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LEAST·COST UTILITY PLANNING

CONSUMER PARTICIPATION MANUAL

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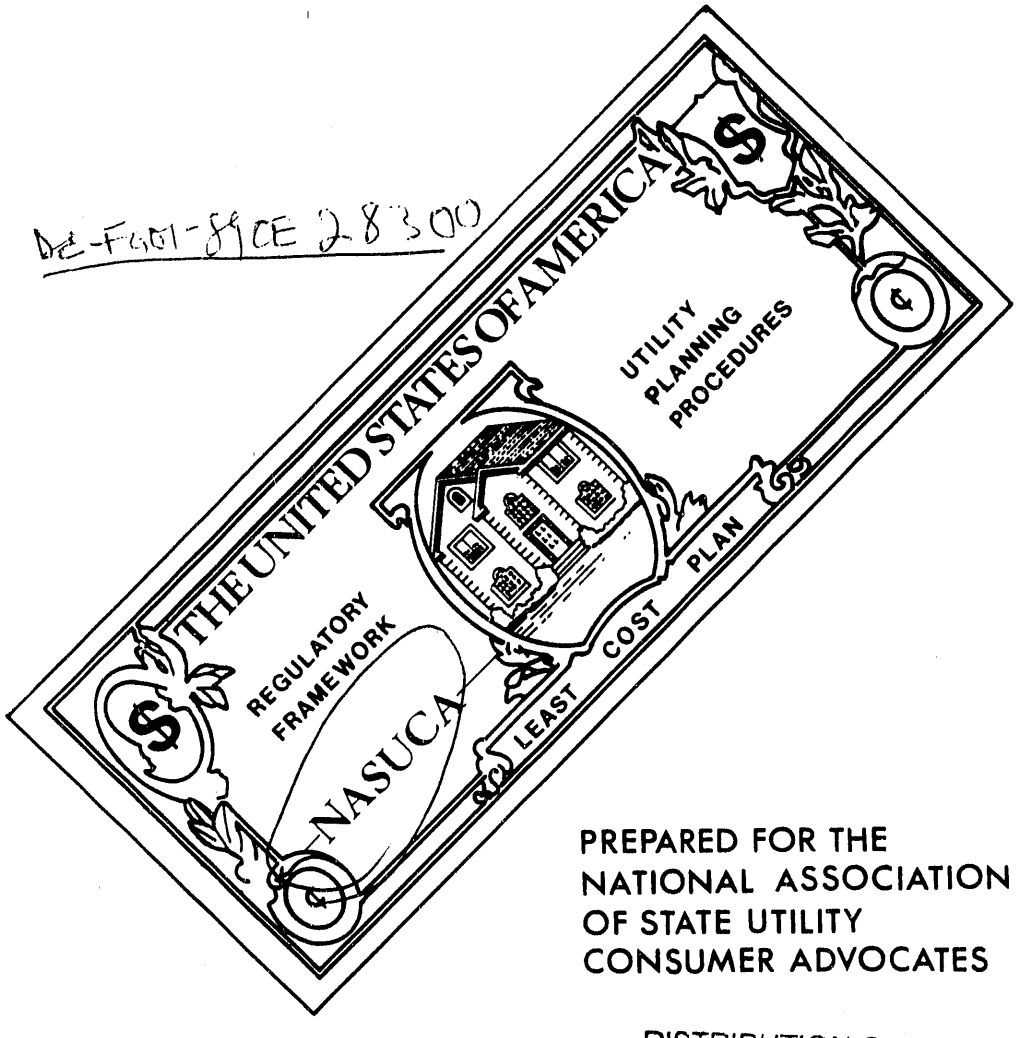

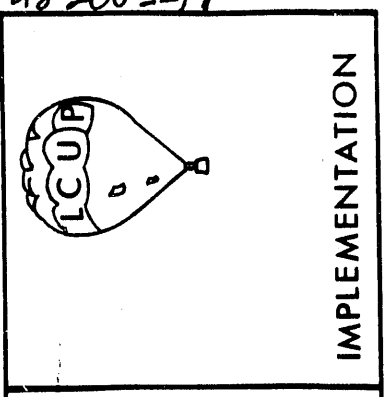

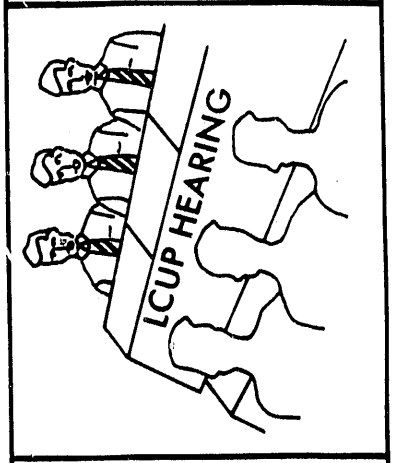

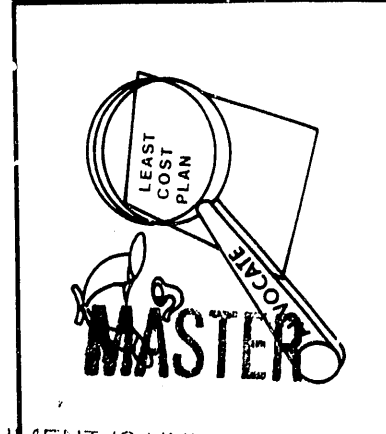

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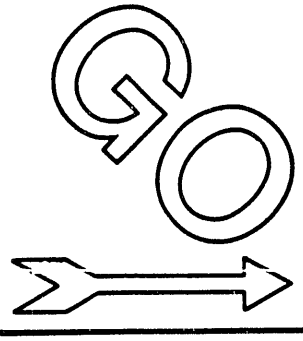

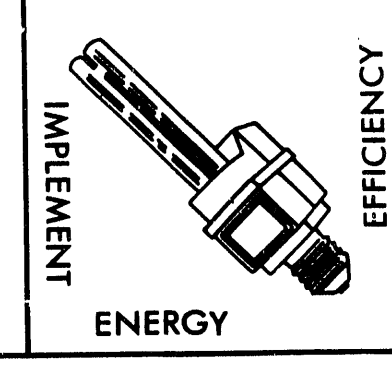

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LCUP CONSUMER PARTICIPATION MANUAL

TABLE OF CONTENTS

	Acknowledgements	ii
	Forward	iii
I.	A Brief History of Regulation	1
II.	Introduction to LCUP	7
III.	Status of the States	14
IV.	States Without LCUP	18
	Step One, Legal Forum	20
	Step Two, The Players	25
	Making the Rules	28
V.	Setting the Process and Beginning to Play	39
	LCUP Procedure	39
	Organization and Budget - The Limits	43
VI.	LCUP Planning Procedure	45
	Strategic Load Shape Objectives	45
	Substantive Checklist for Consumers	47
	Technical Checklist for Consumers	58
VII.	Emerging Issues	70
	Corporate Restructuring	70
	Competitive Opportunities	76
	Environmental Concerns	79
VIII.	Index	83

Appendix A. Model LCUP Statute

Appendix B Model LCUP Regulation

Appendix C Status of States' LCUP Survey Results

Appendix D. "Making Electric Efficiency Profitable", Stephen Wiel,* **Public Utilities Fortnightly**, July 6, 1989

Appendix E EPRI Load Shape Objectives*

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Acknowledgments

This manual has been prepared for the National Association of State Utility Consumer Advocates (NASUCA) by Cynthia Mitchell, Jon Wellinghoff, and Fred Goldberg. The U.S. Department of Energy (DOE) provided a grant to produce a comprehensive guide for state consumer advocates and other state and local consumer groups interested in promoting and participating in least-cost utility planning (LCUP) in their states.

NASUCA is a non-profit organization of state agencies responsible for representing utility consumer interests in state and federal forums. The organization was established for the purpose of providing information and education to its members. NASUCA currently has forty-three members and four affiliates from thirty-nine jurisdictions.

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Foreword

Least•Cost Utility Planning: Consumer Participation Manual is designed to provide guidance to state consumer advocates and other state consumer groups interested in either initiating and/or participating in an LCUP process in their state. Least cost utility planning, as described and discussed below, is examined primarily as a regulatory framework to be implemented by an appropriate state authority -- usually the public utility commission -- for the benefit of the state's citizens and electric utility customers. LCUP is also a planning process to be used by investor owned and public utilities to select, support and justify future expenditures in resource additions.

This manual is not intended to provide all the answers or to even raise all the questions about how to implement and/or participate in an LCUP process in your state. The regulatory environment, number and nature of utilities are different in each jurisdiction, and there is no one clear and best way to pursue least-cost planning. Approaches to LCUP will develop uniquely in every state to which it is applied.

Despite such diversity of implementation and participation in LCUP, the process does require consideration of many of the same issues, making a consumer participation manual invaluable. The experiences of other states do offer an LCUP regulatory framework that may be customized to fit any state's particular circumstances.

This manual is designed as a "How-To" manual for implementing and participating in a statewide LCUP process. Its goal is to guide the reader through the LCUP maze so that meaningful, forward-looking, and cost minimizing electric utility planning can be initiated and sustained in your state. The chapter entitled "Status of the States" provides a simple assessment system by which you, the reader, will be able to evaluate your own state's status in developing an LCUP process. The results of this ranking will assist you in determining how best to utilize this manual so as to address your state's needs. The appendix contains model LCUP statutes and regulations which may be adapted to each particular state's needs.

I. A Brief History of Regulation

the regulatory process leading to LCUP

the beginnings of regulation

From its beginnings in railroads and then to dedicated gas, water, and electricity systems, utility regulation has always recognized a delicate balance between governmental oversight and the opportunity for profit. Utilities were awarded a unique government monopoly to exclusively serve a given geographic area. In return, the utility agreed to submit its rates and practices to regulation by the state. Utilities were permitted the opportunity to earn reasonable profits based on a return on investor capital in exchange for the obligation to provide reliable and adequate service. This became known as return on ratebase or ratebase regulation. The United States Supreme Court secured the utility shareholder's right to the opportunity to earn a fair return on investments in the famous *Hope* and *Bluefield* cases.

With utility investor profits based on a percentage of ratebase invested, demand for electric services escalating, and economies of scale making it possible to build larger generating plants at a lower cost per unit output, profits escalated and electric prices declined. It looked as if the phrase "too cheap to meter" would come true. It didn't.

changing regulatory economics

The mid-seventies saw the electric utility industry turned on its head by a variety of economic conditions: skyrocketing energy prices due to the OPEC oil embargo and declining supplies of fossil fuels; generation plant cost overruns in the nuclear power industry; slowdowns in peak demand growth leading to excess utility plant capacity by wide margins; and diminished economies of scale in electric generation.

These factors led to massive increases in the real rates charged for electric service from the period of 1973 through the mid 1980's. As a direct result of these unprecedented electric rate increases, state regulators, consumers and utility executives began to rethink a number of prevailing precepts of the electric utility industry. Some of the long held beliefs now questioned included:

- Customers will not reduce demand in response to rate increases;

- Social welfare and economic growth are not directly related to increased electricity service and sales;

- The larger the generating unit, the cheaper the unit output (economies of scale);

- Utility owned generation is the only economical means of providing power;

- Adding supply is the only economical and proper way to meet utility's obligation to serve growing demand;

- Planners of a monopoly public service will always develop and implement those resource plans that will provide energy services at the lowest possible cost and highest social value;

- Utility profits are to be coupled to sales and investments in ratebase, and

- Monopoly utility service is the most economically efficient means of providing reliable and adequate service at least-cost.

turmoil in regulation

The regulatory process was changed by this questioning. On the state level, citizen movements formed state consumer advocate organizations to check skyrocketing utility bills. New consumer advocate organizations, consumer groups and existing regulatory commission staffs used traditional rate forums to question the need for and costs of utility generation projects and expenditures for fuel and operations. New plants were cancelled and partially completed plants were kept out of ratebase.

Despite some consumer successes, however, this largely ad hoc approach to the regulation of utility planning and resource acquisition practices more often than not resulted in regulators "splitting the baby" -- compromises borne from an unwillingness by regulators to test the financial community's response to total utility plant investment disallowance. In other instances, consumer groups and utility commissions found themselves unable to challenge massive overbuilding because the utility's planning and resource acquisition decisions had been made and set into motion long before regulatory review. Before the evolution of LCUP, state electric utility regulation was limited to mitigating the after-the-fact impacts of utility actions on both the ratepayers and shareholders, with neither side feeling that their interests were being adequately protected.

Passage by Congress in 1978 of the Public Utility Regulatory Policies Act, or PURPA, added another facet to utility reform. PURPA required state commissions to consider various cost of service and rate design principles. Further, PURPA provided a regulatory mandate which stimulated small independent power production and co-generation by requiring electric utilities to establish rates and offer contracts for purchase of non-utility generation. Thus, PURPA increased utilities' supply options from traditional means of investing in generation themselves and investing in generating technologies through unregulated subsidiaries, to contracting with non-utility parties for capacity and energy at an agreed-upon price.

new directions

We have come to the realization that even though electricity demand may grow with increased economic activity, numerous resource options are available to serve that demand. These include traditional supply side resources such as centralized generating stations, small and independent power projects, renewable energy resources -- both utility and independently owned -- and, finally, demand side management (DSM) resources that reduce customer demand through energy efficiency improvements traditionally known as conservation and load management.

The concept of utilities relying on demand-side resources to fulfill significant portions of their need for new capacity is a relatively new and often resisted notion by utilities. Many utility managers contend that utility financed and supported conservation is either uneconomical, unreliable, or unnecessary because if cost effective, prudent consumers will buy efficiency improvements without utility assistance.

The positive economics benefits of the implementation of significant demand-side resources for virtually every utility system in the country is difficult to challenge. The alternative costs of supplying new capacity through traditional generating resources that range from $.04 to $.12 per kilowatt hour can not compete with a vast array of demand-side measures from efficient lighting to weatherization with typical total delivered costs less than $.02 per kilowatt hour.

The reliability of demand-side resources is undergoing considerable verification. As more and more utilities implement programs and monitor results, reliability data is complied and available for utilization by all utilities. Measurement and verification of reliability for straight forward technologies such as efficient lighting replacements for existing lighting systems should be unquestioned by utility planners. Other, less direct measures such as radiant heat barriers in attics to reduce cooling loads will require more extensive monitoring and analysis. In addition, the full load reduction effects of even the apparently direct technologies have not yet been firmly established in all applications. For example, the cooling load reduction which can be attributed to the installation of efficient lighting needs additional investigation. This is not a reason, however, for utilities or regulators to discount the reliability of the significant saving attributable to the direct effects of such demand-side program installations.

Numerous consumer studies and extensive experience by utilities that have implemented demand-side programs strongly supports

the conclusion that vast amounts of cost effective efficiency improvements exist in all utility consumer sectors. This is easy to see. Think of the last time you were in an office building or hotel and saw rows of incandescent lights in recessed cans in the ceilings of foyers, halls and meeting rooms. These can generally all be replaced with efficient compact fluorescent lights that use 1/4 to 1/10 the energy of the existing lighting and will payback in a year or less. The August 1989 issue of **ENERGY USERS NEWS** analyzed a number of installations of compact fluorescent lights and found project returns on investment ranging from 41 percent to 206 percent. (See **ENERGY USERS NEWS**, August 1989, "Energy Management Investments That Beat the Dow", p. 15.) Yet building owners aren't running out to buy efficient replacements for their lights in the numbers such high financial returns would predict utilizing classical economic theory. Neither are homeowners buying radiant barriers or low-flow showerheads at the rate that investment returns would dictate.

The truth is significant market imperfections and barriers are apparently inhibiting consumer purchases of energy efficient technologies. One such barrier is consumer high discount rates. Most consumers require paybacks of less than two years. Low income and small businesses may have infinite discount rates due to no available capital. Utilities, on the other hand, currently have discount rates of 10 percent to 12 percent and are regulated based on 20 to 30 year paybacks. This "payback gap" between utilities and their consumers leads to the potential for significant uneconomic investments by utility managers.

Other market imperfections include the lack of developed distribution channels. Compact fluorescent lights have been on the market for four to five years. Yet it is difficult, if not impossible to find such products in supermarkets and home improvement stores. The same is true for other energy technologies. For example, efficient refrigerators and air conditioners are difficult to find in many markets outside of such states as California that have mandated standards for many energy using appliances. Manufacturers are required to distribute their most efficient appliances in jurisdictions that have high efficiency requirements, and consequently, "dump" lower efficiency equipment in other states without such standards.

A review of these factors has lead numerous consumers groups, and an ever increasing number of regulators and utilities to conclude there is an unequivocal need for utilities to actively stimulate the market place with utility financed demand-side programs which can effectively remove these consumer barriers if economical least-cost utility and societal investments are to be made.

On the supply side, numerous electric utility planners have also

acknowledged the limits to economies of scale for centralized power generation resources and recognize the significant financial and regulatory risks associated with such options. Most importantly, consumers who are directly affected by the outcome of decisions in the utility sector have learned that in order for their concerns to be addressed they must assume an active role in long-term resource planning.

II. Introduction to LCUP

what it is and what it can mean for your electric bill

LCUP goals and benefits

Least cost utility planning requires supplementing traditional utility regulation with a comprehensive regulatory framework that sets new checkpoints for the electric utility planning process. The principal consumer benefit of LCUP, when viewed as a regulatory construct, lies in changing the roles that regulator and also consumers play in electric utility planning from those of "Monday morning quarterbacks" to active players. With LCUP in place, utility planning and resource acquisition decisions are reviewed and evaluated *prior to* the extensive commitment of time and capital in costly supply projects. Regulators and consumers are thus less likely to be faced with distributing the costs of aborted or unnecessary utility construction activities.

As a utility planning procedure, LCUP benefits consumers by providing a comprehensive and periodic review of utility-preferred resource planning options. The utility is required under LCUP to select resource options so as to (1) meet projected demand at the least-cost, and (2) maintain reliable and adequate service to existing customers. The utility must consider the feasibility and economics of small power production and co-generation projects, but its responsibility for innovation doesn't stop there. LCUP requires the utility to address ways to reduce the demand for electricity through either utility-sponsored energy efficiency strategies or utility-financed programs designed and managed by third parties.

This new planning process utilizes the same engineering and economic expertise and resources that have earned our nation's utilities an outstanding reputation for reliable service, and applies them to the philosophy that a broad-based, integrated utility resource plan will ultimately provide an optimal mix of least-cost resource options. The end result is not limited to lower customer utility bills. LCUP should also improve the financial health and economic stability of utilities.

LCUP synonyms

A variety of terms have been coined to refer to what the authors have chosen to call least-cost utility planning, or LCUP. These include least-cost planning, resource planning, integrated resource planning, integrated least-cost resource planning, and least-cost integrated planning (LCIP).

LCUP defined

LCUP can generally be viewed as both a regulatory framework and a utility planning procedure, the elements of which are depicted below on Figure 1. The planning process is established through statute, regulation, or case precedent. It requires the electric utility periodically to develop and submit for public review and comment a long range plan for meeting future demand at the least-cost. The utility presents its plan at a formal hearing at which time other parties are provided the opportunity to comment on the plan and present alternative positions. The regulatory body is responsible for approving the plan and the utility is responsible for its implementation. Future resource acquisitions, including the construction of new power plant projects, must be part of an approved least-cost plan before they can proceed. Interim workshops may be held between LCUP hearings to simplify issues and check on plan implementation progress.

THE REGULATORY FRAMEWORK OF LEAST-COST UTILITY PLANNING

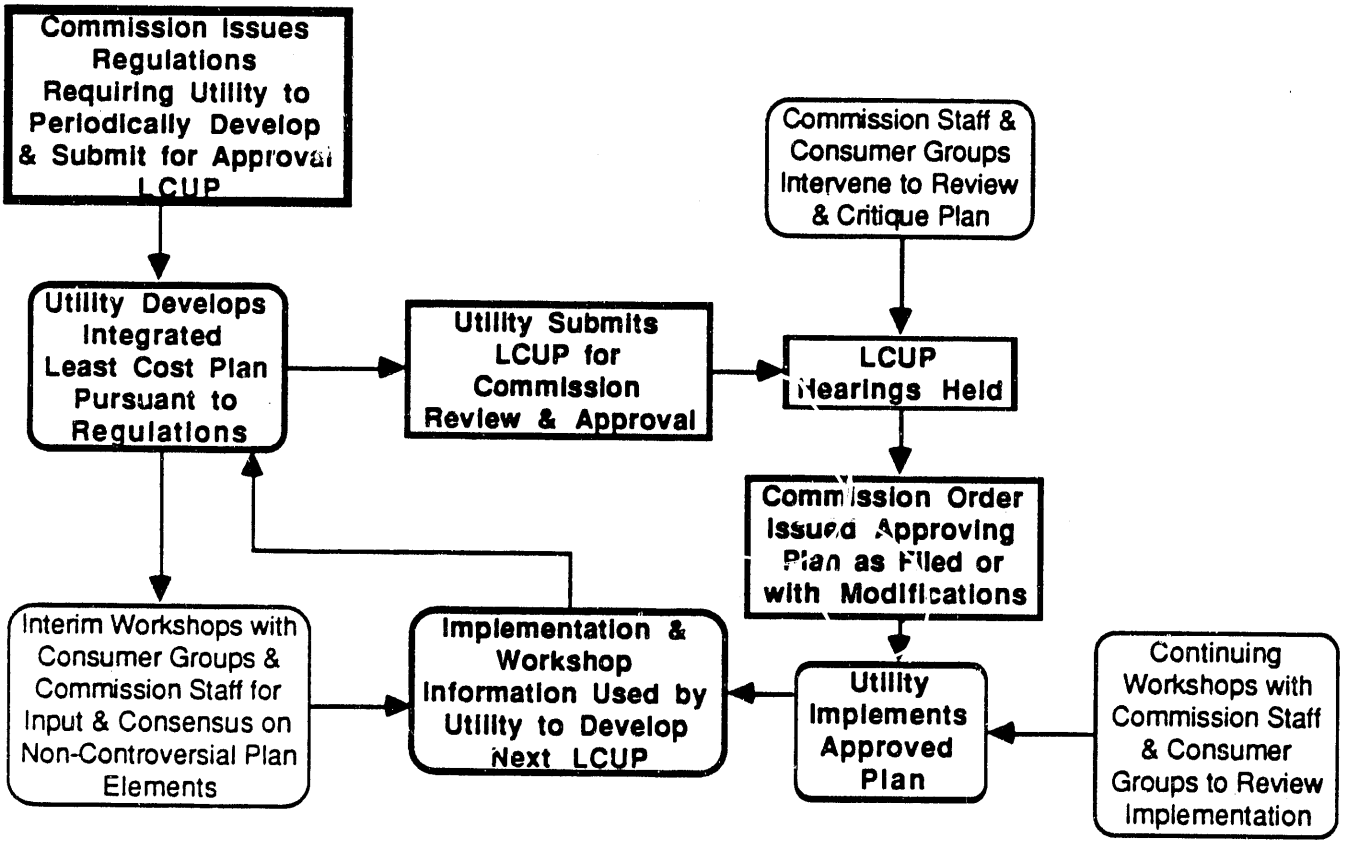

FIGURE No. 1

least-cost plans-contents

The first section of this manual addresses the regulatory aspects of LCUP. We will focus here on the regulatory review process of the utility-developed least-cost plan. Section I is for the LCUP novice. So now would be a good time to evaluate your state and its relative position in LCUP development. To effectively implement an LCUP process where one is not yet in place, a basic understanding of the actual least-cost plan is necessary.

All least-cost plans should share certain common characteristics including:

- The utility must evaluate all resources reasonably available to reliably meet projected energy and demand requirements on a consistent basis;

- Demand and supply resources are integrated to satisfy future demands at the least-cost to all ratepayers and society, while meeting constraints of safety and reliability, and

- In addition to the primary selection criteria of least-cost, the plan considers flexibility, risk, equity among ratepayers and classes, such externalities as environmental consequences, and other factors deemed important by the regulator.

A proper least-cost plan consistently evaluates and integrates demand- and supply-side resources so that energy services are provided at the least possible cost to utility ratepayers and society.

what LCUP is not

With the emergence of any new concept, there is inevitably some confusion and misunderstanding. LCUP evolved in part as a response to the growing realization that demand-side management or DSM (conservation and load management) was in many cases less expensive to implement than construction of new sources of electric generation such as coal or nuclear power plants. Accordingly, LCUP has been equated in some regulatory circles with DSM.

This is not to say that you should minimize the importance of LCUP's role in forcing utilities to implement robust, full-scale demand-side programs. Such programs have consistently been found by regulators to have lower costs than supply side alternatives.

Aside from having lower costs, demand-side resources have other valuable attributes which dictate their selection as alternatives to supply resources. They are more flexible, have shorter lead times, come in smaller increments, in many cases grow with load, and cause little or no environmental impact. Advocating these attributes of demand-side resources is critical to achieving true least-cost planning, as more jurisdictions are recognizing. In an effort to quantify some of these attributes, the Northwest Power Planning Council applies a 10 percent cost premium for risk benefits and a 5 percent premium for environmental benefits of demand-side resources. Work on the quantification of these issues is in its infant stages and may not be resolved for many years. Nevertheless, your group should urge that regulators in your state give some measure of recognition to these inherent advantages of demand-side resource. (See for example: Northwest Power Planning Council, "Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act" at 2. Vermont Public Service Board, Docket No. 5270, Proposed Findings of Fact, Vol. II at 150-155.)

In addition to confusing LCUP with DSM programs, some efforts have been made to direct attention away from LCUP to alternative concepts such as integrated value-based planning or IVP. As developed by the Electric Power Research Institute (EPRI), IVP is based on maximizing the value of service to the consumer rather than minimizing costs. No working examples of the process are in place, and EPRI has yet to provide a complete conceptual model of an IVP regulatory system. Consumer advocates and regulators have generally viewed IVP with great skepticism due to its shift from traditional concepts of cost of service to value of service. The National Association of State Utility Consumer Advocates passed a resolution opposing IVP in November of 1987.

regulatory framework

Figure 1 generally depicts the elements of the regulatory framework of a least-cost planning process. This regulatory framework is composed of a number of elements that can be related to the LCUP process as follows:

Statutes: A state law or series of laws that alone or in combination with existing statutory requirements establishes a least-cost utility planning process. The statute may be detailed and prescriptive as with the statute enacted in Illinois, or it may be a simple grant of regulatory authority containing the minimum procedural guidelines necessary to establish the regulatory LCUP process as was the case of the Nevada statute. Appendix A contains an example of a model LCUP statute which is adapted from the Nevada approach that you may wish to consider for implementation.

