commission policies and activities.
5. Treatment of multi-jurisdictional utilities.
6. Use of common forecasting methodologies.
7. Role of alternative technologies in formulating and evaluating energy plans.
8. Specification of scenarios to be presented in the energy plans.

Of these major issues an operative definition of least-cost emerged as one of the most significant.

III. Balancing Objectives and the Definition of Least-Cost

The Illinois statute places a heavy emphasis on the concept of least-cost. This emphasis may be unfortunate given the problems of operationalizing the planning review process and the subsequent evaluation of alternative plans.

A number of experts in the field of utility planning (representing regulatory commissions, utility firms, and academics) have expressed concern related to the use of the term "least-cost". The preference was instead for the term "integrated resource utility planning," i.e., plans that considered both demand and supply side options and that balanced the needs of energy service consumers and utility investors. While at first this appears only to be a superficial issue of semantics it isn't. In order to issue a rule that operationalizes the goals of Section 8-402 it appears necessary to move away from the ideal public policy goals of identifying the least-cost method of providing energy services to one of identifying the best-cost integrated resource utility plans.

One definition of least-cost that is clearly consistent with the Illinois statute might read:

> Given two plans that provide identical levels of reliability and adequacy, equity among customer classes, and environmental impacts, choose the one that has the "least-cost".

This type of rule is consistent with the concept of cost minimization subject to constraints. A number of problems exist, however, with trying to implement such a definition. The first problem is how to measure "costs" so as to arrive at comparable numbers for each plan. Another problem is that of evaluating and comparing plans that propose different levels of reliability, environmental impacts, or difficult to quantify external effects.

Three alternative means for defining least-cost have arisen during our discussions in Illinois. These are:

a. Minimization of the present value of revenue requirements (PVRR);

b. Minimization of energy rates (or equivalent revenue requirements per unit of energy); and

c. Minimization of the cost of energy services to the consumer.

To better understand the differences in these three definitions consider them when applied to a hypothetical example of estimated outcomes resulting from two alternative utility plans. Plan 1 results in an annual revenue requirement of $1 million dollars for sales of 10 million kilowatt-hours and a per unit cost of 10 cents per kilowatt-hour. Plan 2 results in an annual revenue requirement of $950,000 for sales of 9 million kilowatt-hours and a per unit cost of 10.5 cents per kilowatt-hour. The question is then asked, "which plan is least-cost"?

Assuming that the annual revenue requirements associated with both Plans remain constant during the planning period (20 years for electrics and 10 years for gas), under definition (a) (minimize PVRR), Plan 2 is the better plan; being $50,000/yr. cheaper than Plan 1. However, if definition (b) is used (minimize per unit RR) Plan 1 becomes the least-cost plan. Finally, attempting to answer the question using definition (c) (minimize energy service costs) would result in an "answer" of "not enough information." This apparent dilemma is caused to a large extent by the focus on the concept of "least cost" and the associated implication that alternative plans can be assigned a single value that will identify the "least-cost" plan.

The above comparison of plans subject, for example, to the objective of minimizing per unit RR is based on the value of certain variables at a given point in time. But what is important is not only the value of these variables but their trends over time as well. It may be that after 5, 10, or 15 years, Plan 1 would result in per unit costs going from 10 cents/kWh to 12.5 cents/kWh, while Plan 2 would result in per unit costs going from 10.5 cents/kWh to 11.5 cents/kWh due to differences the rates of increase in the value of the pertinent variables. Thus, a rule based on definition (b) (minimization of per unit RR) could not distinguish the "least-cost" plan either.

In the case of a comparison based on minimizing the PVRR, no consideration of the trend of future rates is assured. In a service territory where the customer base was declining, modest increases in the revenue requirement could lead to rapidly escalating rates. However, alternative plans with higher initial revenue requirements (when the customer pool was still large enough to absorb the cost without significantly higher rates) could feasibly be rejected even if the possibility of lower revenue requirements and rates in the future existed. Also, as the result of discounting future RR, a plan that begins with lower RR during the early portion of the planning period but which rises sharply toward the end may be preferred to a plan with a higher initial but more stable future RR. The number of various scenarios that one could consider is virtually limitless.

The important point is that any quantitative decision rule based on a single factor is likely to fail to perform its function under any set of feasible circumstances.

Only in the case where one plan in a group of alternatives, identical with respect to the properties stated above, is expected to produce both the lowest revenue requirements and the lowest per unit cost of energy over the entire planning horizon can a rule based on a "least-cost" (i.e., single factor) concept be expected to yield a unique choice. However, because this particular case is unlikely, standards more discriminating (albeit more subjective) than "least-cost" need to be considered.

It should now be apparent that the definitions of least-cost listed above as (a) and (b) (minimize PVRR and minimize per unit RRF) are not true alternatives to one another. Both conditions must exist to satisfy a "least-cost" definition. Furthermore, there is most likely some value to considering tradeoffs between the benefits of lower revenue requirements and higher unit costs in one period for lower unit costs in another period. There are other possible scenarios as well just as there are opportunities for tradeoffs between both revenue requirements and rates with the standards of reliability, environmental quality, etc.

This leads to consideration of definition (c) (minimize energy service costs to the consumer). While minimizing costs undoubtedly should be the goal of public policy, the prospects of operationalizing this definition by way of a quantitative decision rule are equally as dismal. In part this is due to the fact that the energy service cost encountered by any given customer is a function of both the energy price(s) faced by the customer and the alternative capital and operational inputs available to the customer to control their level and pattern of usage. Thus energy services are a derived demand and therefore more difficult to quantify for large numbers of customers; each with many variations of choice available to them.

These problems of balancing the objectives of the "least-cost" planning process, defining the term least-cost, and evaluating the plans can only be resolved after it is recognized that some of the standards enumerated in Section 8-401 of the Illinois statute (reliability, adequacy, and environmental quality) are directly related to the costs associated with a given plan. These properties, with the addition of the financial integrity of the utility are commodities to be purchased for a cost, i.e., for a given initial level of revenue requirements and per unit cost. Along with their associated trends, we can purchase these levels and trends of reliability, adequacy, environmental quality, and financial integrity. This type of evaluation is better described as a "best-cost" approach.

IV. Uncertainty Associated with Least-Cost Plans

An important factor to be considered in the development and evaluation of least-cost plans is the great deal of uncertainty associated with future events that must be incorporated into these plans. Section 8-402, paragraph f, of the Illinois Public Utilities Act recognizes the impact of uncertainty in instructing that

> "...the Commission shall select the plan, and components thereof, which will result in the greatest likelihood of providing adequate, efficient, reliable and environmentally safe energy services at the least cost to consumers ..." (emphasis added).

Accounting for the effects of uncertainty involves the investigation of alternative future scenarios by the utility. Section 8-402, paragraph d, specifically states that

> "each energy utility shall include demand projections for services and projected customers by major service classification of the public utility, as well as the basis for such projection, including an examination of possible alternative levels of demand and discussions of the forecasting methodologies and input variables used in making the forecasts."

The salient impact of uncertainty upon the least-cost planning process is that the utility analyst can never know in advance whether any given plan will, in fact, be least cost. The selection of a plan that eventually proves to be the least-cost plan, then, will happen only by accident. As a result uncertainty causes an increase in the cost of providing service above that which could have been realized had the utility analyst had perfect information regarding future events.

The most commonly recognized form of uncertainty involves the difficult task of estimating the future values of the independent variables used in the forecasting process. Examples of such variables include fuel prices, interest rates, construction expenditures, inflation, and plant operating efficiencies. In addition to problems associated with estimating future values, uncertainty may also result from incorrect forecasting model specification and imprecise coefficient estimation.

Typically, utilities have used one or more of three popular methodologies to incorporate uncertainty into their forecasts. These three methodologies are sensitivity analysis, stochastic simulation, and decision analysis.

In sensitivity analysis, the independent variables of the forecasting model are varied over a reasonable range and the effect on the forecasted level of demand is subsequently observed. Frequently, combinations of variable modifications are made simultaneously to establish plausible scenarios which result in changes in forecasted demand. Often, utilities employing sensitivity analysis will present the most-likely high and low demand scenarios. The sensitivity analysis method is flawed, however, in that the probabilities of each of the scenarios occurring are usually not provided.

The stochastic (or Monte Carlo) simulation method does, however, allow specification of probability values. In this method, the analyst first must assign probability distributions to the independent variables. This simulation technique then chooses random values from the assigned probability distribution. The analyst specifies the number of trials to be run in the simulation, and when the simulation has run, average results are calculated. The disadvantage of stochastic simulation lies in the quantity of resources, the time it requires and the usually subjective assignment of the probability distributions.

In decision analysis, a probability tree diagram is used in which branch paths represent alternative scenarios. Independent variables are permitted to assume a limited number of values, each associated with discrete probability values. In this manner, each branch path on the tree can be associated with a probability and a cost. The number of alternative variables examined may be limited by the undesirable complexity the decision tree develops as variables are added.

Most utilities already investigate alternative scenarios when developing their forecasts. Utilities generally believe that the impact of changes in input variables on the forecast output is a necessary and desirable step in developing forecasts. They also feel it is possible to assign probabilities to the alternative scenarios being examined. If the utility only uses sensitivity analysis to examine the effects of uncertainty, any assignments of probability values to these alternative scenarios must be done through entirely subjective evaluation. This subjective assignment of probability values may either be done as the result of the forecaster's informed judgment or the culmination of interviews with resident and/or outside experts.

The incorporation of uncertainty into utility projections is an important part of the forecasting process. Sensitivity analysis can be valuable in establishing the robustness of supply and demand forecasts to changes in the values of independent variables. Sensitivity analysis alone, however, does not give plan reviewers an indication of the likelihood of alternative scenarios occurring. For this reason, subjective probabilities

need to be assigned to the scenarios examined in sensitivity analysis, unless a more formal method is used. Stochastic simulation and decision analysis are two alternative methodologies that specify the probability of each scenario occurring. These more formal methods do involve additional expense, and it is not clear whether this increased cost is justified by gaining superior probability estimates.

V. Linkages to Other Duties and Policies

The least-cost planning sections of the Illinois Public Utilities Act are linked both directly and indirectly to other Commission policies and activities. Least-cost planning procedures and criteria need to be integrated with both proposed and existing Commission policy. For least-cost planning to be most effective, these areas must be addressed and reconciled where necessary.

As an example, the Commission recently investigated (in NOI-86-1) issues related to excess electric generating capacity. One possible outcome of this investigation is to completely exclude excess capacity from rate base consideration, allowing neither a return on or of investments, regardless of the prudency of the construction decision. In fact, some form of exclusion of excess capacity is required by law under Sections 9-212 and 9-215 of the Illinois Public Utilities Act. The more deeply involved the Commission becomes in the capacity decision-making process under least-cost planning, the greater will be its responsibility for mistakes.

Another area in which least-cost planning and Commission policy are related is wheeling of electricity. At the wholesale level, the availability and price of wheeled electric power will impact the utilities' supply planning process. The availability of transmission services at non-discriminatory prices will influence the profitability and amount of cogeneration and small power production. Both cogeneration and small power production are emphasized in the least-cost planning legislation. Some consideration is also being given to the issue of retail wheeling. Under retail wheeling, some customers could bypass their native utility and purchase power from other suppliers such as small power producers and cogenerators. These activities may have a large effect on a utility's planning process as well as the profitability of small power producers.

A general question linking least-cost planning to other Commission policies is whether and/or how least-cost planning should consider only cooperative efforts between parties (utilities and possibly between utility customers. The question itself must be addressed before the relationship between statewide and utility energy plans can be reconciled. If only cooperative efforts are to be considered, the DENR statewide energy plan might ap-

propriately be a summary of individual utility plans accounting for undeveloped potential cooperative efforts. On the other hand, if "least-cost" is to be applied to the State as a whole, the statewide plan would consider policies which might harm some parties, but in the aggregate reduce cost. In this case, the statewide plan may be substantially different than a summary of individual plans. If the second approach is taken, some activities which are appropriate to least-cost planning may violate existing policy or statute. An example of the latter is central dispatch of electric generation statewide. When this occurs, the Commission will have to reassess its existing policy in light of this new information. Retail wheeling, for instance, may reduce costs in the aggregate, but might harm native utilities and, depending upon other Commission policies, may harm the utility's "captive" customers as well. Such a policy might violate the utility's monopoly right and thus the so-called regulatory compact between the utility and ratepayers. The Commission, in this case, would have to carefully consider the ramification of its action in these kinds of situations.

One other point concerns multi-jurisdictional utilities. The Commission has the authority to order the implementation of a least-cost plan. The question then becomes, should this authority apply to out-of-state facilities if they affect the utility's in-state service? Further what happens if the Commission's approved least-cost plan is inconsistent with another regulatory authority's decisions? These questions should be addressed and will likely be related to other Commission policies regarding multi-state utilities.

VI. Conclusion

Least-Cost Energy Planning is a newly proposed regulatory tool. As with most such new proposals their worth is tested against the existing regulatory policies, practices and objectives they affect. By its nature, least-cost energy planning touches most of the basic tenets of current regulation. Thus, the testing of it becomes a complex, and oftentimes contentious, process. This, however, should not deter utilities, regulators and utility customers from taking the time and effort to examine the feasibility of least-cost energy planning. It does hold the promise for being an essential regulatory tool for dealing with today's changing utility markets.

EFFICIENT RATEMAKING PRACTICES

IN A LEAST COST PLANNING ENVIRONMENT

Jim Lazar, Consulting Economist

One concern that comes to mind if a utility undertakes a major program of using conservation investments as an alternative to generating investments is that conservation increases costs without increasing sales. If rates are computed simply by dividing costs by sales, the result is an ever-increasing average rate per kilowatt-hour.

For most utilities, the cost of new, long-life generating resources will significantly exceed the average cost of existing power resources. New power plants are more expensive to build, due to additional environmental controls and due to inflation in construction costs. Adding new power plants will cause increases in average power supply expenses, and will be reflected ultimately in rate increases. However, a new power plant producing power at 7 cents/kwh may increase rates per kilowatt-hour by less than a new conservation resource which conserves power at 5 cents/kwh, simply because the denominator in the ratemaking equation -- total sales -- is increasing. Thus, even though the conservation resource is less expensive and results in smaller increases in costs, the generating resource may result in smaller increases in rates.

One simple solution to this is to bill customers for energy services, rather than just for metered kilowatt-hours. A customer who receives 1000 kwh from the utility should be billed for 1000 kwh. A customer who receives 900 kwh plus an incentive payment to acquire appliances which conserve 100 kwh should be billed for the services they receive; 900 kwh of energy delivered in the form of kilowatt-hours, and 100 kwh delivered in the form of conservation savings.

Professional Energy Services Companies (ESCOs) are now operating in many parts of the United States. These companies make conservation improvements in buildings and industrial facilities, using their own capital. The most widely known ESCO is Johnson Controls, which sells and installs energy management systems for commercial office buildings.

An ESCO collects fees from the owners of the facilities they improve which are tied to the energy savings; the owner retains a portion of the savings at no cost or exposure, and the ESCO is able to make a profit on the investment. In some cases, the ESCO receives a payment from both the owner and from the utility system. To the extent that a utility is able to avoid new generating resources, this arrangement can be beneficial to all of the customers of that utility.

It is conceptually simple to compute a bill for consumers which recovers costs for both metered kilowatt-hours from generating plants, and for imputed kilowatt-hours from conservation programs financed by the utility. So long as the rate per kwh is lower for the imputed kilowatt-hours is lower than the rate for metered kilowatt-hours, a consumer is always better off choosing a utility-financed cost-effective conservation measure than doing without it and using more metered kilowatt-hours.

Conservation reduces the need for new generating resources. If new resources cost more than existing resources, all customers on a system benefit from conservation activities. If conservation measures are not developed, customers will see an increase in their rate per kwh for power used. It is therefore appropriate that customers using generating resources be willing to share in the cost of developing conservation resources. Under most present systems, customers who conserve still face rate increases to pay for new generating plants to serve growth, but there is no reciprocity -- customers creating the need for the growth do not share in the cost of conservation activities that may free up the energy needed to serve that growth.

ABANDONING THE "NO LOSERS" TEST

It is possible that some conservation measures may provide such great savings at such low costs that all customers benefit from utility-financed conservation programs. This is the so called "no-loser's test," by which a utility will only finance those measures which save costs for all consumers, including non-participating consumers. However, many conservation resources do not satisfy the no-loser's test, but are still cost-effective compared with new generating resources.

An appropriate way to ensure that these cost-effective resources are developed prior to the development of more expensive generating resources is to allow customers who directly benefit from such resources to pay for their energy savings the same way they would pay for energy consumption, in the absence of a conservation program -- through the rate per kilowatt-hour that they pay their local utility. If the measures are cost-effective, the rate per kwh for conserved energy will be lower than the rate per kwh for metered energy.

EXAMPLE -- THE REFRIGERATOR INCENTIVE PROGRAM

As discussed in the example of substituting a refrigerator incentive program for a purchase of additional generation, a utility may be able to save its customers money by implementing a $50 incentive payment to pay the additional cost of acquiring a more energy-efficient refrigerator. If one change is made in the example, to assume that distribution costs (in addition to generation costs) must be paid in order to deliver the additional power produced under the "generation" scenario, the scenario changes somewhat.

If delivery costs for the new power equals that for existing power, the generation scenario, adding generation at a price above the cost of existing supplies, will cause rate increases for all customers. Most utilities have faced this problem in recent years. In the

conservation scenario, the direct beneficiaries of the incentive payment will have lower energy usage, and therefore lower bills, and non-participants will have unchanged energy usage, higher rates, and therefore higher bills, there may be an inefficient distribution of costs and benefits.

Using the example of the refrigerator incentive program, assume that existing power purchases are costing Pleasant Valley Electric Cooperative 4 cents/kwh plus 4 cents/kwh to deliver, for average current rates of 8 cents/kwh. Assume that additional power purchases will cost 5 cents/kwh to purchase, and will cost 4 cents/kwh to deliver, for a total of 9 cents/kwh. Under this situation, all customers will benefit from conservation which reduces the need to acquire and deliver additional, more expensive power.

The refrigerator incentive program has annual costs of $147,000 and annual savings of 10 million kwh, for an average cost of 1.5 cents/kwh, much lower than the cost of purchased power.

Pleasant Valley is currently buying 100 million kwh at a price of 4 cents/kwh, for a total purchased power bill of $4 million. Adding 10 million kwh at 5 cents/kwh will increase the total purchased power bill to $4.5 million. Distribution costs will increase from $4 million to $4.4 million, and total revenue requirements will increase from $8 million to $8.9 million. The average rate will then increase from 8 cents to 8.09 cents/kwh, and all rates will have to increase.

One equitable allocation of conservation costs is to establish as a policy that non participants will not be made worse off as a result of a conservation program than they would be if a generating resource were acquired instead to meet their growing needs. In this example, the average purchased power expense for generated and conserved energy would not be allowed to increase more with the refrigerator incentive program than it would without such a demand-side program.

With a refrigerator incentive program and this cost constraint, the average purchased power expense would not be allowed to exceed 4.09 cents/kwh, including the contribution by non participating ratepayers to the refrigerator program. Given sales of 100 million kwh, the amount of revenue which would be generated by adding an increment to purchased power costs equal to what would be incurred absent a conservation program would be .09 cents times 100 million kwh, or $90,000 per year. While this would not cover the full cost of the refrigerator incentive program, it would defray much of the cost.

This approach, however, would still leave $57,000 of annual costs of the refrigerator incentive program which cannot be recovered from ratepayers on the basis of kwh usage without raising rates by more than the generation alternative. These costs can be recovered from the direct beneficiaries of the program. Each of 25,000 direct beneficiaries of the refrigerator incentive program will have received a payment of $50, and is receiving benefits of 400 kwh/year. The program is providing benefits of 10 million kwh/year. Dividing the $57,000 in residual revenue requirement by 10 million kwh/year produces a net cost of .57 cents/kwh. If each of the direct beneficiaries is billed for 400 kwh @ .57 cents/kwh, they will pay $2.28/year (or $.19/month) in additional charges. Not a bad deal for power which at retail rates of 8.09 cents/kwh would cost them $32.36.

The utility now is receiving full recovery of the conservation program costs. All ratepayers are contributing to the cost recovery. Non-participating ratepayers are paying no more than they would pay for identical benefits in the absence of the conservation program. Program participants are paying significantly less than they would pay in the absence of a conservation program. This allocation of costs and benefits meets the Pareto test of economic efficiency: At least one person is made better off (the participants) without making any person worse off. Other allocations of the costs and benefits could be constructed to make all ratepayers better off, and no ratepayers worse off.

The bills of Pleasant Valley Electric Cooperative must be adapted to reflect this change of the utility from a power distribution entity to an energy-services entity. The example below shows a bill for both a participating and non-participating customer, after implementation of the conservation program.

EXAMPLE BILLS
PLEASANT VALLEY ELECTRIC COOPERATIVE

WITHOUT CONSERVATION PROGRAM

ALL CUSTOMERS

1000 Generation KWH @ $.0809	$80.90
Amount due:	$80.90

WITH CONSERVATION PROGRAM

NONPARTICIPATING CUSTOMER

1000 Generation KWH @ $.0809	$80.90
Amount due:	$80.90

PARTICIPATING CUSTOMER

967 Generation KWH @$.0809	$78.23
33 Conservation KWH @ $.0057	$ .19
1000 Total KWH	
Amount due:	$78.42

Alaska State Legislature

HOUSE OF REPRESENTATIVES

Committee on Finance

Official Business

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

TO: Representative Sam Cotten, Co-Chair
Representative Adelheid Herrmann, Co-Chair
House Resources Committee

FROM: Representative Kay Brown

DATE: March 9, 1988

SUBJ: HB 238/239: Least-Cost Energy Planning Legislation

As a result of the least-cost planning conference last fall, the House Resource Committee's interim work session on HB 238/239 and some additional discussions and conversations with utility representatives and public interest groups, I would like to propose some modifications to CS HB 238 (Labor and Commerce) and its companion appropriation measure, CS HB 239 (Labor and Commerce) now pending consideration in the House Resources Committee.

I have attached for your consideration suggested language for a House Resources draft committee substitute for both bills. The changes reflected in the two bills are briefly described below. It is my hope that you would request that these changes be drafted as a CS work draft for consideration by the Resources Committee so that the bills could be heard in the near future.

Proposed Changes to HB 238

The major change suggested is simply one of structure in regard to the reporting requirements. The L&C version of the bill had two distinct, but related, reporting requirements. These have been consolidated into a single "integrated resource plan" requirement. Additionally, the filing deadline for the first integrated resource plan has been moved back; implementation plan updates would be required annually; complete review and re-approval of the integrated resource plan would be required every three years.

The suggested draft provides for expedited cost recovery of expenses associated with the reporting requirements and for recovery of costs incurred as a result of implementation of an approved plan. The proposed

Resources CS work draft retains the requirement that a utility would require approval from the APUC prior to development or acquisition by contract of a new project or supply resource with an equivalent capacity greater than five megawatts. However, the proposed draft recognizes the exemption for Bradley Lake contained in HB 356.

Proposed Changes to HB 239

The essential changes proposed for HB 239 concern the level of funding which would be provided by the bill. At the fall conference on Least Cost Planning, a number of participants commented that the proposed funding level would be inadequate for the planning effort required. The proposed changes also reflect some minor language changes to conform HB 239 with the proposed revisions to HB 238.

I appreciate your consideration of this request and would be happy to discuss this matter at your earliest convenience.

attachments

Attachment A

3/6/88 doc = a:hb238rev

HB 238 - Revised Draft #2

CS HB 238 (WORK DRAFT)

Section 1: Integrated Resource Plans Required

AS 42.05 is amended by adding new sections to read:

AS 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, 1990, and every three (3) years thereafter. Unless otherwise specified, when the plan requires a forecast or projection, the forecast or projection must be for the twenty (20) years following the year prior to the filing.

The integrated resource plan must show how the utility will meet projected power requirements through increased power supplies, improved efficiencies in the generation or delivery of power, the provision of energy services, or any combination of these or other means.

The plan shall

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

(2) include a projected retirement schedule which lists the facilities that the utility expects to remove from service with a discussion of the assumptions used in developing the retirement schedule including, but not limited to, the projected use of specific facilities, the remaining useful life of the facilities and projected maintenance work;

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

(4) include documentation of 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, appliances, and shaft power;

(5) include a projection of 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) include a discussion and analysis of the utility's existing ability to meet increased system demand, 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 programatic conservation efforts; and

E) current utility load management efforts.

(7) include a summary of 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 impacts on utility costs from end-use efficiency changes;

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

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

(8) provide long-term forecasts, on the basis of end-use and econometric methodologies, as appropriate, and including, at a minimum,

A) base, low, and high projections, that project the power requirements for the utility service area;

B) a discussion of the assumptions used in developing the forecast including, but not limited to, reserve margin requirements, population growth or decline, employment growth or decline, economic development, service area expansion or other factors which influence the demand for electrical energy; and

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

(9) evaluate alternative options to meet projected power demand in order to provide for cost-effective utility system development including considerations of availability, reliability, and flexibility;

(10) identify the integrated resource plan scenario with the lowest present value of revenue requirements over the forecast period;

(11) recommend a specific utility system development scenario that identifies projected facility retirement, development of additional generating and transmission systems, load management efforts, conservation and energy end-use efficiency improvements, and a plan for the implementation of the recommended scenario; and

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

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

(c) The Commission shall establish regulations and provisions that all reasonable expenses incurred by a utility in meeting the requirements, including research and data collection, analysis, preparation of reports and documents, and participation in the public review process will be fully recovered in revenue requirements and rates for utility services. Expenses allowed for recovery in rates shall include those expenses reasonably expected to occur in the period of time the rates so established will be in effect. Specific procedures shall be developed for revenue requirement adjustment in lieu of a general rate adjustment filing.

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

Section 2: Review and Approval of Resource Plans

AS 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 which shall include provision for public hearings to be conducted 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 if the Commission finds that the plan adequately addresses conserving electrical energy supply resources through cost-effective, end-use efficiency improvements and that the proposed system development scenario would provide consumers with the lowest reasonable cost of power over the forecast period.

(c) Commission approval of a utility's integrated resource plan and that utility's recommended system development scenario will establish:

(1) that the utility's plan constitutes a reasonable expectation of future load and resource requirements;

(2) that the plan incorporates, as appropriate, life-cycle costing and cost-effectiveness analysis together with explanation of criteria and assumptions;

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

(4) that the plan includes an enumeration of the utility's data collection activities, additional data requirements, and efforts to develop that additional data.

(d) Nothing in this part shall preclude any utility from pursuing activities necessary for the maintenance, repair, upgrade or rebuilding of existing facilities in order to maintain reliable service, nor from pursuing any action to alleviate an emergency situation in which service would be lost or system operation rendered uneconomic.

(e) A report on the implementation of the resource plan, including any departures necessitated by emergency service, maintenance or repair and any significant changes in the underlying assumptions of the resource plan, shall be submitted one year after the approval date of the integrated resource plan and at the end of each year thereafter. Modifications to the plan as a result of a response to (d) above and any changes to underlying assumptions shall be provided by the utility with supporting data and documentation.

(f) Commission review and approval of a utility's integrated resource plan and a specific utility system development scenario, together with any permit required under AS 42.05.___ [Commission Approval for New Construction], will constitute authorization for the utility to pursue actions to implement the plan as approved. Reasonable utility expenses and capital expenditures incurred by the utility in implementing the plan shall be included in the utility revenue requirements and rates, and shall include those expenses reasonably expected to occur in the period of time the rates so established will be in effect. Specific procedures shall be developed for revenue requirement adjustment in lieu of a general rate adjustment filing.

Section 3: Tariffs Consistent with Approved Plans

AS 42.05.411 is amended by adding a new subsection to read:

(d) The Commission may not allow a new or revised tariff to take effect for a utility subject to AS 42.05.415 (Integrated Resource Plans) unless the Commission determines that the tariff is consistent with the most recently approved integrated resource plan, including consideration of departures and modifications identified in the plan implementation reports required under (insert appropriate

Sections 4-5: Intervenor Financing and Cost Allocation

Section 4 - Cost Allocation for Intervenors Allowed

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 and reasonable 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 cost 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 costs paid by the commission under (c) of this section and any out-of-pocket expenses incurred by the commission in the particular meeting.

Section 5 - Commission Process for Intervenor Financing

AS 42.05.651 is amended to add a new subsection:

(c) Prior to a proceeding under AS 42.05.294 or AS 42.05.296 of this chapter, the Commission shall accept applications from any interested person who is not a public utility for compensation of some or all of the reasonable costs of participating, if the compensation is necessary to enable the interested person to adequately participate and present a significant position. The Commission shall review applications and make a determination that compensation is necessary for participation and will not result in the duplication of positions. Prior to providing compensation, the Commission shall allow any person or public utility the opportunity to review the applications and determinations and any person or public utility objecting to the determinations shall be provided an opportunity to be heard.

Section 6: Commission Approval for New Construction

AS 42.05. ___ is amended to add a new section:

(a) Except as provided by AS 42.05.431(c)(1) [ie, the Bradley Lake exemption], 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 or enter into a contract to acquire additional energy resources with an equivalent capacity of five megawatts unless the utility has obtained a permit from the Commission.

(b) The Commission may not issue a permit required by (a) unless the Commission finds that the project is necessary to meet future demand and is consistent with the utilities most recently approved integrated resource plan under AS 42.05.294.

end

Attachment B

Offered: 7/2/87
Referred: Rules

5-0637B

Original sponsors: Brown, Ellis, Dav[illegible] et al.

Funding Information
General Fund $ -0-
Other Funds 555,000
$555,000

BY THE LABOR AND COMMERCE COMMITTEE

IN THE HOUSE

CS FOR HOUSE BILL NO. 239 (L&C)

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act making special appropriations to the Alaska Power Authority for payment as grants to certain public utilities for preparing certain ~~end-use studies, load management reports, and advance resource plans~~ integrated resource plans and to the Alaska Public Utilities Commission for certain costs; and providing for an effective date."

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

* Section 1. The sum of ~~$500,000~~ $1,000,000 is appropriated from the Railbelt energy fund (AS 37.05.153) to the Alaska Power Authority for payment as grants to Railbelt public utilities for the cost of preparing end-use studies, ~~load management reports, and advance resource~~ and integrated resource plans required by law.

* Sec. 2. The sum of ~~$55,000~~ $170,000 is appropriated from the Railbelt energy fund (AS 37.05.153) to the Alaska Public Utilities Commission for ~~a~~ three positions whose responsibility will be to assist public utilities in the preparation and review of ~~load management and advance~~ integrated resource plans required by law.

* Sec. 3. The unexpended and unobligated portions of the appropriations made by this Act lapse into the Railbelt energy fund (AS 37.05.153) June 30, 1988.

* Sec. 4. This Act takes effect on the effective date of an Act enacted by the First Session of the Fifteenth Legislature that requires certain electric public utilities to prepare ~~load management plans and advance~~ integrated resource plans *

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

P.O. Box Y, State Capitol
Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

February 16, 1987

MEMORANDUM

TO: Representative Kay Brown

ATTN: Eric Meyers

FROM: Ginny Fay
Legislative Analyst

RE: **Least-Cost Energy Programs and States' Energy Agencies**
Research Request 87.066

You requested information regarding the structure and function of energy agencies and programs in other states. You specifically asked how other states pursue energy development and regulation. You were also specifically interested in other states that are pursuing "least-cost" energy strategies through demand-side conservation initiatives designed to reduce or avoid the need for additional power production capacity.

In providing this information, this memorandum is organized into three parts. The first part provides background on least-cost energy strategies. The second part discusses least-cost strategies and other pertinent programs in specific states (Pacific Northwest, i.e., Washington, Oregon, Idaho, and Montana; California; Florida; Minnesota; New York; Nevada; Ohio; Oklahoma; Texas; and Wisconsin). The third part discusses the structure and function of energy agencies in other states and contrasts programs and policies with those of Alaska.

Least-Cost Energy Strategy

In the mid-1980s, many utilities in the United States are approaching a critical point in their strategic planning.[1] If forecasts are correct, they must begin in the next few years to build new power generation capacity to meet the demand of the 1990s. Utilities are reluctant to make these investments, however, because electrical demand has grown below expectations during the last decade. There are also numerous examples across the

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[1]Roger F. Naill and Roger W. Sant, "Electricity Markets in the 1990s: Feast or Famine?", Public Utilities Fortnightly, April 26, 1984, p. 19.

nation of additional facility construction that provided additional capacity before it was needed. Because of the excess capacity and cost overruns (especially for nuclear plants), the subsequent energy was often too expensive to sell. Examples include WPPSS (Washington Public Power Supply System) in the Pacific Northwest, Marble Hill in Indiana, Zimmer in Ohio, and Seabrook in New Hampshire. In these cases, public utilities commissions rarely had the opportunity to evaluate whether the additional construction was the most cost-effective means of [illegible]lying future energy or whether the energy was in fact going to be needed at all.[2]

Traditional utility regulation, including facility permitting and siting, has been a hindsight process where decisions were made by regulators who had access to a (theoretically) complete set of facts and information. This procedure is intended to protect the public interest; it is based on the belief that regulators are more likely to make cost-effective plant construction decisions if they rely on projections of past trends in the growth of demand. This is supposed to minimize the risks of resource decisions made by the regulated utility and the regulating agency. The public interest, however, is not protected when retrospective evaluations make mistakes so large that the costs would bankrupt utilities if they were not passed on to utility customers via increases in rates. Ultimately, consumers have paid for the mistakes of incorrect forecasts or excess increases in production capacity with rate shocks. It has also become more clear that past electric consumption is not necessarily a good predictor of future demand.

As mentioned above, hindsight decision making has produced some serious mistakes which have encouraged regulators and utilities to look for other methods to evaluate the acquisition of additional energy production capacity. Most utility managers would prefer not to have to finance any new capital expansion. Despite the decline in the cost of financing, the cost of power plant construction is so high that it often damages the financial health of the company. This situation has created more than enough incentive for regulators and some utilities to seek an improved ability to review resource planning decisions before such disasters occur.[3]

One planning alternative is a **least-cost resource planning** strategy. The basic concept is for utilities to stop thinking of themselves as deliverers of electricity or gas, but instead as marketers of **energy services**: the heat, light, or power needed to operate the buildings and industries in their service area. Their strategic objective is to deliver energy services at the lowest possible cost to customers, which is why it is referred

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[2]Renee Haman-Guild, "State Involvement in Utility Resource Planning: Towards Partnership," Public Utilities Fortnightly, April 18, 1985, p. 22.

[3]Ibid.

to as a least-cost strategy. This strategy leads them to consider conservation options (or end-use technologies that conserve electricity) on an equal basis with constructing new generation facilities in their resource planning. The growth in the demand for energy services can be met by either saving energy or constructing additional generating capacity. Marketing energy services rather than electricity opens up a whole new set of options in utilities' strategic plans.[4]

Instead of focusing on the energy form itself (such as hydroelectric, gas or coal), a least-cost analysis focuses on the services provided by the use of energy. For example, people do not necessarily want electricity or gas in their homes; they want warmth, lighting, and convenience. Similarly, industrial users do not really care about the primary fuel they utilize; they are more concerned with the power used to produce a final product.[5]

The significance of focusing on end-use services is made more apparent when Btu's of energy are traced from primary fuel consumption though delivered or end-use fuel consumption and on to the final consumption of energy services. In 1980, the United States consumed 78 quadrillion Btu's of primary energy inputs (such as coal, natural gas, oil, or renewable fuels). Of this, only 60 quadrillion Btu's were delivered to consumers. The 18 quadrillion Btu's (23 percent) difference was lost in the conversion of primary inputs into more usable forms (mostly in electricity generation) and in the transmitting and distribution of energy to consumers.

The energy delivered to users again requires conversion to produce services of value to consumers. This conversion occurs in energy-using devices in buildings and industries. Final useful energy services totaled 33 quadrillion Btu's in 1980, or 42 percent of the primary energy consumption in that year.

Because of large conversion losses, it is relatively inefficient to increase the level of primary energy inputs in order to satisfy increases in the demand for final energy services. Until the recent price decline, the high cost of petroleum products coupled with the ample technical ability to reduce conversion losses resulted in increased development and investment in more efficient end-use energy devices. Amory Lovins, a national energy specialist, testified before the Wisconsin Public Utilities Commission that the cost of technologies recently developed to save electricity is five to ten times less than the cost of additional electric

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[4]Roger F. Naill, and Roger W. Sant, 1984, p. 19.

[5]This is assuming there are no serious supply considerations such as oil embargos or dramatic increases in fuel costs.

generating capacity.[6] For example, it is usually more cost effective to improve the insulative qualities of buildings than it is to increase power-generating capacity.

Consumers generally act to minimize the cost of energy services (which is not the same as minimizing the cost of energy). Consumers choose the combination of fuels and energy-using equipment to minimize their costs. Thus, as prices rise, it pays to replace worn out equipment with more energy-efficient technologies and/or switch fuels.[7] Using a least-cost approach mimics this type of consumer market behavior; fuels and energy-using technologies are combined to meet energy service demands at the lowest possible cost to the customer. In this sense, least-cost power planning creates a surrogate for market choice.

STATES' APPROACHES TO LEAST-COST STRATEGY AND PLANNING

Introduction

Information on least-cost strategy and resource planning in Nevada, Wisconsin, the Pacific Northwest, California, Florida, Minnesota, New York, Ohio, Oklahoma, and Texas is presented in this section. Nevada's approach and legislation is discussed first and in relatively greater depth because Nevada is considered a model for least-cost planning and consumer and utility involvement. Some factors considered essential for least-cost resource planning are:

- long-range (10 to 20 years) integrated demand and supply forecasts;
- integration of the planning process and the rate-setting process;
- specification of the planning methodology;
- required implementation and monitoring of the plan;
- a regulatory agency with adequate enforcement authority;
- the ability of the planning agency to modify, as well as reject and accept, utility plans; and
- active public involvement.

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[6]Least-cost energy strategies are in part based on theories of Amory Lovins, who is also the author of Soft Energy Paths, Ballinger Publishing Company, Cambridge, Massachuetts, 1977.

[7]This is only true, of course, if prices accurately reflect the real price of energy services. If energy services are subsidized, their use will not be efficient and consumers' decisions regarding energy use will be distorted or inefficient.

Nevada

The 1983 session of the Nevada legislature passed into law the Utility Resource Planning Act (see Attachment A). The legislation, initiated by the state's then recently created Office of Consumer Advocate, is intended to ensure that electric utilities employ accurate forecasts of their future energy needs and that those future needs are fulfilled using the most practical and cost-effective means. Some of the impetus for the legislation was the belief that the commitment of utility capital is the single most important decision facing utilities and that the previous Nevada law did not provide for a systematic or ongoing review of utility resource planning activities. The previous review process was also considered cursory and inadequate by the public and the Office of Consumer Advocate. The Office of Consumer Advocate further argued that the planning and permit reviews came after the utility had already committed resources with no review by the public or public utilities commission. Historically, construction permit proceedings by the commission were held after a utility had made supply resource planning decisions and the proceedings were not designed for detailed review of the economic costs and benefits of alternative supply resources. The new legislation requires utilities to submit every two years to the Nevada Public Service Commission a fully integrated, long-range (20-year) resource plan which must demonstrate that all aspects of a utility's future energy needs have been considered.[8]

Under provisions of the Nevada act, demand and supply functions must be evaluated in a dynamic, iterative process that considers risk, sensitivity, and uncertainty factors. The end result is an integrated least-cost resource plan. Before a utility can receive permission to construct a new generation facility or transmission line, the proposed project must be part of the least-cost mix in a previously approved 20-year resource plan. Five major areas of analysis are required in Nevada plans: 1) forecast of future demand; 2) assessment of demand options, i.e., conservation and load management potential; 3) assessment of supply options; 4) integration of supply and demand; and 5) a two-year implementation plan.[9] The two-year implementation plan essentially monitors the long-range 20-year plan and makes it a truly dynamic, strategic plan.

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[8]Jon B. Wellinghoff and Cynthia K. Mitchell, "A Model for Statewide Integrated Utility Resource Planning," Public Utilities Fortnightly, August 8, 1985, p. 19.

[9]Ibid.

The Nevada Office of Consumer Advocate believes that comprehensive statutes and regulations for utility resource planning must contain the following components:

1) **Planning Process Integration:** Integration must include a forecast of future demand and a comprehensive analysis of demand and supply options available to meet or alter demand which are then unified to derive the least-cost resource plan. On a procedural level, regulators must strive for integration of utility rate making and utility construction permit proceedings with the planning process to ensure that the process actually results in long-term economic benefits to rate payers and financial stability for the utility.

2) **Sufficient Methodological Specification:** Specification of planning methodology is necessary to ensure that state-of-the-art techniques are employed, consistency between filings of plans exists, and a systematic review process for the public and regulators is established. This should not be so rigid as to preclude planning innovation by utility planning staff and permit flexibility where appropriate.

3) **Required Implementation:** The resource planning process must require the submission of an action plan for regulatory review. The plan must detail the means by which the utility plans to acquire and implement resources, with cost-effectiveness being the key priority.

4) **Utility Responsibility for Plan Creation:** If integrated demand and supply planning is to be internalized by investor-owned utilities, the expertise and data for plan development must originate from within. This increases the likelihood that the utilities will abide by their plans and that they will be more successfully implemented.

5) **Plan Enforcement:** Unless the regulatory process provides for an effective enforcement mechanism to ensure that the utility adequately conducts the planning process and follows through with the acquisition and implementation of plan resources, the entire process can become a meaningless exercise. Procedural integration of the planning process can greatly facilitate enforcement of the planning process.[10]

Wisconsin

The 1975 Wisconsin Power Plant Siting Law and implementing regulations of the Wisconsin Public Service Commission (PSC) gave the commission broad planning, siting, and environmental review authority. This landmark law

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[10]Jon B. Wellinghoff and Cynthia K. Mitchell, 1985, p. 20.

initiated capacity planning and the evolution of least-cost planning in Wisconsin. The legislation requires each utility to file an "advance plan" for the construction of facilities. The biennial filing must include a long-range, 20-year demand forecast, plans for the construction of proposed generating and transmission facilities, and an analysis of alternatives to the proposed generation and transmission facilities. The utility advance plans are submitted to the PSC, which compiles the individual plans into the statewide advance plan (see Attachment B for Wisconsin statutes and information on the PSC).