Regulations: A regulation or series of regulations developed by the state utility regulators that requires and specifies in some detail a least-cost utility planning process for the state's electric utilities. Regulations will require a fairly significant amount of detail to be meaningful. Appendix B contains a proposed model regulation adapted from regulations proposed in Massachusetts and the District of Columbia.

Discovery: A procedural process by which parties wishing to gain additional information and data not specified in either the utility's resource plan or other rate and regulatory information on file with regulators may formally request such information and data. The level of required discovery in an LCUP proceeding can be substantial.

Workshops: A process in which interested parties are given the opportunity to review and make recommendations on components of a utility's resource plan prior to its filing. Topics for workshops held between resource plan filings may also include a review of and recommendations on the status of already approved utility resource acquisition activities. Workshops can be extremely valuable in narrowing the issues to be litigated at hearing and in assisting the parties in reaching a consensus on noncontroversial aspects of the plan. Workshops can also be used to develop consensus on proposed LCUP regulations prior to the implementation of a regulatory LCUP framework.

Prefiled Testimony: All parties, including the utility and consumer groups, file technical and policy support or critique of the utility resource plan. The utility prefiled testimony is usually simply an explanation of its plan with policy support. Intervenors, such as consumer group, are afforded an

opportunity to submit an in-depth technical review which typically includes extensive supporting exhibits.

Hearings: The formal process through which regulators review the utility's resource plan.

Opinions and Orders: The written evaluations, reasonings, and conclusions of regulators on the evidence presented them at hearing.

Amended Filings: A procedure by which utilities may make necessary changes, revisions, and updates to resource plan filings in between required submissions.

III. Status of the States

where is Your State in the LCUP Process

This section is designed to assist the reader in evaluating the status of LCUP in your own state.

the EPRI survey

In December 1988 the Electric Power Research Institute (EPRI) released a final report entitled "Status of Least-Cost Planning in the United States". Based on interviews with key regulatory personnel in each state, EPRI attempted to identify and rank the status of LCUP in the states. EPRI also sought to identify the motivating factors behind adoption of the many LCUP approaches.

Our review of the EPRI survey indicates that its results are not particularly useful for consumer advocates or groups needing to evaluate the current status of LCUP in their states. Accordingly, an independent survey was conducted to provide more current and useful information for the users of this manual.

The EPRI survey indicated that 43 states were in the process of adopting or implementing LCUP. The independent survey conducted for this manual determined that many fewer states are actively pursuing the robust strategies contemplated in this manual.

survey questions

The following questions were developed to determined if a state has in place a regulatory process that is designed to achieve the goals and produce the benefits of a fully developed least-cost planning framework:

- Is there a statutory, regulatory, or case law requirement to have each electric utility regularly submit to regulators a utility-developed long-term resource plan which integrates demand- and supply-side resource alternatives?

- Do regulators hold public hearings on the plan and accept input from other parties?

- Do regulators specifically approve the plan?

- Are utilities required to implement and follow the regulator-approved plan for next resource acquisitions?

- Before a utility can receive a permit to construct a generation or transmission facility, must that resource be in an approved resource plan?

- Is there opportunity for input prior to plan filing (i.e. workshops) ?

- Have hearings on any plan submitted been held yet?

In April of 1989, these questions were posed to the same regulators surveyed by EPRI in its study. The authors used these responses to rank the status of each state's LCUP regulatory process. Rankings were made as follows:

0 = Little or no progress in implementing an LCUP regulatory framework. There may have been some forums (even formal ones such as rulemaking), in which LCUP was discussed, but no concrete proposals are currently before any body with authority to adopt such proposals.

1 = Concrete proposals to implement an LCUP regulatory framework are now before an appropriate body, either as a statute or regulation, but such proposals lack a key LCUP element so that the adoption of those proposals would result in an incomplete LCUP regulatory process.

2 = Concrete proposals to implement an LCUP regulatory framework are before the appropriate forum, contain all essential elements, and moving toward adoption.

3 = An LCUP regulatory framework has been adopted which contains all essential elements.

4 = An LCUP regulatory framework containing all essential elements has been adopted and implemented.

Rankings by state for the April 1989 survey are shown on the map depicted in Figure No. 2.

Appendix C provides the individual state responses to each of the survey questions.

With this ranking system, the user has been given a tool with which to precisely gauge a particular state's current LCUP status. A state ranked either "0" or "1" is at the stage in which a consumer advocate or group is needed to initiate or intervene in the current

process to ensure an effective LCUP framework is implemented. Consumer advocates or groups in states with a "0" ranking are essentially starting from scratch, while those in states with a "1" ranking have a proposal on the table from which to work. Intervention is necessary, however, to see that all essential elements of an LCUP regulatory process are incorporated into the final LCUP scheme.

If your state is ranked at "0" or "1", you need to carefully read chapters IV and V which explain how to implement LCUP as a regulatory process in your state.

If your state is ranked at "2", "3", or "4", an LCUP regulatory framework is either in place now or imminent. Intervention may be appropriate in a state ranked "2", if timely, to assist the process to completion. Your organization may not be able to significantly influence the outcome of the process, however, at this late stage. If your state is ranked "3" or "4" you will want to turn to Chapter VI, "The LCUP Process - Beginning Play".

Survey Results:

The individual state results of the independent survey conducted in April 1989 are provided in Appendix C. Figure No. 2 shows the overall ranking for each state. The results indicate that:

•24 states are ranked as 0;

•4 states are ranked as 1;

•4 states are ranked as 2;

•7 states are ranked as 3, and

•10 states are ranked as 4.

THE STATUS OF LEAST-COST UTILITY PLANNING IN THE UNITED STATES

SURVEY RESULTS

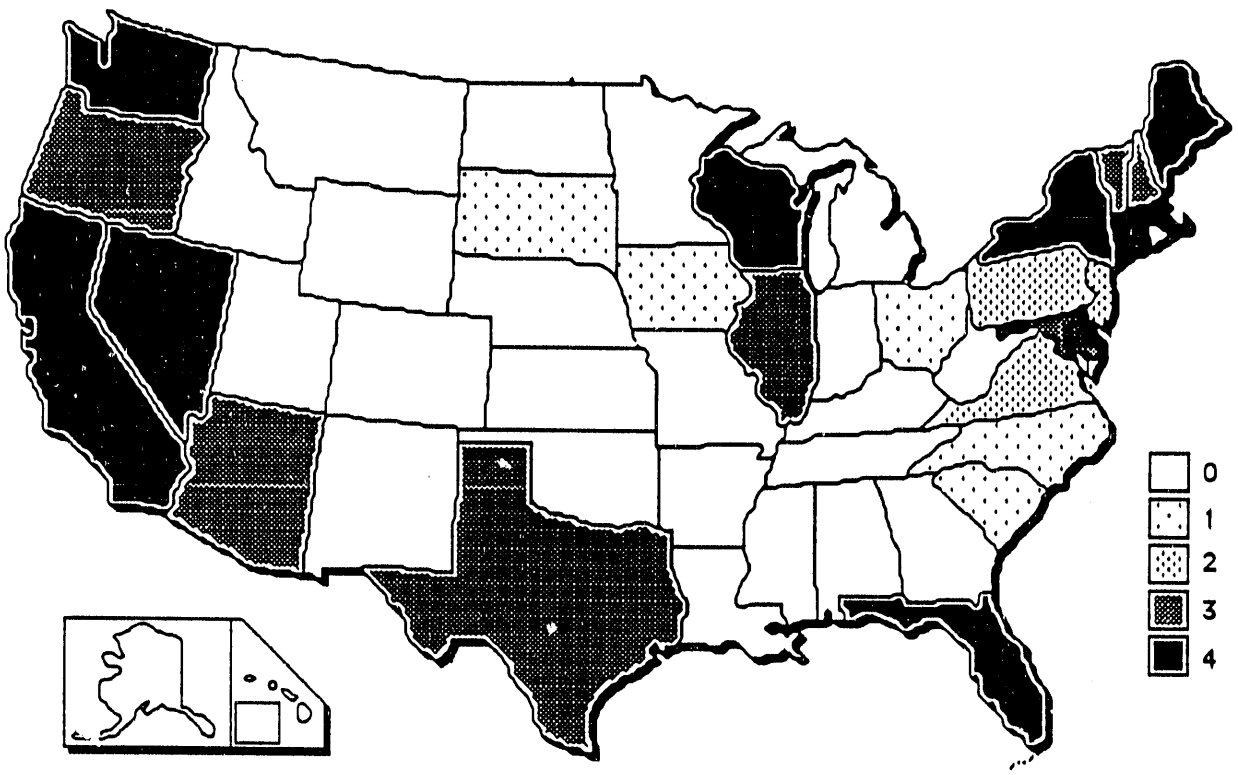

FIGURE No. 2

IV. States Without LCUP

starting the LCUP process in your state

If from the preceding chapter you have determined that your state lacks a formal LCUP regulatory framework, you should consider developing such a process as quickly as possible. This section offers some suggestions on how to get an LCUP process going in your state, and also discusses some of the pitfalls associated with each of the proposed strategies. This should better assist you in selecting the most appropriate approach for your state. Given the number and combination of strategies presented below, however, a few of the fundamentals should be kept in mind.

primary goals

Your initial goal in establishing a continuing LCUP regulatory framework should be to open the utility's planning process to meaningful participation by you and your organization. You must be provided the opportunity to review *and affect* long term electric utility planning decisions -- before your dollars are invested in potentially unnecessary or unneeded projects. Your participation is needed to ensure that the LCUP process results in the lowest cost strategy for reliably serving the demand for electricity.

Your goal at this stage of the process-opening utility planning to public participation -- should not be viewed as an end, once achieved however. The ultimate primary goal of utility provided energy services at the least-cost to society and the environment must be kept in focus. Achieving that goal once public participation is secured requires time, expertise and thus money. The means by which consumers can allocate limited resources to winning the LCUP game is discussed in Section V, "Setting the Process and Beginning to Play"

avoid sub-issues

The goals of an LCUP framework are *not* to:

- Criticize the utility for past actions like overbuilding or failing to implement demand-side measures, and

- Stop construction of an imminent supply side measure such as a power plant or transmission line if construction will commence within two years.

The blind pursuit of either of these sub-issues could easily derail efforts to achieve your initial goal--to open public participation in the utility planning process.

demand-side resource deployment

Concurrent with the initiation of a full featured LCUP process in your state you should initiate a review of your utilities' demand-side resource deployment capabilities.

In order to deploy demand-side resources, as they will be undoubted required in a least-cost planning process, utilities must be capable of delivering them. With some notable exceptions, the vast majority of utilities do not now have the capability to deliver comprehensive energy-efficiency savings on a strategic scale.

Failure to address the need for demand-side capability-building by utilities will weaken and delay the effectiveness of LCUP. Without capability-building investment, utilities may continue to rely on the excuse that they do not know enough about demand-side resources to use them in place of new supply.

Your group should initiate and encourage a parallel path to the LCUP initiation process where your state's utilities develop and test on a pilot basis demand-side programs investing in all cost-effective efficiency potential available within all major customer classes. Only with this experience can utilities determine with confidence costs and magnitudes of demand-side resources available from their customers. This activity is essential for utilities to develop specific efficiency supply curves for their services areas, as are discussed later in this manual. Initial rulemaking may then focus on utilizing this information when it becomes available from the capability-building phase. A growing number of utilities and regulators are recognizing the capability-building imperative for least-cost planning and are requiring pilot demand-side programs conducted in concert with LCUP process initiatives. For example, the Northwest Power Planning Council has urged Bonneville Power Administration and the region's utilities and regulators to pursue capability-building strategies and lost-opportunities since its 1983 Plan. The Northwest Power Planning Council's 1986 Plan reaffirmed this recommendation, in spite of a large capacity surplus. (See: The 1986 Northwest Plan, at 9-28 through 9-30.) The Idaho Public Utilities Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan" and a "Capability-building Plan." (See Order No. 22299, Case No. U-1500-165, January 27, 1989). The proposed decision before the Vermont Public Service Board in Docket 5270 also orders all utilities to produce capability-building

work plans within 90 days of its final order, with implementation plans due 90 days thereafter.

The capability-building path must address appropriate demand-side program designs. This is an extremely important place for public participation. As a rule, the best and most comprehensive efficiency programs have substantial input from intervenors. Be forewarned , however, good program design is an arduous and time-consuming task. Thus, intervenor funding is essential. Utilities in Connecticut, Massachusetts, and Vermont have agreed to participate in a novel collaborative design process initiated by the Conservation Law Foundation of New England. This approach provides for a parallel demand-side implementation path in those state simultaneously with the institution of an LCUP process. In addition, this unique process provides the advantage of utility funding of intervenor input.

step one, legal forum

Your first step in implementing an LCUP process is to identify and understand the legal forums available to you. Consumer advocate or public counsel offices already familiar with these legal forums may wish to skip ahead to the discussion of the LCUP players.

No matter the state, you will always be working within three major legal structures: existing statutory authority, existing regulatory authority, and precedents established in prior rate and regulatory proceedings. The LCUP process does not favor one forum for another. Not only are they interrelated, each of the three forums is influenced by the unique characteristics of the state's utilities, regulatory and political climate.

Selecting the appropriate forum can be the most important step in pursuing an LCUP regulatory framework. You must therefore carefully determine which of these forums offers you the greatest opportunity for success. That choice will depend largely on your assessment of the political and institutional barriers presented by each the available forums, and will be specific to your state's circumstances. The choice will also be affected by the influence and power of the players involved.

legislation

State utility regulators derive their authority from a body of laws developed by the state's legislature. Meaningful LCUP legislation is often difficult to enact since it requires broad coalitions and compromise in order to become law. Also, the process of enactment of legislation by definition need not conform to a legally challengeable procedure. Difficult does not mean impossible, though, and a statute is very difficult to repeal or amend. Thus, an LCUP process established by statute is less subject to radical changes over time.

Issues directly affecting a consumer's pocketbook -- like stabilizing utility bills -- are powerful engines which can be used to drive a legislative initiative. Look for a prior regulatory decision on an expensive supply-side construction project that resulted in a substantial rate increase in rates. Capitalize on this example by showing how that rate increase could have been reduced, deferred, or eliminated by implementing lower cost demand-side measures instead -- measures that would be looked at in an open LCUP process, but which would otherwise go unnoticed in the existing utility planning process. Consumer sentiment and organization are keys to implementing legislation.

If utilities perceive LCUP as a threat, they will most likely attempt to mount a lobbying campaign against it. A "first shot" failure at the legislature is not just discouraging in and of itself. It could also substantially dampen a second effort at the state public utility commission level. It is, therefore, very important to develop good working relationships with key legislators. The effort is well worth it. Success at the legislative level ensures both regulatory and utility commitment to the process and establishes the legal legitimacy of LCUP regulatory framework.

avoiding legislation

It may be possible in certain jurisdictions to avoid the legislature and thereby eliminate this time consuming and often politically impractical step. This strategy should be considered when the following factors are present:

- Regulators already have broad statutory authority to fully regulate the utilities within their jurisdiction (utilities with complex corporate structures such as those controlled by utility holding companies are unlikely candidates for this strategy);

- Regulators have indicated an interest in instituting an LCUP framework, and

- Existing statutes are recognized to authorize regulators to predetermine the need for supply side resources including central station generating facilities and transmissions systems.

The risks of bypassing the legislative process are clear. A premature and incomplete proposal presented to a disinterested regulatory body will certainly be rejected. Even with commission interest, however, regulators must have sufficient legal authority to require, consider, and enforce a long-range utility planning process. If this is not the case, statutory authority should be pursued.

content of legislation

LCUP legislation should describe the broad responsibilities of both regulators and the utilities, establish the policy of "least-cost" planning, and also provide a mechanism for enforcing planning decisions. For example, by linking LCUP legislation to statutes requiring permits to construct generation and transmission facilities, regulators are able to ensure that only LCUP approved facilities are permitted and constructed.

The final determination to be made in determining whether to seek statutory authority for an LCUP process involves the legal question of the extent of existing statutory authority. Draw on your knowledge of the law *and* the political climate in your state in assessing this issue. A reluctant regulatory body can be as important a factor as actual statutory authority.

regulations

Once the statutory authority for LCUP has been established -- whether through existing statutes or new legislation -- regulators must then promulgate rules to guide the process and define the respective rights and responsibilities of the participants.

If you began your campaign with legislation and were successful in getting an LCUP statute enacted, regulations will follow as a matter of course. If, on the other hand, you have determined that regulators have sufficient statutory authority and interest in LCUP to start your quest at the regulatory level, you will need to decide on a strategy to prompt the promulgation of LCUP regulations.

regulation sponsored by regulators

Ideally you will want your regulators to issue a proposed rule of their own drafting. This strategy is preferred because it ensures commitment by the enacting body to the LCUP framework and almost guarantees that the process will not end until final regulations are promulgated. In order to get this process started, however, you must be willing to approach regulators and their staffs informally to lay the groundwork for the proposed rule. Your assessment of regulators' attitudes toward and enthusiasm for the process is key to success under this strategy.

This approach is not recommended unless you have reliable and influential contacts inside the regulatory body. It might also be very helpful to circulate a prototype regulation to those involved in the drafting of the regulator's proposed rule. We have included such a model in Appendix B for just this purpose. Finally, you must be careful to preview the proposed regulation to ensure that it contains the basic framework necessary to implement an LCUP process

regulation requested by petitioners

If a regulator-proposed regulation isn't feasible, you should then consider petitioning the commission to establish rulemaking on the LCUP issue. Your petition should include the following elements:

- A statement of the need for an LCUP process and an analysis of the benefits to be achieved from such a process by consumers, regulators, and the utility;

- An analysis of the statutory authority of regulators to promulgate an LCUP framework, and

- A proposed regulation setting forth the entire LCUP process, and an explanation of the proposed regulation.

With specific data from your own state, the information provided in the introductory sections of this manual should give you a head start in preparing the statement of need. Refer to examples of costly powerplant projects, rate increases and after-the-fact disallowances to illustrate for regulators the benefits of prior review and approval of construction projects. Point to pending construction projects that have not gone through an LCUP type review, and which are likely to impact utility rates significantly. Remember our earlier caveat, however: the LCUP process should *not* be used to block an imminent supply side project *unless* there is sufficient time to fully implement LCUP and adequately consider alternatives to the proposed project before it is completed.

The second element of the petition for rulemaking -- the legal analysis of existing regulatory authority -- will be based on a review of regulatory and court decisions from your jurisdiction. Look for discussions regarding the broad authority of regulators to enact rules absent specific statutory approval. LCUP may have already been proposed in your state legislature and failed. If this is the case, be prepared for arguments from the utilities that the absence of legislation authorizing LCUP is a prohibition against initiating LCUP by regulation.

Finally, your petition should include a proposed regulation that sets forth the LCUP process from implementation to enforcement. A section by section explanation of the proposed regulation should also be provided. Again, refer to the model regulation contained in Appendix B, and do not be afraid to modify it to better fit your own particular needs! Also review the "Making The Rules" section below, which provides the general outline of the regulatory process for LCUP implementation. Use the checklist provided as a guide in tailoring the model regulation to suit your needs.

Some states have used a number of other strategies including negotiation, investigation and study in attempting to implement LCUP. Ohio and Michigan continue to study LCUP exhaustively but without reaching any tangible results. In Colorado, informal negotiations on an LCUP process were tried and ultimately failed. In the majority of instances, attempts to implement an LCUP process without a specific legislative or regulatory mandate have met with little success.

commission order

LCUP proponents in New York have uncovered yet a third approach -- dubbed here the "Commission Order" strategy -- for implementing an LCUP process. The Commission and advocates there have relied on evolving regulatory case law over the years to develop a process that will approximate a full LCUP framework by 1990. This process commenced in New York in 1984 with a Public Service Commission Order which requires utilities in that state to consider demand-side programs as a resource option. (See: New York Public Service Commission Case No. 28223, Opinion 84-15, May 21,1984.) It culminated in an order requiring annual fully integrated least-cost plans to be filed by May of 1990. (See: New York Public Service Commission Case No. 28223, Opinion 89-15, May 23,1989.)

If both the legislative and regulatory strategies seem unworkable in your state, you may wish to consider the New York approach. Patience and consistency over time are essential to success under the case-by-case strategy, and both must be maintained while a robust LCUP process evolves. Be prepared to intervene and participate in every electric utility rate case or generic resource planning related case to come along, each time asking regulators to consider alternatives to the expensive generation and transmission plant additions for which the utility is seeking rate recovery.

The case-by-case approach can be viewed as a way to apply many of the principles of LCUP during a rate case review of current construction and resource acquisition projects. The scope of your LCUP presentation in a rate case proceeding will be at the discretion of the regulatory body, however.

The case-by-case approach does not offer a long term solution to LCUP implementation. Traditional rate proceedings are neither noticed nor designed to provide the information needed to conduct a full-scale least-cost planning evaluation. LCUP requires consistency in both process and substance in order to be successful. Data must be presented consistently as between resource plans and as between utilities and this cannot be accomplished under the case by case approach. You should view the case-by-case approach as a last resort for grabbing the

attention of regulators and utilities so that more long term strategies may be pursued.

step two, the players

In this section, we discuss how to assess the players (both individual and organization) in a regulatory environment.

We can divide LCUP players into two categories: antagonists and catalysts. It would be over simplistic, however, to assume that in all instances the affected utilities will be antagonists in the process and advocates office or regulator the catalysts. Because LCUP is a dynamic and long term process, the same individuals and organizations wear a variety of hats before the process is in place.

When evaluating the potential players in an LCUP movement, keep a careful eye out for a person and/or organization with the exposure and influence to raise LCUP up to the public eye and carry it through to implementation.

regulators

It is the regulator's duty to balance the interests of the various stakeholders (the utility, shareholders, and ratepayers) and to approve a resource plan or investment decision based on the anticipated long-term benefits to all parties. When assessing the role of the regulatory body in an LCUP initiative, both the commission and its support staff should be evaluated for the following information:

Number of commissioners; are they appointed or elected; who is generally considered their constituency base; what are their terms of office, and what is the status of each commissioner's term.

The majority of state utility commissions use either three or five commissioners. Illinois, New York, North Carolina and South Carolina are the exception, each with seven commissioners. Size is not necessarily to your benefit. A larger "pro consumer" commission gives you more opportunities to find your key players. A larger "pro utility" commission gives you more headaches. The time remaining in each commissioner's term poses similar difficulties. You are looking for persons with sufficient experience on the commission to be able to influence their colleagues. Beware of the short-timer though. The process takes time and if your movement is tied to an individual ready to leave the commission, the process may be jeopardized. Also, community influence and efforts to educate commissioners regarding LCUP will be different depending on whether they are elected or appointed.

winning commission support

In assessing the interests and biases of individual commissioners, there are a number of factors to consider. You will want to determine whether any of your sitting commissioners already favor an LCUP process. This can be determined by analyzing past commission decisions -- especially those reviewing central generating station additions. An individual commissioner may have made statements regarding the utility's planning and review process and anticipated rate base treatment of major generation additions that indicate his or her receptiveness to LCUP.

Look to see if any of your sitting commissioners are or have been members of the National Association of Regulatory Utility Commissioners (NARUC) Sub-committee on Energy Conservation. This committee has been very active in promoting LCUP concepts, and any commissioner that has been a member of this committee has at least some knowledge of the process and may be predisposed to LCUP concepts. Finally, any commissioner who has expressed an interest in energy efficiency, demand side measures and environmental concerns is a good target for assisting in your LCUP efforts.

commission staff

If there is a commission staff or division, you must evaluate its relationship to the commission. The size, technical and analytic backgrounds, and areas of expertise of regulatory staff will also influence any LCUP strategy. Some regulatory commissions have extensive staffs or divisions that are fairly independent from pressures and influences of the commission. Other staffs are small and serve the decision-makers directly. With larger staffs, you are likely to find experts in all the necessary professions: economics, accounting, engineering and legal. Smaller staffs are more likely to be one or two dimensional.

winning staff support

Commission staffs are usually overworked and underpaid. Thus, one of the primary hesitations of a commission staff to LCUP is the additional work involved, and for which they have neither the time nor the personnel. You must, therefore, be willing to sit down with the staff and offer your support to obtain additional funding for LCUP activities.

staffing requirements

Staffing requirements for LCUP vary widely. Wisconsin has nearly twenty-four full time people working on their case-by-case LCUP process. The Nevada commission has devoted the equivalent of two full time technical staff to their very formal LCUP process. Staffing levels will depend largely on how the LCUP regulation is structured. If greater responsibility for developing the LCUP plan is assigned to the utility, the burden on the staff is lessened. The converse is true as well. We, therefore, recommend that you bring the commission staff into the process early so that your LCUP strategy recognizes and respects these limitations.

the utilities

The utility is predominantly concerned with reliability and revenues. Reliability is defined by the impact of resource planning decisions on the operation of the utility system. Revenues may be impacted by demand-side program effects on sales, the competitiveness of rates for various classes of customers, and the general financial health of the company. When assessing the role of a utility in an LCUP initiative, the following factors should be evaluated: the number of utilities, their composition (i.e. single or multi-energy service, holding company and subsidiaries, single or multi-state), financial health, existing and potential demand and supply resources, and their political strength.

an aside: prudence reviews

There are several strategies that can be utilized to gain the support of utility executives. Many utility managers are still suffering from the shell-shock of disallowances of major plant construction costs. Accordingly, many are reluctant to commit to substantial capital investment for the construction of new facilities. LCUP can be "sold" to these utility managers by explaining how the preapproval of utility construction projects in the LCUP process reduces the risk of prudency reviews and disallowed costs. The "up front" approval of construction projects in an LCUP process is generally acknowledged as a binding determination by the regulatory body that the initial decision to construct a project was prudent -- and thus that the costs associated with the start-up are just and reasonable.