In the fall of 1986, Wisconsin completed its fourth statewide advance plan. In reviewing this plan, the commission (for the first time) established integrated least-cost planning of both supply and demand-side options as the framework for utility submissions in the upcoming fifth advance plan.[11] The previous lack of integration of supply and demand analyses was seen as the only major short-coming of Wisconsin's planning effort; this supply and demand integration places Wisconsin's planning efforts on par with those of Nevada.

In contrast to Nevada, which passed least-cost legislation, wrote accompanying regulations, and introduced their first resource plans in an approximately one-year period, least-cost planning started earlier but was an evolutionary process in Wisconsin. This successful evolution was dependent, however, on a strong statutory framework and the authority vested in the commission.[12] The Wisconsin PSC indicates that a planning framework should contain the following elements:

1) The commission should have the authority to require utility submission of long-range plans on a regular basis.

2) The commission should have the authority to approve or reject plans based on a weighing and balancing of a broad set of factors (economic, environmental, health, safety, reliability, engineering) in order to best serve the public interest.

3) The commission should have the authority to modify submitted plans to make them acceptable. This is the most important tool to shape the direction of future utility plans. The rejection of plans alone may leave no option for proceeding.

4) There should be a link between the plans that are filed and subsequent approval of construction proposals and rate cases which implement those plans. This allows the commission to monitor the implementation of plan directions and makes plans truly strategic.

5) Utility planning should be open to the public and state agencies for review and input.

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[11] Mary Lou Munts, Chairperson, Wisconsin Public Service Commission, "Least-cost Electricity Planning: Barrier and Benefits", presentation to the National Association Regulatory Utility Commissioners convention, November, 1986.

[12] Ibid.

The Wisconsin PSC has used this authority to make two rather dramatic changes in energy directions. The first occurred in 1978, with the submission of the first advance plan. Utilities were planning to construct seven new nuclear units totaling 6,500 megawatts of capacity in the state. This included three units for which there were active applications before the commission. (It should be noted that Wisconsin's total generating capacity was 10,500 megawatts in 1986, which is considered adequate until the late 1990s). The commission determined that nuclear power would not be an economic choice, and directed the utilities to cease planning for nuclear power. It is uncertain if or when the utilities would have reached this same conclusion, but the commission believes that at least two plants specifically rejected by the commission would have been commenced, potentially costing Wisconsin consumers hundreds of millions of dollars.[13]

The second planning redirection ordered by the commission was the assessment that conservation, renewable resources and cogeneration were technically and economically feasible alternatives to the conventional power plant. This recognition led to the requirement that utilities prepare plans that consider these alternative resources with the goal of avoiding new power plant construction. Least-cost integrated planning is an extension of this direction and requires that all options be evaluated and compared in a systematic and comprehensive framework.[14]

The Wisconsin commission views the comprehensive planning process as a great opportunity to save rate payers money by reducing unnecessary expenditures and by creating a more financially stable environment for utilities. They believe that the benefits to both consumers and utilities of their evolving least-cost planning process have far outweighed its costs.

Pacific Northwest

The Northwest Conservation and Electric Power Plan was issued April 27, 1983, pursuant to the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (also referred to as the Northwest Power Act). The act established the Northwest Power Planning Council, comprised of eight members, two each from the states of Idaho, Montana, Oregon, and Washington. The council in part, is authorized "...to achieve cost-effective conservation, to encourage the development of renewable resources,...to assure the

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[13] Ibid.

[14] Ibid.

region of an efficient and adequate power supply."[15] Under the Northwest Power Act, the Northwest Power Plan must be reviewed at least every five years to determine if the action plans that identify near-term objectives and measures are being met. Because of the number of changes in the regional electrical energy picture, a new plan was adopted in January 1986.[16]

The Northwest Power Plan was utilized in part by the Nevada Office of Consumer Advocate and the Nevada Public Utility Commission as a reference and guide in the development of Nevada's statutes and regulations. Major similarities between the regulations can be seen throughout. For example, both require the development of a range of forecasts to assess the sensitivity and risk of resource options to demand uncertainty. Also, both require the development of two-year implementation plans. The major differences between the Pacific Northwest and Nevada legislation are in the areas of responsibility and enforcement.

Both of these differences stem largely from the fact that the Northwest plan is developed on a regional basis. The plan is not tailored to the unique characteristics of individual utilities. Therefore, the burden of plan development rests with the council and not utilities. The council also has limited powers of enforcement. The Bonneville Power Authority (BPA) and other utilities can seek exemptions to components of the plan's requirements, specifically the model conservation standards. If adopted throughout the region, the conservation standards could save the Northwest two to four coal power plants. Unfortunately, many of the region's major utilities have failed to sign long-term conservation contracts with the BPA. A preliminary study by the council indicates that delaying conservation standards two years could cost the region $200 million.[17]

California

The state of California has two state agencies actively involved in utility regulation, the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC). In general, the CEC is responsible for regulating utility long-range actions such as resource planning. The CPUC is responsible for regulating utility short-term actions such as general rate cases and current conservation programs.

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[15] "Pacific Northwest Electric Power Planning and Conservation Act," Bonneville Power Administration, U.S. Department of Energy, December 5, 1980.

[16] "Report to the Governors-elect of Idaho and Oregon," Northwest Power Planning Council, December, 1986.

[17] "Northwest Energy News," Northwest Planning Council, Vol. 3, No. 6, November-December, 1984.

The 1975 Warren-Alquist State Energy Resources Conservation and Development Act in part established a state policy "... to employ a range of measures to reduce wasteful, uneconomical, and unnecessary uses of energy...." The act requires the CEC to prepare and submit to the governor and legislature: 1) a biennial report assessing current and future energy trends in California; and 2) a state energy policy with recommendations for its implementation. In developing these reports, the CEC requires the utilities to submit long-range supply and demand analyses using methodology prescribed by the CEC. The utility reports submitted to the CEC must contain five, twelve and twenty-year forecasts for electric demand, assessment of supply capacity to service this demand, options for reducing demand, utilization of conservation programs, and potential sources of energy (see Attachment D).[18]

According to an analysis by the Nevada Office of Consumer Advocate, the California landmark legislation is lacking in four respects:

- it does not specifically require the development and implementation of a least-cost plan even though it requires utilities to assess conservation and available options to reduce demand.

- there is no formal integration between the CEC long-range planning efforts and the CPUC rate case proceedings. This weakens the implementation and monitoring aspects of the long-range planning effort and increases the likelihood that important information will fall through the regulatory "cracks".[19]

- the CEC has no clear power of enforcement of plans. Permits are not denied based on a utility's failure to submit information to the CEC.

- the CEC rather than the utility has the primary responsibility for plan development. This can make implementation and enforcement more difficult.

The State of California has indicated, however, that its energy policy is moving away from an integrated resource planning approach to an "avoided cost" or "marginal cost" philosophy for issuing permits for the construction of additional supply capacity. Under this system, permits for new generating facilities would be issued with the understanding that utilities would only be paid its "avoided or marginal cost" for energy from the facility at the time it comes on line. Because of the very high cost of additional generating capacity, it is likely that this process could lead to no construction and subsequent capacity shortages.[20]

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[18]Warren-Alquist [illegible] Sections 25300-25323.

[19]Wellinghoff and [illegible]chell, 1985, p. 22.

[20]Ibid.

Florida

The 1980 Florida Energy Efficiency and Conservation Act (Attachment E) requires "... increasing efficiency of the electric and natural gas systems of Florida and the end uses of these sources of energy...." Regulations adopted by the public service commission require utilities to "review and revise utility operating practices...plan development of the bulk power system...increase the efficiency of existing generating units...aggressively integrate nontraditional sources of power generation...and increase efficiency of transmission and distribution systems." The act established a five-year goal (beginning in January 1981) of an approximate 25 percent reduction for all electric utilities in peak demand and energy consumption.

The governor's energy office 1985 annual report states that reducing Florida's per capita energy consumption and the state's reliance on petroleum is the primary goal of the office. Conservation is the principal focus for the energy office's program. The second major objective is the promotion of renewable energy resources, especially solar energy. The third major objective is to effectively plan for energy disruptions as a result of the state's dependency on petroleum.

Under Florida's planning provisions, the public service commission sets goals which the utilities must meet. Florida has been successful with this approach; utilities have shown an increasing spirit of cooperation in voluntarily proposing major conservation and load management programs. No utilities have proposed new generating facilities despite Florida's high population growth rate. Florida's statutes and regulations, however, do not constitute an integrated resource planning process. Neither a least-cost nor an implementation plan is required. The utilities do not independently assess the optimal level of conservation potential but instead work under the commission's established goals. There is also no enforceable regulatory connection between resource planning and construction permit proceedings. The success to date of Florida's process appears to be a result of the commitment of the people involved in the process rather than the structure of the Florida statutes and regulations.[21]

Minnesota

Minnesota is in the process of establishing least-cost planning legislation. The stated purpose of the legislation is "...to assure that Minnesota consumers pay the lowest cost possible for electricity. Least-cost planning would require that electric utilities plan to invest in all cost-effective supply and demand options (i.e., conservation, cogeneration,

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[21]Wellinghoff and Mitchell, 1985, p. 22.

and renewable energy) instead of building expensive, environmentally risky new power plants to meet consumer needs. Least-cost planning would tie together the state's review of electric utility rates, advance forecasts, requests for permits to build new power plants, and conservation." Minnesota also identifies the following benefits from least-cost planning:

- Significant cost savings to all sectors of the state's economy;
- Increased use of environmentally cleaner sources of energy;
- Decreased dependence on nonrenewable fossil fuels;
- Financially healthier utilities; and
- Improved coordination of state agencies' responsibilities.

The least-cost planning section of the draft legislation requires utilities to submit least-cost plans to the public utilities commission biennially commencing in 1989. The plans must include annual demand, sources of supply, and energy forecasts for a 15-year period. The supply and demand forecasts must be integrated to obtain a least-cost option. The public utilities commission is given the authority to approve, modify, or reject the plan. The draft legislation appropriates $500,000 from the general fund to the public utilities commission to carry out the legislation, which includes the development of regulations and the addition of five staff positions. The appropriation is available until January 1, 1989 (see Attachment E for a copy of the draft legislation).

New York

The 1976 State Energy Law established a State Energy Office to work with other state agencies in the development and coordination of an overall state energy program. Members of the New York Power Pool are required to prepare an annual, comprehensive, long-range forecast of future demand, future generation facilities, and anticipated expenditures for conservation, load management, electric generation, and transmission.[22] The State Energy Office conducts hearings on the utilities' composite filing and prepares a report of the long-range electric and gas demand and supply requirements of the state.

The public service commission is required to review the plan to determine whether it is cost-effective and whether the plan will result in significant energy savings. The commission must also determine if additional supply capacity is warranted based on the plan. In 1984, the commission set a major new energy conservation policy requiring each of the state's electric utilities to place energy conservation on equal footing with power plant construction and alternative forms of electric generation.[23] The utilities have been directed to commit portions of annual revenues to the development of comprehensive energy plans (see Attachment G for New York energy statutes).

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[22]State of New York, Energy Law, Chapter 17-A, July 26, 1976.

[23]New York Public Service Commission, Order 84-15, May, 1984.

Ohio

The state of Ohio initiated least-cost resource planning in November 1986 through a grant to the Public Utilities Commission of Ohio to research the methodology of incorporating least-cost options into the regulatory process. The study is being conducted in cooperation with the Ohio Office of Energy Conservation. Least-cost planning is a priority of the governor. Energy conservation is also a high priority of the state; conservation is considered a primary tool to foster economic development in Ohio. In 1983, legislation was passed that requires every major gas and electric utility to submit a long-range forecast and a description of planned utility supply resources to the Public Utilities Commission of Ohio. The present least-cost study is aimed at amending the current statute to specifically require integrated least-cost resource planning. See Attachment G for an overview of the Ohio least-cost study and Ohio statutes.

Oklahoma

Oklahoma does not have a formal least-cost planning effort, but the Oklahoma Corporation Commission (OCC, which is the public utilities commission) "encourages" utilities to do so. The legislature has also given the OCC a directive to biennially prepare a 10-year electricity supply and demand forecast.[24] The Public Service Company of Oklahoma proposed to the commission a comprehensive rate program which the company calls the "New Direction." The program's goals--to encourage conservation, decrease the need for future generating units, improve utilization of existing generating equipment, and provide opportunity for greater consumer choice--are similar to most least-cost resource planning efforts. The New Direction program uses an innovative rate structure to attain these goals. The program has been in place since 1984.

The New Direction strategy utilizes the marketplace and the most powerful marketing variable--price--as both a fundamental cause of and potential solution to the problems of customers and utilities. A selection of price and service options as well as meaningful incentives for prudent and efficient energy use are offered to various customer segments. The New Direction program recognizes the difference in customer needs and their effect on the energy marketplace. Finally, the strategy recognizes that only those customers who require special services should pay for those services.[25]

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[24]Personal communication, Oklahoma Corporation Commission staff, January 1987.

[25]Baker, Hamp, "A New Direction for an Electric Utility - A Commissioner's Viewpoint," Public Utilities Fortnightly, November 22, 1984, p. 23.

The New Direction program offers the following four residential programs.

- an optional base price which offers price incentives to residential customers who can minimize the amount of energy they use above 800 kilowatt hours (KWH) per month during peak months;

- incentives to customers who upgrade low-efficiency equipment to high-efficiency units;

- price reduction for homes qualifying as energy-efficient; and

- a price break for customers who consistently use less than 400 KWH per month.[26] This latter option rewards customers who consistently conserve electricity; it is opposite to previous electrical pricing options which encouraged energy usage by reducing the price as consumption increased.

The program also offers commercial and industrial programs which include level-of-service price schedules, time-of-day prices, and an industrial interruptible price option. Similar to the residential programs, the industrial and commercial programs recognize the different needs of customers, reward conservation, and are aimed at shifting demand away from high-use periods to lower-use periods. Basic to the program is the recognition that the cost of energy is not constant throughout the day or the year. Variable pricing encourages customers to alter their use patterns in order to use cheaper power. The program achieves more efficient use of energy through load management and encouraging conservation.

The New Direction program is revenue neutral, meaning that it offers no immediate revenue increase to the utility company. The ten-year goals for the program are: 1) no change in energy sales; 2) reduce peak demand 527 megawatts (13 percent) which equals one major generating unit; 3) reduce energy prices by ten percent per kilowatt-hour; 4) lower revenue requirements by $566 million; and 5) earn a reasonable return on investment. The OCC requires that the program must benefit all the customers of the utility (both those who qualify for new rates, credit, or payments and those who do not).[27] See Attachment I for more information on the New Directions program.

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[26]Ibid.

[27]Ibid, p. 24.

Texas

In 1983, the legislature amended the Public Utility Regulatory Act to require the Texas Public Utility Commission (TPUC) to develop a long-term statewide electrical energy forecast to be sent to the governor biennially. The forecast must include an assessment of how alternative energy sources, conservation, and load management will meet the state's energy needs. The act also requires each utility to submit to the commission a ten-year forecast of demand and supply options available to service the demand. The Texas legislation requires an integrated resource planning approach. Least-cost planning, however, is addressed only in the rules developed by the TPUC.

Recent conversations with TPUC staff indicate that the resource planning process is presently experiencing considerable upheaval. While the Public Utility Regulatory Act is considered fairly rigorous, the rules developed by the TPUC commissioners are considered too general to be binding on the utilities. This has resulted in utilities filing plans that are considered inadequate by TPUC staff and the public. In September 1986, 16 Texas consumer groups filed a petition against the TPUC to expand the rules and make them more specific. The petition was denied by the commissioners, who instead created a task force to study the problem. Public hearings regarding these controversies are presently underway. See Attachment J for a copy of Texas statutes, rules, and the citizen petition.

ENERGY AGENCIES AND POLICIES IN OTHER STATES

The organization and function of energy agencies in the states appears to be in a transitional stage. Conversations with staff at the Council of State Governments, National Conference of State Legislatures, and a number of state energy agencies indicate that department level energy agencies were usually established in the mid-1970s in response to the oil embargo. There is presently a trend to dissolve these departments and shift the responsibilities to divisions or offices in other agencies. The reasons for these changes were most often identified as being part of a more general consolidation trend aimed at increased fiscal efficiency and/or a maturation and shift in state energy policy. The majority of states' energy agencies are divisions or offices. Table 1 presents the most recent summary of state energy agencies dates from the 1982 Book of the States.

MAJOR STATE SERVICES

Table 1
STATE ENERGY AGENCIES

State	Organizational category*				Basis of establishment	
	Department-agency	Commission-council	Office	Division	Statute	Executive order
Alabama	•	•			Act 80-449 of 1980	
Alaska				•		21
Arizona			•			77-10
Arkansas				•	Act 7 of 1981	
California		•			Pub. Res. Code 25000 et seq.	
Colorado			•			Issued 7/17/81
Connecticut				•	Title 16a	
Delaware				•	63 Del. Law C60, Sec. 56(b)	
Florida			•		377.601-709 F.S.	
Georgia			•		Ga. Law 1976, P 1740	
Hawaii			•		Act 237, 1974	
Idaho			•			76-4
Illinois	•				Chap. 96½, Sec. 7401 et seq.	
Indiana				•		1973 Ex. order
Iowa		•			93.1-93.16	
Kansas	•				74-6801 et seq.	
Kentucky	•				S.B. 307	
Louisiana				•	LRS 30:501 et seq.	
Maine			•		Title 5, Chap. 338 MRS	
Maryland				•		1973 Ex. order
Massachusetts	•				Chap. 25A	
Michigan			•			1976-2
Minnesota	•				Chap. 116H, 116J	
Mississippi		•				No. 151, 164, 177 & 270
Missouri				•		1977 Ex. order
Montana				•		1979 Ex. order
Nebraska	•				L.B. 954, 1980	1980 Ex. order
Nevada	•				NRS 523, all et seq.	
New Hampshire		•				73-12
New Jersey	•				N.J.S.A. Title 14, Sec. 1 1, Chap. 146	
New Mexico	•				Chap. 236	
New York			•		Chap. 859 & 707, L. 1975	
North Carolina				•	Chap. 1138	
North Dakota			•			1974-1
Ohio	•				H.B. 415	
Oklahoma		•			Tit. 5, 1981, Sec. 14 1	
Oregon	•				Rev. Stat. 469.010 et seq.	
Pennsylvania		•				Issued 7/19/79
Rhode Island				•		E.O. 81-4
South Carolina			•			Issued 9/11/78
South Dakota			•			77-5
Tennessee	•				T.C.A. 4-26-101 et seq.	
Texas		•				
Utah				•	41-22-27	
Vermont			•		13, Chap. 41, Sec. 2286 VSA	
Virginia				•		No. 5-1978
Washington	•				Chap. 295, 1 81	
West Virginia				•		
Wisconsin				•	Chap. 16, 1977	
Wyoming			•			

* Key: Department-agency—one man agency or state human agency of state human cabinet level status. Commission-council—governing body composed of appointed or ex-officio members. Office—functional unit of executive office (governor or lieutenant governor). Division—major agency under the direction of a cabinet level department.

Source: Book of the States, 1982-1983, Council of State Governments, p. 658.

The structural organization and role of these agencies are generally a reflection of energy policy in the state; policies in the states tend to be influenced by whether the state is a net buyer or seller of primary energy resources. States that are primarily buyers and/or heavy users of energy resources focus their energy policy towards conservation. An example is Ohio which has an Office of Energy Conservation in its Department of Development. Staff in that office stressed that energy conservation is considered a primary development tool in Ohio. States that are producers of energy resources tend to be more focused on production and are often relatively high per capita users of energy. The higher use of energy may in part be attributed to the lower price of local resources and/or the perception that these resources are not scarce. Regardless of whether states are net buyers or sellers of energy resources, the office or division of energy is often part of the governor's office or in a department of commerce and economic development. In regard to your question concerning the consolidation of other state energy programs, almost all other states' programs appear to be considerably more consolidated than Alaska's. The only exception to this is California, where the organization of energy programs is very complex as a result of the the state's large population and size.

For all states, the three major government energy responsibilities are regulation and plant siting, planning and forecasting, and conservation. Most states place regulation and siting responsibilities with their public utilities commission (PUC). The development of new projects are almost always reviewed by PUCs in other states. The primary function of commissions is to balance the public's and utilities' interests. Because of this, most states also have a consumer advocate office staffed with economists and attorneys to represent consumers before the commission; utilities are usually amply represented. There is no office in Alaska that plays the role of a consumer advocate office. Generally speaking, other states' PUCs are statutorily granted greater authority to provide more utility oversight than the Alaska PUC. The majority of states have three commissioners in the PUC; Alaska has five (see Table 2). Attached is information on utility regulation in other states and a draft model consumer advocacy legislation prepared by the Council of State Governments (Attachment K).

Table 2
STATE PUBLIC UTILITY COMMISSIONS

State or other jurisdiction	Regulatory authority	Members: Number	Members: Selection	Selection of chair	Length of commissioners' terms (in years)	Number of full-time employees
Alabama	Public Service Commission	3	E	E	4	90
Alaska	Public Utilities Commission	5	GL	G(a)	5	49
Arizona	Corporation Commission	3	E	C	6	167
Arkansas	Public Service Commission	3	GS	G	6	101
California	Public Utilities Commission	5	GS	G	6	987
Colorado	Public Utilities Commission	3	GS	G	6	96
Connecticut	Public Utilities Control Authority	5	GL	C	4	107
Delaware	Public Service Commission	5	GS	G	3	17
Florida	Public Service Commission	5	GS	C	4	336
Georgia	Public Service Commission	5	E	C	6	119
Hawaii	Public Utilities Commission	3	GS	G	6	17
Idaho	Public Utilities Commission	3	GS	G	6	55
Illinois	Commerce Commission	*	G	G	5	348
Indiana	Public Service Commission	5	G(b)	G	4	91
Iowa	State Commerce Commission	3	GS	G	6	175
Kansas	State Corporation Commission	3	GS	C	4	254
Kentucky	Public Service Commission	3	G	G	3	90
Louisiana	Public Service Commission	5	E	C	6	74
Maine	Public Utilities Commission	3	GS	G	6	54
Maryland	Public Service Commission	5	GS	G	5	123
Massachusetts	Dept. of Public Utilities	3	G	G	4(c)	134
Michigan	Public Service Commission	3	GS	G	6	215
Minnesota	Public Utilities Commission	5	GS	G	6	74
Mississippi	Public Service Commission	3	E	C	4	115
Missouri	Public Service Commission	5	GS	G	6	261
Montana	Public Service Commission	5	E	C	4	44
Nebraska	Public Service Commission	5	E	C	6	54
Nevada	Public Service Commission	3	G	G	4	82
New Hampshire	Public Utilities Commission	3	G	G	6	51
New Jersey	Board of Public Utilities	3	GS	G	6	323
New Mexico	Public Service Commission	3	GS	G	6	60
New York	Public Service Commission	6	GS	G	6	603
North Carolina	Utilities Commission	7	GI	G	6	168
North Dakota	Public Service Commission	3	E	C	6	60
Ohio	Public Utilities Commission	5	GS	G	5	375
Oklahoma	Corporation Commission	3	E	C	6	413
Oregon	Public Utility Commissioner	1	G		4	349
Pennsylvania	Public Utility Commission	5	GS	G	10	575
Rhode Island	Public Utilities Commission	3	GS	G	6	41
South Carolina	Public Service Commission	7	GS	(d)	4	145(e)
South Dakota	Public Utilities Commission	3	E	C	6	24
Tennessee	Public Service Commission	3	E	C	6	155
Texas	Public Utility Commission	3	GS	C	6	204
Utah	Public Service Commission	3	GS	G	6	48
Vermont	Public Service Board	3	GS	G	6	26(e)
Virginia	State Corporation Commission	3	L	C	6	668
Washington	Utilities and Transportation Commission	3	GS	G	6	199
West Virginia	Public Service Commission	3	GS	C	6	177
Wisconsin	Public Service Commission	3	GS	G(f)	6	158
Wyoming	Public Service Commission	3	GS	C	6	41
Dist. of Col.	Public Service Commission	3	M	C	3	31
Puerto Rico	Public Service Commission	5	GS	GS	4	243

Source: National Association of Regulatory Utility Commissioners, *Annual Report on Utility and Carrier Regulation, 1984* (Washington, D.C. 1985).

Key
G—Appointed by Governor
GS—Appointed by Governor, with consent of Senate
GL—Appointed by Governor, with consent of entire Legislature
E—Elected by the Public
C—Elected by the Commission
L—Appointed by the Legislature
M—Appointed by the Mayor

(a) Chairman serves in that position for four years.
(b) Legislation enacted in 1983 created a nominating commission members of which submit a panel of three candidates to the governor for consideration.
(c) Coterminous with governor's.
(d) Chairmanship rotates every two years.
(e) Updated information not available. No response to survey.
(f) Chairman serves in that position for two years.

Source: Book of the States, 1986-1987, Council of State Governments, p. 358.

Many of the functions of the Alaska Power Authority (APA) are conducted by public utility commissions, utilities, and energy offices in other states. The APA also appears to be a unique entity among the 50 states. There are power project bonding authorities in other states but their roles are usually limited to that function alone. West Virginia created the Public Energy Development Authority in 1985 to issue bonds for constructing energy-related facilities (i.e., power plants and transmission lines). The function of the West Virginia authority is only to issue bonds. Energy plan development and facility promotion and financing are generally viewed as conflicting objectives in other states.

In the area of planning and forecasting, these activities are usually the responsibility of the office or division of energy. Most of the states discussed in this memorandum have an extensive planning process which results in the development of a statewide plan. The planning process entails the specification of energy policy and the formulation of objectives or goals. The plan identifies how these objectives are to be met and requires implementation and monitoring to assure that the goals are achieved. True strategic plans such as those of Nevada and Wisconsin are a dynamic process. In contrast, Alaska's Energy Plan, which is prepared by the APA, is more of a catalogue of energy information and activities. This is probably the result of the lack of a lead energy agency formulating state energy policy and the disaggregation of programs among agencies.

States vary considerably as to whether they conduct energy plans or whether the utilities are required to present plans developed in accordance with state statutes and regulations which are then incorporated by a state agency into a statewide plan. Most of the states discussed in this memorandum require utilities to submit plans; the costs for plans are covered by utility rates which are approved by the PUC. The states which require utilities to develop plans have generally been more successful with implementation and enforcement. In states where utilities prepare plans, the office of energy conducts demand and supply forecasts, provides technical information regarding conservation and alternative energy, and takes a lead role in formulating and carrying out state energy policies. In Wisconsin, for example, the PUC writes a statewide energy plan which incorporates the plans submitted by individual utilities.

In some states, the PUC is responsible for energy planning and demand forecasting. They believe this more closely ties the planning process to utility rate determinations, which is the ultimate objective of utility regulation. The Wisconsin PUC, for example, has divisions of planning, rate determination, and conservation.

Many of the offices of energy have a separate functional section that covers conservation, weatherization, and federal programs. Energy assistance (federal dollars to directly pay utility bill), however, is sometimes administered through departments of social service with other state and federal low-income assistance programs. In Alaska, weatherization and some federal dollars are administered by the Department of Community and Regional Affairs; energy assistance is administered by the Department of Health and social Services.

* * * *

If you have any questions, or wish additional information, please contact this agency.

Attachments

cc HB238 members files

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

P.O. Box Y, State Capitol
Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

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			Interstate pipeline companies	Natural Gas Producers	Electric			Gas			Electric			Gas			
	Private	Public	Cooperative	Private	Public	Telephone			Private	Public	Cooperative	Private	Public	Telephone	Private	Public	Cooperative	Private	Public		
FCC						X 16/								X 16/		1/					
FERC		1/					17/	17/		1/								X			
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	53/	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			
CALIFORNIA PUC	X			X		X			X			X		X	X			X			
CANADIAN RTC						X									X		X	X			
COLORADO PUC	X		X	X		X			X		X	X			X			X			
CONNECTICUT DPUC	X			X		X			X			X		X	X		X	X			
DELAWARE PSC	X		X	X		X			X		X	X		X	X			X			
D.C. PSC	X		X	X		X			X		X	X		X	X	X 43/	X 43/	X			
FLORIDA PSC	X	X 43/	X 43/	X		X			X	X 43/	X 43/	X		X	X			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		
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			X			
MONTANA PSC	X	X		X	X	X	X	X	X	X		X	X	X	X	X		X	X		
NEBRASKA PSC 42/						X															
NEVADA PSC	X	6/	65/	X	6/	X			X	6/	65/	X	6/		X	6/	65/	X	6/		
NEW HAMPSHIRE PUC	X	X 3/	X	X		X			X	X 3/	X	X		X	X	X 3/	X	X			
NEW JERSEY BPU	X	7/		X		X			X			X		X	X			X			
NEW MEXICO PSC	X	8/	X	X			X 18/		X	8/	X	X			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			
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		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 EGP	X			X					X			X		X							
QUEBEC RSP						X															
RHODE ISLAND PUC	X	X	X	X	X	X			X	X	X	X	X	X	X	X	X	X	X		
SASKATCHEWAN PUHC	X	X		X	X	X		X		X			X	X							
SOUTH CAROLINA PSC	X			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							
TEXAS PUC	X	X 48/	X			X			X	X 48/	X			X	X	X 48/	X		X	X 8/	
TEXAS RC				X	X 8/								X 8/								
UTAH PSC	X		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	X	
VIRGIN ISLANDS PSC		X				X				X				X							
VIRGINIA SCC	X		X	X		X 73/								X	X			X			
WASHINGTON UTC	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	X	
WISCONSIN PSC	X	X	14/	X	X	X	12/	12/	X	X	19/	X	X	X	X	X	14/	X	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	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 -												Abandonment of Facilities or Service					
	Distribution Lines						Other Plant											
	ELECTRIC			GAS			ELECTRIC			GAS			ELECTRIC			GAS		
	Private	Public	Co-op	Private	Public	Telephone	Private	Public	Co-op	Private	Public	Telephone	Private	Public	Co-op	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.

HB 238 files

Alaska Consumer Advocacy Program

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

March 31, 1988

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

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

ENERGY PLANNING IN ALASKA: PAST EFFORTS AND A FUTURE DIRECTION

House Research Agency
Alaska State Legislature
February 1988

House Research Agency Report 88-B

From Steven Wiel

NEVADA REVISED STATUTES

Containing All Statute Laws of Nevada of a General, Public and Permanent Nature; Constitutions and Related Matter

VOLUME 29

Classified, Arranged, Indexed and Published (Pursuant to chapter 220 of NRS)

BY THE
LEGISLATIVE COUNSEL
STATE OF NEVADA

LEGISLATIVE COUNSEL BUREAU
CARSON CITY, NEVADA

704.736 Applicability of NRS 704.741, 704.746 and 704.751. The application of NRS 704.741, 704.746 and 704.751 is limited to any public utility in the business of supplying electricity which has an annual operating revenue in this state of $2,500,000 or more.
(Added to NRS by 1983, 886)

704.741 Plan to increase supply or decrease demands: Biennial submission required; contents prescribed by regulation.
1. A utility which supplies electricity in this state shall, on or before July 1 of every even-numbered year, submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the commission.
2. The commission shall, by regulation, prescribe the contents of such a plan including, but not limited to, the methods or formulas which are used by the utility to:
(a) Forecast the future demands; and
(b) Determine the best combination of sources of supply to meet the demands or the best method to reduce them.
(Added to NRS by 1983, 886)

704.746 Public hearing on adequacy of plan; determination by commission.
1. Not more than 60 days after a utility has filed its plan, the commission shall convene a public hearing on the adequacy of the plan.
2. At the hearing any interested person may make comments to the commission regarding the contents and adequacy of the plan.
3. After the hearing the commission shall determine whether:
(a) The utility's forecast requirements are based on substantially accurate data and an adequate method of forecasting;
(b) The plan identifies and takes into account any present and projected reductions in the demand for energy which may result from measures for conservation and management of loads in the industrial, commercial, residential and energy producing sectors of the area being served; and
(c) The utility's plan shows an adequate consideration of the following possible measures and sources of supply:
(1) Conservation;
(2) Load management;
(3) Pooling of power;
(4) Purchases of power from neighboring states or countries;
(5) Facilities which operate on solar or geothermal energy or wind; and
(6) Facilities which operate on the principle of cogeneration or hydrogeneration.
(Added to NRS by 1983, 887)

(over)

704.751 Order accepting plan or specifying inadequacies; recovery of costs from customers.

1. Within 105 days after a utility has filed its plan, the commission shall issue an order accepting the plan as filed or specifying any portions of the plan which it deems to be inadequate.

2. All prudent and reasonable expenditures made to develop the utility's plan, including environmental, engineering and other studies, must be recovered from the rates charged to the utility's customers.

(Added to NRS by 1983, 887)

704.890 Grant or denial of application; required findings; service of copies of order.

1. The commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such terms, conditions or modifications of the construction, operation or maintenance of the utility facility as the commission may deem appropriate. The commission may not grant a permit for the construction, operation and maintenance of a utility facility, either as proposed or as modified by the commission, unless it finds and determines:

(a) The basis for the need of the facility;

(b) The nature of the probable environmental impact;

(c) That the facility represents the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives, and other pertinent considerations;

(d) That the location of the facility as proposed conforms to applicable state and local laws and regulations issued thereunder;

(e) That the facility will serve the public interest; and

(f) That if the facility or a part thereof is intended to meet the requirements of customers in this state for electricity, it is included in the utility's plan to increase its supply of electricity or decrease the demands made on its system by its customers.

2. If the commission determines that the location of all or a part of the proposed facility should be modified, it may condition its permit upon such a modification.

3. A copy of the order and any opinion issued with it must be served upon each party.

(Added to NRS by 1971, 557; A 1983, 887)

Senate Bill No. 456--Committee on Commerce and Labor

CHAPTER 420

AN ACT relating to public utilities; requiring a public utility which supplies electricity to submit its plan to increase its supply of electricity or reduce demand every third year; and providing other matters properly relating thereto.

[Approved June 11, 1987]

THE PEOPLE OF THE STATE OF NEVADA, REPRESENTED IN SENATE AND ASSEMBLY, DO ENACT AS FOLLOWS:

Section 1. NRS 704.741 is hereby amended to read as follows:

704.741 1. A utility which supplies electricity in this state shall, on or before July 1 of every [even-numbered] *third* year, *in the manner specified by the commission*, submit a plan to increase its supply of electricity or decrease the demands made on its system by its customers to the commission.

2. The commission shall, by regulation, prescribe the contents of such a plan including, but not limited to, the methods or formulas which are used by the utility to:

(a) Forecast the future demands; and

(b) Determine the best combination of sources of supply to meet the demands or the best method to reduce them.

"

PUBLIC CITIZEN
Critical Mass Energy Project
215 Pennsylvania Ave., S.E. • Washington, D.C. 20003 • (202) 546-4996

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)

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.

can be viewed as new electrical sources just as assuredly as a new nuclear or coal-fired power plant.

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 devastating. Many of the power plants ordered in the early 1970's have recently started (or soon will

by 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

[1] *The Least-Cost Energy Strategy: Minimizing Consumer Costs Through Competition*, 1979. Roger Sant, Carnegie Mellon University Press, Pittsburgh, PA.

[2] *Power Plant Cost Escalation: Nuclear and Coal Costs, Regulation, and Economics*, 1981. Charles Komanoff, Van Nostrand Reinhold, NY.

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[4] *Rate Shock: Confronting the Cost of Nuclear Power*, 1984. Alan Nogee, Environmental Action, Washington, DC.

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

[6] "Saving Gigabucks with Negawatts", 1985. Amory Lovins, *Public Utilities Fortnightly*, March 21, 1985.

[7] *Ibid*

[8] *Electricity's Future: The Shift to Efficiency and Small-Scale Power*, 1984. Chris Flavin, Worldwatch Institute, Washington, DC.

[9] *1981 Conservation and Load Management Program*, 1981. South California Edison Co., Rosemead, CA.

[10] "The Great PG & E Rebate Program", 1984. Pacific Gas and Electric Co., San Francisco, CA.

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

[12] "Questions and Answers" from Nevada Public Service Commissioner Stephen Wiel at March 5, 1985 hearings before the Energy Development and Applications Subcommittee hearings on Department of Energy 1986 budget.

[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 Commissioners (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.

PUBLIC CITIZEN
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Is Your State Charting A Least-Cost Electrical Strategy?

A Guide to Evaluating State Laws and Regulations

PAUL MARKOWITZ AUGUST 1986

INTRODUCTION

Since 1973, the electric utility industry has undergone massive changes. Huge increases in power plant construction costs combined with sharp declines in electrical demand growth have resulted in exponential increases in electric rates. These changes have rocked the economic foundation of large-scale generating facilities, and consequently have radically altered the manner in which utilities plan to meet new electrical demand.

In response to these changes, the concept of a least-cost energy strategy has emerged among regulatory commissioners, consumer advocates and some utility planners. A least-cost strategy utilizes those additional sources of energy supply or energy demand reductions that can be obtained for the least total cost to utilities and their ratepayers. Conservation forms the basis for a least-cost strategy because energy efficiency improvements are the most cost-effective of all resource options.

However, a least-cost strategy involves utilizing all available resources for meeting future demand, including: load management, renewable energy resources and cogeneration. Consequently, a least-cost strategy minimizes the cost of electrical service, offers significant environmental benefits, and provides economic benefits to local communities by emphasizing the use of locally-available energy resources.

States can implement a least-cost electrical strategy by adopting laws and regulations which ensure that utilities invest in the most cost-effective resources for meeting new demand. These laws and regulations can ensure that new power plants are constructed only if they represent the least-cost means of providing electricity.

Effective least-cost regulations consist of three major components:[1]

1) Planning: Utilities must submit resource plans that document how they will meet electrical demand at the lowest possible cost.
2) Evaluation: Proposed utility plans are carefully evaluated by the regulatory commission and public.
3) Enforcement: The commission accepts a revised utility plan, and uses its regulatory authority over power plant licensing and setting of utility rates to ensure that actual utility investments conform to the adopted resource plan.

MODEL STATE LEAST-COST ELECTRICAL POLICY

This triad, planning, evaluation and enforcement, provide a framework for evaluating how well your state is ensuring utility investments in least-cost electrical resources.

A. PLANNING: EACH UTILITY SUBMITS A LEAST-COST RESOURCE PLAN

Planning requirements ensure that utilities have identified all available options for meeting new electrical demand before making large expenditures.

Are your utilities required to file long-range resource plans?

Each utility should be required to submit a long-range (ten or twenty years) resource plan every one or two years to the state regulatory commission. Comprehensive utility plans should include all of the following components:[2]

a. Forecast of Future Demand: Utilities should file forecasts of future electrical demand which identify two-to-three possible scenarios for demand growth to help account for the large degree of uncertainty regarding future energy consumption. Demand forecasts should utilize a combination of the following forecast methodologies:

End-use analysis: This methodology calculates the number, type and efficiency of electrical end-uses (e.g. water heaters, lighting, industrial motors) in each customer class. It incorporates the impacts of changes in efficient technologies, appliance saturation levels, and utility sponsored conservation programs.

Econometric analysis: This methodology examines the impact of economic changes (e.g. increases in personal income, population growth, price increases in alternative fuels) upon electricity consumption.

b. Assessment of Supply-Side Resource Options: Utility plans should specify how the utility intends to meet future demand through various supply-side options, including: renewable energy resources (e.g. wind, solar, geothermal, hydro power, biomass), cogeneration, power purchased from

power plant. A certificate of need should only be issued when:

1. *The plant is in compliance with the utility's resource plan:* Permits for new plants should only be considered if the plant is consistent with the utility's most recently approved resource plan. This ensures integration and consistency of utility investments with the utility planning process.[9]

2. *The need for the plant has been firmly established:* Utility demand forecasts should be scrutinized in light of state-conducted forecasts, for compliance with state specifications, and to account for any changes which may have occurred since the resource plan was filed.[10]

3. *The plant is the least-cost means of meeting the need:* Utilities should be required to demonstrate that the proposed plant is the least-cost option in light of all available demand-side and supply-side options.

Further, the commission should have the authority to review the certificate of need every two years in light of any changes in the utility's approved resource plan, with the burden of proof resting on the utilities. Again, state authority to require a certificate of need should be strongly tied to its ability to evaluate proposed utility power plants in light of least-cost alternatives. Further, the commission should still maintain the authority to disallow imprudent costs from the rate base.

Has your commission used its ratemaking powers to encourage utility least-cost investments?

Ratemaking authority is important as a final check to ensure least-cost investments, but is most effective when used in conjunction with comprehensive planning and plant licensing processes. Proposed rate increases should be evaluated in the context of the utility's most recently approved resource plan, and rate recovery should be allowed only for those investments which have been included in the plan. Further, the commission should develop regulatory guidelines for what constitutes used and useful investments to assure that uneconomic utility expenditures are disallowed from the rate base.

Does your commission have authority to require utility conservation programs?

Your commission should have regulatory authority to require utilities to offer financial incentives designed to stimulate customer investments in energy conservation, such as low-interest loans or cash rebates. While most commissions are granted specific statutory authority to require these investments, many commissions have relied on broad regulatory powers to ensure "adequate and reasonable supplies of electricity" as the legal basis for requiring conservation investments.[11]

A few state commissions offer utilities financial incentives and/or impose financial penalties to encourage conservation investments. For instance, some commissions provide revenue guarantees to utilities for innovative or untested resource investments (e.g. pilot conservation programs). Other commissions are moving toward performance based financial incentives whereby utilities are rewarded or penalized according to their progress in achieving certain efficiency goals, rather than a strict rate-of-return on total assets. In this manner, commissions can reward or penalize a utility based upon progress toward achieving conservation goals or implementing its resource plan.[12]

Has your commission set avoided cost rates which require utilities to purchase electricity from small-power producers?