This presumption of prudence is rebuttable, however. If the utility withheld information or presented it in such a manner as to distort the plan and the regulator's approval, the unjust and unreasonable costs related to this conduct may be excluded from rates. Also, resource planning does not excuse imprudent management of projects once the decision to construct is approved -- only just and reasonable labor and material expenditures can be recovered in rates. Finally, if circumstances affecting the regulator's prudence decision later change dramatically -- for example, gold prices drop so that the state's mining industry collapses, and all the load associated with the industry drops off the system -- a decision by the utility to continue

the construction of an LCUP approved generation project -- may be reviewed for prudence, and any unjust and unreasonable costs incurred may be excluded from rates **after** the dramatic change in demand should have been known to utility managers. This precise issue has yet to be addressed by any regulatory body overseeing an LCUP process.

the ratepayer advocate

The consumer advocate's perspective can be narrowed to ratepayer interests. Ratepayers typically place strong emphasis on the near term and the total utility bill. When assessing the role of a state advocate's office in an LCUP initiative, the following factors should be evaluated: budget and size of the advocate's office, office stability, popular support, political support, statutory mandate, existing workload, in-house legal and technical capabilities, and size of consulting budget.

other consumers

When framing an LCUP strategy, it is important to avoid pitting one customer class against another. LCUP should represent a win-win for *all* ratepayers, not just residential and small commercial customers.

other state agencies

Not to be overlooked in any LCUP initiative are the other public agencies such as state environmental and siting boards that are available to lend their support and the state energy office.

making the rules

As the state survey presented above shows, the progress of regulators in considering and implementing LCUP varies widely. Discreet segments of the LCUP framework are being implemented by regulatory commissions throughout the country. Some commissions take the position that mandatory demand-side programs or a resource bidding system constitute LCUP. Others believe that the periodic submission by their electric utilities of a forecast of future demand with a generation planning table of contemplated loads and resources is LCUP. Both are pieces of the LCUP puzzle, but alone they do not achieve the integrated whole that is LCUP. It is critical that LCUP be designed as an integrated, comprehensive process if consumers are to realize its full benefits. This chapter discusses those components of the process that must be incorporated into the statutes and regulations establishing the complete LCUP framework. These components are then illustrated through a discussion of a model LCUP statute and a model LCUP regulation.

This section should give you the tools needed to initiate LCUP in your state. Once in place, however, much work will remain to be done to ensure that implementation continues to realize the maximum benefits for your state's consumers. Later sections will show you how to participate in and evaluate the success of an LCUP program already in place.

rules checklist for consumers

Figure No. 1 illustrated how LCUP is composed of distinct procedural and substantive elements. Each element represents an aspect of the integrated resource planning that must be brought into an overall regulatory framework to ensure a comprehensive process. In addition to the components of LCUP illustrated on Figure I, there are five basis elements that must be incorporated into any procedural and substantive LCUP framework your organization attempts to enact.

planning process integration

Integration must take place at both the regulatory and utility plan level. Substantively, a utility LCUP must integrate a forecast of future demand and a comprehensive analysis of demand and supply resource options available to meet or alter the forecasted demand. Substantive integration is accomplished by screening options and ultimately selecting a total resource option package that meets projected demand at the least overall cost. The criteria most often utilized in determining "least-cost" are the minimization of the present worth of revenue requirements or minimization of average total bills.

On the procedural level, regulators must integrate utility rate making and construction permit processes with the LCUP process. Failure to integrate these procedures can entirely subvert the LCUP process. The approved LCUP plan will indicate the preferred path for resource acquisition. If, for example, the utility is allowed through a separate construction permit proceeding to pursue a generating resource that is different from those approved in the LCUP plan or that was not included in the LCUP plan, the LCUP process was a waste of time and effort. Other items which should be integrated into the procedural review of LCUP include avoided cost determinations, qualifying facility (QF) review and review of utility purchased power decisions.

utility responsibility

If integrated demand and supply planning is to be adopted by investor owned utilities, the expertise and data for planned development must originate from within. Encouraging this expertise increases the likelihood that utilities will stand behind their plans and utilize them internally. By placing primary responsibility for creating and coordinating the plan with the individual utilities, successful implementation is more likely. It should be noted that a number of states place part of the responsibility for creating the plan with state agencies. California, for example, assigns forecast responsibility with the state. Despite these seeming forays into government planning for the utilities, in most instances such state planning activities are only utilized as benchmarks for comparison to utility submitted resource plan elements.

specifying the methodology

Despite the requirement for utility plan creation, regulatory guidelines must be provided to utilities to establish sufficient methodological specifications to ensure the following:

- Sophisticated approaches are being employed;
- Plans are consistent over time, and
- The process is open to systematic review by interested parties.

The methods you select must not be so rigorous as to thwart innovation by the utility's resource planning staffs. Be flexible where appropriate, but also demand techniques which can adequately assess cost effectiveness at the design phase. Sophistication should not reach a level, however, that paralysis results before implementation of cost effective programs can be set in motion.

required implementation

The LCUP process is dependent on public review. The details of this review process and its procedural elements are set forth in the checklist discussed in the following sub-section. Both the plan and its implementation must be subject to this public review.

This is accomplished by requiring that the plan includes both the long-range determination of least-cost options, but also a short-term action plan that details the means by which the utility will acquire and implement resources between plan filings. The hearings must allow consideration of both the long-range plans and the near-term action plan.

plan enforcement

The regulatory process must provide for effective enforcement of LCUP decisions. As discussed earlier, integrating the LCUP process with other regulatory procedures will greatly facilitate the enforcement of the planning process. Utility managers should derive comfort from the likelihood that expenditures related to investments in LCUP approved projects will be recovered. Conversely, investments in projects not approved in the LCUP process should carry a corresponding increase in risk of disallowance by regulators. Effective enforcement and utility cooperation are thus fostered when traditional regulatory processes are integrated with the LCUP framework.

model statute

This section summarizes the basics of any LCUP statute. We have included a model statute in Appendix A as well. In the discussion below we've used one of the most succinct authorizing statutes in use -- that of Nevada -- as our launching point.

define concepts

The act should require that the utilities develop long range plans that include a demand forecast and an assessment of the least-cost way to meet that demand. You do not necessarily need to define "long range". Leave that to the discretion of the regulators and the implementing regulation. A definition of "least-cost " should be specified, however, either here or in provision five below.

The statute should specifically state that all potential resources including energy efficiency, renewable energy (solar and wind), co-generation, small power production, independent power production, purchased power, as well as utility-operated generation, must be evaluated consistently.

regulations required

The act should require that the public utilities commission develop regulations that specify the methodologies by which the utilities will forecast demand, assess resource options, and evaluate the least-cost combination of future resources. This provision should allow for flexibility, however.

utility responsibility for the plan

The act should mandate that the plan be created by the utility. By making the utility responsible for the initial planning effort, you foster the utility's support for the plan. Utility managers do not enjoy being associated with shoddy projects -- even when they are not something they necessarily wanted to do in the first place.

Several states including Illinois do allow regulators to develop their own plans in conjunction with the utility-prepared plan. The interface between the agency-developed plan and the utility's plan has yet to be established in Illinois, but it is presumed that the agency plan will provide a base case against which regulators can test the reasonableness of individual utility filings. In either case, a statute that allows third parties to submit an independent resource plan as a substitute for the utility's plan may jeopardize success of the entire planning process.

review process

The act should establish the basic procedures for submitting and reviewing utility-sponsored plans . The act should require that regulators hold public hearings on the plan, where they take evidence and listen to the testimony of intervenors.

evaluation criteria

The act should establish the criteria by which regulators evaluate the plan.

model rule

This section summarizes the major components of an LCUP regulation. We have also included a model rule in Appendix B. We would like to make it clear that the model rule is by no means all inclusive and may not be perfectly suited for your particular circumstance. In fact, you may determine that, like New York, you do not need a rule and that a case-by-case approach is more appropriate for your jurisdiction.

Also, we have not discussed one of the more significant emerging areas of interest in LCUP regulation. Competitive bidding -- the process by which the utility lets out for bid to third parties its resource acquisition needs -- is such a vast new field that thorough treatment would far exceed the scope of this manual. We have highlighted some competitive bidding issues in the section entitled "Emerging Issues".

commission authority and scope

The following items should be specifically included in your LCUP regulation:

- The state public utility commission's authority to require "least-cost" utility planning must be plainly set forth;

- The procedures under which the utility's plan will be evaluated should be specified. This should include the provision that a hearing will be required on all plan filings. The regulator's authority to summarily reject any filing that is not in compliance the regulations, but that such rejection is without prejudice permitting refiling.

definitions

The definitions section should establish a common understanding of the concepts embodied in the regulations -- especially such concepts as "least-cost" and "cost benefit test". Terms of art and phrases not usually used in traditional regulation should be defined as well.

filing requirements and procedure

Requirements for filing the plan, its format, and a description of its contents must be specified. The regulation should require that a plain language executive summary be filed with the plan so that the general public and regulators can quickly obtain an overview of the issues before plunging into the volumes of technical data

The regulation should also require the utility disclose in the filing its intent to restrict the discovery of any information supporting the plan. This disclosure should include a general description of the information the utility seeks to protect, the need for restricted access, and the terms under which the restricted information will be made available -- i.e. under a non-disclosure agreement, viewed but not copied, in a closed deposition or hearing, with sealed transcript, etc. This disclosure requirement is necessary to

ensure that discovery will proceed expeditiously and that critical data necessary for analysis will be provided to all parties in a timely manner.

load forecasting

The following items should be specifically set forth in the LCUP regulation:

- The forecasting period must be indicated. A range of ten to twenty years is common. Ten years of historical demand data (annual energy, peak demand and reserve requirements) is also needed to project the trend of load change over time;

- A range of forecasts -- base, high and low -- is required. The base forecast should represent the utility's best estimate of future events. The high and low forecasts are used to evaluate the sensitivity of different resource option scenarios to varying levels of future demand;

- Price-induced and government-sponsored demand reduction programs must be explicitly accounted for in the load forecast;

- To the extent possible, "end-use" forecasting should be required for residential and commercial forecasts. Our experience has shown that end-use forecasting is more accurate and thus favored over alternative forecasting methods. End-use data is also valuable for designing and implementing demand-side programs. End-use forecasting is expensive. So, you will need to regularly evaluate the costs of the methodology compared to the benefits of increased accuracy and the availability of end-use data for demand side planning, and

- Finally, the utility must be required to describe and justify the forecasting models, techniques and methodologies it adopts.

identifying resources

In this section, we set forth the data that the utility must be required to submit to show how demand- and supply-side resources meet existing and new loads. This is the heart of your LCUP regulation.

existing resources

All existing demand- and supply-side resources should be described and discussed in the plan. Ten years of actual historical data should be provided. The role that existing resources are expected to play in meeting future demand requirements should also be stated. For example, life extensions of existing generating units, conversions, plans to increase generating and transmission efficiencies should all be put forth in the plan and evaluated.

utility-sponsored demand-side programs

The full range of technically feasible demand-side resources must be assessed. Technical potential is determined without regard to economic limitations or market barriers, and is measured by the amount of capacity and energy savings realized by using the most efficient equipment and technology available.

Demand-side resources must be screened for economic viability using the "all ratepayers test" or Total Resource Cost (TRC) test. An option "passes" this cost-benefit test if the net present value of the program's benefits exceed the net present value of the program's costs. Be aware that there is a controversy as to what is the proper cost benefit test for screening demand-side programs. The majority of states use the all rate payers test or Total Resource Cost test or a derivative but there is a movement among utility managers and others to use the so-called "non-participants test" or Rate Impact test(RIM). We have included in the following section a more detailed description of the TRC test, the RIM test, and other demand-side screening measures.

Demand-side programs are designated as either full scale or pilot programs. Full scale programs should consider alternative designs for realizing optimum market penetration. Optimum market penetration is that level of market penetration which produces the greatest ratepayer benefit for the least unit cost.

Programs should be designed to minimize cream skimming and free riders. Cream skimming occurs when only *some* cost-effective demand-side measures are installed on a customer's premises. It then becomes economically impractical to return to that facility later to install the next incremental demand-side resource. A free rider is a utility customer who would have installed a demand-side measure without an incentive. Utility managers argue that most demand-side programs are burdened with free riders, but this occurrence can be minimized. Rapid implementation of program activities and pre-program surveys identify free riders up front, making it possible for you to adjust your program design and minimize the cost burden of free riders.

Full program designs should consider different types of utility actions so that optimum market penetration (defined above), is achieved. A laundry list of utility actions might include financial incentives like rebates, bill credits, shared savings, low and no interest loans, and third party payments; direct installation of measures at low or no cost to the consumer; information and education programs; and building and efficiency requirements hook-up fees.

The plan should include detailed estimates of program costs.

The effect on energy consumption and peak demand of each program designed and developed is estimated by end-use or program as appropriate.

The external program costs and benefits are identified, described, and quantified. Consideration must be given to ratepayer equity as measured through the rate impact test. Externalities include environmental impacts, public health and safety effects, and economic benefits to the state.

The risks and uncertainties surrounding each program design and associated data and estimates should be assessed.

purchases from other utilities

The plan must identify and discuss all power import and export options available to meet all or part of the forecasted demand

new utility-sponsored generation and transmission

The plan should identify and fully describe all new utility-sponsored supply-side options. An initial screening of all supply-side options should be performed to eliminate those options that are not cost-effective or that pose unacceptable risks to system reliability.

plan assumption and modeling information

The plan must fully describe all assumptions and models used. The utility should be required to employ the following minimum set of models or methods in their analysis:

- A screening model;
- A production costing and reliability model;
- A capacity-expansion model consistent with the production costing and reliability model;
- A risk analysis model;
- A corporate financial model, and
- A method for integrating the previous models.

integrating the plan

The utility now integrates the demand-side resource options with the supply-side resource options in order to derive the "least-cost" resource plan. Your LCUP regulation should address these items.

Revenue requirement is the primary criterion for integration. Other important considerations include the qualitative and quantitative impacts on the environment and society. Quantifying these effects is difficult, but several jurisdictions are investigating ways to measure them.

The utility must evaluate the multiple combinations of resources and determine which minimizes the present worth of revenue requirement (PWRR) over the planning period. This criteria does not apply to that part of demand-side investments paid for by utility customers or participants. Consideration should be given to financial planning, regulatory constraints, competitive bidding, and efficiency incentives. Sensitivities of all major assumptions and estimates used in the plan should be conducted.

The utility should establish a resource block of at least five percent of its current peak load to be used in determining long-run capacity and energy rates for qualifying facilities. These avoided cost should be determined utilizing a methodology that reflects the least-cost alternatives approved in the resource plan. Marginal capacity costs should reflect the total costs of plant additions over the planning horizon. Marginal energy costs should be determined using a production costing model that calculates avoided fuel, operation and maintenance (O&M) costs over time. Long-run energy and capacity rates should be determined prospectively and should be based on the utility's least-cost resource plan.

cost recovery

Cost recovery is the single most important and controversial aspect of LCUP regulation. Our experience with LCUP has demonstrated **consistently** that utility managers do not discuss or consider LCUP seriously until adequate cost recovery is on the table. It must be addressed by you up front. Consumer advocates are often reluctant to offer adequate cost recovery until utilities capitulate to an LCUP process. This "chicken or the egg" dilemma should be avoided and cost recovery addressed at the onset of developing regulations. Advocates and consumer groups should utilize the leverage afforded them by utility interest in adequate cost recovery to secure satisfactory commitments on issues important to LCUP success such as the use of the Total Resource Cost test for screening demand-side resources and the initiation of parallel pilot demand-side programs to establish utility demand-side deployment mechanisms.

The specific form of cost recovery, and what may be considered as "adequate", is also a controversial topic currently subject to much debate. Commissioner Stephen Wiel of Nevada, Chairman of the NARUC Energy Conservation Committee has published a recent paper on this issue which has been reprinted with his permission in Appendix D. The subject of cost recovery is treated more extensively in Section VI. of this manual. For purposes of a model regulation, we have included a "plain vanilla" cost recovery mechanism that we believe to be the base minimum an LCUP advocate group should offer to a utility for discussion purposes. It provides for balancing account recovery for start-up planning costs and pilot DSM programs with ratebasing or expensing and amortization of expenses for full scale DSM programs.

action plan

The plan should include a program of implementation of the "least-cost" resource plan. The action plan should detail the utility's work plan and budget for implementing the demand- and supply-side resources identified in the plan during the interim period between plan filings. The utility should also identify all computer models, data, equipment, personnel, and facilities which it intends to use or acquire for developing its next resource plan.

working groups

Working groups comprised of utility, commission staff and consumer advocate representatives should meet between plan filings to keep abreast of the utility's progress in implementing the approved least-cost utility plan.

amending the plan

The regulation should prescribe the conditions under which a utility will be allowed amend its plan.

final thoughts on initiating an LCUP framework

The keys to successfully initiating an LCUP regulatory framework are consistency and attention to your goals. Certain issues like assuring profitability and cost recovery must be settled at the beginning of the process. But if you allow your organization to be drawn into a long battle over the Rate Impact test, for example, it is easy to loose sight of your primary goal -- getting LCUP up and running. Battles over these sub-issues may be better urged once the framework is in place. You may need to retreat from early battles in order to win the LCUP war.

V. Setting the Process and Beginning Play

introduction

This section of the manual is designed to assist consumer groups in the few states that have a full featured LCUP process in place. It describes the procedural and substantive aspects of the process that are needed to maximize benefits for consumers in your state.

LCUP procedure
procedure checklist for consumers

Whether developing, implementing, or fine-tuning the LCUP regulatory framework, be aware of several procedural issues that require your attention.

frequency of plan filings

Resource plan filings need not be more than once every two or three years. More frequent filings can stall the process before it really gets started. The same people who put the plan together are also in charge of implementation. If plans are filed more often than once every two years, utility personnel get stuck on a planning treadmill and never get to implementation.

In some instances a filing every two years may prove to be too frequent. In Nevada, for example, the two year filing timetable did not allow adequate time in the interim for plan implementation. Lawmakers in Nevada amended the LCUP statute to extend the filing requirement to three years. If you have more than two utilities filing resource plans, the three year cycle is even more preferable. Stagger your filings as well so that one utility's plan does not overlap with the filing of another utility.

length of proceedings

Assuming fair disclosure by utilities, a resource plan proceeding should take no more than six months to complete, with sufficient time and attention devoted to each of the following procedural steps:

- Plan and utility's prefiled testimony are filed;
- Commission prehearing at which time discovery, testimony and hearing schedule are established, and issues identified by the parties;
- Intervenor discovery requires at least two rounds with ten days to two weeks between requests and responses. As an intervenor, you will need at least two to three weeks to review the filing and formulate your discovery questions;
- Intervenor direct testimony is filed two weeks after the last discovery responses are delivered on intervenors;

- Utility questions on intervenor direct testimony should be delivered within one week following the testimony filing date. It will take at least one week to provide responses, more if you are relying on out-of-town experts;

- A final commission pre-hearing may be necessary to resolve discovery disputes or other procedural matters;

- Hearings on utility plan filing and intervenor direct testimony should be limited to one or two weeks;

- Utility rebuttal testimony should be written and filed at the conclusion of the hearing on direct testimony. Intervenors should be afforded a minimum of three days to review rebuttal;

- Rebuttal hearing can take a day or a week, depending on the issues and the strength of the intervenors' direct case;

- Post hearing briefs should be filed within a reasonable period, no more than 30 days after the last hearing transcript is made available, and

- Commission deliberation can take one month or more with a written order following immediately.

The above schedule and procedural elements are described for illustrative purposes. Your state's procedural requirements may differ.

prehearing discovery and establishing intervenor rights

A well defined discovery process that clearly specifies all parties' discovery rights will smooth the way for resource planning review. If existing regulations adequately provide for discovery and discovery rights, incorporate them by reference. If existing regulations on discovery are weak, your LCUP regulation will need to be more specific than the general rule. In either case, your LCUP process must also include the following discovery provisions.

intervenors should be afforded the opportunity to make formal data requests between filings if informal workshop discussions prove insufficient. These requests should be treated the same as discovery requests sent to the utility after a plan filing

The utility must be required by regulation to file or make available with the resource plan all documents that support the filing. Such documents include workpapers, reports, and the input and output reports of all computer runs and system dispatching models.

workshops- help before the hearing

Because a least-cost planning process provides the opportunity to explore a utility's resource planning and acquisition process in a level of detail and complexity not afforded in other rate and regulatory forums, workshops can be an invaluable opportunity for the various parties to:

- Discuss a variety of resource planning issues in a nonadversarial, informal atmosphere;

- Gain more information and understanding as to the characteristics of the service territory and utility operation;

- Establish requests to the utility on the direction and type of work and analyses for components of the resource plan;

- Reach consensus on key data and variables used in the analyses prior to commencement of, or finalization of work and results;

- Establish positions on key issues that may be controversial in the hearing process;

- Provide the opportunity to reach stipulated agreements prior to hearing on components of the resource plan;

- Review the status of and provide direction on the development and implementation of demand- and supply-side resources, and

- Review expenditures and provide input on planning budgets.

Before starting a workshop process, parties will need to decide whether or not the workshop minutes and information should be part of formal resource plan filing and, thus, the case record, or remain informal. If the workshop process is formalized, then parties can be held accountable to positions and actions established in the workshops and positions can be developed in workshops and carried over to hearings. However, a formalized workshop process can also stifle the free flow of information and ideas if parties think it might be used against them in hearings.

Workshops, as discussed earlier, can be extremely effective in narrowing issues for resolution at hearing. Workshops can also present traps for the unwary, however. Utilities may present a great deal of information in the workshop process. Unless there is a clear understanding of the purpose of such presentation, misunderstandings can be fatal at hearing. For example, if the information is presented for discussion, all parties should agree as

to the meaning and consequences of no comment by your group. Does no comment indicate approval or simply lack of time and current ability for thorough analysis and critiques. These issues should be made clear at the onset of the workshop process. Otherwise you may be faced at hearing with utility arguments that your group has already reviewed **and approved** aspects of the least-coast plan which you are now challenging.

The flip side of the above dilemma is a workshop process where there is all take and no give by the advocate group participants. Utilities tend to view such situations as merely the provision of early discovery with no benefits to them. You should not only seek information in the workshop process, but you must also demonstrate a willingness to compromise and narrow issues where possible. The workshop process must be a two way street for it to be successful.

Workshops may be utilized not only for prehearing plan review but also for interim development and negotiation of demand-side program design. Such a workshop process, as discussed above, was first initiated in New England as the "collaborative design process". This procedure provided for utilities in the region to pay for independent experts chosen by consumer groups participating in informal workshops. In those workshops, demand-side programs and utility planning issues were negotiated. In order for this type of collaborative process to succeed and be meaningful, you should insist on specific deadlines within the workshop process. There must also be established "cut-out" points in the process where everyone returns to the regulatory body to report progress and seek resolution of disputed issues.

organization and budget -- the limits

As has been discussed throughout this manual, LCUP represents a significant departure from traditional forms of regulatory review. The level and detail of oversight of utility planning and acquisition decisions is greatly expanded. If an advocate's office is to play a strong role in the LCUP process, it will require not only a reevaluation and reorganization of agency goals and priorities, but also a reallocation of staff and funds. This section will discuss some of the key organizational and budget issues that an advocate's office will face in getting started in a least-cost planning process.

For consumer groups not associated with a state funded advocates' office, other sources of effective intervenor funding should be explored. Some states, such as California, have provided intervenor funding to groups that have demonstrated meaningful contributions to the regulatory process. These options should be pursued with your state regulatory commission. Other options include funding of a collaborative design process as discussed above, where utilities pay intervenor experts to help design demand-side programs and resolve planning issues.

staff and consultant needs

Under this example of two utilities filing plans on a staggered basis, an advocate group will require a minimum of one full time equivalent employee for LCUP oversight. In addition, you will need a consulting budget of a minimum of $50,000 per plan filing to provide adequate input into the process and participate meaningfully at hearing.

The discipline required for your in-house employee can be varied, but should be well grounded in either economics or engineering. Outside consultants may be required in either of these areas or could require expertise in accounting, depending upon the issues in controversy in the case. Consultants are usually more cost effective than full time staff, because issues can be diverse from case to case and may not reoccur in subsequent proceedings. One case may pivot on transmission capacity and purchase power economics where the next may be solely dependent on demand-side issues.

The central full time staffer is needed to coordinate and focus issues, but consultants can best present the pinpoint testimony required to win a case.

Some cases present numerous critical issues. Such situations require personal and resource allocation to adequately address the key issues of the case. In such instances, sharing resources with other compatible intervenors such as the commission staff may be necessary.

minimum players: The number of utilities involved and timing of resource plan filings will influence the amount of time and resources an advocate's office will need to commit to develop effective participation in a LCUP process. For purposes of this discussion, a hypothetical example will be developed drawn from actual experience in Nevada which assumes a state has two utilities that are required to file resource plans on a three year, staggered basis.

VI. LCUP Planning Procedure

The following section describes and discusses the critical substantiative aspects of least-cost planning with which you must be familiar to participate in the process. It is an introduction and not a primer. More detailed information can be found in Volume 2 of the NARUC Handbook on Least Cost Planning. (See:"Least-Cost Utility Planning: A Handbook for Public Utility Commissioners; Volume 2; The Demand Side: Conceptual and Methodological Issues".)

As reflected in Figure No.1, LCUP is both a regulatory framework and utility planning procedure. Defined and described below are the key substantiative elements of a utility plan and following is more discussion of those elements and significant economic issues of the planning process. This material should give you the basic information necessary to analyze a filed utility plan.

strategic load shape objectives

"Strategic load shape objectives" refers to the evaluation of changes in utility operating and capital costs from the shaping or modification of utility load. Through demand-side management programs demand can be modified on an annual, seasonal, and daily basis. The Electric Power Research Institute (EPRI) has defined six strategic load shape objectives: Peak Clipping -- the reduction of system peak loads; Valley Filling -- the building of off-peak loads; Load Shifting -- the shifting of load from on-peak to off-peak; Strategic Conservation -- the reduction in sales and change in pattern of use; Strategic Load Growth -- the general increase in sales beyond valley filling; and Flexible Load Shape -- a planning constraint related to the concept of reliability. Appendix E provides a description of the EPRI strategic load shape objectives.

data acquisition program

The purpose of a data acquisition program is to gather information and data the way electricity is used on an end use basis. End use data can be utilized in both load forecasting and demand side management. A data acquisition program generally has three major data components: customer count and type data; appliance and end use saturations, and usage and demand data.

load forecast

Load forecasting is the projection of the demand for electricity over some future period of time. Load forecasts can be short term (one year or less), or long term (generally up to twenty years), and can include sensitivities that establish the upper and lower limits of predicted demand growth. Energy efficiency is considered on both a gross and net basis. A gross load forecast considers price induced energy efficiency; i. e. efficiency resulting from laws, regulations and governmental programs, and efficiency from existing utility sponsored programs. A net load forecast considers the effect on system load potential from utility sponsored programs.