The Public Utilities Regulatory Policies Act (PURPA) of 1978 (Title I of the National Energy Act) requires electric utilities to purchase electricity from small-power (renewable energy and cogeneration) producers at a price equal to the utility's cost of producing electricity. Your commission should establish rates that reflect the long-term cost of building new power plants. This will maximize the development of alternative resources, while assuring lower rates for all ratepayers.

DRAWING UPON STATE EXPERIENCES

Several lessons can be drawn from state experiences in implementing least-cost electrical strategies:

1. The planning process offers a unique opportunity for regulators and the public to review proposed utility investments *before* the utility spends money. Commission authority to set utility rates is a necessary but insufficient mechanism for ensuring utility least-cost investments. As the current rate shock problem has shown, commission ratemaking authority alone is insufficient to assure utility least-cost investments; i.e., regulators are limited to reviewing utility investments after the money has been spent.

   Least-cost energy planning establishes a process whereby regulators and the public can evaluate utility investment decisions before these investments are made. This planning process can ensure that utilities examine the economic potential for all resource options, particularly energy conservation and small-power sources, and invest in the cheapest options first. This will help: 1) avoid building unnecessary power plants; 2) improve local economies by emphasizing the efficient use of electricity and the use of locally-available resources; and 3) provide significant environmental benefits by emphasizing the use of environmentally benign resources.

2. The level of commission resources available to evaluate utility filings should be directly proportional to the extent of the commission's involvement in the resource planning process. A commission with a strong mandate to develop a least-cost electrical strategy for its state must have sufficient staff and adequate financial resources in order to conduct a thorough examination of utility resource plans and other filing requirements.

3. State involvement in the resource planning process should complement, not replace, utility efforts to develop the "in-house" capabilities to plan for and evaluate conservation and alternative resource investments. Some states, such as New York, have initially taken a strong hand in deciding which resource investments are most cost-effective and have ordered utilities to make these investments. Often, utility capabilities to plan for and evaluate alternatives remain limited, and commissions have found themselves im-

3-30-88

SECTIONAL ANALYSIS
OF
PROPOSED RESOURCES COMMITTEE SUBSTITUTE

House Bill 238

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 projected retirement schedule
- describe the utility's interconnection relationships
- document energy end-use in the service area
- set out a projection of system power demand (load duration curves)
- analyze the utility's existing ability to meet increased demand
- summarize load research
- provide long term forecasts (base, high, low) including assumptions used in developing 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, including joint filing by closely integrated utilities.

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) adequately addresses conserving electrical energy;
2) would provide consumers with the lowest reasonable cost of power;
3) documents a reasonable expectation of future power requirements;
4) uses appropriate methodology for the evaluation of options;
5) adequately evaluates resource alternatives currently available or reliably anticipated to exist in the forecast period; and
6) 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.

The legislation establishes that 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

The Commission is directed to only allow a new or revised tariff to take effect only if consistent with a utility's most recently approved plan.

Section 3

Allows for the allocation of costs of compensation for third parties to commission proceedings as described in section 4 of the bill.

Section 4

Intervenor Financing Provision. Enables the Commission, during a proceeding relating to integrated resource plans, to accept applications from persons other than utilities (ie, intervenors) for compensation of costs for participation in the proceedings. The Commission is authorized to award compensation if it finds that compensation is needed to enable the person to adequately participate and present a "significant position that does not result in the duplication of positions."

Section 5

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

Section 6

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

Section 7

Establishes the due date for the first plan as January 15, 1990.

prepared by: Eric Myers (Office of Representative Kay Brown)

3-30-88

SECTIONAL ANALYSIS
OF
PROPOSED RESOURCES COMMITTEE SUBSTITUTE

House Bill 239

Section 1

$1,000,000 appropriated from the Railbelt Energy Fund to the Alaska Power Authority for the purpose of making grants to Railbelt utilities for integrated resource plans.

Section 2

$170,000 appropriated from the Railbelt Energy Fund to the Alaska Public Utilities Commission to establish three positions to assist with the preparation of integrated resource plans.

Section 3

Lapse date of June 30, 1989.

Section 4

Effective date

prepared by: Eric Myers (Office of Representative Kay Brown)

Municipality of Anchorage

OFFICE OF THE MAYOR

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TOM FINK,
MAYOR

March 30, 1988

Representative Sam Cotten
Co-Chair, House Resources Committee
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

Alaska State Legislature

HOUSE OF REPRESENTATIVES

Committee on Finance

Official Business

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

TO: Representative Sam Cotten, Co-Chair
Representative Adelheid Herrmann, Co-Chair
House Resources Committee

FROM: Representative Kay Brown

DATE: March 29, 1988

SUBJ: HB 238/239: Integrated Resource Planning Legislation

As you know, CS HB 238 (Labor and Commerce) and its companion appropriation measure, CS HB 239 (Labor and Commerce) were the subject of a work session last fall during a Least-Cost Planning conference held in Anchorage. On the basis of the interim worksession, the fall conference and additional discussions with utility representatives and consumer organizations, I would like to propose the attached draft bills for adoption by the Resources Committee as committee substitutes.

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. The integrated resource planning approach 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 the integrated resource planning approach is being 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.

A reading of the recently released energy report by the House Research Agency (*Energy Planning in Alaska: Past Efforts and A Future Direction*, February 1988) indicates that integrated resource planning for Alaska is long overdue. Although APA statutes and regulations specify a multi-step review process for 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 more 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 an integrated resource planning process 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 traditional project-based, supply-side approach used by the APA and Railbelt utilities has resulted in the futile pursuit of infeasible projects (eg, Susitna) as well as to the development of overbuilt systems with expensive excess capacity (eg, Soldotna One).

As with the legislation originally proposed, the integrated resource planning requirements proposed in the suggested Committee Substitute for **HB 238 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.

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.

A brief outline of changes from the original bills are outlined below.

Proposed Committee Substitute - HB 238

The major change reflected in the proposed workdraft is one of structure regarding the reporting requirements. The L&C version of the bill had two distinct, but related, reporting requirements. The **reporting requirement has been consolidated** into a single **integrated resource plan**. In addition, the filing deadline for the first integrated resource plan has been moved back; annual implementation updates would be required; and comprehensive review of the integrated resource plan would be required every three years.

The suggested draft also provides for **expedited cost recovery of expenses** associated with the reporting requirements and for recovery of costs incurred as a result of implementation of an approved plan. The proposed draft also **eliminates the requirement that a utility would need approval from the APUC prior to development of a new project or supply resource** with an equivalent capacity greater than five megawatts. The proposed bill retains the requirement that APUC tariff changes would have to be consistent with a utility's most recently approved integrated resource plan.

Proposed Committee Substitute - HB 239

The changes proposed for HB 239 concern an **increased level of funding** for utilities to be provided by the bill. At the fall conference on Least-Cost Planning, a number of participants commented that the proposed funding level would be inadequate for the planning effort required. The proposed changes also reflect some minor language changes to conform HB 239 with the proposed revisions to HB 238.

* * * * *

If there are any questions regarding these measures, I would appreciate an opportunity to meet with you at your earliest convenience.

Rep. Cotten

Kay Brown

Alaska State Legislature
House of Representatives

MEMORANDUM

TO: Representative Dave Donley, Chair
House Labor and Commerce Committee

FROM: Representative Kay Brown

DATE: May 12, 1987

SUBJ: HB 238 and 239 - Least Cost Energy Policy

As a result of last Thursday s teleconference and other comments I have recieved on HB 238 and 239, I would like to suggest that the Labor and Commerce Committee consider making a few changes and clarifications in the bills. Please find attached a summary of these recommended changes.

As you know, some of the issues raised by testimony given during the teleconference require consideration in the larger context of overall state energy policy. Because this will be a major focus of the House Resources Committee over the interim, I would again urge that the Labor and Commerce Committee pass these bills along with minor clarifying amendments. I welcome and encourage individual members of the Labor and Committee who have an interest in energy issues to work closely with the Resources Committee on this legislation.

Once again, thank you for scheduling the teleconference on the bills. As you heard from the various witnesses, there is broad support to establish least cost energy planning requirements for the Railbelt.

cc: Labor and Commerce Committee members
Representative Sam Cotten, Co-Chair, Resources Committee
HB 238/239 co-sponsors

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5/13/87

SUGGESTED AMENDMENTS
by Representative Brown

House Bill 238

Section 1

Sec 42.05.294. Advance Resource Plans.

1. **.294(a) and (a)(1)**: Clarify that a long-term, 20-year power forecast is not optional, but required as part of the Advance Resource Plan. Also, the plan should include "base", "low" and "high" energy demand scenarios.

(See attached work draft language.)

2. **.294(a)(6)**: Clarifying the distinction in subpart (a)(6) between a qualifying cogenerator and a small power producer eligible for system interconnection pursuant to PURPA. Also add load management.

(See attached work draft language.)

3. **.294(a)(8)**: Clarify that the reference in subpart (a)(8) to "load management efforts, load research, and energy end-use analysis efforts made by the utility" are the same as the efforts undertaken pursuant to Sec. 3 - Load Management Reports (AS 42.05.415).

(See attached work draft language.)

4. **.294(a)(9)**: Require that the recommended electrical energy resource supply plan include not only a supply plan but a proposal for implementation of the plan.

(See attached work draft language.)

5. **New subpart - .294(a)(10)**: Add a new subpart (a)(10) allowing the Commission to require additional information.

(See attached work draft language.)

6. **New subpart - .294(b)**: Clarification that forecasts and projections for the Advance Resource Plan should be for a 20 year period.

(See attached work draft language.)

7. **.294(d)-(Fomerly subsection (c))**: Redrafted to provide that the Commission may not only approve, but after a public hearing may also propose modifications to, a utility's Advance Resource Plan.

(See attached work draft language.)

Section 2

8. **.411(d)**: The phrase "tariff" is an overly broad term and should be replaced in this section with the terms "rate" or "rate revision".

(See attached work draft language.)

Section 3

(No changes proposed.)

Section 4

(No changes proposed.)

Section 5

(No changes proposed.)

SUGGESTED AMENDMENTS

by Representative Brown

House Bill 239

Only one change is proposed for HB 239. In Section 3, the unexpended and unobligated portions of the appropriations from the Railbelt Energy Fuind should lapse back into the Railbelt Energy Fund (and not lapse into the general fund). This change will correct an oversight in the original draft.

(Work draft forthcoming.)

5-0638B
Cramer
5/13/87

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

Changes [ ] — shown to original bill

IN THE HOUSE

CS FOR HOUSE BILL NO. 238 ( )

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 Utility 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

moved to p.2 lines 19-20

[WHEN THE PLAN INCLUDES ... NEXT 20 YEARS.]

(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.

Least-Cost Utility Planning: a Research and Analysis Perspective

Abstract

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The purpose of the paper is to provide an overview of methodological and empirical aspects of least-cost utility planning studies. An overview of the key elements of a least-cost utility planning effort is presented. Recent results are presented in four areas:

- the cost-effective potential of demand-side programs, using results from a recent study of electricity options for the state of Michigan
- issues in forecasting electricity sales and relationship to utility least-cost planning
- recent work on hourly load shapes and its relevance to least-cost utility planning
- economic studies of impacts of demand-side programs and integrated utility planning, with examples from studies of Nevada Power, Texas Power and Light, and Pacific Gas and Electric Company
- discussion of the applicability to least-cost utility planning to electric utility issues facing Alaska

Statement of

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and

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on the Least Cost Utility Planning Initiative
before the

Subcommittee on Energy Development and Applications
of the
Committee on Science and Technology
U.S. House of Representatives

September 26, 1985

I. Introduction

Mr. Chairman, I am here representing myself and my colleague, Dr. Mark Levine. Both of us have responsibility for engineering/economic data bases and analytic tools at LBL that are capable of producing "Supply Curves" of conserved energy and of avoided peak power. These data are used by utilities as input to their resource plans and by the California Energy Commission and the California Public Utilities Commission in evaluating these plans.

I appreciate the opportunity to discuss how we view least cost planning, what we have accomplished so far, and how we hope to contribute to the new initiative.

II. What is a Least Cost Plan?

We believe that gas and electric utilities should strive to provide energy services to their customers at the least practical life-cycle cost, treating investments in end-use efficiency and in new supply on an equal and balanced basis.

Roger Sant popularized the term "Least Cost Scenario" to describe such a plan. Since utilities use supply curves of gas or electricity to describe the cost of supplying a new therm or a new kWh, Sant suggested calculating "Supply Curves of Conserved Energy" to mesh with the utility curves for new energy, and be merged into one least cost curve that includes both demand and supply options for energy services [1].

III. Status of Least Cost Planning in the Utility Industry

The idea of least cost planning is beginning to receive attention in the utility industry. The substantial number and diversity of utility conservation and load management programs signifies the growing importance of measures to control demand growth. Utilities have long been concerned with load management (reducing peaks and filling valleys)

as a strategy to reduce costs of delivered electricity; their involvement in conservation programs is much more recent

We believe that a combination of factors has led to this attention to energy conservation programs: public service and utility commission requirements, high cost and risk of building large, central station power plants, good public relations with utility customers, and a growing awareness within the industry of the role of demand-side programs in increasing economic efficiency of utility operations are among the most important of these factors

The good news is that utilities have implemented a variety of demand-side programs over the past half decade They have gained considerable experience about these types of activities The bad news, in our judgment, is that many of the programs have been adopted as a palliative to satisfy an immediate problem rather than as a result of an overall strategy to provide services to the consumer at the least cost

We have looked into utility planning activities to find out the extent to which end use (particularly energy conservation) programs are an intrinsic part of the utility planning process We sought information about utilities that are among the best-known for their end use activities We have discovered that comparatively little effort is placed on estimating financial and economic impacts of conservation plans While many millions of dollars are spent evaluating costs of alternative supply strategies and determining how different supply options fit into the overall utility resource plan before a decision to build new capacity is made, conservation programs are established with much less understanding of their relation to the overall utility plans

This state of affairs raises concerns for the longer term. As many utilities come out of a long period of financial difficulty, they will return to a more business-as-usual approach to their decisions. With a market-to-book ratio of the stock at one or above and with improved bond ratings, many utilities once again have access to capital

markets. The tendency for them to do what they have traditionally done--build new power plants--increases accordingly

New generating facilities are often needed. But they should not be built if demand-side programs can satisfy the demand for services at lower cost than new supply technologies

A number of utilities are presently attempting to treat investments in end-use efficiency on an equal basis with new supply. Pacific Gas and Electric Company (PG&E) explicitly uses the term "least cost planning" in its efforts to achieve this balance. In its 1984 Annual Report [2], PG&E estimated that "conservation will allow us to avoid $5 to $7 billion in outlays for new capacity that would otherwise be needed in the next decade." The Bonneville Power Administration (BPA) is performing extensive studies and planning the implementation of a wide variety of programs to increase energy efficiency, in response to the Congressional mandate that BPA must invest in the least cost measures, with a balanced treatment of both demand- and supply-side programs (BPA gives a 10 percent benefit to demand-side programs) Thus BPA, under the requirements of the Northwest Power Planning Act, is *required by law* to develop and implement least cost resource plans.

We have worked with several other utilities that are embarking on the least cost strategy. In our experience, these utilities have generally found the process of changing their planning approach to be slow and painstaking. The data and analysis requirements for incorporating end-use plans into the overall planning exercise are substantial We turn later to the ways in which the federal government can assist in speeding up this process.

It is important to note that the Edison Electric Institute (EEI) in concert with the Electric Power Research Institute (EPRI) have started to provide assistance on demand-side management alternatives to the industry as a whole. EEI and EPRI have joint

produced a set of documents jointly entitled "Demand-Side Management--Evaluation of Alternatives" [3] We believe that this is a good start in improving access of utilities to important information to assist them in the least cost planning process We would, however, contrast this early effort by the industry on the demand side with the thousands of times more information available to the industry on investments in supply options

To summarize we believe that the utilities have made an important start in the least cost planning process Some utilities have made commitments to going down this path Industry-wide organizations (EEI and EPRI) are contributing to this process However, to date most demand-side activities have been developed and implemented on an *ad hoc* basis Long-term commitment is uncertain Great effort is needed to achieve a true balance between demand and supply investments One should not expect that this balance will be achieved quickly or without considerable reallocation of research, manpower, and priorities among utility and regulatory commission staffs

IV. Supply Curves of Conserved Energy and Avoided Peak Power

Since 1975, we at Berkeley have been tabulating least cost potentials for the buildings sector of our economy. We started casting them as supply curves in 1979 While our experience and data are (to date) limited to buildings and appliances, this type of information is particularly important for electric utilities, since two-thirds of their electricity goes to buildings, and three-quarters of their income is derived from this sector

Conserved Energy. Figure 1 is a residential electric conservation supply curve for 2000 AD for the Bonneville Power Administration (BPA) [4]. Each small step in the curve represents a conservation measure Its width represents the annual electricity savings and its height is the cost of conserved energy (CCE). A measure is cost-effective if its CCE is less than the cost of the energy it displaces

The cost of conserved energy and the regional electricity savings (in billions of kilowatt hours or BkWh) are calculated for 336 measures, ranked cheapest first The options include retrofit of existing homes and improvements in new homes and appliances. The base case for the calculations assumes "frozen efficiencies" i e , floorspace and amenities are projected to grow according to BPA's resource plan, but efficiencies stay frozen as of 1983 For this base case, in 2000, BPA would have to supply about 81 TWh (1 TWh = 1 BkWh) Actual BPA forecasts count on price increases and on conservation programs to improve efficiencies and cut usage by 13 TWh to 68 TWh Figure 1 shows that 215 measures save electricity for less than 4 cents/kWh (the 1983 price), with a cumulative potential savings of 34 TWh below Base, and 21 TWh below the BPA forecast of 68 TWh. 21 TWh represents the output of about 4 typical 1000-MW baseload power plants whose construction should certainly be deferred until a serious effort is made to acquire the equivalent savings from conservation In fact, a kWh generated by these new plants will sell for about 10 cents instead of 4 cents, in which case we should invest instead in the supply curve up to 10 cents/kWh, which yields another 5 TWh, i e , another conservation power plant

Avoided Peak Power. Figure 2 shows a supply curve, not of kWh, but of avoided peak kW, which we now produce to supplement the kWh curves The curve comes from our current study with the University of Texas at Austin, for the Texas PUC [5] The curve covers 18 measures that improve heating, cooling, and air conditioning in the Texas commercial sector, and shows that about 50% of today's commercial cooling peak can, by 2000 AD, be avoided for less than $1000/kW. The 18 measures are listed at the bottom of Figure 2. These measures can again be merged with equivalent utility data for purchasing new capacity to give a combined capacity resource acquisition plan.

Figure 3 summarizes our Texas study. The top bar charts show potential savings of 50% in BkWh, and the lower ones show similar potential savings in peak power.

V. Relation Between Potentials and Projections

A conservation potential is not a forecast; it is only a calculation of what could happen if suddenly we all began to make rational investments and then didn't reinvest any of our savings in increased amenity. But in this section, we want to show that our potential least cost scenarios, because they are based on engineering/economic calculations, have actually been more useful in describing reality than have older-fashioned, safer-sounding utility forecasts.

We shall give two examples, and we start with **Figure 4**, which dates back to the 1975 testimony of Rosenfeld and Goldstein to the California legislature [6]. It gives the utility projection and our least cost scenario for growth in California peak power. The upper curve shows the average 5 percent/year growth forecast by the utilities; the lower curve is our potential of only 1.2 percent, and the large X's (added later) are what actually happened. One never expects a potential actually to be achieved in this real world, but we see that our scenario missed the mark by only 2.5 GW. By contrast, the utility forecasts were too high by 15 GW.

In 1975, the California utilities were shocked by these estimates, but let's see what remarkable changes have been wrought in their point of view by 10 years of price rises, successful conservation programs, and the beginning of least cost planning among California utilities. **Figure 5** is PG&E's 1984 version of our scenario [7]. Without conservation and load management programs, growth would still be 5 percent/year, but least cost planning, now a planning objective of the utility, cuts this growth to 1.75 percent, similar to our earlier 1.2 percent potential. PG&E thus avoids the need to invest in 6 power plants in the next 20 years (and this scales to 12 plants statewide). Also, it's pleasing to note that we are now working with PG&E on Project Merlin, a study of the potential for yet another "conservation power plant" in the residential sector.

Figure 6 tells a similar story, not for an electric utility, but for the whole U.S. It is a plot of trends per capita in resource energy use vs national income for the U.S. and other industrial nations. We see that energy use is falling fast for all the countries plotted except the USSR, Poland, and Canada. We have added sloping lines corresponding, at today's energy prices, to energy bills of 5 percent through 20 percent of national income. We see that the U.S., which spent 14 percent of its GNP on energy in 1980, has dropped (in constant energy prices) to 12.2 percent in 1984, and France and Japan are way ahead of us and headed for 5 percent. To the Figure we have added the 2000 AD least cost potential energy use for the United States (65 quads) from the SERI Solar/Conservation study [8]. The study assumed that GNP grew by a factor of 1.8 between 1980 and 2000, so that 65 quads corresponds to 6% of year-2000 GNP. In 1981, many people were surprised by the conclusions of this study, but recent trends in Figure 6 suggest that there is a good chance that we'll approach the 6 percent potential by 2000 AD.

We conclude that least cost calculations are a very important way to assess impacts on utilities of the rapid technological changes that have been triggered by energy price rises. Their remarkable messages have quickly turned plausible.

VI. Role of Efficiency Calculations in Utility Planning

In this section, we refer to the data and calculations used by utility planners and discuss where DOE and its laboratories could be helpful.

Figure 7 is a typical utility planning flow diagram, with heavy borders on boxes where we see a useful federal contribution, medium borders where some utilities might want help, and light borders on the boxes where the utilities are doing fine without federal help.

Box A has data for the utility's territory on the stocks and flows of buildings, appliances, equipment, and "eligible fractions" (ie., the fraction of attics that remain to be insulated, clock thermostats to be installed, etc)

Box B contains the data on the hundreds of measures to be considered when calculating the micro supply curves for a single prototype building or energy service (lighting, refrigeration, etc) Box B also contains data on the technical success of buildings and appliances as monitored in the field (see the section on BECA below) By combining Boxes A and B, utilities and laboratories can collaborate to produce the macro supply curves illustrated earlier and the time-of-use profiles needed for Box C

Box C (load shape data by end use) and the accompanying load forecast are essential to the analysis of the impacts of demand-side programs We have done considerable research at LBL to built a computer model that simulates the hourly load impacts *by end use* of demand-side programs The significance of this step is that different end-use programs have different impacts on the load shape of utilities These load shape impacts have large implications on economic consequences of demand-side programs Although utilities perform load forecasts, they rarely evaluate the load shape and resulting economic effects of conservation programs. This omission often means that important benefits (capacity savings) of conservation programs are not taken into consideration in the development of long-term plans

Box D is crucial, but quite different It covers experience on conservation programs: information, incentives, rebates, standards, quality control. Collecting and distributing this information requires a clearinghouse covering federal, state, local, and utility case histories, reports, and evaluations Under the Least Cost Initiative, the natural sponsors of Box D might be NARUC, EPRI, GRI, or similar institutions

An important point about Box D is that its inclusion in the planning activity as shown in Figure 7 is essential to the development of a least cost utility resource plan.

The traditional utility planning process develops a generation expansion plan treating the level of demand (and investment in conservation programs) as a constant, exogenous variable. A crucial point made in Figure 7 is that the effects and costs of conservation programs need to be varied along with the different supply options to produce the long-term utility resource plan Even the California utilities, which are actively pursuing least cost planning, have not yet fully incorported conservation and other demand-side programs into the utility planning effort in the manner shown in Figure 7. Virtually all large utilities have sophisticated models and extensive data for optimizing the supply choices, *but they do this optimization at one or a few demand levels instead of performing the analysis for both demand and supply options together*

VII. Possible Organization of a Least Cost Study

The Least Cost Initiative is to be a national study in the sense that it must be useful to utilities all over the U S. But if it is to yield real least cost plans, it must involve selected individual utilities, each with its characteristic weather, energy supply and prices, stocks and flows of buildings and industry, and related data

We believe that the study should be undertaken as a collaboration between the DOE labs and about ten utilities (or combinations of utilities and PUC's) which are already upgrading their resource plans and wish to work together We would update and upgrade our data bases and computer programs as they apply to these utilities, paying particular attention to measures that are nearly independent of region (lighting, appliances, etc ,) and to time-of-use data for load management

NARUC/EPRI/GRI would work with the same utilities to supply experience on programs from the clearinghouse.

Each utility would use this technical and programmatic information to improve its least cost resources plan.

Finally, we would all strive to have the plans follow a common methodology. This approach will permit the transfer of the tools and portions of the data to other utilities, and will be particularly useful for smaller utilities with limited resources. With ten plans available, we could assess the national implications for conservation and load management, and the needs for filling gaps in information.

This is an ambitious program that will take several years. Data bases are not established overnight. But these resource plans will reduce the risk that we have too few or too many power plants and natural gas facilities. The U.S. conservation potential is about $250 billion/year in reduced costs of energy to the consumer, accounting for investments in efficiency improvements, the American consumer can realize a net saving of more than $100 billion/year. If the Least Cost Initiative can promote programs which lead to the capture of an additional 1 percent of that potential, it will save us $1 billion/year--an amazing payback for a $1 million/year investment.

VIII. Field Monitoring and Calibration of Engineering Calculations

The BECA Data Bases

For simplicity, we have discussed CCE (the cost of conserved energy) as if it can be simply calculated from engineering and price data. In fact, we calibrate our calculations with field performance measurements and typically have to degrade our potential savings, and raise the CCE, by 20%.

Eric Hirst and his excellent group at Oak Ridge have monitored many utility programs; Pacific Northwest Laboratory is monitoring conservation programs sponsored by BPA; and in 1979 at LBL we started the BECA (Building Energy Use Compilation and

Analysis) data bases. By now we have two residential data bases (new and existing) and two commercial bases (new and existing) which we publish regularly, and additional specialized data bases on thermal storage and load management, building energy simulation validation, etc. Every two years we hold a conference at Santa Cruz on "what works" to improve building energy efficiency.

Figures 8 and 9 illustrate the need for calibration. Figure 8 is a 45-year perspective of office building energy intensity [9]. Energy use rises to a peak at the time of the OPEC embargo, then falls over a cliff towards the voluntary standards series of ASHRAE (American Society of Heating, Refrigerating, and Air-Conditioning Engineers), or the mandatory series of California Title 24.

But Figure 9 shows our collection of 83 new office buildings, most of which have won awards for energy efficiency. They are a lot better than the average (30 year-old) building, labelled NBECS (Non-Residential Building Energy Consumption Survey) at 264 kBtu/sq ft., but many fail to comply with the new standards whose range (over weather) is pictured at the top of the Figure. We are currently trying to sort our these failures. How much is because the building was not built as designed, or operated as planned, and how much is poor quality control? Clearly, these are questions which must be addressed by utility planners.

We at the National Laboratories believe that data bases like these, the experience that goes with them, and the incorporation of the data into the development of least cost plans are our most valuable contributions to Least Cost planning. We would like to work with utilities to share data and analysis tools, to make their and our data more reliable and accessible.

Finally, we should remark that the discontinuity in Figure 8 sheds light on why potential calculations have usually been closer to the mark than conventional utility projections. We see that sudden price changes and energy awareness are causing very rapid

improvements in technology, and indeed in whole buildings. Detailed engineering models, used for potentials, can handle discontinuities, but conventional elasticity models simply cannot.

Figures 10, 11, and 12 are a trilogy illustrating how we rank measures for retrofitting a home. Figure 10 is called a technology cost curve, and is generated by computer simulation. It shows energy use decreasing as efficiency improvements are made in the home. Nine measures reduce annual space heat from 120 to 50 million Btu. The next four measures reduce energy requirements for water heating by 50 percent. Next, we address cooling which is reduced from 3600 to 1000 kwh per year at low cost. Appliances and lighting are then dropped to about 50 percent. The theoretical overall reduction is to about 35 percent of the initial energy requirements of the home, for an investment of $3000.

Figure 11 displays space heat savings versus pre-retrofit energy use for real homes that have been weatherized [10]. The large X's represent "optimal weatherization" of about 100 homes in 10 cities. These retrofits were performed by the Community Services Administration (CSA) with assistance from the National Bureau of Standards (NBS). "Optimum" means that furnaces and ducts were retrofit, as compared with the then prevalent practice of merely fixing the shell of the home. The median savings for these retrofits was an encouraging 47 percent, at a median cost of $3000. This is good agreement with the computer calculations. But we must be careful: most auditors and contractors are not as well-trained and supervised as those carrying out the retrofits, even though the NBS experiment was done with CETA labor. The black dots in the Figure represent samples of homes that were retrofit under the DOE weatherization program, which unfortunately concentrated on the shell. The median savings are about 15 percent.

We thus use the computer simulations as the basis for our supply curves, but we recognize that the conservation programs will only achieve the predicted savings if they are carried out properly. In particular, we believe that it is useful to publicize the importance of furnace and duct retrofits in homes and measures to improve air conditioning and other building equipment efficiency in commercial buildings, as such activities often yield large benefits.

Figure 12 recasts the data of the technology cost curve of Figure 10 into a supply curve, with the measures ranked (lowest CCE first). Note that the first envelope measure--attic insulation--does not appear until measure 9.

IX. Results of Least Cost Analyses

Figure 13 shows the results of an analysis we have performed using detailed information about efficiency measures, residential load shapes, customer rate classes, and marginal electricity and power costs for the Pacific Gas and Electric Company [11]. This Figure is only for one of a very large number of efficiency improvements that can be applied to homes. We have chosen to illustrate the impact of a program that resulted in the adoption of very efficient central air conditioners in new homes. Efficiency improvements in air conditioners are of particular interest, because they lead to a large decrease in peak power and a relatively small decrease in baseload electricity sales.

Three primary economic impacts result from sales of highly efficient air conditioners: (1) revenue is lost from reduced sales of electricity, (2) costs are reduced because of lower fuel requirements, and (3) investment in new peaking capacity is reduced because of the slower growth of peak power demand. In this case, the dominant term is the reduction in investment for new peaking units. The utility or the ratepayers in the PG&E service area stand to gain some $30 to $40 million per year--a very large benefit

even for a service area the size of PG&E--from the introduction of this one efficiency improvement in new and replacement central air conditioners.

An important point, not illustrated in the Figure, is that results of demand-side programs will vary enormously among different utilities. The economics depends critically on not only the impact of the specific efficiency improvement but also on the load shape, rate structures, marginal cost during peak and off-peak times, and demand growth of the utility. It is this complexity that requires that least cost planning be undertaken for a range of utilities throughout the nation. The enormous richness of conservation and load management options requires that a very extensive data base describing these options be developed and made widely available among utilities, if the real benefits of this new initiative are to be realized.

X. Conclusions

We believe the Least Cost Initiative is a well-conceived idea that can yield significant benefits to the Nation. We recognize that the undertaking will require much effort, and that it needs several years before its fruits can be realized. However, we anticipate that the relatively small federal contribution to the least cost planning effort, when carried out in concert with utilities, will play a critical role in increasing the economic efficiency of very large investments by the utility sector, leading to economic benefits to ratepayers and utilities. As we previously noted, if the Least Cost Initiative promotes programs which can lead to the capture of an additional 1 percent of the potential benefits of cost-effective efficiency improvements in the Nation, it will save us $1 billion per year--an amazing payback for a $1 million per year investment.

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11. E. Kahn, C. Pignone, J. Eto, J. McMahon, and M. D. Levine, "The Effect of Conservation Programs on Electric Utility Earnings: Results of Two Case Studies," submitted to *Energy Policy*, (1985).

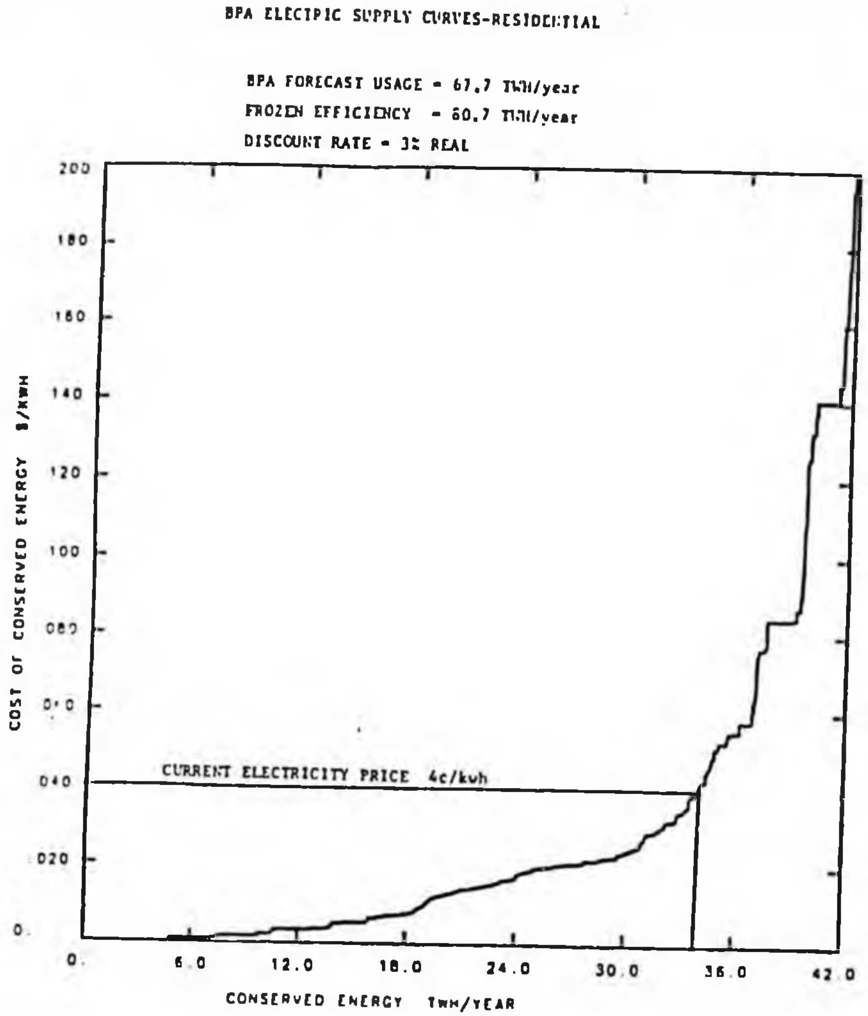
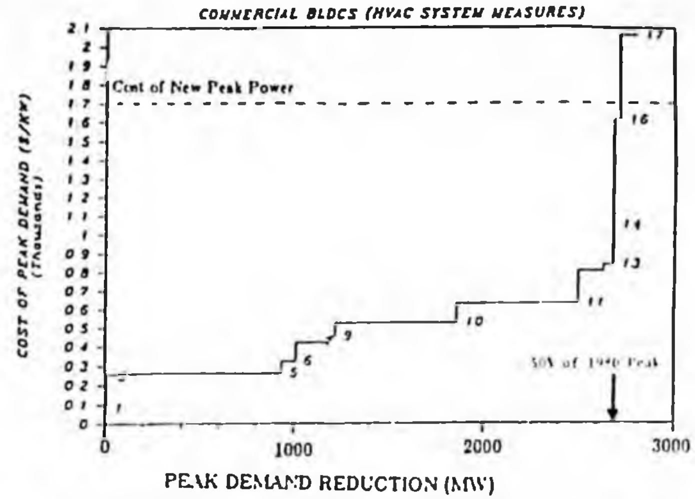


Fig 1 Grand Residential Conservation Supply Curve for 2000 Source reference [4]



ID CODE	LABEL	DESCRIPTION	COST ($K) MIN	COST ($K) MAX	LIFE (YRS)	MICRO SAVINGS (MW)	MICRO CCE ($/KW)	MACRO SAVINGS (MW)	MACRO CCE ($/KW)
[illegible]	1	Reduce system size	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2	Controls package	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	3	Controls package	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	4	Reduce system size	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	5	High COP cooling	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	6	High COP cooling	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	7	Conversion to VAV	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	8	Conversion to VAV	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	9	Reduce system size	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	10	Evaporative cooling	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	11	Chilled water storage	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	11	Evaporative cooling	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	12	High eff fan motors	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	14	Convert to VAV	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	15	High eff fan motors	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	16	High eff fan motors	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	17	Higher COP cooling equip	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	18	Fan motor speed control	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Fig 2 Supply curve for avoided peak power for 18 HVAC measures for commercial buildings in Texas Source Hunn et al, University of Texas (Austin)/ LBL study for PUC of Texas (1985)

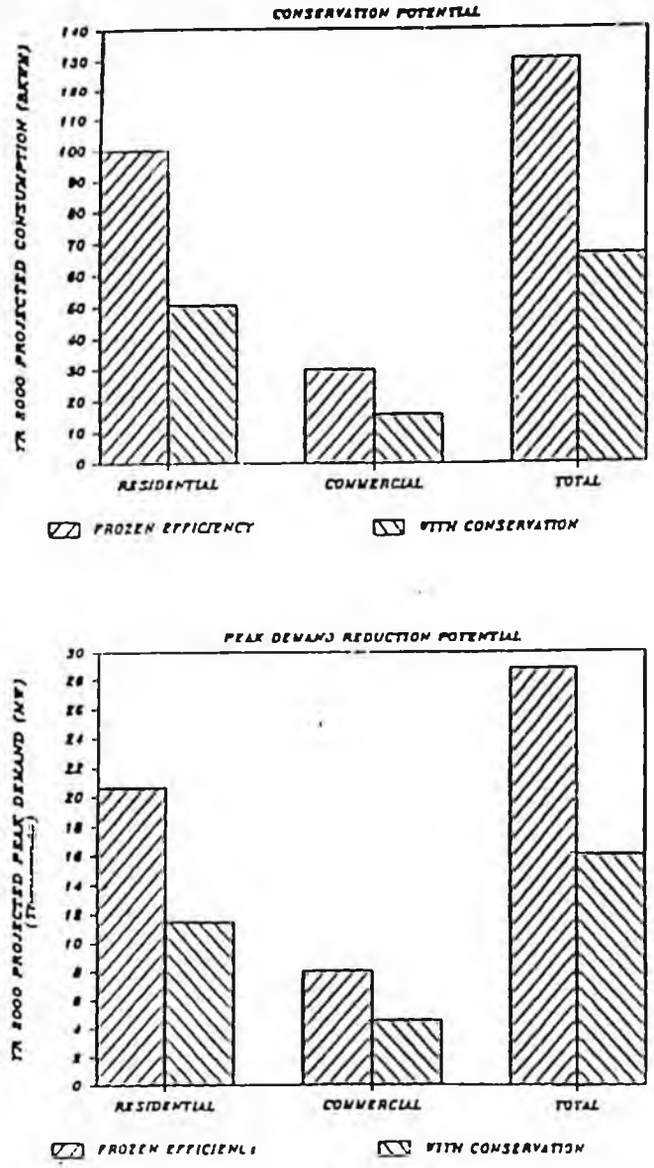


Fig 3. Conservation Potential in 2000 A.D. vs. Frozen Efficiency Projections for Texas. Source: reference [5].

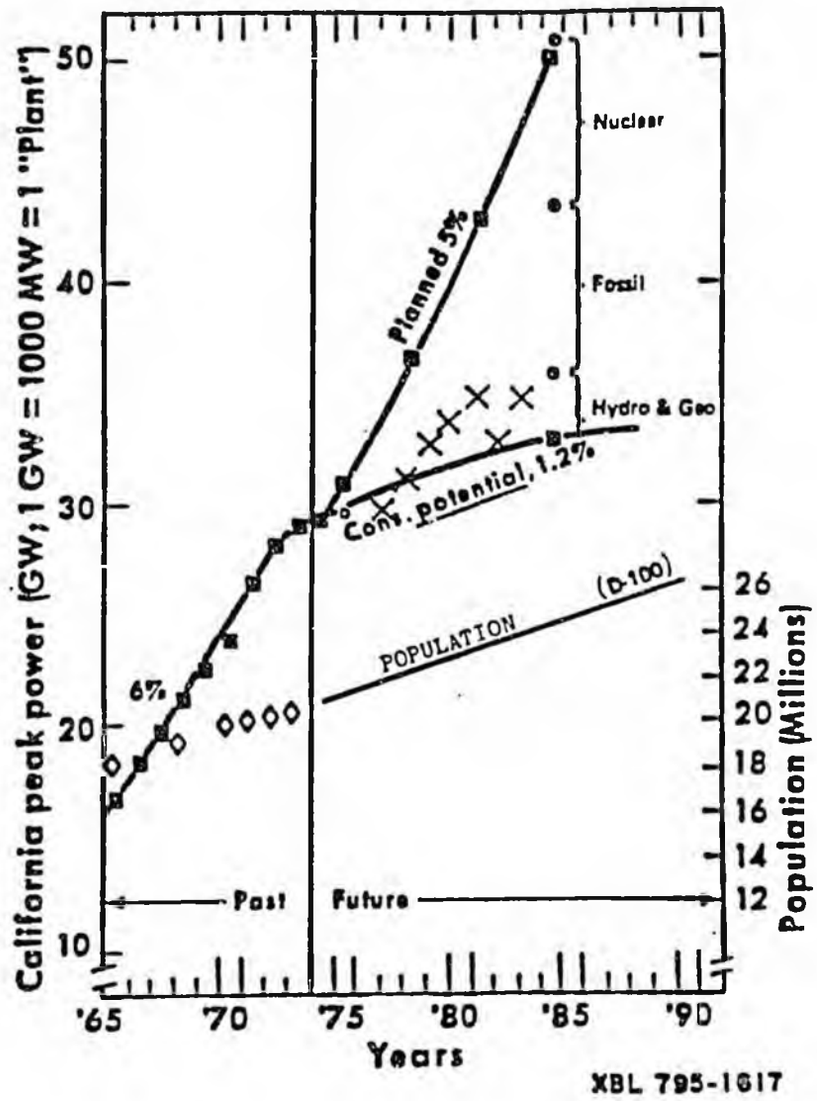


Fig. 4. Coincident Peak Power in California. Utility projections vs. conservation potential as calculated by A.H. Rosenfeld for Warren Committee Hearings, California Assembly, December 4, 1975. Actual subsequent demand is plotted as X's. Source: reference [6].