Forecasting methods range in sophistication from trend extrapolation to econometrics to costly and detailed end-use metering. End-use data is useful not only in the production of accurate forecasts, but in the design and implementation of demand-side resources. Although end-use techniques are desirable, excessive metering costs can result in expensive data which does not provide commensurate benefits. A balance should be struck between collecting costly end-use data and achieving the next increment of accuracy.

demand side resources

Demand side resources or demand side management (DSM) refers to the utility's ability to meet the demand for electricity through efficiency increases in the production, distribution, or use of energy which result in reduction in the consumption of electric power. The assessment of demand side resource generally involves three components: determination of technical feasibility, cost-effectiveness, and market penetration.

supply side resources

Supply side resources refers to the utility's ability to meet the demand for electricity through resources such as generation facilities, transmission and distribution facilities, purchases of power from other utilities, and purchases of power from small power and cogeneration facilities. The analysis of supply side resources generally involves five components: defining the options, quantifying the inputs, quantifying system operation criteria, screening of resource combinations, and decision analysis.

integration

The integration component involves the bringing together of the demand- and supply-side resources into one process where varying combinations of demand and supply side options are analyzed. The basic technique is one of simulation of utility system operation in future years and calculation of system operating and capital costs over a long term planning horizon.

sensitivity and risk analyses

A component of the integration process, sensitivity and risk analysis, involves the consideration and quantification of uncertainty in the resource evaluation process. Major factors of uncertainty considered can include: differing estimates of the capital and operating cost; availability, and timing, of various supply side resources; differing levels of future demand for electricity; and differing costs and amounts of future demand side resources. Often sensitivity and risk analyses will employ probabilistic decision theory.

least-cost plan

Refers to the integrated least-cost resource plan filed by the utilities pursuant to state public utility commission regulations.

action plan

A component of the least-cost plan filing, the action plan specifies the schedule for implementation and financial budget of the demand- and supply-side resources in the order of least-cost during the interim period between resource plan filings.

substantive checklist for consumers

Three topics have been highlighted for discussion in this section: how to quantify least-cost, how to ensure a consistent economic evaluation of demand and supply side resources, and utility cost recovery and other financial incentives.

how to quantify "least-cost"

In Section II, "Introduction to LCUP", least-cost utility planning was described as both a regulatory framework and utility planning procedure in which there is a consistent evaluation and integration of demand- and supply-side resources in a manner that results in the provision of adequate energy services at the **least possible cost to utility ratepayers.** This establishes economic efficiency as the least-cost criterion with nothing said as to how economic efficiency is to be defined and quantified. Differing approaches to the quantification of economic efficiency or least-cost can be summarized into two competing camps: provision of energy services at the lowest overall cost, and the provision of electricity at the lowest possible rates.

Before these approaches can be debated, understanding of the the concept of economic efficiency should be established. In general terms, economic efficiency simply refers to the use of resources so as to realize the greatest output per unit of input. Least-cost then simply becomes another way of stating economic efficiency. Economic efficiency is achieved when resources (land, labor, and capital) are allocated in an "optimal" or "greatest output per unit of input" manner. The higher the ratio between input and output, the higher the level of achieved economic efficiency. When the principle is not adhered to, there occurs a suboptimal, or economically inefficient, allocation of resources. In the case of electric utility resource acquisition, economic efficiency necessitates evaluating and implementing resources so as to

provide the greatest amount of supply (units of electricity, KW or KWH) for the least cost (dollars per KW or KWH).

The first interpretation of economic efficiency or least-cost -- provision of energy services at the lowest overall cost -- is measured through minimization of utility revenue requirement. Total customer utility bill, not the per unit energy rate, becomes the determining least-cost criterion. For example, an efficiency measure which happens to increase the unit cost of providing energy would still be consistent with least-cost planning if the increased efficiency reduced the need for energy as to more than offset the increase in unit cost. For example, installation of a high efficiency air conditioner which provides equivalent cooling using half the electricity of an existing air conditioner would be least-cost as long as the savings in consumption are not offset by higher total costs. The provision of energy services at the lowest overall cost as measured through minimization of utility revenue requirement interprets economic efficiency to be the use of resources as to realize the greatest output per unit of input.

The second interpretation, the provision of electricity at the lowest possible rates, argues that economic efficiency is achieved in a least-cost planning framework through the minimization of rates rather than revenues. Selection of utility resource plan "A" with a higher total revenue requirement than plan "B" would be justified if plan "A" resulted in a lower per unit energy rate than plan "B". For example, installation of less efficient air conditioning units that caused a higher level of electricity demand would be deemed "least-cost" even though they contributed to the acquisition of new supply-side resources and an increased utility revenue requirement. In this scenario, total utility revenue requirement would be spread or allocated across an increased sales base, resulting in a lower per unit energy cost. However, total customer bills would be higher because more units of energy would be required to operate the air conditioner and provide the desired level of cooling comfort.

Thus, interpreting least-cost as lowest rates violates the principle of economic efficiency because the greatest amount of effective or useful output is not realized with the least amount of input. More kilowatts and kilowatt hours (input), are required to meet a customer's energy end use needs (output), for applications such as machinery operations, space conditioning, and lighting.

This manual establishes in the Model Rule that minimization of utility revenue requirement should be the fundamental criterion by which to evaluate individual resources and analyze multiple combinations of potential resources.

Minimization of utility revenue requirement invites consideration of the revenue stream associated with a utility's load and resource needs over a long term planning horizon. Because the value of a dollar is not fixed or constant over time, a projected revenue requirement stream must be discounted in order to find the monetary value in today's dollars of a future payment or series of payments over time. This process, called present value or present worth analysis, is used in least-cost planning to evaluate the economic efficiency of various utility expansion plans. Generation expansion models are employed extensively in the utility industry as a least-cost planning and evaluation tool. Through a series of complex mathematical techniques, generation expansion models will produce an "optimal" schedule for the operation of existing resources and the addition of new resources. Minimization of utility revenue requirement is the operative criterion.

how to ensure consistent economic evaluation of demand- and supply-side resources.

In the previous section, it was established that one of the components of "least-cost" as the principal criterion for evaluating energy demand and supply resources is economic efficiency through minimization of total costs. There is a second equally important and interrelated component to least-cost: demand- and supply-side resource options should be evaluated by the same economic criteria. This section will consider three issues that affect whether demand- and supply-side resources are evaluated in a consistent manner. They are: the role of short run and long run marginal cost methodologies in cost- benefit analysis, establishing the appropriate use and interpretation of the various cost-benefit tests, and the concept of revenue shortfall in cost-benefit analysis.

the role of marginal cost methodologies in cost-benefit analysis.

As noted, the principle of least-cost requires use of a quantitative methodology that examines the economic value of demand and supply resources so as to determine economic efficiency or "the greatest output per unit of input." Methodology requirements include the ability to reflect not only costs in total, but also the benefits in total associated with the resource options. While the discussion has considered the quantification of total costs, no attention has yet been given to the interpretation and measurement of total benefits.

When considering supply-side resources, utility benefits refer to the amount of demand and energy (KW and KWH) produced over the life of the resource. For demand-side resources, utility benefits refer to the value or cost of demand and energy avoided or saved over the life of the resource. Establishing the benefits associated with supply-side resources is fairly straightforward -- they simply represent the amount of electricity provided. What constitutes the value of avoided demand and energy from demand-side

resources is generally considered more complex and involves application of marginal cost theory.

In utility economic theory, marginal or incremental values represent not only the the costs associated with the new or next units of demand- and supply-side resources, but total benefits as well. Marginal costs and benefits can be quantified on either a short run or long run basis. In the case of electricity, the distinction between the short run and long run centers on whether the primary factors of production -- the generation and transmission facilities (often called the capacity cost component) are fixed or allowed to vary. In evaluating utility short run marginal costs, capacity costs are considered fixed and measured as utility shortage cost during periods of capacity shortages or utility surplus cost during periods of capacity excess. The cost of "pure capacity", often reflected as the capital cost associated with a combustion turbine generation facility, is used to characterize shortage cost. The cost of retiring a utility's excess generating facility(ies) is often used to represent excess capacity cost. The shortage or surplus capacity cost, coupled with estimated marginal fuel and operation and maintenance expenses (i.e. system lambdas), represents the utility's variable costs (often called the energy cost component).

Long run marginal cost methodologies consider the costs associated with a utility's projected future mix of resources, with the intent to reflect the capacity and energy costs of incremental or new resources. In long run costing analysis, capacity and energy costs are allowed to change or vary over time. The principle of economic efficiency is approximated in long run marginal costing by considering what mix of current and future resources optimizes economic efficiency by providing the "greatest output per unit of input".

In demand-side resource cost-benefit analysis, the benefit or value of avoided or saved demand and energy is most often quantified through a short run marginal costing methodology. This can, in many instances, result in an undervaluation of the potential benefit of demand side resources, particularly when various measures are considered together as a larger block of resources. Demand side resources will often allow the utility to avoid the construction and operation costs associated with more costly supply-side resource options than those reflected in short run marginal cost analysis.

establishing the appropriate use and interpretation of cost-benefit tests

In evaluating demand side resources, there are a variety of cost-benefit tests that can be applied. While the various tests all attempt to quantify the costs and benefits of a particular demand side resource option, they differ in perspectives. There are four perspectives that are most often evaluated: the costs and benefits of a particular demand side resource (1) in total, the Total Resource Cost test, "TRC"; (2) to the utility, the Utility Cost test, (3) to the participating customer, the Participants test; and, (4) the impact on customer bills or rates from a particular measure, the Rate Impact test or "RIM", (previously called the non-participants test). Over the last several years, a controversy has existed over the appropriate use and interpretation of the various cost-benefit tests. In particular, some have argued that RIM should be used to determine the economic efficiency of demand-side resources.

TRC vs. RIM

Of the four tests listed, advocates and consumer groups should fight to ensure that the TRC test is established in your LCUP regulations as the primary determinate of demand-side program cost effectiveness. This must be a high priority if a full range of demand-side strategies is to be available in your jurisdiction. If the RIM test is utilized for demand-side program screening, many fewer strategies will be available for implementation. This problem is inherent in the interpretation of the results of the RIM test as discussed below.

The issue of TRC versus RIM is one that advocates should be able to win handily. Every jurisdiction that has examined this issue has rejected the RIM test as a primary economic screen for demand-side investment. (See for example: 1986 Northwest Plan, op. cit.,at 3-7. Wisconsin Public Service Commission, Findings of Fact, Conclusions of Law and Order in Docket 05-EP-4, 5 August 1986, at pp. 8-9. Vermont utilities are prohibited from using the RIM test to reject efficiency investments in the Public Service Board's Recommended Decision in Docket 5270, pp. III 85-88. The District of Columbia Public Service Commission rejected the RIM test as a primary screen on demand-side investment in its March 1988 order in D.C. PSC F.C. 834 (Phase II). So did the Idaho Commission in Order No. 22299, Case No.U-1500-165 (Jan. 27, 1989). The Nevada Public Service Commission in its October 1986 decision in Docket 86-701 regarding the resource planning of Sierra Pacific Power: See also the New York PSC in its July 26, 1988 decision in Opinion No. 88-20 in Case 29409, pp. 23-49. Wisconsin re-affirmed its rejection of the no-losers test in its fifth Advance Plan decision in April 1989 in Docket 05-EP-5.)

total resource cost test

The TRC test attempts to quantify the principle of economic efficiency when evaluating demand side resources. TRC compares the total benefits of the demand side resource to the total costs of the demand side resource. If benefits exceed costs, the resource is deemed cost-effective. The costs calculated in this test are the total costs of the demand side resource, regardless of the allocation between the utility and participating customer. The benefits calculated in this test are the total benefits from the demand side resource, defined as the utility's cost of "saved" demand and energy in periods when load has been reduced and the increase in revenues for any periods in which load has been increased.

A variation of TRC is the Societal test which attempts to expand the benefits and costs considered to include the effects of externalities such as economic development and environmental considerations. This expansion of the variables to be considered has raised considerable controversy. Precise measurement of the environmental and indirect social benefits of demand-side resource implementation has not been achieved. Work is currently in progress in Wisconsin and other jurisdictions to address this issue.

The strength of TRC is its ability to analyze the principle of economic efficiency by considering all costs and all benefits of a demand side resource, regardless of the distribution of the costs and benefits between the utility, participating, and non participating customers.

The results of TRC can be presented as either net present value, cost-benefit ratio, or levelized cost. The net present value is the primary test.

the utility cost test

The Utility Cost test attempts to quantify the costs and benefits of demand side resources to the utility. The costs calculated in this test are the total costs of the demand side resource to the utility only. The benefits calculated in this test are the same as for the Total Resource Cost test; the utility's cost of "saved" demand and energy in periods when load has been reduced and the increase in revenues for any periods in which load has been increased.

Because the Utility Cost test does not include customer direct costs, it allows for comparison with similarly defined supply side projects. The Utility Cost test, coupled with the results of the Participant's test, can help resource planners assess program designs that would allocate differing amounts of demand side resource costs between the utility and participating customers. For example, the Utility Cost test can help determine the minimum

amount of costs the utility can absorb and to still produce a positive cost-benefit result.

As with the Total Resource Cost test, the results of the Utility Cost test can be presented as either net present value, cost-benefit ratio, or levelized cost. The net present value is the primary test.

the participant's test

The Participant's test attempts to quantify the costs and benefits of demand side resources to the participating customer. The costs and benefits calculated in this test are the total costs and benefits of the demand side resource to the participating customer. The costs calculated in this test are the total costs incurred by a customer from participating in the program plus any increases in the customer's utility bill(s). The benefits calculated in this test are the reduction in participating customer utility bills, any incentives paid by the utility, and any federal, state or local tax credits received.

Because the Participant's test looks only at the costs and benefits to the participating customer, this test provides information as to the benefit or desirability of the program to customers.

The results of the Participant test can be presented as either net present value for the total program, discounted payback, cost-benefit ratio, or present value per average participant. The first three represent the primary means of presenting the test results.

the rate impact test

The Rate Impact test (RIM) attempts to quantify the impact on unit rates from the implementation of demand side resources. If a demand side resource causes an increase in the per unit rate for electricity then the demand side resource "fails" RIM. Per unit rates can increase in a situation where the demand side resource lowers the demand for electricity and utility revenue, and increases utility total costs. The costs calculated in this test are the total costs to the utility of the demand side resource, including decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The benefits calculated in this test are the total benefit from the demand side resource, defined as the utility's cost of "saved" demand and energy in periods when load has been reduced and the increase in revenues for any periods in which load has been increased.

RIM is useful in evaluating the direction and magnitude of the expected change in customer bills or rate levels. Some have argued that if the results of the RIM test indicate that a demand side resource(s) will cause an increase in the total cost for electricity, then the resource(s) are not economically efficient and should be rejected. There are problems with trying to interpret RIM in this manner. First, whether or not a resource would cause an

increase in total utility bills has nothing to do with the principle of economic efficiency. Achieving the "greatest output per unit of input" may in fact result in higher utility bills. The focus should be on selecting resources that can provide the most energy (output) for the least-cost (input). Second, if this criterion were to be applied equally to the evaluation of supply side resources, no power plants or transmission lines would ever be constructed since they result in an increase in total utility costs and customer bills.

the concept of revenue shortfall in cost-benefit analysis

Some have argued that TRC and the Utility Cost test should consider in the cost portion of the equation the "cost" of revenue "lost" from the "saved" energy or reduced sales. Applying this cost element to the economic evaluation of demand-side resources may not always be appropriate for the following reasons. First, it is important to remember that short run marginal costs are most often used to quantify the benefits associated with demand-side resources. In the short run, most utility costs are variable or avoidable. Thus, if a demand side resource results in a reduced demand for electricity, then electricity production will be adjusted resulting in lower costs and lower required revenue to the utility. Little or no revenue shortfall occurs.

Second, the revenue shortfall calculation offered does not take into account the dynamic reality and growth of the utility system. Rather, the analysis is conducted in a vacuum that does not recognize and offset new customers and growth in sales with "saved" energy.

Further, if demand- and supply-side resources are to be compared on the same footing, the revenue shortfall argument should be applied to supply side resources as well. Revenue shortfall can be computed for supply-side options if the likely price elasticity effect on sales and revenue caused by placing substantial and expensive supply side resources into rate base are considered. With supply-side resources the utility recognizes that even though existing customers may respond to the rate increase from the resource addition and reduce their consumption, the growing customer base compensates for this occurrence by allowing the greater revenue requirement to be spread across increased sales.

cost recovery for utilities and other financial incentives

Before the advent of LCUP, utility managers committed only minimal capital to energy efficiency programs. There was not much concern about mechanisms to recover demand-side resource expenditures or the effect of successful energy efficiency programs on utility sales, revenues, and profits. Increased interest and involvement of utilities and the regulatory community in least-cost planning has spurred a dialogue on whether or not traditional regulatory practices act to encourage or discourage utility investments in energy efficiency. This section will consider how traditional regulation can potentially hamper energy efficiency investments and some of the various modifications and reforms being considered.

Utility regulation in general establishes rates for a defined period of time to cover the utility's costs including a return on equity. Return is calculated as a percentage of the allowed invested capital, called the rate base. Rates thus include an element for fixed costs, such as bond payments, and for variable costs, such as fuel costs, as well as a margin over what are typically thought of as costs to cover return on equity. Return on equity is the swing element, the amount that is left over after all the utility's other costs are paid out of the revenue received. A utility is not guaranteed, but rather given the opportunity to earn the established rate of return. The approved costs, termed the revenue requirements, are divided by the sales to get the rates. Provisions are generally made through rate adjustment clauses for cost variations, such as fuel costs, considered beyond the utility's control.

Traditional regulatory practices as outlined above are generally considered a disincentive to utility investment in demand side resources because successful energy efficiency programs: (1) reduce sales and thus reduce revenues, and (2) do not contribute to invested capital or rate base. Events that reduce sales can reduce the margin between a utility's total revenues and total costs, thereby reducing the profit available to utility stockholders. While this "lost revenue" can be offset in subsequent rate cases, the shortfall in revenue is usually lost forever since rates are not set to recoup past deficiencies of allowed return or refund past excess returns. While there are a variety of factors that contribute to sales attrition and a utility's inability to earn their allowed rate of return (e.g. weather fluctuations, price elasticity, population fluctuations, customer bypass, inefficient operations, imprudent investments), reduction in sales from successful energy efficiency investments is currently being targeted by utilities as a major factor in the "lost revenue" equation. Events that do not contribute to a utility's invested capital or rate base can also reduce the profit available to utility stockholders because only capital investments included in the rate base receive a return. Resources such as energy efficiency programs as well as contracted power

purchases are generally treated as annual expenses in ratemaking. Thus, traditional regulatory practices are increasingly being viewed as a series of incentives that encourage utilities to pursue "grow and build" strategies.

The National Association of Regulatory Utility Commissioners' (NARUC) Energy Conservation Committee has recently held a series of open discussions on cost recovery and financial incentives for utility investments in energy efficiency. The following quote from one of the Committee's working papers summarizes the issues and goals being analyzed:

> "The basic goal here is simple; to ensure that the regulatory system makes it profitable for a utility to utilize a 2 cent conservation investment rather than a 3 cent supply option, a 5 cent supply option rather than a 6 cent conservation or supply option, and to more closely align the private economic interest of public utilities with the broad public interest of securing the least-cost energy."

At its 1988 summer meetings, the NARUC Energy Conservation Committee formulated a position statement entitled "The Loss of Profits as an Obstacle to Least-Cost Planning" (See Appendix D) which establishes that a utility's least-cost plan should also be its most profitable plan. The position statement recommends state commissions adopt appropriate mechanisms to compensate utilities for earnings attrition from successful energy efficiency programs.

To meet the goals of the LCUP process, alternative regulatory treatments should meet three criteria. Regulatory treatment should:

- Give the utility adequate incentives to treat demand-side and supply-side programs on a comparable basis,

- Encourage the utility to make demand-side investments which maximize economic efficiency, and

- Provide adequate ratepayer safeguards consistent with the LCUP process.

One of the first steps taken by various state commissions to remove the perceived financial disincentives to utility investment in demand-side resources is to allow capitalization of energy efficiency expenditures. Another regulatory action involves adjustment of a utility's rate of return. Variations include adjustments on either the entire rate base, or only the capitalized energy efficiency expenditures as a reward for implementation of successful energy efficiency programs. By itself, rate basing is a

questionable incentive to allow demand-side resources to fairly compete with supply-side investments. All other factors being equal, a utility's rate of return will be greater from investments in supply-side resources which generally have a higher cost per kilowatt. An additional concern with rate basing and an adjusted rate of return is that "gold plating" can occur without specific performance standards to determine the level of savings achieved from the energy efficiency investment. Also, these approaches may discourage utilities from implementing capital free energy efficiency programs such as time of use rates or education programs. Further, these approaches do not address the sales attrition problem.

There are several ideas on how to decouple sales and profit. The most prominent one being discussed is California's Electric Revenue Adjustment Mechanism (ERAM). The ERAM is a balancing account used to adjust rates to eliminate "lost revenues." Rates are periodically adjusted to make net revenues insensitive to sales volume. The approach reduces the fluctuation in sales from changing weather and economic conditions and successful energy efficiency programs. Sales and revenues are adjusted to those established in the previous rate case so that if sales increase beyond the forecast revenues and profits are not increased, and vice versa. Under the ERAM, California utilities have no incentive to increase sales above its forecasted level because rates will be adjusted downward if sales increase, and be adjusted upward if sales decrease, to maintain a relatively constant utility rate of return. While ERAM does reduce the linkage between sales and revenues it provides no increased incentive to make energy efficiency investments. One of the criticisms of ERAM is that it may also reduce the incentive to improve system operations. Revenue requirement becomes guaranteed regardless of the utility's operational efficiency and productivity.

A second approach, still in the conceptual,stage is the "Moskovitz Proposal", developed by David Moskovitz, a recent commissioner with the Maine Commission. The Moskovitz Proposal would establish a competitive league among utilities with comparable service territories, numbers and types of customers, fuel mixes, etc. Utilities would be evaluated in relationship to one another with rewards given to those that achieve the greatest efficiency improvements. The approach would link a utility's return on equity to changes in its average customer bills relative to the changes in the average customer bills of the reference set. The Moskovitz Proposal addresses many of the disincentives discussed to utility investment in energy efficiency, but it would also represent a very significant revision of the existing regulatory structure. Two major benefits are often cited to this proposal. First, it provides a direct mechanism for measuring performance. Second, it provides an increased scope of mechanisms to lower

customer utility bills from energy efficiency, fuel switching, efficient system operations, and other creative actions. Rate adjustment mechanisms could also be avoided since revenue erosion and disincentives are addressed in one approach. There is also a variety of problems perceived with the Moskovitz approach. The most obvious problem would be finding a satisfactory comparable group. The approach could also cause perverse and unintended behaviors by establishing lower customer bills, not the provision of least-cost energy services, as the primary objective. The indexing approach would also tend to reward utilities which can successfully shift more of the costs of energy efficiency to ratepayers outside of the ratemaking process. This is not desirable if the total energy efficiency cost exceeds the real avoided cost of supply. Further, the proposal appears to have a methodological defect. Contrary to appearance, it does not, in fact, deal with the problem of revenue erosion. For example, assume a utility achieves a 2 percent reduction in average revenue requirements per customer through energy efficiency while at the same time the reference group of utilities achieves on average the same savings. Under the Moskovitz Proposal, there will be no rate adjustments even though the utility will have experienced a sales drop in the previous year and "lost revenues". To remedy this, some form of true-up adjustment would be necessary, and the absolute level of conservation achievement would need to be estimated.

There is no cost recovery mechanism that has been successfully demonstrated to achieve the goal of profitable least-cost planning. Experiments are currently underway in Maine, Massachusetts, and California. Your state will need to decide both which direction and how far in that direction it can go to motivate the good faith implementation of LCUP among your utilities. The "plain vanilla" approach depicted in the Model Regulation is a good conservative approach. You may wish to suggest a more extensive experimentation and implementation cost recovery proposal outlined in Appendix D.

technical checklist for consumers

The previous section highlighted the major substantive components of a least-cost plan. For many of these components, there are a variety of technical issues that can be critical in a least-cost plan.

load forecasting methodologies

The state-of-the-art in demand forecasting analysis has been evolving from a strictly macroeconometric approach to end use/microeconometric modeling. End-use microeconometric and macroeconometric models differ essentially in the level of disaggregation used. The macroeconometric approach constructs a forecast using statistical techniques for highly aggregated classes of customers based on historical data and relationships. An end use model examines potential demand at the level of the specific end use -- the actual use to which energy is applied by a given class of customers. Data for this purpose is obtained by end use, building type, and fuel type for each class. The individual end use demand forecasts derived from these data, and based on economic and demographic growth assumptions, are then summed to yield an aggregate forecast. End use models, thus, work from the bottom up, using disaggregated energy end uses as a starting point. When econometric methods are applied at the end use level to forecast saturation or energy use and are fit within an overall energy accounting structure, it becomes an end use/microeconometric method. The end use approach introduces the concept of energy service, in that it is the services of energy-using equipment that are desired, not the energy itself. These services include cooked food, a heated home, and an illuminated office. An end use technique is capable of explaining more fully how energy is actually used, and, thus, can adapt to changing circumstances over time. Because econometric models are fundamentally tied to historical trends they must unavoidably assume an unchanging relationship between economic/demographic factors and energy demand. An end use model can accommodate deviations from historical trends. Because end use modeling explains each component of consumption, it can produce a more informative and accurate forecast. Newly emerging energy efficiency technologies, regulatory policies and standards, and varying levels of utility-sponsored energy efficiency can be considered. The following is a discussion some of the major factors that should be considered in an end use/microeconometric forecast:

behavioral components

Behavioral responses at an individual customer level are important in a least-cost forecast since the demand for energy at each end-use is driven by several underlying factors, including differences in operating costs between competing fuels on the selection of new equipment, the change in the level of equipment operation with changes in energy price, and changes in customer energy usage behavior attributed to a gain or loss in personal purchasing power. To capture the behavioral response to changes in price and income, elasticities of demand should be incorporated into the model at each end-use level.

competing fuel forms

In modeling the demand for electricity, it is important to capture the effects of fuel substitution. Other fuels can provide the same energy service, often at greater efficiency and lower cost. The penetration of competing fuel forms is dependent on its cost and availability. The degree of saturation of alternate fuel appliances will depend on the availability of alternate fuels. The inter-dependence of appliance decisions should also be taken into account given there is a high correlation between the choice of fuel for space-heating and the choice for water heating and cooking.

energy efficiency quantification

In order to include the effects of energy efficiency in a forecast, there must be a method available to quantify these effects. A problem that can arise when energy efficiency effects are incorporated into the forecast is the inadvertent counting of a single effect twice, or "double counting". Since multiple motivations to conserve are operating simultaneously (rising energy prices, regulatory standards, utility programs) careful attention must be paid to 1) correctly estimating the total resulting effect, and 2) allocating the effect among the causes. The total energy efficiency effect is the savings resulting from a combination of overlapping programs or forces that encourage or mandate certain measures. In no case can this result exceed 100 percent of the potential savings. The effect of a program given the existence of another related program will be less than if the former were operating alone, and overlooking this point is the source of double counting error. End use models handle the problem by considering the final effect of a measure at the individual end use level. The portions of total response can then be allocated among the influential programs.

customer sectors versus rate classes

Because so much utility data is readily available by rate class division, there has been a tendency in the past to forecast solely by rate classes. Often times rate classes will not be disaggregated at the level necessary to establish classes with homogeneous energy-using behavior. For forecasting purposes new customer sectors will often be created. The Standard Industrial Code (SIC) is used to reclassify the commercial and industrial sectors.

levels of disaggregation

In an end-use model, the greater the level of disaggregation the greater the potential accuracy. The model should permit the user to determine the level of end use/fuel form/dwelling disaggregation. The following tables contain useful levels of disaggregation for building type, end use and fuel form for the residential and commercial sectors. To limit the data acquisition requirements, some of the smaller categories for a service area can be lumped together.

economic and demographic assumptions

The economic and demographic assumptions used in forecasting are critical determinants of the output. History has shown that there can be significant changes in growth rates even from year to year, and resources put into improving the accuracy of these assumptions are well spent. There must also be assurance that these inputs are consistent with each other. That is, employment, population, and income should all move as one. In addition, internally generated data should be compared to that from external sources as a further check on accuracy.

fuel prices

It is also important that estimated fuel prices are consistent with each other. Projected electricity prices should be consistent with levels of natural gas prices, and the price of gas should in turn be consistent with world oil prices. Fuel prices are not only linked to each other, but are intricately tied to the economic assumptions as well. Estimated fuel price escalation rates will be highly dependent on the value chosen for inflation. The economy, likewise, is dependent on fuel prices -- different economic conditions tend to be associated with different fuel price levels. All of these effects must be integrated together, and alternative scenarios should be constructed to allow for future variations, particularly in oil prices and economic growth.

load forecasting models

The discussion in this section is limited to describing in general the major components of end-use models for forecasting system peak, residential, commercial, industrial loads. Specific models are not described.

system peak

Many peak load models are now based on the results of the end use sales forecast, instead of being econometrically projected from historical peak consumption. For each sector, the sales forecasts are divided up first by month with energy use per day then determined based on the different schedules for different end uses (e.g., weekday vs. weekend). The hourly patterns of use are then estimated from load profiles, distributing daily use across each hour. Fixed load profiles can be used for non-space-conditioning end uses, while weather variables are incorporated into the load profiles for space conditioning, resulting in normalized, weather-adjusted load shapes. After totaling all sectors and allowing for line losses, system peak days and hours can be observed.

residential

The three main components in forecasting residential demand are the number of households, the saturation of the appliance or end use, and the unit energy consumption (UEC). Models should consider the major modeling aspects of households, housing, appliance efficiency, appliance saturation, and appliance usage, all assembled within a cohort accounting framework (i.e., a framework that keeps track of the age of each item and determines useful life precisely). In addition, models should reflect explicitly fuel availability and carefully coordinate the selection of the space conditioning and water heating end uses and building structural components.

commercial

Commercial buildings, which consume most commercial sector energy, are often separated out for modeling purposes. Models in general take a capital-stock approach projecting energy demand from three factors: 1) the stock of energy-using capital as measured in the commercial sector by floor space, 2) base year energy use, and 3) actual energy utilization of the equipment relative to the base year. Only the energy utilization index (EUI) changes in the short run (capital stock is fixed), in response to external factors such as fuel price changes. In the long run, efficiency and fuel characteristics of the stock can change as well.

industrial

Manufacturing is generally the largest energy-consuming segment of the industrial sector (depending on the industrial mix in a service area). Reliable end-use models for manufacturing, or any other industry type, simply are not currently available for most utilities. Most models use an econometric estimation framework at the two-digit SIC code level.

In order to understand how a model behaves and to predict its accuracy, the following information must be obtained from demand forecasting models:

- Base case forecast of future energy demand as monthly and annual load projections by customer class;
- Discussion of the variables, model structure, and estimation procedures used in the development of these projections;
- Documentation of forecast assumptions and the role of judgement on the forecast;
- Probable effect of alternative policy options and of changing assumptions about input variables;
- Price elasticity of energy demand;

- Statistical tests of reasonableness, and
- Degree of uncertainty over future energy requirements.

designing data acquisition program

A least-cost planning process requires information and data on how energy is applied on the specific end use -- the actual use to which energy is applied by a given class of customers. The need for this data is twofold:

- To assess the influence of demand side resources on the utility system's future demand and energy resource requirements, and
- To gather the data required for end-use load forecasting.

Information and data is needed in the following general categories: demographic character of the customer (such as household size); building characteristics (such as vintage, square footage, type and number of windows, and type of insulation present); saturations of equipment and fuel type; energy efficiency measure penetration levels; customer energy use habits, and energy usage per end use. There are several ways in which the necessary information and data can be gathered, including surveys, building simulation models, conditional demand analysis, and direct metering. Surveys can provide information for all the categories listed above excepting energy usage per end use. Building simulation models, conditional demand analysis, and metering are all techniques used to ascertain energy usage per end use.

utility surveys

A customer survey is the most basic method for obtaining detailed, service area specific data for use in end use forecasting and demand-side analysis. Surveys can vary in scope, level of detail, and relative usefulness. Survey forms include mail, phone, and on-site interviews. While the mail survey is the least expensive way to collect data, the level and accuracy of response is difficult to predict. Many customers are confused about the type of equipment they use, particularly for some of the most energy intensive end uses such as water and space heating. Mail surveys can be followed up by on-site surveys to estimate the biases and correct for them. In addition to verifying mail survey data, on-site visits can provide additional information that characterizes structures for building simulation models, conditional demand analysis, and direct metering programs.

building simulation models

Heat load modeling or building simulation models are used to simulate the thermal characteristics of buildings. The most familiar is the Department of Energy's (DOE) model. Structural characteristics, equipment part load performance characteristics, internal heat loads, behavioral and climatic factors are all used to calculate the heating and cooling requirements. The various forms of the DOE simulation model compute heat transfer to and from a building based on its shape, level of insulation, tenant behavior, and other variables.

conditional demand analysis

Conditional Demand Analysis (CDA) is a statistical method, using regression analysis estimate the demand for energy by end use. The method is based on data such as ownership of appliances, structure of buildings, weather zones, demographics, and billing. One difficulty with CDA is that it is impossible to separate out UECs for ubiquitous end uses such as lighting and small appliances in the residential sector.

direct metering

Load studies or direct metering is most accurate, and most expensive means of determining energy usage per end use. Meters are attached to the equipment within a sample of buildings and the electricity used is measured over an established period of time. Combining this metered data with detailed building survey data can yield very good end use consumption estimates.

demand side resources

A utility's strategic load shape objectives will directly influence the the overall direction and cost of a utility's resource planning and acquisition decisions, including the types of energy efficiency programs implemented. Strategic load shape objectives are usually based on a set of corporate planning goals. For example, a utility may have established improvement in system load factor and preservation and growth in sales as their corporate planning goals. How these corporate planning goals are then operationally achieved is where selection of a set of load shape objectives comes into play. Improvement in system load factor can be pursed through either the strategic load shape objectives of peak clipping and strategic conservation, or load shifting and strategic load growth, with only the latter set of objectives addressing the preservation and growth in sales objective. Peak clipping and strategic conservation support-energy efficiency programs that modify load shape through a change in the pattern of use as well as a reduction in sales. Examples include air conditioning load management and high efficiency air conditioner rebate programs. Load shifting and strategic load growth support energy efficiency programs that shift load from on-peak to off-peak periods and increase sales beyond general valley filling in off-peak periods. Examples include cool storage and electric heat pump programs. If successful, these two sets of load shape objectives will result in differing resource planning and acquisition decisions, and total utility revenue requirement. Peak clipping and strategic conservation will work to reduce system energy and demand requirements, whereas load shifting and strategic load growth will work to increase system energy and demand requirements. Utility revenue requirement over time will be less under the former set of strategic load shape objectives, and greater under the latter. Serious conflicts between the utility and regulators can result in a situation such as this where a utility's corporate planning goals cause a utility to pursue a resource planning strategy that is not truly least-cost .

Because of this, it is important that a utility establish and justify up front in the least-cost planning process not only its strategic load shape objectives but also the decision-making process and any analysis involved in determining them. A utility should be required to show that there is no economic conflict between its corporate planning goals and strategic load shape objectives. This can be done through production costing simulations that assess the impact on utility total revenue requirement over time from the different load shape modifications.

conservation supply curves

Demand-side planning requires a detailed assessment of the energy efficiency measures that can be applied to various end uses, and their costs relative to other sources of supply. One technique is to construct conservation supply curves which describe the amount of "conserved energy" available from a given measure and its unit cost. Such a curve can convey the technical conservation potential for each end use in an entire customer class. For long term planning purposes, the curve can describe costs and savings spread over a 15 to 20 year period. Applicable energy efficiency measures are ordered by increasing unit cost from left to right. The vertical axis measures the energy savings that would result from the implementation of a measure. The curve slopes upward to the right, as for any conventional supply curve, indicating an increased cost for increased supply. A supply curve for energy efficiency allows conserved energy to be viewed like any other sources of supply. It also permits easy identification of the least-costly measures and the associated savings. Most important, an explicit comparison between the cost of conserved energy and the cost of conventional sources can be made. To construct these curves, estimates must be made of the average energy savings, useful lifetime, and lifetime costs for each measure.

supply side resources

system reliability

There are many technical reliability issues involved in connecting any generating technology to the electric utility grid. These include the operation of the generating technology and the effect of that operation on the utility system. The most common reliability considerations include:

Project Performance Reliability

- Output during peak and off-peak demand periods
- Availability during hours of expected operation
- Operating lifetime
- Forced outage rate

Utility System Operating Reliability

- Availability during system emergency
- Firm capacity value
- Required harmonic output
- Safety to utility line workers

- Dispatchability and operation control

The U.S. utility industry prides itself on safe and reliable operation of the utility system. The North American Electric Reliability Council sets standards for reliability for the industry. To the extent that there is a trade-off between reliability and cost, the level of acceptance for such a balance of competing objectives should be explicitly stated.

resource flexibility

Flexibility corresponds to the ability of a resource option to meet changing resource needs. There are economies of scale and minimum lead times for most technologies. Flexibility can be expressed in terms of:

- Modularity (unit size), and
- Lead time (period required between deployment decision and initial operation)

Short lead time, small unit size resource options provide the greatest level of flexibility. They also provide the closest match between supply and demand. Demand-side options such as energy-efficient new housing stock provide flexibility by reducing the uncertainty of demand.

environmental impact

The construction, operation (and decommissioning) of a generating facility affect the environment in many ways. Objectives which address environmental impact should be as explicit as possible so that relative comparisons can be made between resource options. Sample environmental impacts include:

- Biological impacts (vegetation and wildlife);
- Water use (pollution and consumption);
- Land use (siting for facility and waste disposal);
- Air quality;
- Hazardous wastes, and
- Cultural resources (archaeological and historical).

resource diversity

A diverse portfolio of resource options is a stated objective of most utility and state utility commission-sponsored long-term resource plans. Diversity can be achieved through redundancy in generating stations so that the failure in one or a few stations cannot jeopardize meeting demand. More commonly, diversity is referred to in terms of fuel sources.

resource commitment

The time period of the resource plan has a direct impact on the acceptability of various resource options. It is typical for resource plans to forecast demand and identify resources necessary to meet that demand for 20 years or more. However, the uncertainty associated with long-range planning imposes limits on the period for resource commitments. While the forecast period may be 20 years, commitment to resources may be as limited as to be the period of time between plan filings.

capacity reserves

Capacity reserve margins are required for all electric utilities, usually stated as a percent of the peak demand on the system. In resource planning, the reserve level selected should provide adequate reliability at least-cost. There are a variety of technical issues that arise in calculating the acceptable reserve capacity margin including:

- Extreme peak event adjustments (due to weather or unusual seasonal factors);
- Reliance on nonfirm imports to provide reserves;
- Sensitivity to force outage rates, and
- Lack of planned capacity due to slippage of scheduled maintenance and derating for seasonal operation.

resource preferences

Inherent in many resource planning decisions is a preference toward one or more resources. These preferences should be stated explicitly to avoid challenges to the resource decision. For example, the 1980 Regional Power Act governing the Bonneville Power Administration resource planning activities dictated the following resource priorities: first, conservation; second, renewable resources; third, cogeneration or other high efficiency generation plants, and finally, conventional thermal power plants. As discussed previously, the Act provides for a 10 percent premium for energy efficiency investments. Where possible, the LCUP process should provide for such a premium that quantifies the state's preferences.

resource plan robustness

A resource plan is considered "robust" if the cost of supply varies little relative to changes in the planning environment. For example, if fuel costs were to increase unexpectedly, a robust plan would still produce the equivalent amount of energy services at a similar cost as if the fuel price had behaved as predicted.

financial feasibility

Utilities have financial goals that will affect the resource deployment decision. Utilities consider the effects of an investment decision on asset concentration, debt to equity ratio, and other financial indicators. The financial and planning advantages of short lead time generating technologies include:

- Capacity additions and cancellations lead to a closer match between generating capacity and load;

- The utility accumulates less allowance for funds used during construction (AFUDC) during the construction interval and is less vulnerable to cash flow problems from "non-cash" earnings, and

- Construction is completed sooner allowing the utility to place plant assets in ratebase sooner.

VII. EMERGING ISSUES

introduction

The recent combined effects of lessened inflationary pressure, reduced interest rates and stabilized fuel costs have allowed the electric utility industry to begin recovery from the traumatic experience of the early 1970s and 1980s. Utility construction programs that were impacted by unexpected declines in electric load requirements are now winding down with costs already absorbed either through rate increases or through write-offs, or both. More and more electric utilities have found it unnecessary to seek additional rate increases with rate reductions ordered by many regulatory commissions. Even though a few electric utilities are still struggling to place their nuclear generating units in service, most companies have overcome their precarious circumstances of the late 1970s and early 1980s and are in better financial condition.

The electric utility industry now finds itself in a period of transition marked by corporate restructuring, competitive opportunities, and environmental concerns. Because these events are still in the early stages of development, it is uncertain the extent to which any of them will affect the nature of the operation and regulation of the electric utility industry. To the extent that these emerging issues do develop as some predict, least-cost utility planning as generally established in this manual may be the best, if only, tool to stabilize both a moving and an increasingly evasive target.

purpose

This section of the manual provides a brief overview of the key issues and actions in the areas of corporate restructuring, competitive opportunities and environmental concerns which will affect least-cost planning in the future. Your understanding of these issues will be helpful in maintaining an appropriate perspective when analyzing least-cost planning strategies proposed by your state's utilities.

corporate restructuring

diversification

Traditional franchised utilities with distribution monopolies no longer enjoy the certainty of rising demand, rising revenues and rising profits. Advances in generation technology are creating unprecedented opportunities to nurture a competitive generating sector. In response to these new market and regulatory risks, traditional utilities have initiated a flurry of restructuring activity in particular creation of holding companies and utility subsidiaries. Utilities that restructure frequently have the following goals:

- Reduce state oversight of future power plant construction;
- Free monopoly utilities to compete against "true independents" in wholesale bulk power markets;
- Transfer efficiency savings from ratepayers to shareholders, and
- Permit utility diversification into risky nonutility enterprises with greater risks and returns.

mergers and acquisition

In the U.S. electricity industry, the consolidation of Cleveland Electric and Toledo Edison, the Southern Company and Savannah Electric, Pacific Power and Utah Power, and numerous utility acquisitions by Utilicorp and Catalyst Energy have been consummated in the last few years. Both Southern California Edison and Tucson Electric have offered to buy San Diego Gas and Electric. Central Maine, Central Vermont, New England Electric, and Northeast Utilities have all expressed a desire to buy the operating assets of Public Service of New Hampshire (minus the share in its Seabrook nuclear plant).

The largest recent merger involves FERC's October 26, 1988 conditional approval of a merger agreement executed by PacifiCorp (doing business as Pacific Power and Light Company) and Utah Power and Light Company. The merged utility, PacifiCorp Oregon, will operate two electrical divisions, which will maintain separate retail identities, but their power supply and transmission systems will be planned and operated on a single-utility basis. The FERC directed mandatory wheeling of electricity as a condition of merger approval to avoid likely anticompetitive effects. Without such a condition, the merger would not have been consistent with the public interest. Thus, an absolute obligation was imposed on PacifiCorp to provide firm wholesale transmission service at cost-based rates to any utility that requested such service. This long-term obligation was necessary to prevent an exercise of market power by the merged utility which would be able to foreclose access by competitors to bulk power markets in the future. Short-term conditions, designed to mitigate the exercise of monopoly power by PacifiCorp during a five-year transitional period, were also imposed. *Re Utah Power & Light Co, et al.*, 96 PUR4th 325 (FERC 1988).(Currently on appeal).

The Investor Responsibility Research Center (IRRC) predicts "the largest wave of mergers and financial restructuring activity" in the electric utility industry since the 1930's. The report cites the possibility of five merger deals a year over the next 10 years and many cooperative and municipal consolidations.

While the trend toward consolidation by merger will continue, some believe the industry will not shrink appreciably for two reasons. First, FERC's imposed transmission access requirements in the PP&L-UP&L merger may be troublesome for many utilities. Second, mergers cause a diversion of resources and create inflationary pressures that drive up the cost of debt to the merged company and to all companies in the industry.

Utility mergers can have significant implications for least-cost utility planning. Mergers provide incentives to purchase power from sources which are not the least-cost, such as unused generation capacity on the merged system. Mergers may affect demand-side programs, and can result in emphasis on marketing and wheeling available capacity and energy to maximize profits rather than least-cost planning to minimize total bills. This dilemma must be resolved by establishing regulatory procedures that ensure a utility's least-cost plan is also its most profitable plan.

the FERC NOPR on IPPs

On March 16, 1988, FERC issued three separate Notices of Proposed Rulemaking (NOPRs). Docket No. RM88-4-000 called for the establishment of a new class of electric power suppliers, called independent power producers (IPPs), that would own, lease, or control independent power facilities (IPFs). IPFs are defined as generating facilities that are not included in any utility's rate base and that would be exempt from virtually all rate and nonrate regulation by the FERC to which other electric utilities are subject.

An IPP could be: (1) an industrial concern that owns generation in excess of its needs; (2) a "nontraditional utility" that is defined as a company that owns, leases, or otherwise controls IPFs for the sole purpose of selling power in the wholesale market, including a broker that buys and sells power produced by an IPF; and (3) a franchised electric utility that owns, leases, or otherwise controls IPFs which supply power for sale outside of that utility's retail franchised territory.

FERC's proposed IPP-NOPR is generally viewed as an attempt to document the PUHCA debate (see next topic). Opponents of the FERC's proposal argue that it would result in a fundamental restructuring of this country's power supply industry by shifting the production of electric power from individual, vertically integrated, regulated electric utilities which now have the legal "obligation to serve" all customers in their franchised service area to unregulated IPPs (which have no obligation to serve).

It is generally considered that FERC's NOPRs are on hold indefinitely. If the NOPRs are reactivated, least-cost planning

could be significantly affected primarily by preemption. This topic is discussed below.

Public Utility Holding Company Act (PUHCA) 1935

PUHCA is concerned with the effect of utility corporate structure on fair competition, consumer welfare and regulatory effectiveness. The Act specifically regulates changes in utility corporate structure, i.e. formation of holding companies or subsidiaries, mergers and acquisitions, and interaffiliate transactions. The Act prohibits utilities from using such structures to "concentrate control" in the marketplace, increase consumer risk or evade regulatory accountability. The Act contains the following major elements:

- Pre-Acquisition Review: The Act's pre-acquisition review standards, under Sections 10 (b) and 10 (c), prevent restructuring which is anticompetitive, uneconomical, or too complicated for regulators to untangle in subsequent rate proceedings.

- Ongoing Financial Monitoring: The Act requires the Securities Exchange Commission (SEC) to monitor the financial issuances and interaffiliate transactions of "registered companies" and also limits registered utility investment in nonutility ventures. These provisions protect consumers from the risks of, among other things, financial instability and cross subsidies.

Efforts to repeal or amend the Act are not new. In 1982-83, the electric utility industry asserted that it burdened efforts to diversify into non-utility activities. That effort was short-lived and unsuccessful, and bears little resemblance to the current effort. The present effort is altogether different, and far more serious with a shift in emphasis from "diversification" to "competition".

In recent times, many have called for greater competition in electric generation markets and have recommended some limited relaxation of the Act's restrictions on Independent Power Projects (IPPs). There are currently two sources of pressure to amend PUHCA. The first source comes from the franchised utilities themselves and is motivated by the economic forces driving utilities to restructure. In this regard the Edison Electric Institute (EEI) proposed to Congress in 1988 that the Act be amended to ease the way for investor-owned utilities that wanted to branch out into affiliate wholesale businesses. EEI has suggested that such amendment be made without regard to market power and with utilities continuing to control transmission access. The second source is from the "true IPPs", i.e. those entrepreneurs that have tried to develop electric generation facilities under PURPA's qualifying facilities requirements. In this regard, a variety of organizations are requesting Congress to consider what some view as the real roadblocks to increased competition:

transmission access, state regulatory preemption by FERC, utility self-dealing, and competition for wholesale power markets.

While the utility industry has correctly stated the problem, it offers a flawed solution. For example, it is true the that post-PURPA technological advances have made wholesale competition possible in many generation markets, and that such competition is desirable. Further, it is also true that the Act blocks certain kinds of corporate entities from entering generation markets. However, elimination of the Act without regard for its essential protections against utility abuse of captive customers and fair competition would be detrimental. In short, the utility industry is using a defensible policy goal --- encouraging competition -- to justify an indefensible policy -- weakening a statute that protects against competitive abuses. Moreover, the industry remains silent on the real barrier blocking market entry by truly independent generators: its refusal to grant nondiscriminatory access to essential transmission facilities.

In a related matter, the Securities Exchange Commission (SEC) has recently issued proposed Rule 17 on diversification into non-utility businesses by exempt intrastate public utility holding companies. Some believe that the SEC's proposed rule would abandon the requirements to protect the consumer from improper diversification by providing a "safe harbor" clause that would allow intrastate holding companies to diversify as long as there is a state statute providing for it. In this situation, the weaker state statute would essentially preempt the more stringent diversification requirements of the PUHCA. The implications of these proposed actions for least-cost planning could be significant. Easier formation of holding companies would encourage unregulated profit centers which could emphasize maximizing profits over minimizing bills where the two are incompatible. Again, the ultimate solution is to ensure regulatory compatibility between these two goals.

federal preemption

On June 24, 1988, the United States Supreme Court issued a decision that not only severely hampers the ability of state regulatory commissions to prevent the pass through of plant construction costs to retail ratepayers, but also, under the specific circumstances described below, places a matter that has been traditionally within the province of state regulators -- the prudence of the purchasing decisions of retail distribution utilities -- under the exclusive jurisdiction of the Federal Energy Regulatory Commission (FERC).

The decision, *Mississippi Power & Light Co. v. Mississippi ex rel. Moore*, --- U.S. ---, 93 PUR4th 293 (1988), marks the second time in as many years that the Supreme Court has frustrated attempts by the states to insulate ratepayers from the cost-of-service effects

of FERC decisions involving interstate agreements governing allocations of wholesale electric power.

The first decision, *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 74 PUR4th 464 (1986), established that states may not alter FERC ordered allocations of power by substituting their own determinations of what would be just and fair and further held those allocations are binding on the states when determining retail rates. The *Mississippi Power* decision establishes that states cannot evaluate either the prudence of an electric utility's decision to invest in generating plant constructed to meet the needs of an integrated interstate electric utility system or the prudence of an electric utility's decision to be *a party to agreements* to construct and operate a generating plant designed to meet the needs of such a system.

The direct effect of the two decisions is to bar state commissions from reviewing the prudence of costs incurred by electric distribution utilities to acquire power or capacity if the utility operates as part of an integrated multistate system and obtains the power from the system through interstate power allocations that are approved by the FERC.

In addition to that direct effect, the decisions have the potential to:

- Encourage electric utilities to operate through integrated systems in which their generating capacity is constructed, owned, and operated by subsidiaries that produce wholesale power for sale to separate entities engaged only in the retail distribution of power, thereby establishing a "safe harbor" from state regulation.

- Increase the participation of state commissions and consumer advocate groups in FERC proceedings involving the allocation of wholesale power among the retail operating utilities of integrated electric utility systems, and

- Restrict the ability of state regulators to disallow costs incurred by gas utilities pursuant to wholesale purchased gas contracts.

Although the latter effect is somewhat speculative, it can be expected to result from the rationale underlying the *Nantahala* and *Mississippi* decisions, i.e., that the states are prohibited from "trapping" federally approved costs by preventing a retail utility from passing through to retail ratepayers costs that it is legally obligated to incur pursuant to a FERC decision.

That issue has, in fact, already been addressed by the U.S. Court of Appeals for the Third Circuit in the case of *Kentucky West*

Virginia Gas Co. v. Pennsylvania Pub. Utility Commission, 837 F.2d 600 (3d.Cir.1988), wherein a retail gas distribution utility argued, albeit unsuccessfully, that its purchased gas costs were fixed and unavoidable because they would have to be incurred under a FERC approved contract containing minimum bill provision and, therefore, must be included in retail rates to avoid a prohibited trapping of federally mandated wholesale costs.

The effect on least-cost planning of federal preemption could be severe. It could "preempt" state least-cost planning. The likelihood of this occurring appears remote, however. States have broad regulatory authority to control and oversee utility monopoly activities within their jurisdiction. The FERC, under the Federal Power Act, has only that specific authority delegated by the Act. The Act does not give FERC the power to review a utility's long range planning process nor to determine which resource options presented in such a process like least-cost. One could argue that a state's enactment of a least-cost planning process is the garlic necklace which will ward off the federal preemption vampire. In any case, state least-cost planning vs. federal preemption has yet to be decided in the courts.

competitive opportunities

competitive bidding

A November 1988 study by the National Regulatory Research Institute (NRRI) entitled "Competitive Bidding for Electric Generating Capacity: Application and Implementation" cites six states (California, Colorado, Connecticut, Maine, Massachusetts, and New York) as having adopted bidding programs and seven states (Florida, Hawaii, Nevada, New Hampshire, North Carolina, Vermont and Virginia) as having allowed utilities to solicit bids without formal bidding rules in place. The state bidding programs have both similarities and differences. All six states adopted sealed bidding. With the exception of California, they all use a first-price bidding procedure under which each winning bidder is paid its own bid price. Wheeling is required only in Maine and Massachusetts. In Colorado, Maine, and New York, energy efficiency programs are allowed to bid with supply options. The states grant voluntary exemption from the bidding process to some small power producers. Qualifying facilities are generally granted the right to sell electricity to utilities at avoided energy cost if they choose not to participate in the bidding programs. The utilities are permitted to secure supplies of electric power outside of the bidding process.