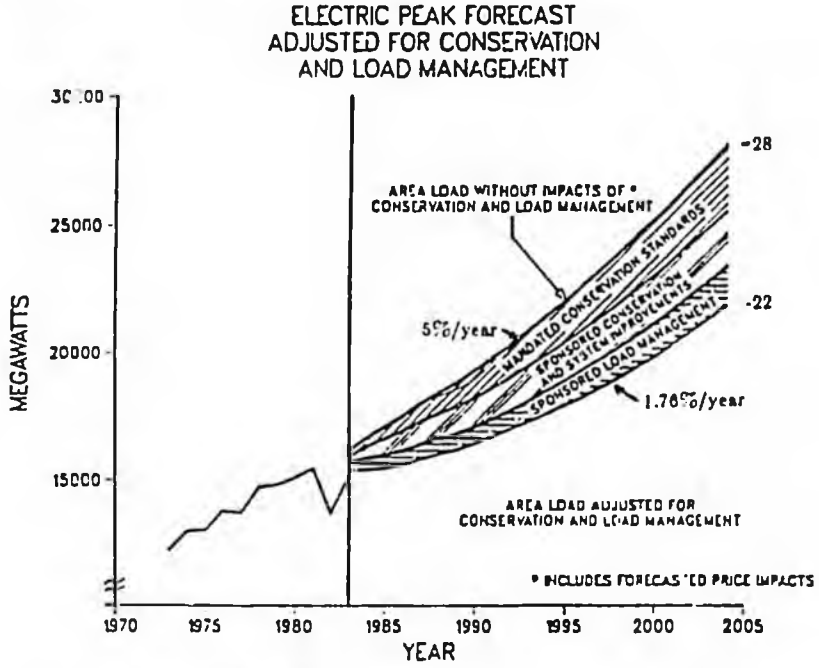


Fig 5. Long-Term Planning Results, 1985-2004 Pacific Gas and Electric 20-year plan. Source: reference [7]

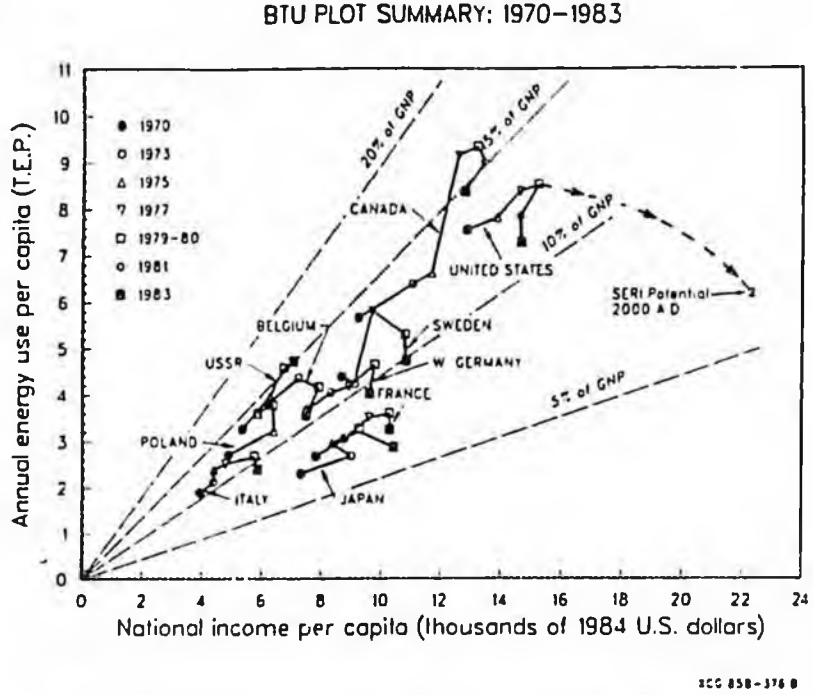


Fig 6. Resource Energy Use vs GDP (both per capita) For 11 Industrial Countries
Each country is a sequence of 7 or fewer points joined by straight lines. The conversion from local GDP to dollars depends only on the 1984 exchange rate; earlier points are plotted using individual national deflators. The energy data comes from the OECD/IEA volume "Energy Balances". In the case of income data, there are two different series (before and after 1980), so we scaled the incomes to match at 1980. We convert electricity to resource (primary) energy using the national heat rate (e.g., U.S. efficiency = 33%), except Japan, which uses a nominal efficiency of 35.1%, and 3 "hydro" countries, which use an OECD average efficiency of 37%. For the lines labeled 10%, 15%, and 20% of GNP, we use an average 1984 price of resource energy of $5.68/Mbtu or about $220 per TEP. Conversion: 1 TEP (Tonne equivalent of petroleum) = 40 Mbtu. Source for price: DOE/EIA-0376 (1983).

Long-Term Utility Planning: Traditional and Least-Cost

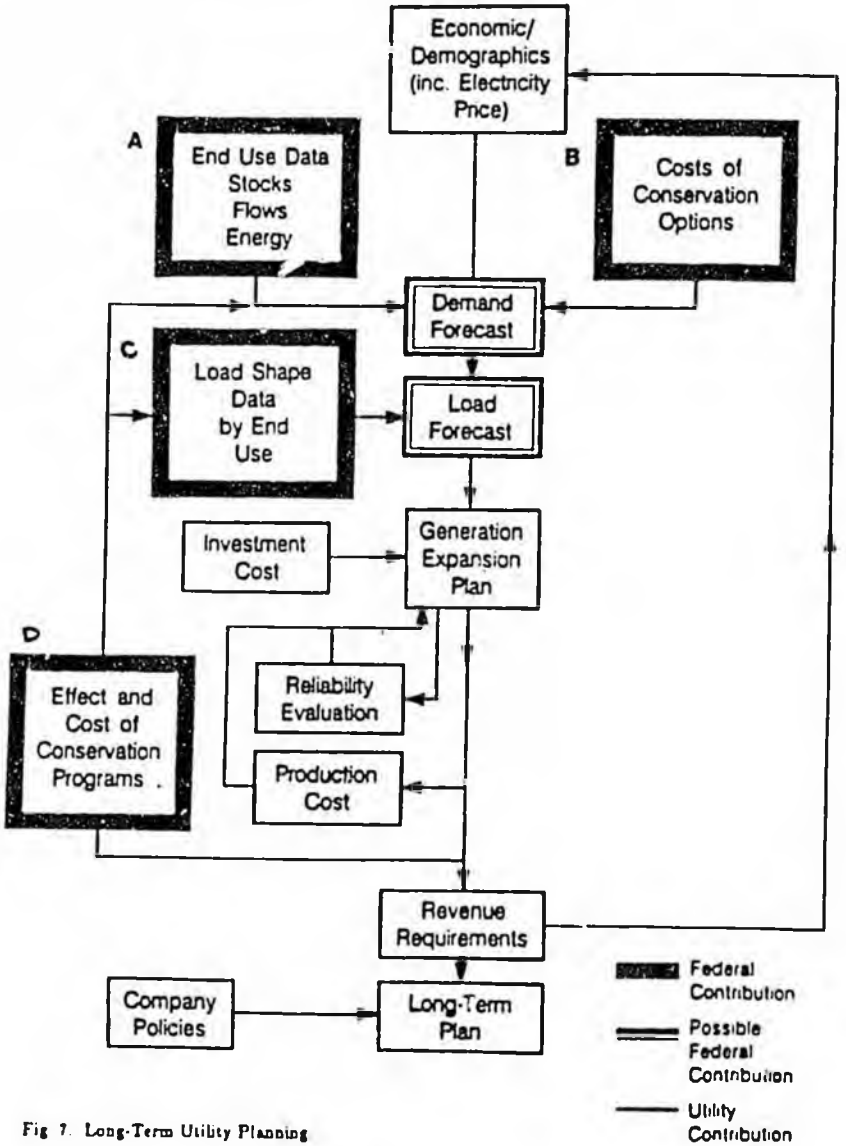


Fig 7. Long-Term Utility Planning

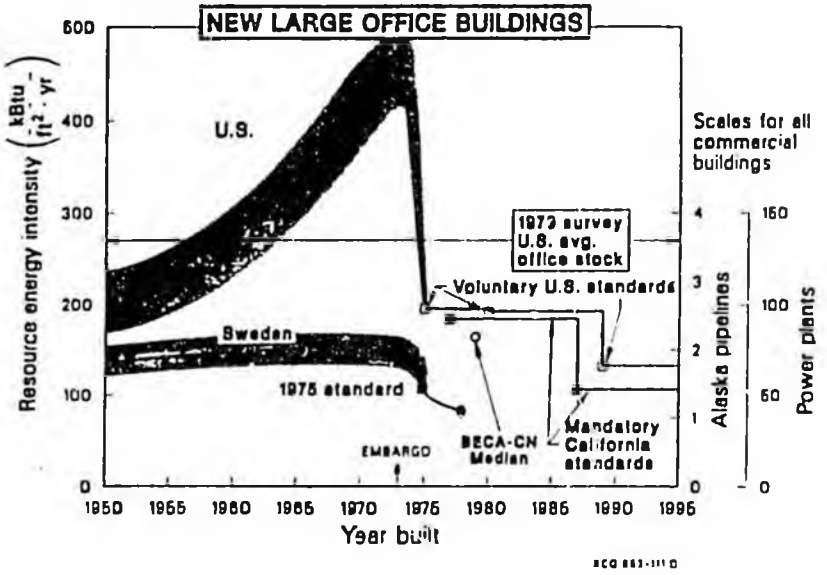


Fig 8. Trends in Resource Energy Use in New Large Office Buildings. The scales on the right apply to all 50 Bft² of U.S. commercial buildings, assuming they follow the same trend as office buildings. Source: reference [8]

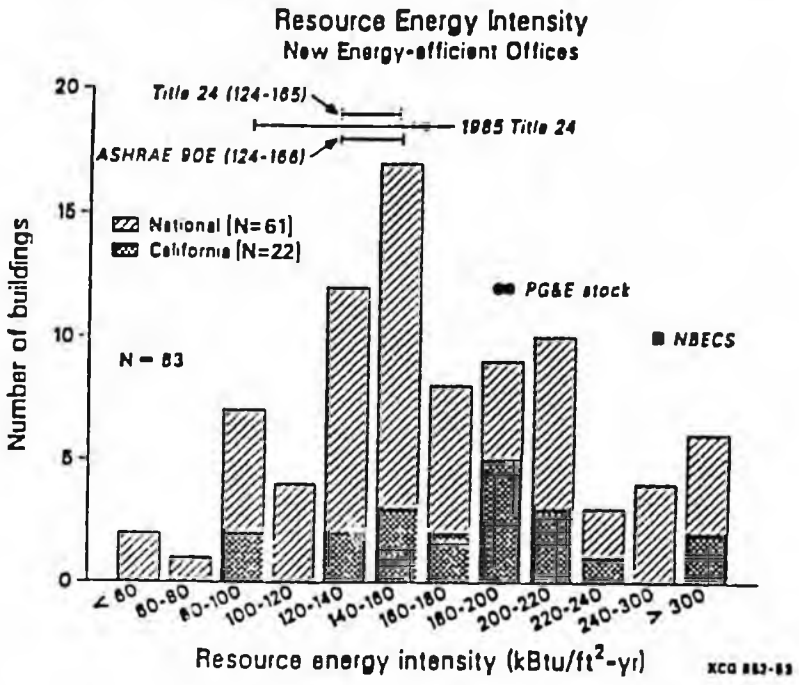


Fig 9 22 California offices compared to 61 other offices and to various standards and measures of stock Source LBL

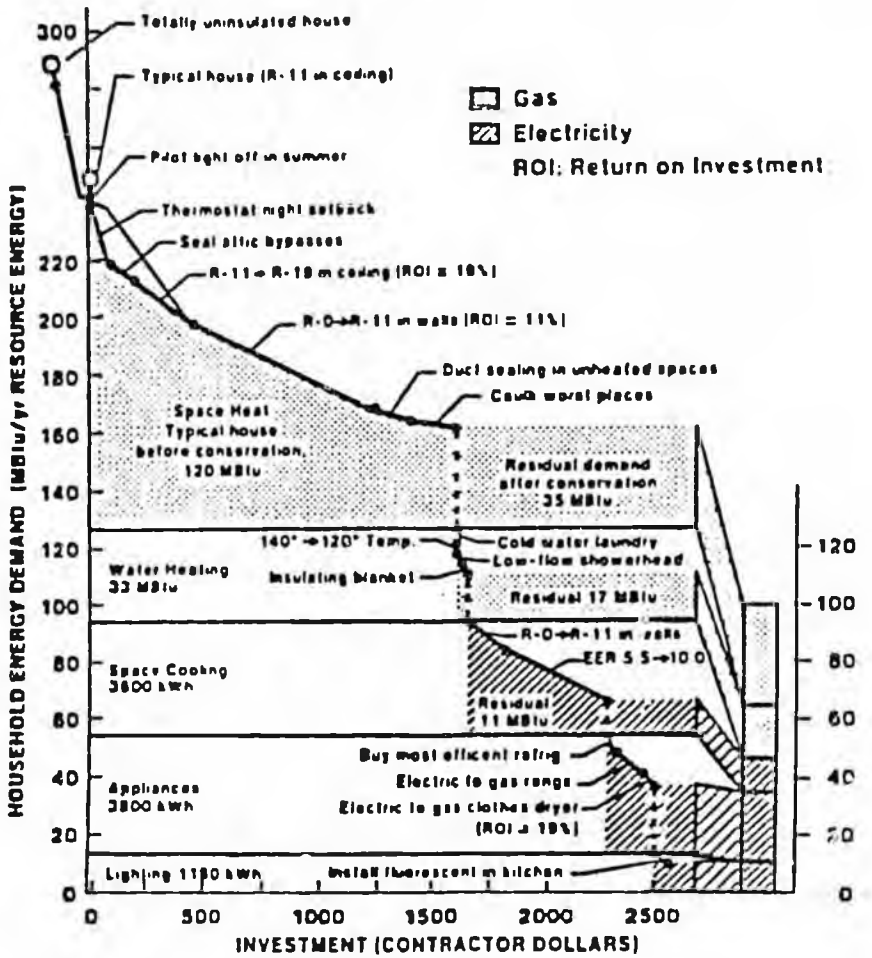


Fig. 10. Retrofit Conservation Potential in a Northern California Single Family Home, Gas Heat (1200 sq ft., 3000 Heating Degree-Days) XBL 812-7946

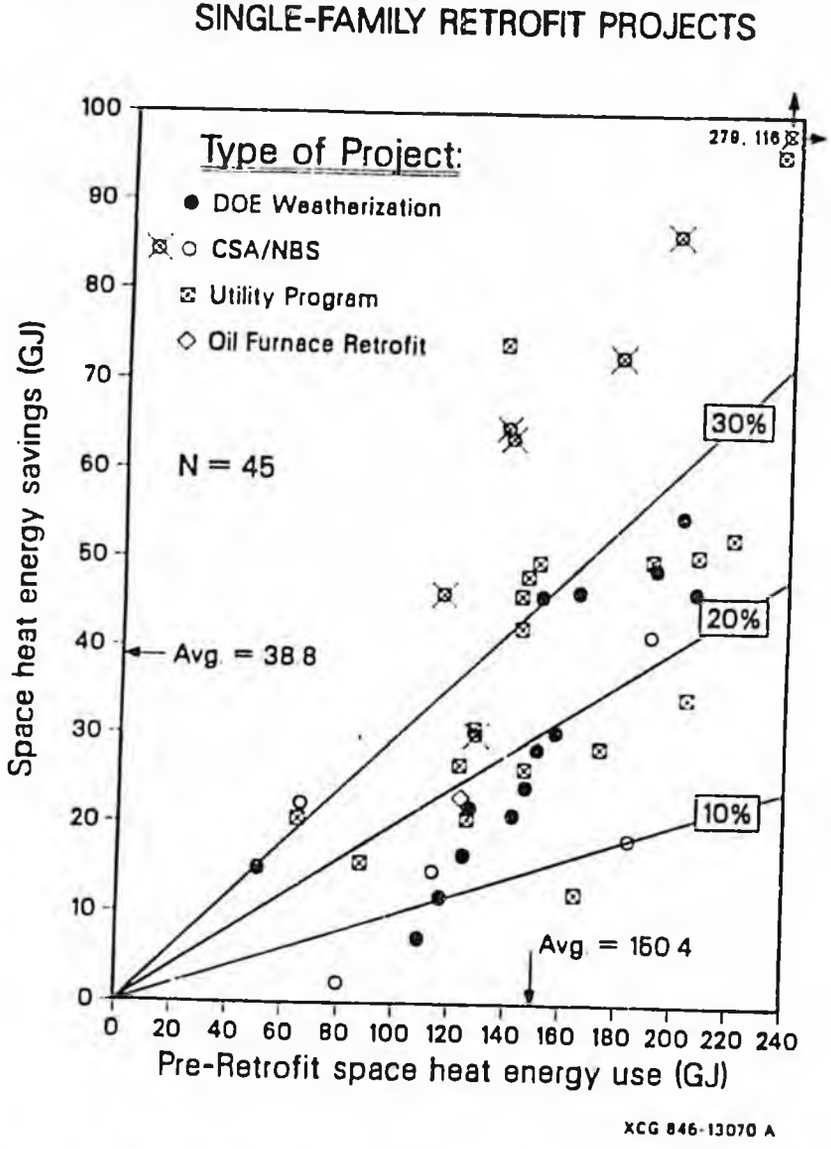


Fig. 11. The median point is the middle, or 50th percentile, point. One GJ = 1 MBtu (million Btu). Source: Reference [9]

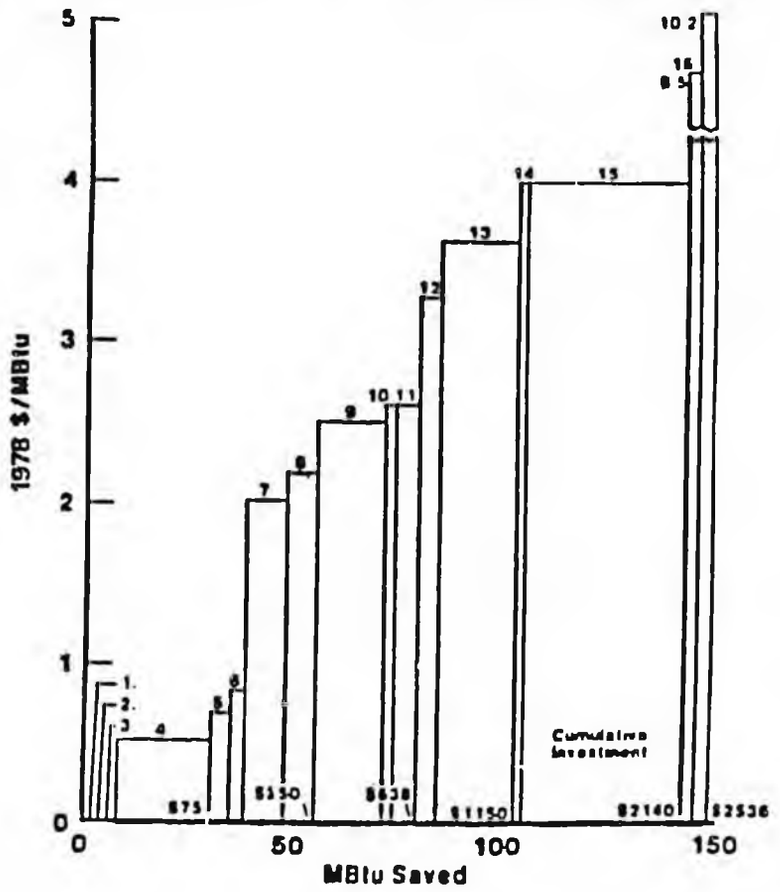


Fig. 12. Retrofit Conservation Potential in the Northern California Single Family Home, replotted as a conservation supply curve. Cost of conserved energy in $/MBtu of resource energy, calculated using 10% cost of money, plus depreciation, with all installation done by a contractor. Total annual energy consumption of the house before retrofit was 250 MBtu/year.

1. Turn furn. pilot off in summer.
2. Reduce hot water temperature, 140 to 120 degree-F.
3. Cold laundry rinse.
4. Thermostat night setback to 60 degree-F.
5. Buy most efficient refrig.
6. Install low-flow shower head.
7. Furnace tune-up (biennial).
8. Change from electric to gas range.
9. Increase ceiling insulation, from R-11 to R-19.
10. Install fluorescent lighting in kitchen.
11. Change from electric to gas clothes dryer.
12. Seal attic bypasses.
13. Change to high-efficiency air conditioner, EER 5.5 to 10.0.
14. Install water heater insulating blanket.
15. Insulate walls, R-0 to R-11.
16. Seal and insulate ducts in unheated spaces.
17. Caulk building shell (in worst places).