The FERC September 1988 NOPR in Docket No. RM-88-5-000 details guidelines for the establishment at the direction of the individual state regulatory commissions of "competitive bidding" procedures that, once established, would become mandatory for each electric utility to follow whenever such utility finds the need

for additional generating capacity on its system. The bidding process would be open to all independent power producers, qualifying facilities, and utility subsidiaries, subject to certain restrictions.

The effect of competitive bidding on least-cost planning is one of potential de facto preemption. Some states, such as Massachusetts and Colorado view competitive bidding as a substitute for least-cost planning.

Transmission Access

In the United States, 80-90 percent of the transmission grid is owned by private electric utilities that are vertically integrated into the generation, transmission and distribution functions. That means that these private transmission owners are in direct competition at the generation supply and retail customer levels with other entities that have no choice but to rely on the intervening transmission network of their competitors. In addition, approximately 40 percent of the electricity generated by major utilities today is sold to other utilities for resale, either through long-term wholesale transactions or short-term economy sales.

The amount of power that can be transferred between and among states and regions is limited by not only the amount of physical transmission capacity but also its availability due to utility access limitations. A September, 1987 National Regulatory Research Institute (NRRI) study, "Non-Technical Impediments to Power Transfers", identified three major impediments :

- Opposition to mandatory wheeling;
- Roadblocks to constructing new lines, and
- Incorrect pricing of transmission service.

Utility opposition to mandatory wheeling arises from a number of concerns including competitive considerations; concerns about potential vertical disintegration of power systems; fear of the creation of a national grid; and a host of other institutional, regulatory, and legal questions concerning open access and common carrier issues.

The adoption of a pricing methodology that assures such an equitable division of benefits from properly priced wheeling arrangements, including benefits to parties experiencing inadvertent power flows, may be a necessary first step in addressing the optimal use and expansion of the bulk power transmission networks. The key principle is that pricing must send the appropriate signals for investment in facilities which will not only render the existing system more efficient but where appropriate, enhance capacity. Exclusive use of embedded cost

pricing techniques, with its resultant lower rates, may discourage voluntary wheeling and reduce the likelihood of the construction of new transmission facilities dedicated to bulk power transactions. Likewise, exclusive use of marginal cost pricing may work severe hardships for captive customers.

The second major impediment identified by NRRI concerns governmental and private roadblocks to constructing new transmission lines. Although it is possible to view the construction of new transmission lines as an alternative to constructing additional generation, at least in the short term, NRRI correctly recognizes that new high-voltage transmission lines of even intermediate length have long lead times and are not without opposition. The National Governors Association (NGA) has developed a position paper on electric transmission which stresses that proper wheeling and wholesale rate development by FERC, coupled with proper capital cost treatment in the states, should provide the necessary incentives for the development of projects to serve wholesale markets, while at the same time assuring that customers of utilities providing transmission service receive the benefits from the provision of such services.

The common thread running through the investigations and reports concerning transmission and its role in economic power transfers is proper pricing. Unless, and until, the proper wholesale rate methodologies concerning bulk power transfer and wheeling are adopted by the FERC, the addition of new bulk power transmission facilities to the interconnected grid will not take place. Questions of access for IPPs, QFs, and other non-utility generators, for instance, will be moot if additional power transfers on the grid are not feasible due to facility limitations.

Opening of transmission access could have positive and negative effects on least-cost planning. On the negative side, open access could produce increased pressure to purchase resources that are economically attractive in the short run, but uneconomical long term. Distribution utilities currently capacity short may be offered opportunities not now available, locking them into long term contracts. On the positive side, open transmission access could be a boon to enhance incentives to develop demand-side resources. With open access, even utilities with excess capacity will be able to take advantage of demand-side savings and market their excess capacity to other utilities that are capacity short. Experiments in the "sale" of demand-side savings to other utilities are currently underway within the Bonneville system.

environmental concerns

global warming

The greenhouse effect is a warming of the earth's surface temperature caused by a buildup of carbon dioxide in the atmosphere that curtails the amount of the sun's rays that the earth reflect back into space. This effect will eventually have a pervasive and severe impact on the electric utility industry. The global warming hypothesis suggests that a doubling of CO_2 levels in the next 50 to 100 years will increase global average temperatures by 1.5 to 4.5 degrees Centigrade, warmer than any time in human history, and will set in motion major worldwide environmental, political, economic, and social changes.

CO_2 emissions, resulting mostly from the burning of fossil fuels, are estimated to produce 50 percent of the greenhouse effect while methane accounts for 20 percent, CFCs 15 percent, nitrous oxides 10 percent, and ground-level ozone 5 percent. If CO_2 concentrations are a problem, its dimensions are worldwide. A 1985 Environmental Protection Agency study estimated that the U.S. generates 20 percent of the world's CO_2 emissions followed by the Soviet Union, the developing countries, and Western Europe.

According to the DOE, utilities were responsible for 7.5 percent of CO_2 emissions worldwide in 1987. U.S. utilities produce approximately 30 percent of CO_2 emissions in the United States with the transportation sector, industry, businesses, and residences producing approximately equal amounts. A continued national focus on global warming, some specialists suggest, will likely create renewed pressure on utilities to lessen dependence upon coal-fired plants through renewed energy efficiency efforts and the use of gas-fired power plants.

Several pieces of legislation were introduced in the Congress in 1988 that addressed the global warming issue. The 1989 legislative agenda so far includes the Global Warming Prevention Act, introduced by Representatives Claudine Schneider (Republican, Rhode Island) and George Brown, (Democrat, California), and the National Energy Policy Act, sponsored by Senator Timothy Wirth (Democrat, Colorado). Key goals of the Schneider/Brown bill include a 20 percent reduction of the 1987 CO_2 emissions by 2005 and an international agreement on the atmosphere by 1992 setting a global goal of 20 percent CO_2 reductions of 1987 levels by 2005. The guiding principle of this bill is to implement a federal wide, least-cost planning process. Least-cost planning provisions include directing the FERC to pursue least-cost utility planning in interstate and intrastate power sales. It also includes qualifying efficiency in PURPA cogeneration and small power production purchases by utilities,

as well as competitive bidding. The bill also directs the DOE to prioritize policies in line with least-cost options, expands the DOE's least-cost electric utility planning initiative, and implements a least-cost gas utility planning initiative.

The U.S. Environmental Protection Agency in a draft report (March 1989) to Congress advocates pricing and regulation strategies as the most effective short-term means of reducing emissions of gases, including carbon dioxide. The agency's office of policy, planning, and evaluation stated in that draft report:

> "The most direct means of allowing markets to incorporate the risk of climatic change is to assure that the prices of fossil fuels and other sources of greenhouse gases reflect their full social costs, possibly by imposition of emission fees."

The issue of greenhouse effect will push regulators to accelerate LCUP efforts and focus on non-fossil fuel resources both on the demand and supply-side. The greenhouse effect can provide additional economic support for demand-side alternatives to fossil fuel generation. Difficulties lie in the quantification of economic costs of continued CO_2 emissions and the benefits from hazardous emissions of demand-side programs.

Acid Rain

Numerous studies conclude that acid deposition (commonly referred to as acid rain) is adversely affecting aquatic ecosystems, forests, croplands, materials, and even human health. Analyses have shown that the damage is costing the U.S. at least $10 billion per year. Sulfur dioxide (SO_2) is the primary acid rain precursor in most regions, and electric utilities generate approximately 65 percent of total SO_2 emissions in the U.S. Therefore, large reductions in electric utility SO_2 emissions are being recommended.

Certain nations and states are already making large reductions in SO_2 emissions. West Germany is committed to a 50 percent reduction in SO_2 emissions while the providence of Ontario, Canada is committed to a two-thirds reduction. In the U.S., Massachusetts, Minnesota, New Hampshire, New York, and Wisconsin have adopted legislation requiring a 25-50 percent reduction in statewide SO_2 emissions. However, efforts to curb acid rain emissions at the national level have remained deadlocked. A number of acid rain control bills have been introduced in the Congress in recent years, with the Reagan Administration opposed and the Congress failing to pass any such legislation. Hearings are again underway in the House on a bill reintroduced from the previous two sessions, (H.R. 1470), sponsored by Rep. Gerry Sikorski (Democrat-Minnesota) with the support of Henry Waxman (Democrat-California), Chairman of the

Energy & Commerce Committee's Health and the Environment Subcommittee, which has jurisdiction over the issue. The Sikorski-Waxman bill calls for the reduction in SO_2 emissions by 5 million tons by 1994 and 10 million by 1998.

The Bush Administration bill HR 3030 calls for reduction in SO_2 emissions of 10 million tons from 1980 levels by the year 2000.The cost of emissions control is a major obstacle to passage of acid rain legislation in the U.S. An 8-12 million ton reduction in annual SO_2 emissions would cost an estimated $2-6 billion per year assuming use of conventional control approaches such as flue gas scrubbers or switching to low-sulfur coal. The proposed reductions represent 45-70 percent of utility CO_2 emissions in 1985.

Utilities have argued that costs of this magnitude are unacceptable, especially in states such as Ohio and West Virginia that are very dependent on high-sulfur coal for generating electricity. Electricity rates could climb by 10 percent or more in these states under some of the acid rain control proposals. Consequently, there is considerable interest in developing alternative emissions control strategies that are less expensive than conventional approaches.

Energy efficiency is one alternative approach to emissions control that is receiving increased attention. Because energy efficiency leads to less combustion of coal and other fuels, it directly lowers pollutant emissions. In addition, energy efficiency usually reduces the cost of providing energy services, thereby making the cost for further emissions reductions more acceptable. A study by the American Council for an Energy Efficient Economy, "Acid Rain and Electricity Conservation", (June 1987) determined that for the East Central Area Reliability (ECAR) power pool -- a major acid rain-emitting area in the Midwest -- more efficient end-use technologies can reduce electricity consumption by 26 percent without lowering the level of energy services. The analysis for the ECAR region determined that it is possible to reduce utility CO_2 emissions by 7-11 percent during the 1990s as a result of accelerated energy efficiency. The direct emissions reduction is likely to fall off after 2000 because it is more economical to use energy efficiency for avoiding or deferring construction of new power plants rather than reducing operation of existing, dirty power plants. Thus, energy efficiency cannot eliminate the need for pollution controls such as flue gas scrubbers or low-sulfur coal if a large reduction in acid rain emissions is mandated. The ACEEE report goes on to cite how energy efficiency can lower and offset the costs associated with emissions control legislation. A 55 percent reduction in SO_2 emission in the ECAR region by 2000 is estimated to cost consumers $3.6-8.4 billion. An accelerated energy efficiency program deployed in conjunction with

conventional emissions control measures could reduce expenditures on scrubbers and low-sulfur coal by 25 percent or more. Furthermore, the economic savings from avoiding construction of new power plants more than compensate for the emissions control costs. Consumers in the ECAR region could save $3.7- $7.7 billion when accelerated energy efficiency and emissions control are simultaneously pursued.

As with the greenhouse effect, the problems of acid rain are expected to accelerate the LCUP movement across the country. The cost/benefit determination related to acid rain is also a difficult problem, and supportable quantification may require extensive analysis beyond the budget of most consumer organizations. One thing is certain, however. Demand-side technologies can have a measurable and perhaps pivotal effect on the reduction of SO_2 and CO_2 emissions. Replacement of a 75-watt incandescent light bulb with an 18-watt compact fluorescent prevents 400 pounds of coal from being burned, stops the release of 12 pounds of SO_2, prevents 1600 pounds of CO_2 emissions, and saves the American economy $15. Because LCUP can significantly accelerate and stimulate the implementation of demand-side technologies, it may hold the key to our environmental and economic survival.

VIII. Index

acid rain, 80-82
Allowance for Funds Used During Construction (AFUDC), 69
American Council for an Energy Efficient Economy (ACEE), 81
appliance efficiency, 5, 48
avoided costs, 29, 36
Bluefield Decision, 1
Bonneville Power Administration, 19, 68, 78
Brown, Rep. George, 79
Bush Administration, 81
California, 29, 57-58, 76
Canada, 80
capacity reserve margins, 68
Catalyst Energy Co., 71
Central Maine Power Company, 71
Central Vermont Power Co., 71
Cleveland Electric Illuminating Co., 71
co-generation, 3, 31
Colorado, 24, 76-77
competitive bidding, 32, 36, 76
Conditional Demand Analysis, 64
Connecticut, 20, 76
Conservation Law Foundation of New England, 20
consumer advocacy groups (role of), 3, 28, 37, 42, 75
corporate restructuring, 70-73
customer classes, 60, 62
demand side management (DSM)
    contrasted with LCUP, 11
    contrasted with supply, 11
    cost effectiveness, 4, 34, 36, 50-53
    customer behavior, 59-60
    defined, 4
    distribution channels (lack thereof), 5
    economic viability, 34
    generally, 34, 36-37, 42, 45-46, 64
    lighting efficiency, 4-5, 65
    Participants test, 53
    payback rates, 5
    pilot projects, 19, 34
    quanitfication of benefits, 11
    Rate Impact Test (RIM), 34-35, 38, 51-52
        contrasted with TRC, 51
    reliability, 4, 27
    strategic load shape objectives, 45, 65
        Flexible Load Shape, 45
        Load Shifting, 45, 65
        Peak Clipping, 45, 65
        Strategic Conservation, 45, 65
        Strategic Load Growth, 45, 65
        Valley Filling, 45, 65
    supply side resource options (integration with), 35, 46, 66
    Total Resource Cost Test (TRC), 34, 36, 51-52
        contrasted with RIM, 51
    Utility Cost Test, 52-53
    utility deployment capabilities, 19-20
    utility financed, 5, 7
    verification, 4
    weatherization, 4
District of Columbia, 12
District of Columbia Public Service Commission, 51
diversification, 70
East Central Area Reliability (ECAR), 81-82
Edison Electric Institute (EEI), 73

Electric Power Research Institute (EPRI), 11, 13, 15, 45
Electric Revenue Adjustment Mechanism (ERAM), 57
emerging issues, 70-82
energy efficiency, 31, 47-48, 55-56, 60, 76, 79
Energy Users News, 5
environmental concerns, 79-82
environmental premiums, 11
excess capacity (costs), 50, 78
Federal Energy Regulatory Commission (FERC), 71-72, 74-76, 78-79
    NOPR on Competitive Bidding, 76
    NOPR on IPPs, 72
Federal Power Act, 76
federal preemption, 74-76
Florida, 76
fuel pricing, 60-61
H.R. 1470
H.R. 3030
Hawaii, 76
global warming, 79
Global Warming Prevention Act, 79
greenhouse effect, 79-80
Hope Natural Gas Decision, 1
Idaho Public Utilities Commission, 19, 51
Illinois, 12, 25, 31
Independent Power Producers (IPP), 72-73, 77-78
independent power production, 31, 73
integrated least cost planning, 10
integrated value based planning ,(IVP), 11
intervenor funding, 20, 43
Investor Responsibility Research Center (IRRC), 71
Kentucky West Virginia Gas Co. v. Pa. PUC, 75-76
Least Cost Utility Planning (LCUP)
    case-by-case approach, 24
    commission ordered, 24
    contrasted with DSM, 11
    contrasted with integrated value based planning, 11
    cost recovery, 37-38, 47, 55-57
    data acquisition, 45, 63
    data acquisition programs, 64
    defined, 7
    demand forecasts (use of), 29, 31, 33, 45
    demand forecast methods, 46, 59, 61-62
    discovery process, 32-33, 40
    economic efficiency, 47-49, 52-53
    evaluation procedures, 32
    goals and benefits, 7, 18
    initiating the process, 18-38
    legal forums, 20
    legislation, 20-22
    load forecasting, 33, 59
    methodology selection, 30
    petitions for rulemaking, 23
    planning procedure, 8-9, 29, 38-40, 45-70,
    potential pitfalls, 18, 29, 34, 38, 41
    preapproval process, 27
    prudence reviews, 27-28
    public participation, 18, 20, 39-40
    quantification (of), 47
    regulators' role, 25, 31-32, 40
    regulatory framework, 9, 12, 22-23, 28-32, 35-40, 55-56
    resource planning review, 40-41, 48, 67-68
    rule or regulation (model), 32, 35, 40, 48, 58
    staffing and budget requirements, 27, 43
    state-by-state evaluation, 10, 14-17
    statutes (model), 30-31
    workshops, 12, 37, 41-42
least cost integrated planning, 8

legal forums
proper selection, 20-21, 24,
Maine, 58, 76
Maine Public Service Commission, 57
marginal capacity costs, 36
marginal cost methodologies, 49-50
Massachusetts, 20, 58, 76-77, 80
mergers and acquisitions, 71-72
Michigan, 24
Minnesota, 80
Mississippi Power & Light Co. v. Miss. ex. rel. Moore, 74-75
modeling, 35, 59-60
Moskovitz, David, 57
Moskovitz Proposal, 57-58
Nantahala Power & Light Co. v Thornburg, 75
National Association of Regulatory Utility Commissioners (NARUC)
Energy Conservation Committee, 26, 37, 56
Handbook on Least Cost Planning, 45
National Association of State Utility Consumer Advocates (NASUCA)
resolution opposing IVP, 11
National Energy Policy Act, 79
National Governors Association (NGA), 78
National Regulatory Research Institute (NRRI), 76-78
Nevada, 12, 30, 37, 39, 44, 76
Nevada Public Service Commission, 51
New England, 42
New England Electric Company, 71
New Hampshire, 76, 80
New York, 24-25, 32, 76, 80
New York Public Service Commission, 24, 51
North American Electric Reliability Council, 67
North Carolina, 25, 76
Northeast Utilities Corp., 71
Northwest Power Planning Council, 11, 19
Ohio, 24, 81
OPEC, 1
Pacificorp, 71
Pacific Power & Light Company, 71
pollution control, 81
present worth revenue requirements(PWRR), 36
prudence reviews, 27
Public Service Company of New Hampshire, 71
Public Utility Holding Company Act (PUHCA), 72-74
Public Utility Regulatory Policy Act (PURPA), 3, 73-74, 79
purchased power, 29, 31, 35
qualifying facilities (QFs), 29
ratebase regulation, 1, 55
Reagan Administration, 80
Regional Power Act, 68
renewable energy, 31
resource planning, 8
revenue shortfall, 54-55
risk analysis, 47
risk premiums, 11
San Diego Gas & Electric Company, 71
Savannah Electric Power Co., 71
Schneider, Rep. Claudine, 79
Seabrook nuclear plant, 71
sensitivity analysis, 47
Sierra-Pacific Power Co., 51
Sikorski, Rep. Gerry, 80
South Carolina, 25
Southern California Edison Co., 71
Southern Company, 71
Soviet Union, 79
Standard Industrial Code (SIC), 60, 62
supply options, 3, 66, 76

environmental impacts, 67
transmission access, 71-74, 77-78
Toledo Edison Electric Co., 71
US Congress, 3, 73, 79-80
House Subcommittee on Health & the Environment, 80-81
US Court of Appeals, Third Circuit, 75
US Department of Energy, 64, 79-80
US Environmental Protection Agency, 79-80
US Securities and Exchange Commission (SEC), 73-74
US Supreme Court, 1, 74
Utah Power & Light Company, 71
Utilicorp, 71
utility regulatory commissions, 25-26, 32, 74-75
Vermont, 20, 51, 76
Vermont Public Service Board, 19
Virginia, 76
Waxman, Rep. Henry, 80
Weil, Stephen, 37
West Germany, 80
West Virginia, 81
Western Europe, 79
wheeling, 71, 76-78
Wirth, Sen. Timothy, 79
Wisconsin, 52, 80
Wisconsin Public Service Commission, 51

APPENDIX A
MODEL LEAST COST UTILITY PLANNING STATE STATUTE

Description: An Act relating to public utilities; requiring certain utilities which supply electricity to submit plans containing predictions of future demands for their services and appropriate measures for acquiring resources to meet or reduce those demands; and providing other matters properly relating thereto.

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

Section 1. Chapter _____ is hereby amended by adding thereto the provisions set forth as sections 2 to 5, inclusive, of this act.

Section 2. The application of sections 3 to 5, inclusive, of this act is limited to any public utility in the business of supplying electricity which has an annual operating revenue in this state of $_____or more.

Section 3. 1. A utility which supplies electricity in this state shall, on or before _____ of every _____ 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.

Section 4. 1. Not more than _____ 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, commerical, 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) Improvements in energy efficiency;
(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 or biomass; and

(6) Facilities which operate on the principle of cogeneration or hydrogeneration.

Section 5. 1. Within _____ 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, can be recovered from the rates charged to the utility's customers.

Section 6. (The state statute pertaining to the licensing of utility facilities should be amended to require that:)

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

APPENDIX B
MODEL LEAST COST UTILITY PLANNING STATE REGULATION

TABLE OF CONTENTS

SECTION

^^00 COMMISSION AUTHORITY AND SCOPE OF PROVISIONS
^^01 DEFINITIONS
^^02 FILING REQUIREMENTS AND PROCEDURE
^^03 FORECASTING REQUIREMENTS
^^04 UTILITY RESOURCE IDENTIFICATION AND INFORMATION
^^05 UTILITY DEMAND-SIDE PROGRAM OPTIONS
^^06 DEVELOPMENT OF INTEGRATED LEAST-COST PLAN
^^07 TWO YEAR ACTION PLAN, WORKING GROUPS, PLAN AMENDMENT, AND SEVERABILITY
^^08 COST RECOVERY

^^00 COMMISSION AUTHORITY AND SCOPE OF PROVISIONS

^^00.1 Consistent with (cite state statute, if applicable) each electrical corporation (hereinafter "utility") doing business within the State of _____shall be required to develop and file for review and approval by the Public Service Commission (hereinafter "Commission") a least-cost resource plan as described by these regulations. These regulations establish guidelines for the development and submission of plans, and for the procedures for a periodic regulatory review of each utility's integrated least-cost resource plan. Interim plan monitoring is established through working groups and reporting requirements.

^^00.2 The Commission will either approve the utility's least-cost resource plan, approve it subject to stated conditions, approve it in part and reject it in part, or reject the utility's resource plan as filed, only upon a finding, after a hearing conducted determines that the action is in the public interest.

^^00.3 Not withstanding the provisions of subsection ^^00.2, above, failure to substantially comply with the provisions of this chapter may result in summary rejection of an applicant's plan. Such rejection may be without prejudice to the refiling of the application.

^^01 DEFINITIONS

^^^01.1 Avoided Cost: The cost over a future period to the electric utility of marginal energy and capacity from a utility supply resource for which an alternative resource may be substituted. Avoided cost is determined utilizing a system planning methodology which incorporates the least-cost alternatives for generation capacity additions to be obtained directly by the utility, and has the ability to endogenously consider all realistic sizes of capacity additions. Marginal capacity costs must reflect the total costs of plant additions over the entire planning horizon. Data developed in the utility's integrated least-cost plan must be utilized for determining avoided cost so that realistic assumptions regarding the utility's actual anticipated operating characteristics are incorporated into the calculation. No specific avoided cost "model" is adopted in this regulation so that the utility is free to choose any methodology which conforms to the guidelines set forth above.

^^01.2 Capacity Factor: The ratio of the energy produced by a generating facility to the amount of energy that could have been produced, in the absence of any outages, in any selected time period.

^^01.3 Customer (or Participant) Contribution: The incremental cost to the customer (or to any person or entity, other than the utility serving that customer), for a demand-side measure that requires an expenditure of utility funds.

^^01.4 Demand or Demand-Side Resource or Measure: An energy efficiency or energy management device or application which is installed as a result of a program implemented by the utility or provided by a third party selected by the utility in response to an all-source bid solicitation

^^01.5 End-Use: Light, heat, cooling, refrigeration, motor drive, microwave energy, video or audio signal, computer processing, electrolytic process, or other useful work produced by electricity or its substitute. If equivalent amenity levels and/or productivity are maintained, the end-use service is considered constant for purposes of these regulations.

^^01.6 Energy Efficiency: The decrease of kilowatt or kilowatt-hour requirements of participating customers during any selected time period, with end-use service held constant (see definition of "end-use").

^^01.7 Energy Management: The modification of the time pattern of customer energy usage, with end-use service held constant.

^^01.08 Equivalent Availability: The availability of a generating facility in any selected time period, considering both scheduled and unscheduled, partial and full outages.

^^01.09 Externalities (or External Costs/Benefits): Those costs (or benefits) which result from the generation, transmission, distribution, or reduction in use through efficiency improvements of electricity which are external to the transaction between the supplier (including the supplier of efficiency improvements) and the wholesale (utility) or retail (ratepayer) customer. Any reductions in the use of fuels other than those required to satisfy electric end-use services are not included as "externalities", but shall be explicitly considered in the Total Resource Cost Test.

^^01.10 Full Scale Demand-Side Program: An energy efficiency or energy management program which is implemented by the utility for one or any combination of customer classes, and for which program design, technology, and method of implementation have been proven to be cost effective by passing the Total Resource Cost Test using actual program costs and benefits from either the implementation of a pilot program in the utility's service territory, or the implementation of a full scale program in the service territory of another electric utility as input data.

^^01.11 Least-Cost Utility Planning (LCUP): A utility resource planning process in which:

(a.) All resources reasonably available to reliably meet projected energy and demand requirements are considered by the utility on a consistent basis;
(b.) An integrated combination of demand and supply resources satisfy future demands at the least cost to all ratepayers and society, and meet constraints of safety and reliability as selected from the combination of available resources;
(c.) In addition to the primary selection criteria of least-cost, considers flexibility, risk, equity among ratepayers and classes, externalities and other factors as may be determined appropriate by the Commission.

^^01.12 Net Dependable Capacity: The maximum capacity a generating facility can sustain over a specified period of time, as modified for ambient limitations and less auxiliary loads.

^^01.13 Pilot Demand Side Program: An energy efficiency or energy management program which is implemented by the utility for one or any combination of customer classes for which program design, technology, and method of implementation has not yet been proven cost effective through either the implementation of a pilot program in the utility's service territory or the implementation of a full scale program in the service territory of another electric utility. Pilot programs are limited in scope either as to target population, duration or a combination of these factors.

^^01.14 Plan: The integrated least-cost resource plan filed by the utility pursuant to these regulations.

^^01.15 Rate Impact Test: An analysis of the extent to which unit rates for electricity are altered by the implementation of a demand side program.

^^01.16 Standard Estimates of Energy Efficiency Improvement: Standard estimates of the energy efficiency improvement from the implementation of a demand-side resource may be based upon reliable engineering or other data rather than metering. Such estimates may be utilized where it is, for example, economically impractical to monitor the actual savings of every installed demand-side measure. Where estimates are used, additional verification of energy efficiency improvement should be conducted through customer bill analysis.

^^01.17 Supply Resource: A resource or option which can provide for a supply of additional electrical energy and/or capacity to the utility beyond that currently available. A supply resource includes utility owned electric generating facilities, supply from other utilities, co-generators, or independent third parties via existing or new transmission facilities; and the life extension or upgrading of existing

facilities of the utility, whether they be generation, transmission, or distribution.

^01.18 Total Resource Cost Test : An analysis of the overall economic efficiency of the use of ratepayer resources to produce electric-driven end-uses. A program satisfies this test if the program cost per unit of electricity saved is less than the cost per unit of the supply resource avoided.

^^02 FILING REQUIREMENTS AND PROCEDURE

^^02.1 Beginning on or before _____, and every two *(or three)* years thereafter, each utility shall file a fifteen-year (15) *(or twenty- year (20))* least-cost utility plan with the Commission and an application for approval of that plan. Copies of the plan shall be provided to: *(specify at minimum the commission staff, the advocate's office, the state energy office)* , and other interested parties as may intervene in the proceeding. The application for review and approval of the plan shall clearly identify:

(a.) The name of the applicant and address of the principal place of business of the applicant;

(b.) The name, title, and address of the person authorized to receive notices and communications with respect to the application;

(c.) The location or locations that the public may inspect a copy of the application;

(d.) Requests by the utility that any information utilized in the plan which the utility deems proprietary be filed pursuant to a protective agreement allowing limited access to and distribution of such information to the parties to the LCUP proceeding. The Commission shall rule on such requests and issue an appropriate order.

^^02.2 Copies of the plans shall be made available free of charge to interested parties, as requested. Copies of an Executive Summary shall be made available to the public free of charge.

^^02.3 Plan Filing: Specific Requirements.

(a.) Executive Summary. Each utility shall prepare an Executive Summary, separately bound and suitable for distribution to the public, which shall be a non-technical description of the plan. This document shall summarize the contents of the Technical Volume(s). The summary shall include:

1. A brief introduction describing the utility, its existing facilities, and the purpose of the plan;
2. The forecast of low, high, and base growth of peak demand and energy for the next fifteen (15) years *(or twenty (20) years)* with and without utility demand-side programs, and an explanation of the economic and demographic assumptions associated with each;
3. A summary of the plan to reduce demand, listing each program and its effectiveness in terms of costs and benefits:

4. A summary of the plan to increase supply, showing each planned addition to the system for the next fifteen (15) years *(or twenty (20) years)* with its anticipated capacity, costs, and in service date;

5. A summary of the activities, acquisitions and costs included in the utility's Two *(or Three)* Year Action Plan;

6. Such other information as the Commission may determine appropriate.

(b.) Technical Volume(s). Each utility shall prepare Technical Volume(s) which shall include the information required by Sections ^^03 through ^^06, below;

(c.) Two *(or Three)* Year Action Plan. Each plan shall include a Two *(or Three)* Year Action Plan which describes the proposed resource acquisition actions which the utility must take prior to the next plan filing, and contains the information required in Section ^^10, below;

(d). Technical Appendix. A utility's plan must include a technical appendix. The appendix must contain the following:

1. Sufficient detail to enable the technically proficient reader to understand how the plan and its forecasts were prepared and to verify the adequacy and accuracy of the assumptions, and the data and the methods used in developing the plan;
2. Citations to the sources of all significant information used in the plan;
3. Documentation, inputs, and summary outputs for all models and formulas used, consistent with any proprietary requirements imposed upon the utility by outside suppliers of the models

(e.) Standard Documents. As part of its plan filing each utility shall include:

1. Its annual report to stockholders for the most recent two years;
2. FERC Form 1 for the most recent two years;
3. SEC Forms 8K and 10K for the most recent two years;

^^02.4 Hearing and Review of Least-Cost Resource Plans.

(a.) Proceedings; Timing. The Commission shall commence a hearing within three months of receipt of a utility's complete integrated least-cost resource plan;

(b.) Standard for Approval. Based upon the evidence of record presented at the hearing on the plan, the Commission shall render a decision either approving the plan, approving it subject to stated conditions, approving it in part and rejecting it in part, or rejecting it. A utility's integrated least-cost resource plan shall be approved if found to be in the public interest and to substantially comply with these regulation.

^^03 Energy and Demand Forecasting Requirements

^^03.1 Time Frame of Analysis.

(a.) Historic Data. Energy and demand forecasts shall utilize and report historic data from the ten years preceding the filing year when

such historic data are available. If actual data are not available, estimates shall be used;

(b). Forecast period. All energy and demand forecasts shall be performed for the fifteen-year (15) *(or twenty (20) year)* period beginning with the filing year.

^^03.2 Contents of Energy and Demand Forecasts.

(a). Characteristics. All of the forecasts specified below shall be weather normalized. All methodologies and processes to normalize for weather shall be fully described and justified. Non-weather normalized sales and peak demand forecasts shall also be provided, where practicable.

(b.) The load forecast shall include and report the following items for each of the historic and forecast years it covers:

1. The total annual jurisdictional sales for electricity, for the utility system and for each of the utility's aggregate customer classes;
2. The peak demands for the entire utility system and the jurisdictional portion of the system in the State of _____ for each of the aggregate customer classes, for both summer and winter;
3. Annual load factor;
4. Annual load duration curve, defined as the duration in hours of each level of kilowatt-demand over the year;
5. System load profiles, defined as kilowatt-loads and graphed as a function of the time of day, for a representative weekday in the peak winter and summer months, and for actual winter and summer peak days for the entire utility system and the jurisdictional portion of the system in the State of _____;

(b). Analysis and Documentation of Peak Demand and Energy Forecasts. The historic data and forecast of peak demand and energy usage shall include, and shall separately identify and describe the impact on peak demand and energy usage of the following load requirements and resources:

1. Utility demand-side programs which were implemented before preparing the plan under consideration;
2. Existing government-sponsored or mandated demand-side programs;
3. Substitution of alternative fuels for electricity;
4. Actual and expected interruptible demand, including number of customers and firm capacity contracted for interruption from each customer;
5. Self-generation and cogeneration by existing and future customers, including the number of customers with such capacity, their total capacity rating and, where applicable, the capacity and energy they are contracted to provide;
6. Transmission and distribution losses;

(d.) Evaluation of Previous Forecasts. Each utility plan shall contain an evaluation of previous forecasts for the purpose of improving the current forecast. The evaluation must assess the accuracy of

previous forecasts, attempt to explain the deviation between forecasted and actual energy and demand, and propose revisions to subsequent methodologies and assumptions in order to correct for potential deviations, as appropriate.

^^03.3 Forecasting Methodology.

(a.) Forecasting Methodology and Determinants. Utility forecasts shall be based on disaggregated end-use methodologies to the extent practicable and economically feasible. Forecasts based on any other methodology shall be fully explained and justified. Each forecast of energy and demand shall identify and describe the significant determinants assumed in forecasting future peak demand and energy usage. The following determinants of future peak demand and energy usage shall be accounted for in each forecast where appropriate:

1. Demographics, including population, number of households, household type (e.g., single versus multi-family), employment, and income;
2. Economic conditions, including gross product of the service area;
3. Price of electricity and price elasticity for demand for electricity;
4. The substitution of electricity for and with competing fuels in end-uses, including the rates of penetration and saturation of the market of those end-uses;
5. The future price of competing end-use fuels;
6. Behavioral factors which affect energy use by customers;
7. Energy policies of the District and federal government affecting energy use, both existing and reasonably anticipated;
8. Any other factors deemed relevant.

(b.) Each energy and demand forecast shall include detailed descriptions of the source of all determinants upon which it relies and shall document and fully justify the procedure by which the determinants were incorporated into the peak demand and energy usage forecasts. The determinants used in forecasting energy and demand must be consistent with and integrated into the different components of the forecast;

(c.) Data Requirements. Energy and demand forecasts shall be based on the best available data. Where reliable data are not available, estimates should be used and fully justified. To the extent economically feasible, each utility shall develop a data base of electricity consumption patterns by customer class and by end-use. Each utility shall conduct periodic customer surveys to obtain current data on end-use appliance penetration and saturation rates and end-use electricity consumption patterns. A proposed schedule for such surveys shall be submitted with each energy and demand forecast. Each forecast shall include a detailed description of data used in making the forecast, an identification of the sources of such data, and an explanation of techniques employed for gathering, organizing adjusting, or interpreting the data;

(d.) Econometric Forecasting Methods. Where statistical or econometric methods are used in developing forecast inputs or in the forecasting process, analyses of the reasonableness of such methods and models shall be presented, including statistical documentation and justification of each equation, variable selection, estimated coefficients, theoretical or empirical basis for functional form, and method of estimation;
(e.) Forecasting Model. Each energy and demand forecast shall include a complete description of the model or models used, including justification of model design and explanation of variables used.

^^^03.4 Sensitivity Analyses and Contingency Planning.
(a.) Sensitivity to Major Assumptions. Each energy and demand forecast shall include an analysis of the sensitivity of results to the major assumptions and estimates used in preparing the forecast. The major assumptions to be tested should include end-use efficiencies and saturation rates, electricity prices, prices of competing fuels, demographic projections, economic projections, and any other major determinant of energy use or demand. Sensitivity analyses shall assess the uncertainty ranges and the consequences of uncertainty for each of the major assumptions and combination of assumptions.
(b.) Contingency Planning. Each utility plan must contain a series of demand forecasts which represents a reasonable range of electricity sales and demand which its system may be required to serve. The range must include three levels of expected growth based on alternative assumptions of demand determinants, as follows:
1. A base case scenario, which incorporates all assumptions which the utility determines to be most likely. This case shall be used to project revenue requirements, avoided costs, ceiling prices, and resource blocks;
2. A high growth scenario, to be as a basis for developing a full array of resource options for consideration;
3. A low growth scenario, to be used as a basis for assessing the

^^04 UTILITY RESOURCE IDENTIFICATION AND INFORMATION

^^04.1 Existing Resources.
(a.) Data Requirements. The utility shall discuss and describe to the extent practicable all existing resources, including demand-side options, purchases from resource developers, purchases from other utilities, pooling or coordination agreements that reduce resource requirements, and owned or partially-owned generating facilities. This description shall include the same information required for potential future options, as described in subsections ^^04.2 through ^^04.5 below. The utility shall report actual historic information (including the most recent ten (10) years), as well as forecast future information through the life of the resource. Any forecast changes must be fully documented and justified. The information assembled

must be used by the utility in evaluating existing resources and assessing future resource options;
(b.) Assessment of Future Options. Each utility shall assess the role of existing resources in meeting future demand requirements. All existing resources shall be separately reassessed and considered in a manner consistent with potential future resources. Each resource shall be considered for the potential of continued use, upgrading, repowering, life extension, temporary mothballing, retirement, or other option. For those resources for which any action other that continued use appears to be cost-effective, the utility shall assess and document the cost and benefit associated with any such action, and justify why such action will or will not be taken. Each utility shall report any planned retirements, changes in ratings, or any other expected changes in the amount or availability of existing resources.

^^04.2 Potential Utility Demand-Side Resource Options.
(a). Assessing Technical Options. Demand-side technical options refer to any hardware, equipment, or practice that may be installed or instituted for energy efficiency or energy management purposes. Each utility shall assess the full range of technical options available for future demand-side resources, to be used in developing demand-side programs and an integrated least-cost resource plan. The assessment of technical options shall consider and, where appropriate, be based upon the inventory of end-use devices and consumption patterns developed for energy and demand forecasting as described in Section^^03, above. Each utility shall assess the full technical potential of future demand-side resources as a guide for developing comprehensive demand-side programs. For purposes of these regulations, full technical potential is defined as the amount of capacity and energy that could be obtained from the direct installation and use of the most efficient equipment and technology, without regard for economic limitations or market barriers;
(b.) The utility shall perform an initial screening of all demand-side technical options utilizing the Total Resource Cost Test.

1. An option passes the Total Resource Cost Test if the net present value of the program's benefits exceed the net present value of the program's costs. The net present value must be calculated using the discount rate employed by the utility during the same time period for analysis of the economics of acquisition of electric supply-side resources.
2. In calculating program benefits under this test the utility shall include its avoided costs as are defined in subsection ^^01.3, above. In the case of fuel substitution programs, benefits shall also include the reduction in the costs of production, transmission, and distribution of natural gas, valued at the margin due to reductions in gas usage. Program costs include all the utility's costs of implementing the program and the participant's direct costs of participation. Participant's costs are incremental costs and include only those costs which would not have been incurred

but for participation in the program. In the event a program also provides other benefits, such as improved amenities or other fuel savings, a reasonable allocation of program costs will be made.

3. Utility estimates of these costs and benefits should, to the extent practicable, be differentiated according to seasonal, daily, and hourly cost variations. The time period for evaluation of a program's cost-effectiveness should be the same period used by the utility for evaluating electric supply resources;

(c.) Those options which fail the Total Resource Cost Test or pose unacceptable risk to system reliability shall be eliminated from pilot or full program consideration. If the utility eliminates any demand-side options, each such option shall be identified, and the reason for rejection shall be fully explained and justified:

^^04.3 Potential Purchases from and Sales to Other Utilities.

(a.) The utility shall identify and fully describe all power import and export options, both firm and non-firm, which are likely to be available to it for all or part of the fifteen-year (15) *(or twenty (20) year)* planning period. Each major new commitment for purchase, sale, or exchange of power must be documented and justified as a cost beneficial resource for inclusion in the utility's integrated least-cost plan in a manner consistent with the screening of other supply-side options as set forth in subsection ^^04.4 (b), below ;

(b.) The description of each potential or existing purchase, sale, or exchange of power from or to another utility shall include, but not be limited to, the following:

1. The nature of the purchase or sale, (e.g., firm capacity, summer only);
2. The amount of power to be purchased, sold, or exchanged;
3. The contract price;
4. Requirements to improve its generating and/or transmission system and associated costs. Such description of facilities and costs shall be made in a manner consistent with the description of new generating facilities as set forth in subsection ^^04.4(c), below;
5. Timing and duration;
6. Constraints on the utility system caused by wheeling arrangements, whether on the utility's system or on an interconnected system, or by other contract terms or separate interconnect agreements.

(c.) The utility shall demonstrate that its plan has taken full advantage of the economic opportunities for cooperative planning and coordination of pooling of power and purchasing power in order to:

1. Obtain economy energy from systems having lower costs;
2. Improve reliability;
3. Reduce reserve margins;
4. Obtain emergency power;
5. Alleviate constraints on the system caused by wheeling arrangements;

6. To the extent that any coordination or pooling agreements exist between the utility and associated utility systems or power pools, or any coordinating organization, or are under consideration, the utility shall describe those agreements and provide the following:

i. The name of the parties to each agreement, identifying the role of each party;

ii. The Federal Energy Regulatory Commission or Commission docket or file number, if any, associated with the agreement;

iii. The commencement and termination date of each agreement;

iv. A summary of significant provisions of each agreement, and the effect of the agreement on the utility's system peak demand requirements.

(d.) The utility shall fully describe and justify its reserve margin requirement for the planning period.

^^04.4 Potential New Utility Generating Facilities.

(a.) The utility shall identify and fully describe all new utility supply-side options for meeting future demand. To the extent practicable and economically feasible, the options considered should include all technologies and designs which are expected to be available within the fifteen-year (15) *(or twenty (20) year)* planning period, either on a commercial scale or on a demonstration scale;

(b.) The utility shall perform an initial screening of all future supply-side resource options to eliminate those which, upon preliminary evaluation, are either not cost-effective in relationship to other available supply-side resources, or pose unacceptable risks to system reliability. If the utility eliminates any supply-side options, then each such option shall be identified, and the reason for rejection shall be fully explained and justified. The screening criteria used by the utility to exclude supply-side resources as planning options shall be fully described and justified.

(c.) A description, as appropriate, of each supply resource (both existing and proposed) to be considered for the integrated least-cost plan shall be provided and shall include the following information (estimated where necessary), site-specific where known, and on an annual basis:

1. Technology and design, including major pollution control equipment;
2. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
3. Lead time, separately identifying the estimated time required for, engineering, permitting and licensing, design, construction and pre-commercial operation date testing;
4. In-service date, and project schedule;
5. Installed capacity and net dependable capability;
6. Estimated costs, in accordance with the breakdown specified in the Uniform System of Accounts, separately identifying the following:

i. The total base cost in current dollars, and annual flows of expenditures in current dollars. "Base cost" shall be defined as total capital costs of construction, net of prospective inflation, finance costs (allowance for funds used during construction), and operation and maintenance. Base costs are the sum of the utility's estimated quarterly planning and construction expenditures;

ii. The annual flows of total incremental and sunk facility costs, including inflation and finance costs, disaggregated by allowance for funds used during construction and direct costs;

iii. Annual depreciation on capital investment;

iv. Annual return and taxes on capital investment;

v. The operation and maintenance (O&M) costs over the life of the facility described as:

a. Costs which are variable, in current dollars per kilowatt-hour, with expenses for fuel and other items indicated separately;

b. Costs which are fixed, in current dollars per kilowatt-hour;

vi. Waste disposal;

vii. Decommissioning;

viii. Insurance;

ix. Property taxes;

xi. Dedicated transmission and distribution facilities costs;

xii. Other appropriate expenses.

7. The rates of escalation of cost, including:

i. Capital costs;

ii. O&M costs which are variable and related to fuel;

iii. O&M costs which are variable and unrelated to fuel;

iv. O&M costs which are fixed

8. The total annual average cost per kilowatt-hour at projected loads in current dollars for each year of the plan for each existing and proposed facility;

9. Equivalent availability factors, including both scheduled and forced outage rates;

10. Capacity factors;

11. Duty cycle, i.e., baseload, intermediate, or peaking;

12. Heat rates (efficiency), for various levels of operation;

13. Unit lifetime, both book and engineering;

14. Complete list of applicable state, local and federal licenses necessary for the facilities;

15. Potential socio-economic impacts such as employment, personal income levels, and the competitiveness and health of the marketplace economy of the state;

16. Any other information necessary to perform the resource assessment described in Section ^^06.

(d.) Assumptions should be fully justified and, where appropriate, explicitly compared to the historic values of similar existing resources

of the company, as described in subsection ^^04.1, or of other companies.

^^04.5 Financial Information.

(a.) The financial assumptions and models used in the plan shall be fully described. Those assumptions which shall be stated and justified include at a minimum:

1. The general rate of inflation;
2. The AFUDC rates used in the plan;
3. The cost of capital rates used in the plan;
4. The discount rates used in the calculations to determine present worth;
5. The tax rates used in the plan.

(b.) The plan shall include at a minimum the following financial information, together with supporting documentation and justification:

1. Present worth of revenue requirements for each alternative plan considered for evaluation and risk analysis;
2. Nominal revenue requirements by year;
3. Average system rates per kilowatt-hour by year;
4. Total ratebase by year;

^^05 UTILITY DEMAND-SIDE PROGRAM OPTIONS

^^05.1 Development of Demand-Side Program Designs.

(a.) Each utility shall develop a comprehensive set of demand-side management program designs. The program designs shall be matched to those technical demand-side resource options identified in subsection ^^04.2(a) which pass the Total Resource Cost Test discussed in subsections ^^04.2 (b), above;

(b.) Programs should be designed as either full scale or pilot programs. A full scale program is appropriate only when the demand-side technology has been proven cost effective in a full scale program in another utility service territory, or when a pilot program of the demand-side technology has been proven cost effective by the utility in the State of _____;

(c.) For full scale programs, alternative program designs shall be described to realize the optimum market penetration for each technical demand-side resource option. Optimum market penetration is that level of market penetration which produces the greatest ratepayer benefit for the least unit cost. To the extent practicable and economically feasible, market penetration estimates shall be made for each program design based on varying levels and types of incentives to determine the appropriate incentive required to achieve optimum market penetration;

(d.) Programs shall be designed to minimize cream skimming and free riders, wherever feasible. Cream skimming is that instance in which some, but not all, cost-effective demand-side measures are installed or otherwise implemented at a customer's facility, and it then becomes uneconomical or impractical to return at a later time to that facility to obtain the next incremental demand-side resource. Free

riders are those customers who would have implemented a demand-side measure regardless of the utility demand-side program;
(e.) At least one program design shall be developed to realize the optimum market penetration for each technical demand-side resource option passing the Total Resource Cost Test;
(f.) In developing full program designs, each utility shall consider the applicability of different types of utility actions to achieve optimum market penetration for each cost effective demand-side option. Types of utility action considered shall include at least the following:

1. Financial incentives for demand-side measure adoption, including:
   i. Rebates to customers or demand-side measure vendors;
   ii. Customer bill credits and shared savings;
   iii. Loans at no interest or below-market interest;
   iv. Payments to customers or third parties based on estimated or measured energy and/or demand savings;
   v. Any combination of the above or other incentives as appropriate.
2. Direct installation of demand-side measures in customer premises at varying levels of cost to the customer, including no cost to the customer;
3. Information and education, including:
   i. Educational literature and advertising;
   ii. On-site energy audits or surveys in customer premises;
   iii. Design team or other technical assistance to architects, contractors, builders, and developers;
   iv. Other information as appropriate.
4. Building and equipment efficiency requirements as tariff conditions for the determination of hook-up fees for initiation of utility service to new or existing facilities.

^^05.2 Program Costs

(a.) For each program design developed, detailed estimates of program costs shall be developed by end-use or program as appropriate. In developing these estimates, the following components of cost shall be separately identified:

1. Expected demand-side measure expenditures by program participants, if any;
2. Expected demand-side measure expenditures by the utility, if any;
3. Utility administrative expenses for the program that add to the total cost of the demand-side measure(s).

(b.) For demand-side programs that entail utility expenditures for all or part of the direct cost of demand-side technologies, each utility shall include a program cost estimate based on the assumption that appropriate direct expenditures are recovered in a manner consistent with the provisions of Section ^^09 of these regulations;
(c.) The costs of utility educational and informational activities that are focused on demand-side programs, but that do not directly cause

demand-side measure implementation must be separately described and justified.

^^05.3 Projected Effects of Program Designs. The effects on energy consumption and peak demand of each program design developed pursuant to this section shall be estimated by end-use or program, as appropriate.

(a.) The estimates shall be based on the technology performance data developed pursuant to subsection ^^04.2(a) and the market penetration estimates developed pursuant to subsection ^^05.1 (c);

(b.) The estimates shall include the annual change in energy consumption and peak demand pursuant to the program for:

1. Each year of the program's assumed operation; and
2. Each year after the program's assumed cessation in which the demand-side measures caused to be implemented by the program are expected to remain in place.

(c.) For program designs whose demand-side measures impact gas and/or oil and electricity use, the effects of the program on the rate of use of energy other than electricity shall also be estimated. At a minimum, where applicable, program effects on maximum annual (hourly or daily) demand, maximum seasonal demand, and average demand during any time-varying energy costing periods used by the utility (on-peak, off-peak, shoulder) shall be estimated.

^^05.4 External Program Costs and Effects. The costs and effects of each program design, other than those identified pursuant to subsections ^^05.2 and ^^05.3 above, shall be identified, described, and, where feasible, quantified. This description shall address at a minimum the expected net effects of the program on:

(a.) The equity of the costs to and benefits of utility sponsored demand-side programs among individual households, businesses, and agencies, and among classes of customers. One measure to determine this factor is the use of the rate impact test. Failure of the rate impact test is not a basis for excluding a measure or program from further consideration, but it may be used to develop a relative ranking of programs for implementation;

(b.) Air quality, water quality, and other measures of environmental protection;

(c.) Public health and safety;

(d.) Employment and personal income levels in the state;

(e). The competitiveness and health of the marketplace economy in the State of _____

(f.) The degree to which the program has the potential to reach optimum market penetration of the appropriate technical demand-side resource option(s).

^^05.5 Risk Assessment. To the extent practicable and economically feasible, the risks and uncertainties surrounding each program

design, and associated data and estimates shall be assessed. Items to be considered for assessment include but are not limited to:
(a.) Uncertainties in the assumed market penetration rates;
(b.) Uncertainties in the implementation schedule;
(c.) Uncertainties in the estimates of demand-side technology effects;
(d.) Uncertainties in the estimates of utility administrative expenses;
(e.) The risks of unanticipated changes in customer energy usage patterns;
(f.) The risks that the implementation of the program will result in legal action against the utility or its agents.

^^05.6 Program Evaluation.
(a.) Each utility shall develop a plan to evaluate the impact on energy use of demand-side programs. The plan shall identify the anticipated method for evaluating the effects of each program design developed pursuant to subsection ^^05.1 above. The plan shall identify procedures to be employed with regard to the following aspects of the evaluation of each program:

1. Establishment of protocols to collect basic data describing program activity, including utility actions to optimize market penetration of programs;
2. Comparison of demand patterns of similar participant and nonparticipant groups, and/or use of customer bill analysis, engineering estimates, meter data or other methods to identify the impact before and after program participation on customer's usage and demand patterns.

(b.) The utility shall use program evaluation data gathered from previous demand-side programs implemented in the past two years to assist in the development of program design options required in the preceding subsections ^^05.1 through ^^05.5.

^^06 DEVELOPMENT OF LEAST-COST PLAN

^^06.1 Assessment of Individual Resources. All potential resources which were identified and described as required in Section ^^04, and which were not excluded by the utility's screening process, shall be considered for inclusion in the utility's integrated least-cost resource plan. Each potential resource shall be assessed based on at least the following criteria:
(a.) Revenue requirements, including all direct and internal costs associated with the resource;
(b.) Impact on the utility system and its customers, including non-price criteria such as operating performance of the resource, and ability to meet energy service needs of customers;
(c.) The qualitative and, to the extent practicable, quantitative impact on the environment and society, including all appropriate external costs associated with the resource;
(d.) Where limited data are available to assess fully any of the above criteria, the utility shall use its best estimate of the data. The utility

shall identify and fully describe and justify any methodologies used to evaluate or rank potential resources using the criteria listed above.