XBL 812-7947

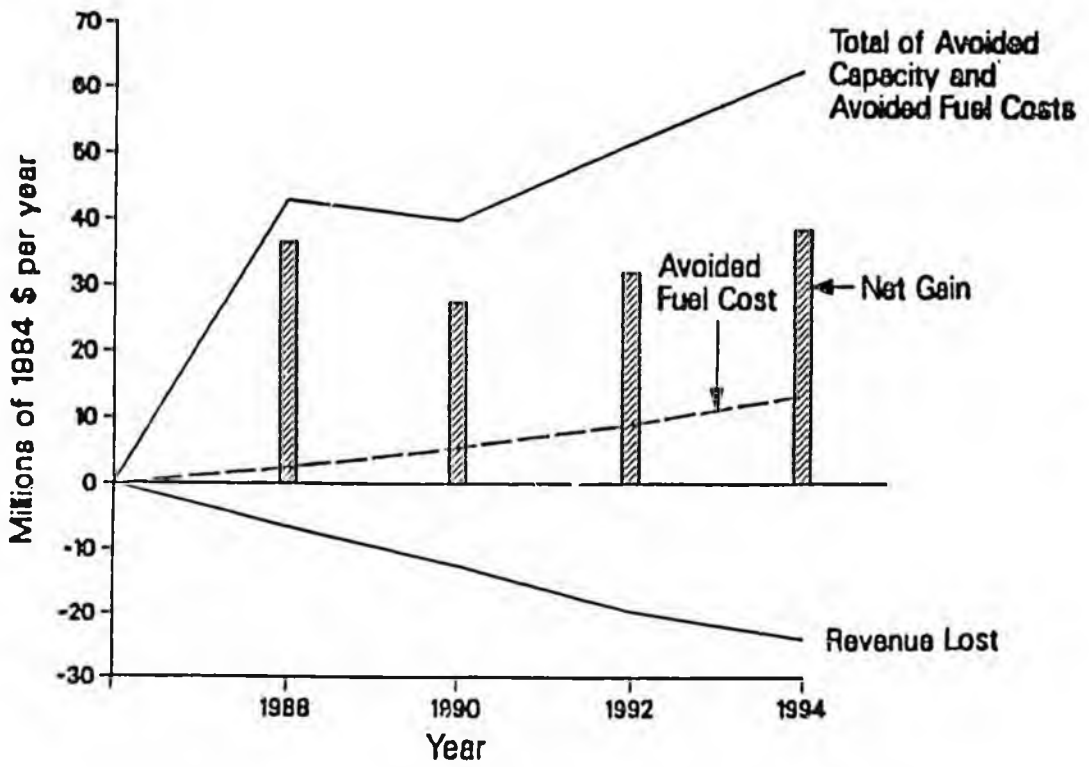


Fig. 13. Economic Impacts of Highly Efficient (SEER = 12) Central Air Conditioners on Pacific Gas and Electric Company and its Ratepayers. Source: reference [10].

5/6/87

Sectional Analysis: HB 238 and 239

by

Representative Kay Brown

House Bill 238

This bill amends Title 42 statutes of the Alaska Public Utilities Commission to establish least cost energy planning requirements for Alaska's larger regulated utilities. The bill would establish requirements for the preparation of "advance resource plans" and more detailed "load management reports" for approval by the Commission. The development of new power facilities would require approval from the Commission and would be subject to a determination that future demand cannot be met by cost-effective efficiency and conservation improvements. Approval of rate increases would also be subject to a determination that the increase would be consistent with the development or maintenance of a least cost energy supply system. This bill also grants the APUC authority to compensate participants in commission proceedings under certain circumstances.

Section 1: Advance Resource Plans and New Facility Development

Regulated electric utilities with annual sales that exceed 300 million kilowatt hours are required to prepare and submit "advance resource plans" to the APUC for approval. The first advance resource plan would be due january 1, 1989 and every four years thereafter. Affected utilities include Chugach Electric Association, Anchorage Municipal Light and Power, Matanuska Electric Association, Golden Valley Electric Association, and Homer Electric Association. The required elements of the advance resource plans include:

- a long-term (20-year) demand forecast;
- description of existing system facilities and future facility requirements;
- description of factors affecting demand for electrical energy (such as population, urban development, industrial expansion);
- description of additional system capacity which could be achieved through energy conservation and end-use efficiency improvements;
- description of the utility's relationship to other energy systems and power suppliers;
- summary of efforts relating to load management and end-use analysis;

- a recommended electrical energy resource supply plan with projected plant retirement/additions, load management efforts, energy conservation and efficiency improvements.

The Commission shall establish consistent reporting methodology for the advance resource plans. The plans are subject to Commission approval.

For utilities with annual sales above 300 million kilowatts hours, the Commission must permit new facilities larger than 5 megawatts. This permit is subject to a determination by the Commission that any new facilities are necessary to meet future demand that cannot be met through cost-effective load management, conservation, and energy end-use improvments.

Section 2: Rate Increases Consistent with Load Management Reports

New or revised tariffs must be consistent with development or maintenance of the lowest cost electrical energy supply system for the utility under the utility's most recent load management report.

Section 3: Load Management Reports

Regulated electric utilities with annual sales that exceed 300 million kilowatt hours are required to prepare and submit "load management reports" to the APUC for approval every two years. The APUC shall establish guidelines for these reports. The reports shall:

- include the cost of service for specific classes of customers;
- assess opportunities for improved load management;
- evaluate potential for reduced system costs by reducing demand through end-use efficiency improvements;
- include current and projected load for the next 10 years;
- provide an analysis of energy end-use in the service area;
- review current and anticipated load research activities; and
- provide a comprehensive analysis of opportunities to lower total system costs.

The Commission has responsibility to coordinate preparation of the reports.

Sections 4: Authorization to Provide Intervenor Compensation

This section gives the Commission authority to compensate, through allocated costs, parties other than utilities.

Section 5: Eligibility for Intervenor Compensation

This section defines the circumstances under which parties other than utilities may be compensated. As a discretionary authority, the Commission may, during a proceeding, compensate an interested party other than a public utility for some or all costs if the Commission determines that such compensation is necessary to enable adequate participation and presentation of a significant position in which the party has a substantial interest.

The Commission may, after a proceeding, compensate an interested party other than a utility if the Commission finds that the participation was significant and has caused a substantial financial hardship.

House Bill 239

This companion measure would appropriate funds from the Railbelt Energy Fund to the Alaska Power Authority and the Alaska Public Utilities Commission to assist with the implementation of HB 238.

Section 1: Grants to Railbelt Utilities

$500,000 would be appropriated to the Alaska Power Authority for payment as grants to Railbelt utilities for the cost of preparing the end-use studies, load management reports, and advance resource plans required by HB 238.

Section 2: Least Cost Staff Position at the APUC

$55,000 would be appropriated to the Alaska Public Utilities Commission for a new position to assist in the preparation and review of load management and advance resource plans required by HB 238.

Section 3: Lapse Date

Unexpended funds as of June 30, 1988 lapse into the general fund.

Section 4: Effective Date

The effective date is tied to the effective date of HB 238.

5/5/87

SELECTED LEAST COST ENERGY MATERIALS

Markowitz, P. "The Least Cost Alternative to New Power Plant Construction," Critical Mass Energy Project (October 1985).

Markowitz, P. "Is Your State Charting A Least Cost Electrical Strategy", Critical Mass Energy Project (August 1986).

House Research Agency, Least Cost Energy Programs and States Energy Agencies (February 16, 1987).

TO: Ned Farquhar

FROM: Eric Myers

DATE: October 17, 1987

SUBJ: October 26 House Resources Work Session on HB 238

As we discussed on the phone, I have contacted the following individuals regarding their participation in the evening work session:

Paul Markowitz
Energy Conservation Coalition
tel: at AkPIRG on Monday AM 278-3661 about 9am-12noon

Mark Levine
Lawrence Berkley Laboratory
tel: (415) 486-5238

Steven Weil, Commissioner
Nevada PSC
tel: (702) 883-3087

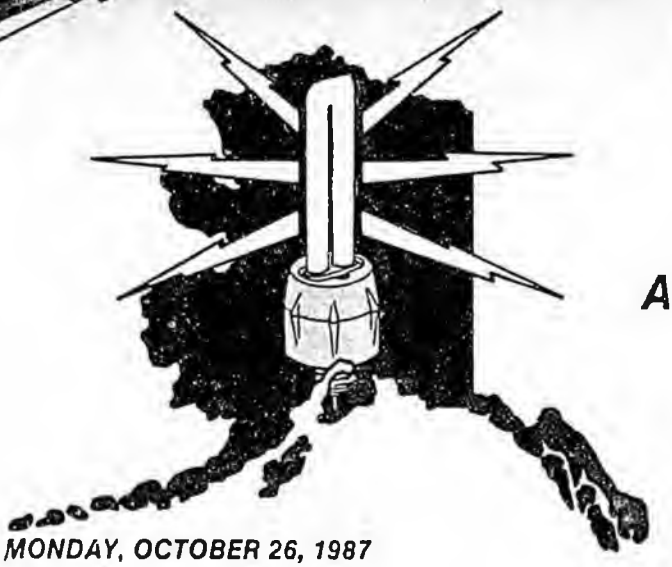
A copy of the conference agenda which gives a description of each of these individuals is attached.

I indicated that you would probably call to confirm their participation.

The concept, as I described it to them was to have each of them give about 10-15 minutes worth of comments to the Committee with the balance of the time left for Committee discussion. The objective would be to review "least cost" planning efforts in general without necessarily getting into detail on HB 238.

I would propose to have Kay start off with some general remarks to the committee about HB 238 followed by Markowitz with an overview of L-C efforts around the country, then Levine talking about denmand side technologies and applications used by utilities, and then Weil describing the situation in Nevada.

I'll be back in the office on Thursday (actually upstairs at the Energy Policy Task Force meeting).



Least-Cost Planning

October 26-27, 1987
Egan Convention Center
Anchorage, Alaska

A CONFERENCE FOR ALASKA

MONDAY, OCTOBER 26, 1987

7:45 a.m. **OPEN REGISTRATION**

8:15 a.m. **WELCOME & OPENING REMARKS**
David G. Hoffman, Commissioner
Department of Community & Regional Affairs

8:30 a.m. ***Larry Lewis: "Perspectives on Utility Planning — Issues and New Directions."*** Mr. Lewis is a Senior Project Manager for the Energy Management and Utilization Division at Electric Power Research Institute in Palo Alto California. EPRI was founded in 1972 by the nation's electric utilities to develop and manage a technology program for improving electric power production, distribution and utilization. Mr. Lewis has experience and expertise in demand side and market planning programs in both the private and the public sector. He will give a historical perspective on utility planning, and define least-cost planning.

9:00 a.m. **KEYNOTE ADDRESSES**
"DIFFERENT PATHS TOWARDS IMPLEMENTATION OF LEAST-COST PLANNING"
Larry Hobart: "Utility Initiated Least-Cost Planning Programs." Mr. Hobart is Executive Director of the American Public Power Association, an organization of publicly owned electric utilities throughout the U.S. He has spoken on the concept of least-cost planning before Congress and at utility conferences nationwide.

Paul Markowitz: "State-Chartered Least-Cost Planning Strategies." Mr. Markowitz is State Program Coordinator with the Energy Conservation Coalition in Washington, D.C. In this capacity, he promotes least-cost electrical planning at the state level, as well as strong federal conservation policies.

10:00 a.m. **BREAK**

10:15 a.m. **"LOOKING AT LEAST-COST PLANNING FROM A UTILITY PERSPECTIVE"**
Panel discussion involving utility managers and analysts who are actively dealing with least-cost planning strategies, either through their own initiation or because of state legislation.

MODERATOR:
David Hutchens, Executive Director, Alaska Rural Electric Cooperative Association (ARECA)

SPEAKERS:
Matt Dillon: Board Member, Snohomish Public Utility District, Everett, Washington. Snohomish is a publicly owned, winter-peaking utility that is currently integrating least-cost strategies into their planning process. Mr. Dillon is chairman of a committee, composed of utility staff, board members, and consumers, that is addressing the implementation of these strategies.

C. Mac Eddy: Manager, Navopache Electric Cooperative, Lakeside, Arizona. Mr. Eddy has been responsible for many innovative load management programs including budget-billing, off-peak rates, weatherization and heat-pump loans. Navopache Electric Cooperative is participating in the Western Area Power Association "utility matching" program, sharing its experiences with other similar utilities.

SPEAKERS (continued)

Mark Levine: Deputy Program Leader, Energy Analysis Program, Lawrence Berkeley Laboratory. Mr. Levine represents a program which is funded by the Department of Energy to create a national data base on the cost-effectiveness of demand-side options, and to disseminate this information. This program is responsible for the development of analytical tools for evaluating demand-side and supply-side programs and for integrating them to find least-cost solutions to future electric needs.

Eric Hirst: Energy Analyst, Oak Ridge National Laboratory. Mr. Hirst has worked with utilities to integrate supply and demand-side programs. He was most recently a consultant to Puget Power and Light in Washington.

Larry Hobart: American Public Power Association

Larry Lewis: Electric Power Research Association

12:00 a.m. **LUNCH**

1:00 p.m. **"LEAST-COST PLANNING FROM THE REGULATORY PERSPECTIVE"**
Panel discussion involving members of public utility commissions from several states that have developed different styles of least-cost planning regulation.

MODERATOR:
Susan Knowles: Commissioner, Alaska Public Utilities Commission

SPEAKERS:
Steven Wiel: Commissioner, Nevada Public Service Commission. In 1983, the State of Nevada enacted a Utility Resource Planning Act which requires major electric utilities to submit fully-integrated, long-range resource plans every two years to the PSC, demonstrating that all aspects of their future energy needs have been considered. Mr. Wiel, as one of three commissioners responsible for plan evaluation and enforcement, is in great demand as a speaker who will realistically present the "highs and lows" of this law from the regulatory p[illegible]

Paul Galen: Manager, Policy Analysis and Research Division, Illinois Commerce Commission. In 1985, the Illinois General Assembly revised the Illinois Public Utilities Act to require least-cost energy planning by electric and natural gas utilities. The ICC was given the authority to determine the precise form, scope and content of the plans. Mr. Galen has been responsible for conducting hearings and workshops to identify the issues of greatest importance in the design and implementation of the least-cost planning process. His final report includes conceptual, methodological content, procedural and policy considerations.

Jerry Mendl, Director, Systems Planning, Wisconsin Public Service Commission. Mr. Mendl has been involved in the regulatory aspect of Wisconsin's long range utility resource planning legislation since its adoption in 1975. He has drafted a least-cost planning primer for state regulatory agencies, soon to be published by the National Association of Regulatory Utility Commissioners.

Jim Lazar, Consulting Economist, Olympia, Washington. Mr. Lazar has completed studies on utility rate reform, resource allocation and energy conservation program design. He has appeared as an expert witness before numerous utility regulatory commissions in the Pacific Northwest. Of particular interest is his work on the role of utility conservation programs during a period of surplus capacity.

We finally get some straight talk from someone in Juneau

satch carlson

Hell, Ben, don't sugar-coat it; tell it to her *straight*!

At last, some good news out of Juneau, something even better than a boatload of lawyers hitting an Iranian mine. House Speaker Ben Grussendorf has taken off the gloves. In fact, once he took them off, he slapped Senate President Jan Faiks right across the kisser with 'em.

Good show.

This all started with the self-serving Senate newsletter that you got in your mailbox a week or so ago. You know, the one that Faiks commissioned because she was distressed that the press, in particular this very fishwrapper, had done very little to polish the reputation of the Senate, which in our opinion had done very little, period.

I hope you didn't just throw out this particular mailing, since it cost some Thirty Large of your money. It isn't exactly a stirring read, I'll admit, but I was curious to see whether it would convince me that the last session of the legislature had been useful and productive, especially on the Senate side, where the Dragon Lady rules with an autocratic fist.

Sure enough, the Alaska State Senate Public Report, as this thing is called, painted the Senate as a dedicated group of hard-working saints committed to saving the Permanent Fund from the encroaching hordes of Visigothic raiders, namely the House and the governor. And there are listings of bills and resolutions passed during the session. You know, important stuff, like the resolution condemning not only *Armenian* genocide, but genocide in general, and I say it's about time.

But when Ben Grussendorf got his copy of this novel exercise in creative writing — I haven't seen anything this creative since I received a financial statement from a mutual fund company explaining how marvelous it was that my investment had fallen to about half its original worth — he got mad. Seems the House members, usually cast as the clowns in the legislative circus, were feeling pretty good about their own activities, and I suspect they were secretly pleased that this year it's the Senate that has proved such an embarrassment to the very notion of representative government.

So when Ben reads this thinly veiled put-down of the House, he loads up his typewriter and fires off a blast at Faiks. Comes near to calling her everything but clean. Calls the Alaska State Senate Public Report a "bear scat newsletter." Points out that while we're reading these Senators' noble self-evaluations, they're toiling away on the beaches of Waikiki. Calls Faiks' personal political ambitions "an expensive embarrassment to many of us in public office in Alaska."

I love it.

See, usually what we get for public consumption is this mamby-pamby politeness, in which members of the legislative club say things like, "I'm afraid my esteemed colleague may be in error," and such, even when they really hate each other's guts, if they have any. Part of this is a clannish protection against Outsiders, which means us; the other part is the tendency to get along by going along, to hope some crumbs of power might fall from the Dragon Queen's table if one tugs his forelock properly.

Me, I prefer honesty, even when it means blood feuds and political suicide. While it is the duty and delight of us in the Observer Corps to point out what we see as reality, to note the Emperor's apparent coating of goose pimples and wonder why everybody else is marvelling at his taste in duds, it is refreshing to hear such a voice from the inside.

Hell, I'm the one who wants to bring back the duel as a forum for political debate.

Meanwhile, lest you think the entire House was lined up behind Grussendorf, let me remind you that several representatives of that body leaped to Faiks' defense, especially in regard to the now-famous Hawaii trip, of which the Dragon Queen herself said, "Waikiki is no picnic." Rep. Ramona "Boom Boom" Barnes defended the trip, saying, "We worked our behinds off over there."

If this is true, given the average size of legislative fannies, I will admit they must have worked very hard, indeed. I look forward to reviewing the results.

☐ Satch Carlson is an Anchorage columnist.

REPRESENTATIVE
BEN GRUSSENDORF

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(907) 747-8458

RULES COMMITTEE
LEGISLATIVE COUNCIL

DISTRICT 3
ELFIN COVE
PELICAN
PORT ALEXANDER
SITKA
TENAKEE

Alaska State Legislature

WHILE IN JUNEAU
P O Box V
JUNEAU ALASKA 99811

(907) 465-3824
(907) 465-3720

House of Representatives
SPEAKER OF THE HOUSE

September 30, 1987

Senator Jan Faiks
President of the Senate
3111 C Street, Suite 525
Anchorage, Alaska 99503

Madam President:

My colleagues know the high level of tolerance that I possess in trying to seek out that last bit of public good that may be hidden from the logic of the moment. It has also been said that patience is one of my strong virtues. However, your excessive politics has pushed my patience and tolerance to the breaking point; and I can no longer view your political antics as an entertained bystander.

It is now the general feeling that the President of the Senate has crossed the line of public trust with blatant partisan politics that do not serve the public interest. Even more alarming is your use of public monies to accomplish those ends.

The only consolation I can hope for is that the public who paid for the Faiks Newsletter does not feel obligated to believe it! It's no wonder that the Alaska media in the last session labeled the House as the shakers and movers on the issues before us. You spent the session making campaign promises and electioneering, and you haven't stopped. I would like to say talk is cheap but, observing your expenditures of public funds for such rhetoric, it is expensive. Even more ironic was that bear scat newsletter being mailed out while you were in Hawaii on the public nickel. (Yes, I know you justified it by stating "Waikiki is no picnic.")

Now, Madam President, comes the main reason for this letter. The most questionable action of all is your determination to use state

funds to pay airfare and other travel expenses to have fund raises in Houston, Los Angeles and Seattle. Those fundraisers undoubtedly will be cloaked under the guise of "Oil Seminars". Believe me, Madam President, many oil company executives are privately amused at your petty political extortion--and your greed in trying to label the House Majority as anti-oil industry. The House Majority encourages and respects the industry's economic efforts in Alaska. As Speaker, all I want from them is respect for the State and its people. I believe that respect exists.

You're so busy preparing for the next campaign that it appears the upcoming session is going to be a political nightmare, especially since it's reported your Senate fundraisers will target Outside monies to influence House races as well. (This on the heels of your recent "gift" of public funds to the House Minority Leader so that he could hire a campaign consultant). Would you consider an electioneering truce until at least May so we can accomplish something other than campaigning? One house alone can do nothing despite all its noble efforts.

At this time, Madam President, your personal political ambitions are an expensive embarrassment to many of us in public office in Alaska, and I ask you to reconsider your windmill strategy. Our working relationship is on the brink of no return. If all you plan to do this session is campaign, the second year of the 15th Legislature will be unproductive and brutal.

I patiently await your reply and, with great tolerance, will try to understand your thoughts.

Respectfully yours,

Rep. Ben Grussendorf
Speaker of the House

cc: House Majority Leader
Senate Majority members