^^06.2 Development of a Least-Cost Resource Plan

(a.) Each utility shall develop a least-cost resource plan to meet the needs identified by each demand forecast scenario described in subsection ^^03.5, based on the least-cost combination of the potential demand and supply resources assessed. The utility shall perform an analysis which integrates resources found to be cost beneficial with considerations of:

1. Financial planning;
2. Regulatory constraints;
3. All source bidding;
4. Efficiency incentives.

(b.) The development of such a plan shall be primarily based on utility system assessment of multiple combinations of potential resources, and a determination of which combination of resources minimizes the present worth of total revenue requirements (PWRR) over the planning period. The purpose of this assessment is to determine the minimum costs of providing energy services provided by electricity to the utility's customers, including benefits associated with reductions in the use of competing energy resources;

(c.) The utility shall conduct an analysis of the sensitivity of all major assumptions and estimates used in its plan. Those analyses shall at a minimum include:

1. Risk and Uncertainty. The utility shall consider the risks and uncertainties associated with its resource plans. Any plan which poses unacceptable risks or uncertainties shall be rejected by the utility or modified to reduce such risks or uncertainties. A detailed explanation for any such rejection shall be provided by the utility. Items of risk and uncertainty to be considered include:
   i. Forecast of load;
   ii. In service dates;
   iii. Unit availability;
   iv. Fuel prices;
   v. Schedule and impact of demand-side programs;
   vi. Inflation in plant construction costs and costs of capital;
   vii. Availability and costs of purchase power.
2. Equity of Rate Impacts Between Classes. The utility shall determine whether, after considering risk and uncertainty, its least-cost resource plan will result in inequitable rate impacts between customer classes, or between significant components of any customer class. Such impacts shall be considered by the utility in the ranking and order of implementation of demand-side programs, but should not be used as a screening tool;
3. End Effects. The utility shall extrapolate its resource planning period five (5) years beyond the base fifteen (15) year (or twenty (20) year) period to determine the sensitivity of its least-cost resource plan to such an extension of the planning period.

^^06.3 Each least-cost resource plan shall be fully explained and documented. The utility shall specify the basis for selecting the plan, and shall describe how the plan meets the criteria described in subsections ^06.1 and ^06.2, above. The utility's analysis must address the relationship among the factors used in making the utility's decision including the relationship between avoidance of risk and the minimization of cost.

^^07 TWO *(OR THREE)* YEAR ACTION PLAN, WORKING GROUPS, PLAN AMENDMENT, AND SEVERABILITY

^^07.1 Two *(or three)* year action plan based on integrated analysis.

(a.) Each Plan of a utility must include a detailed action plan based on its integrated analysis. In the action plan, the utility shall specify all tasks which are necessary to implement its plan in the succeeding two (2) year *(or three year)* period, prior to the filing of its next plan. The action plan must contain;

1. A schedule for the acquisition of data, including planned activities to update and refine the quality of data used in forecasting, and a budget for such acquisition;
2. A section in which the models and techniques used to develop the forecast are compared with currently recognized procedures. Any proposed changes in the methodology must be fully justified, including an analysis of the costs and benefits;
3. A section describing any plans to acquire new or additional models for forecasting, or resource or integration analysis and evaluation;
5. A section describing demand-side programs and activities during the action plan period, including:
   - i. A description of continued planning efforts to develop new demand-side programs;
   - ii. A listing of each demand-side program which will be implemented in the action period, and justification for implementation of each through a cost benefit analysis;
   - iii. Designation of whether those programs will be a full or pilot program, and a justification for such designation;
   - iv. Estimated savings of energy and demand from the implementation of each program;
   - v. Detailed time tables for implementation and resource acquisition;
   - vi. Description of the method for evaluation of each program, and verification of energy and demand savings;
   - vii. Detailed budgets for costs to be incurred for each program during the action period.
6. A section describing the acquisition or construction of supply-side resources during the action period, including:
   - i. A listing of each supply-side facility to be constructed or to commence construction in the action period;

ii. A listing of each new firm power purchase to be made during the action period, and the timing and cost of that purchase;
iii. A time table for acquiring a permit to construct and a construction schedule for each facility;
iv. A detailed construction budget for each facility to be constructed or under construction during the action period, and, in the case of facilities already under construction, a comparison of the last submitted budget in the previous plan filing with actual expenditures to date.

7. A tabulation of all costs associated with the development of the plan;
8. A tabulation of costs for which the utility will seek recovery under the provisions of Sections ^^08 and ^^09, above, in the action period, and the method and timing of that recovery;

(b.) All budgets for demand and supply resource acquisition activities in the action period must be in a format which facilitates the comparison of budgeted with actual expenditures. Expenses must be presented in a format which is consistent with the categories and periods to be presented in subsequent filings for cost recovery as described in Sections ^^08 and ^^09, above;

(c.) The action plan must contain schedules suitable for comparing planned and actual activities. Points of decision committing major expenditures must be shown;

(d.) The Commission's Order on the plan shall separately address the utility's action plan. The Commission will approve the utility's action plan as filed, approve it subject to stated conditions, approve it in part and reject it in part, or reject it, as filed pursuant to these regulations, only upon a finding, after hearing, conducted in accord with _____, that the action plan is in the public interest, and substantially complies with these regulations;

(e.) Approval of an action plan constitutes only approval of the programs contained in the plan. The prudence of the expenditures to be recovered will be reviewed by the Commission in a separate proceeding in accordance with _____, above, or in a general rate proceeding, as may be appropriate;

(f.) Every six (6) months after the approval of a two (2) year *(or three year)* action plan the utility shall submit to the Commission and other parties to the proceeding a progress report of the actions taken and expenditures incurred to implement the action plan. This report shall compare the expenditures budgeted and incurred, the actions proposed and taken, and explain any significant deviations from the utility's approved action plan. Any party of record may request the Commission hold a hearing on the report.

^^07.2 Working Groups.

(a.) A least-cost working group shall be formed for each utility which is composed of representatives from: *(specify at minimum the effected utilities, commission staff, advocate's office).*

(b.) Each entity represented, as listed above, shall have one vote. Votes shall be non-binding, and shall be advisory only;
(c.) All meetings of the working group shall be open to other intervenors to the plan proceeding, interested parties, and the general public;
(d.) The utility shall chair the working group and schedule meeting as necessary;
(e.) Working Group meetings shall be scheduled on a periodic basis between plan filings for the purpose of:

1. Learning of utility progress in developing plans and plan amendments;
2. Determining whether key assumptions are reasonable and are being applied in a consistent manner;
3. Determining whether models and modeling techniques are reasonable and consistent;
4. Determining whether key results are reasonable;
5. Determining whether progress on the activities described in the utility's most recently approved two (2) year action plan are consistent with the plan;
6. Offering recommendations and suggestions as appropriate.

(f.) The utility shall prepare a summary of the agendas and the conclusions reached by the working group, if any, at each meeting. The summaries shall be filed with the utility's plan.

^^07.3 Amendment of the plan. The utility may apply for permission to amend its plan before it submits its next plan if:
(a.) It anticipates submitting an application for a permit to construct a generating or transmission facility, or purchase interest in generating or transmission capacity pursuant to the provisions of _____ of the Commission's regulations, which was not previously approved as part of a two (2) year action plan;
(b.) It anticipates the need to make a binding commitment for the acquisition or construction of a supply or demand resource which was not previously approved as part of a two (2) year action plan;
(c.) The basic data used in the formulation of its last approved plan requires significant modification which affects the choice of a resource which was approved as part of a two (2) year action plan;
(d.) The conditions under which an amendment is sought must be specifically set forth in the application for amendment.

^^07.4 Severability. If any provision of this Chapter is held invalid, the Commission intends that such invalidity not effect the remaining provisions to the extent that they can be given effect.

^^08.0 COST RECOVERY

^^08.1 Recovery of cost of developing plan
(a.) All costs incurred by a utility in developing its plan must be accounted for in its books & records separated from amounts attributable to any of its other activities. All accounts, including

subaccounts, must be maintained in such a manner as will allow these costs to be identified readily. These costs must be segregated into the same categories as specified in the budget for the plan of action.
(b.) The commission will consider all prudent & reasonable costs incurred by a utility in developing its plan to include all costs of trial programs.
(c.) A balancing account treatment may be used to recover the cost of developing the resource plan.
(d.) Prior approval of the amount to be charged or credited must be obtained from the commission.

^^08.2 Recovery of costs to implement programs for conservation and load management.
(a.) All prudent and reasonable costs incurred by a utility in implementing full programs for conservation and load management which have been approved by the commission as part of the utility's plan of action are eligible for recovery through general rates pursuant to the established procedures for adjusting general rates.
(b.) At the commission's hearing to consider the utility's plan, the utility shall demonstrate the projected amount and duration of the savings in energy and demand of all proposed full programs. The commission will treat appropriate preapproved costs associated with those programs for conservation and load management as operating expenses or as ratebase.
(c.) All full programs previously ordered or approved by the commission for implementation before the filing of the utility's next plan will be treated as operating expense or as ratebase.
(d.) All costs of implementing the programs for conservation and load management must be accounted for in the utility's books and records separately from accounts attributable to any other activities. All accounts must be maintained in such a manner as will allow these costs to be identified in readily. Costs attributable to specific programs must be readily identified. These costs must be segregated into the same categories as specified in the budget for the plan of action.

APPENDIX C
STATUS OF STATES' LEAST COST UTILITY PLANNING SURVEY RESULTS

The folowing survey questions were ask in April of 1989 of the same state regulators who participated in the EPRI December 1988 survey on the status of Least Cost Utility Planning in the United States.

Due to rapid changes in the utility planning field you should update these responses to ensure the most accurate information regarding the status of LCUP in your state.

Survey Questions:

1. Is there a statutory, regulatory, or case law requirement to have each electric utility regularly submit to regulators a utility-developed long-term resource plan which integrates demand- and supply-side resource alternatives?

2. Do regulators hold public hearings on the plan and accept input from other parties?

3. Do regulators specifically approve the plan?

4. Are utilities required to implement and follow the regulator-approved plan for next resource acquisitions?

5. Before a utility can receive a permit to construct a generation or transmission facility, must that resource be in an approved resource plan?

6. Is there opportunity for interim input (i.e. workshops) ?

7. Have hearings on any plan submitted been held yet?

ALABAMA
Charles Stults, Public Service Commission (205) 261-5868
1. No. No least cost planning activities anticipated due to 35% excess capacity.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

ALASKA
Mike Tavella, Public Utilities Commission, (907) 276-6222
1. No. There has been no reintroduction of 1987 LCUP legislation. Recent strategy includes trying to get LCUP started through establishing a body of case law history, beginning with Staff recommendations on alternative rate design

proposals other than incentive rates to potential cogeneration and by-pass customers
(Ranking: 0)

ARIZONA
David Berry, Arizona Corporation Commission (602) 542-4251
1. Yes. There is a LCUP regulation in place as of February 1989 requiring for the 4 effected utilities that plans be filed once every 3 years.
2. Yes
3. No. The PUC will only evaluate the plans. Staff will also conduct their own independent analysis.
4. No
5. No. The PUC would probably look askance at utility failure to include a requested resource in previous LCUP plans. Requests for permits to construct generation or transmission facilities is made by a state Siting Board made up of members from various agencies, which includes the commission chairman.
6. Not specifically established in the rules. The commission expects there to be workshops. Utilities are required once a year to make a filing updating demand and supply side data.
7. No, first filing 1990
(Ranking: 3)

ARKANSAS
John Strode, Public Service Commission (501) 682-5685 (Donna Campbell has left the Commission since the EPRI survey.)
1. No.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

CALIFORNIA
Eric Woychik, Public Utilities Commission (415) 557-1997
1. Yes
2. Yes
3. Yes
4. Yes
5. Yes
6. Yes
7. No The new integrated provision is just out with testimony to be filed in May. The PG&E rate case in February 89 did contain integration principles using 1990 test year. Reference Docket 88-12009.
(Ranking: 4)

COLORADO

Warren Wendling, and Gary Schmitz Public Utilities Commission (303) 894-2033

1. No. Supply side bidding is being implemented by the PUC It is the position of the utilities that a statute is needed to implement a state LCUP process 15 PUC positions were cut in 1987 to give the message that LCUP wouldn't be tolerated. The bidding process is currently disjointed with no recognition of demand side resources. There is an agreement to begin 5 pilot projects including a limited demand side bidding program even though Public Service of Colorado does not want to integrate demand side pilots. The calculation of avoided cost and the use of the no losers test are still being debated.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A

(Ranking: 0)

CONNECTICUT

Paul Horowitz, Public Utility Control (203) 827-1553

1. Yes. There is a series of case law and statutory requirements that come together to require Connecticut's two major electric utilities to conduct least cost planning analysis. Every April the utilities are required to make an avoided cost filing that includes all of the components generally considered in a least cost plan. Connecticut is in the process of adopting regulations on competitive bidding and for ratebasing incentives for demand-side resources.
2. Yes
3. Yes
4. Yes
5. No. There is a separate Siting Council on which a member of the commission participates. While there is no statutory enforcement linkage between the resource plans and permits to construct, Mr. Horowitz believes it would be very difficult to construct a resource not in a commission-approved avoided cost filing.
6. Yes
7. Yes

(Ranking: 4)

DELAWARE

Dennis Maczyknski, Public Service Commission (302) 736-3227

1. No. Though there is no commission regulation, the state's one major electric utility, Delmarva P&L made in 1987 a 20 year load and resource plan that included DSM potential called "Challenge 2000". The 1987 filing was considered phase 1; with the commission now reviewing phase 3. It is expected that these periodic filings will continue.
2. Yes
3. Yes
4. Yes

5. Yes
6. Yes
7. Yes
(Ranking: 4)

DISTRICT OF COLUMBIA
Phillip Cross, Public Service Commission (202) 626-5100
1. No. A regulation is pending before the commission for approval.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 2)

FLORIDA
Jim Dean, Public Service Commission, (904) 488-8501.
1. No. While there is not one statute or regulation that requires least cost planning, there are two statutes passed in the late '70's early '80's that require conservation assessment and needs determination. In combination, the result is least cost planning.
2. Yes
3. Yes
4. No
5. No
6. Yes
7. Yes
Ranking: 4)

GEORGIA
James Cole, Public Service Commission (404) 656-4501
1. No. However, rulemaking process has been initiated by the Commission.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

HAWAII
Mr. Tsumura, Administrative Director at the Public Utilities Commission, (808) 548-3990
1. No. The PUC has hired Synergic Resources to do a study on LCUP. The draft study has been prepared with the recommendation that the utilities do least cost planning; however it is still uncertain at this time what procedural mechanism will be recommended for implementation of a LCUP process.
2. N/A

3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

IDAHO
Tom Faull, Public Utilities Commission (208) 334-3143
1. No. Commission taking a wait and see attitude towards LCUP. Utilities question cost-effectiveness of conservation given current surplus capacity.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

ILLINOIS
Dave Hutchinson, Illinois Commerce Commission (217) 782-2743
1. Yes
2. Yes
3. Yes
4. Yes
5. Yes
6. Yes
7. No.
(Ranking: 3)

INDIANA
Greg Turk, Public Service Commission (317) 232-2756
1. No. There is no statutory or regulatory requirement for utilities to conduct least cost planning. The state's certificate of need process contains language requiring comparison of proposed new capacity with other options, including DSM. The first certificate of need hearing pursuant to this language is scheduled for September 1989. The Commission requested that a utility conduct a least cost analysis. They came back with a long term analysis by Stone and Webster using a production costing model that considered a few supply side options with DSM "implicitly" considered. Staff will be using this hearing and others to develop case law basis for developing a formalized LCUP process through statute or regulation.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

IOWA

Gordon Dunn, Iowa Utilities Board, (515) 281-5893

1. Yes. As cited in the EPRI survey, utilities are required since 1982 to file on an annual basis long range resource plans. However, to date Iowa utilities have never complied with this requirement claiming that excess capacity makes it unnecessary to do long range planning.

The record peak demands of the summer of 1988 changed all of this with the utilities requesting in the Fall of 1988 through the state's plant certification process permission to construct a new generation facility. The Board is having to hold hearings without the benefit of a long range resource plan.

2. Yes
3. Yes.
4. No.
5. No. Utilities can file a permit to construct for a facility without that facility being in an approved resource plan.
6. Yes
7. No

(Ranking: 3)

KANSAS

Shirley Sicilian, Corporation Commission, (913) 296-2757

1. No. LCUP is still just in discussion stage. The Commission has hired staff person to study least cost planning and make recommendations back to the Commission.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A

(Ranking: 0)

KENTUCKY

Micheal Alexander, Public Service Commission, (502) 564-2982

1. No. The state is essentially at same stage as that cited in EPRI survey. The task force established in 1986 has been on hold until recently. The Commission staff has recently issued an order initiating a LCUP process.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A

(Ranking: 0)

LOUISIANA

Robert Crowe, Public Service Commission (504) 342-4404

1. No. No commission actions or interests expressed.

2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

MAINE**
Norman Leonard, Public Utilities Commission (207) 289-3831
1. Yes The state's LCUP process focuses more on bidding than LCUP as defined in this manual. This represents a new "hybrid" approach to least cost planning.
2. Yes
3. Yes
4. Yes
5. Yes
6. Yes
7. Yes
(**Ranking: 4, even though the state's process does not conform to LCUP as defined in this manual)

MARYLAND
Doug Kinney, Public Service Commission, (301) 333-6022
1. Yes. Since 1976 there has been a statutory provision requiring the filing on an annual basis long-range plans which include "...adequate provisions to promote energy conservation in order to decrease or moderate electric... demand from their customers.".
2. No, unless Staff or another interested party petitions the commission for a hearing.
3. No.
4. N/A
5. Yes. Utilities must file a certificate application 2 years prior to planned construction. By law utilities are required to justify the resource as least cost.
6. Yes. The commission staff on an annual basis conducts extensive discovery prior to plan submission.
7. No
(Ranking: 3)

MASSACHUSETS**
Catherine Morris, Department of Public Utilities (617) 727-3500
1. Yes. The state's LCUP process focuses more on bidding than LCUP as defined in this manual. This represents a new "hybrid" approach to least cost planning.
2. Yes
3. Yes
4. Yes
5. Yes
6. Yes

7. No
(**Ranking: 4, even though the state's process does not conform to LCUP as defined in this manual)

MICHIGAN
Geoff Crandall, Public Service Commission (517) 334-6445
1. Yes. Consumer's Power Co. has been directed by the Commission through case law to file a resource plan. Detroit Edison already does on a voluntary basis.
2. There will be hearings.
3. The Commission will specifically approve or reject.
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

MINNESOTA
Katie O'Connell, Department of Public Service (612) 296-8663
1. No
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

MISSISSIPPI
Keith Powell, Public Service Commission (601) 961-5400.
1. No
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

MISSOURI
Martin Turner, Public Service Commission, (314) 751-7494
1. No, LCUP is still in the discussion stage with no timetable announced. The commission authority to require resource plans as stated in the EPRI study refers to just the Commission's general oversight authority.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A

7. N/A
(Ranking: 0)

MONTANA
Dan Elliott, Public Service Commission (406) 444-6199.
1. No. A task force has been established as a result of an ongoing rate case to look at least cost planning for Montana Power. This is not a commission-ordered or directed task force, but rather a "self motivated" approach between the commission staff and the utility. The task force will probably issue a joint resource plan for Montana Power that addresses the next two years of load and resource needs. The commission is concerned that if they get too involved they will get caught in a pre-approval trap.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

NEBRASKA
John Doudna, Nebraska Public Power District (402) 536-4071.
1. N/A. All public power, no ratemaking authority.

NEVADA
Frank McRae, Nevada Public Service Commission (702) 885-4180.
1. Yes
2. Yes
3. Yes
4. Yes
5. Yes
6. Yes
7. Yes
(Ranking: 4)

NEW HAMPSHIRE
Janet Besser, Public Utilities Commission (603) 271-2431. (Mark Collin has left the commission since the EPRI survey.)
1. Yes. Order issued by commission in April 1988. First filings are due May 1, 1989, and every two years thereafter.
2. Yes
3. No. The commission will review and issue recommendations.
4. No. Because the plans are not formally approved, the utilities are not explicitly bound to them.
5. No. There is a separate state Siting Board, with the chairman of the commission a member. While there is no statutory enforcement linkage between resource plans and the siting board, Ms. Besser believes the siting board would not easily issue a permit to construct a resource not in a resource plan.

6. Yes.
7. No.
(Ranking: 3)

NEW JERSEY
Rene Demuynck, Board of Public Utilities, (201) 648-4968.
1. Yes. The plans are developed usually on an annual basis and most of the time are submitted to the Board. The Board is starting to review and make modifications based on the role they play in determining the amount of resources to be let out in competitive bid.
2. No
3. No
4. No
5. No
(Ranking: 2)

NEW MEXICO
Buddy McDowell, Public Service Commission, (505) 827-6940
1. Capacity construction has to be approved by the Commission and is under their review.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

NEW YORK**
Sam Swanson, Public Service Commission (518) 474-8702
1. No. The state is backing off integration and going to full scale bidding. The PSC is placing alot of faith in the bidding process. Utilities can go lower than the bid and can also bid in its own auction. The PSC just approved a bid plan for Orange & Rockland. There is no integration between the demand side management plan and bidding. The next plans will be filed in October 1989 and will reflect bidding.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(**Ranking: 4)

NORTH CAROLINA
James McLawhorn, Utilities Commission (919) 733-2267
1. No. The commission issued an order in December 1988 which sets forth guidelines and a first-cut rule on LCUP. Hearings are scheduled for September 1989.

2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 1)

NORTH DAKOTA
Jerry Lein, Public Service Commission, (701) 224-2400
1. No. The state's three IOU's file annually a 10-year project of loads and supply-side resources, with a status report on what they are doing in the area of conservation. The reports are filed on a voluntary nature by 2 of the utilities, and under Commission order by the third.
2. No. For the two utilities that file voluntarily, the Staff just reviews; for the one filing under commission order, the Staff will review and make a motion to the commission to either adopt or reject.
3. See 2
4. No
5. No. Utilities in North Dakota can build what they want without a need determination. Siting cases evaluate facility locations only. It is the utilities responsibility to evaluate their own need which they have to justify before they can get cost recovery.
(Ranking: 0)

OHIO
Kerry Stroup, Public Utilities Commission (614) 466-6305
1. No In 1987 there was a failed attempt to get consensus for a statute. The commission went forward under generic authority with the first proposed rules in November 1988; with revised rules issued April 1989 for a new round of comments. The new chairman and others at commission want to look at rates, market forces and competitive bidding as alternatives. The proposed rule does require biannual submittals of integrated LCUP to commission for review and approval. with a hearing required every four years, or more often based on good cause. Need determination by siting authority is determined by commission in LCUP proceeding.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 1)

OKLAHOMA
Glenn Gregory, Corporation Commission (405) 521-2264.
1. No. LCUP receiving only minimal consideration.
2. N/A
3. N/A

4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

OREGON
Lee Sparling, Public Utility Commission, (503) 378-6137
1. Yes. Commission order establishing a least cost rule is just out in April 1989.
2. Yes.
3. Not directly. The commission will "acknowledge" plans, not formally approve. The commission is worried that this could establish preapproval of costs.
4. No specific requirement.
5. No. Siting decisions are made by a separate governmental entity, the Energy Facilities Siting Council. Mr. Sparling presumes that there will be some type of linkage
6. Yes
7. No
(Ranking: 3)

PENNSYLVANIA
Blaine Loper, Public Utility Commission (717) 783-1373
1. Yes
2. No
3. No
4. No
5. No
6. No
7. No
(Ranking: 2)

RHODE ISLAND
Mary Kilmarx, Public Utilities Commission (401) 227-3550
1. No. The state has a consensus demand side management program, but no LCUP process as defined in this manual.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

SOUTH CAROLINA
Bill Sheely, Public Service Commission (803) 737-5110.
1. No. No statute has been passed. The commission has opened a docket on least cost planning. Hearings are expected the end of 1989 or the beginning of 1990. In preparation for the hearings, utilities are suppose to develop and file

long-range resource plans. The hearings will most likely address the adoption of regulations and review of utility resource plans.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 1)

TENNESSEE
Hal Novak, Public Service Commission (615) 741-3939
1. No. The commission is not considering LCUP as almost all electric power is through TVA.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

TEXAS
Nat Treadway, Public Utility Commission (512) 458-0310
1. No. While there is the requirement that utilities file a ten-year load and capacity report and always trying to integrate through the state plan they prepare. The utilities do not consider conservation as a demand-side resource, even though Staff does.
2. No. Staff just trys to work out the "wrinkles" with the utilities.
3. N/A
4. N/A
5. No. While a utility could bring forward a resource to construct that had never been in a ten-year load and capacity report, the utilities would have to explain why.
6. No.
7. No.
(Ranking: 3)

UTAH
Rodger Weaver, Division of Public Utilities (801) 530-6771
1. No. LCUP only under general consideration.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

VERMONT
Mike Dworkin, Public Service Board (802) 828-2358
1. No. The Department of Public Service (staff to the Public Service Board) is issuing a "Statement of Policies" to the Board on least cost planning. An order on LCUP is expected to follow, with the first plans filed by the summer of 1990. This is considered the second interaction in the development and implementation of Vermont's least cost planning process given the existing requirement that the Department of Public Service prepare a 20-Year Electric Plan.
2. N/A
3. N/A
4. N/A
5. N/A. The existing body of law would prohibit utilities from seeking permission to construct resources because utilities have to show resource need cannot be met more cost effectively through demand-side resources.
6. N/A
7. N/A
(Ranking: 3)

VIRGINIA
Bob Lacy, Corporation Commission (804) 786-3611
1. Yes.
2. No.
3. No. Staff reviews the plans and sometimes meets with the utilities. Considers the construction permit proceedings the time the commission can review their planning decisions.
4. No.
5. No.
6. Yes.
7. No.
(Ranking: 2)

WASHINGTON
Bruce Folsom, Utilities Division (206) 753-6423
1. Yes
2. Yes
3. No. The commission only reviews with neither approval or rejection.
4. No. Legally no, but from a policy perspective, yes.
5. No
6. Yes
7. Yes
(Ranking: 4)

WEST VIRGINIA
Earl Melton, Public Service Commission, (304) 340-0392
1. No. The utilities are only required to submit on an annual basis a 10 year forecast of loads with a supply capacity expansion plan; no demand side analysis.
2. N/A

3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

WISCONSIN
Steve Brick, Public Service Commission (608) 267-3592
1. Yes
2. Yes
3. Yes
4. Yes
5. Yes
6. Yes
7. Yes
(Ranking 4)

WYOMING
Phil Lehr, Public Service Commission (307) 777-7427
1. No. LCUP is not even under consideration.
2. N/A
3. N/A
4. N/A
5. N/A
6. N/A
7. N/A
(Ranking: 0)

END

DATE
FILMED
4/15/92