ETO

# LEAST-COST UTILITY PLANNING

## A HANDBOOK FOR PUBLIC UTILITY COMMISSIONERS

National Association
of Regulatory Utility Commissioners

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# PLANNING HANDBOOK FOR

# PUBLIC UTILITY COMMISSIONERS

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**Regulatory Utility Commissioners**
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# A LEAST-COST PLANNING HANDBOOK FOR PUBLIC UTILITY COMMISSIONS

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# FOREWORD

This handbook has been prepared as a guide to the subject of least-cost planning (LCP). It is intended to serve commissioners and senior staff as a primer on the process.

It is not intended as a detailed, step by step "cookbook" on least-cost planning. Each state must find its own way based on its particular situation. Each commission operates within a different statutory framework, and each regulates a group of utilities facing different operating and marketing situations. Therefore, each state will evolve in a different manner.

There are, however, similarities among states and among certain least-cost planning concepts. The experiences of one State can be used as a building block in developing the least-cost process in another. Wherever possible the handbook contains examples of how individual states have handled a particular issue. These commissions can be contacted for further details.

For those persons desiring additional information, references are footnoted in the text and cited at the end of each chapter. In addition, a bibliography of publicly available material is appended.

Volume II, a more technical work, is currently under preparation by the Lawrence Berkeley Laboratory in California and will be published soon.

# EXECUTIVE SUMMARY

Regulators have traditionally required extensive economic analyses when public utilities have requested rate hikes, additional generating capacity, expanded distribution capability, or power purchases. The regulators have then judged the requested action in terms of the economics of the situation. However, economic analyses often do not take into account environmental effects, social impacts, and the risks and uncertainties associated with changing economic and social climates. Moreover, although economic analyses can produce meaningful results concerning the production of electricity (the supply side of the service), they can fail when applied to the consumption of electricity (the demand side).

Least-cost planning is a way of analyzing the growth and operation of utilities that considers a wide variety of both supply and demand factors so the optimal way of providing electric service to the public can be determined. A path is chosen that will ensure reliable service for the customers, economic stability and a reasonable return on investment for the utility, environmental protection, equity among ratepayers, and the lowest costs to the utility and the consumer. A least-cost plan balances three interests (reliability, profitability, and affordability) while keeping a sharp eye on the risks and uncertainties associated with each component of the plan. Moreover, through periodic review and reassessment, least-cost planning detects changes in the economics of providing electric service and allows corrections to be made. These changes allow the utility to cope with unexpected changes in fuel costs, variations in demand, advances in technology, or other changes affecting the utility's economics. This flexibility of least-cost planning allows utilities to respond to the ups and downs of the national and regional economies and minimizes the social impacts that the operations and costs of utilities can have on an economy, especially a depressed one.

Finally, least-cost planning often reveals opportunities to save fuel and thereby reduces the environmental impacts of utilities' operations.

Least-cost planning usually consists of a number of discrete steps:

1. Identifying the objectives of the plan (e.g., reliable service, minimal environmental effects, low cost of environmental controls, meeting peak demand in a cost-effective manner, and a reasonable price for consumers).

2. Developing one or more load forecasts.

3. Determining the levels of capacity expected for each year of the plan.

4. Identifying needed resources (e.g., fuels, generating capacity, distribution capability, a manageable load shape, and perhaps periodic decreased demand).

5. Evaluating all of the resources in a consistent fashion.

6. Selecting the most promising options for fashioning an effective, flexible, and responsive plan.

7. Integrating methods of supplying needed power with methods for controlling and moderating demand.

8. Constructing scenarios, pitting the selected mixes of options against possible economic, environmental, and social circumstances.

9. Evaluating the economic and technical success of each mix of options under the circumstances of the various scenarios.

10. Analyzing the uncertainty associated with each possible plan of action.

11. Screening the alternatives to eliminate those that are not suitable.

12. Rank ordering the alternative courses of action.



13. Testing each alternative for cost effectiveness from a variety of viewpoints (e.g., the utility, ratepayers of different classes, and society).

14. Reevaluating the alternatives considering economic, environmental, and societal factors.

15. Selecting and approving a plan for implementation, one that most nearly satisfies all the objectives of the plan.

16. Developing a plan of action.

17. Implementing the plan of action to bring about the least-cost provision of electric power.

18. Monitoring and evaluating the operation of the utility under the plan and revising the plan as necessary.

Least-cost planning is not without its difficulties and limitations. Primary among them is that it deals with a whole new array of factors about which little is known. For example, although much is known about fuel availability, distribution losses, and the probability of generator downtime, little is known about how demographics determine demand for electricity, how prices of electricity and other fuels affect electricity usage, how electricity consumption is distributed among all its end uses, and how changes in technology (e.g., domestic refrigeration) affect demand. As a result, when least-cost planners attempt to factor these influences into their projections, data are often lacking and must be developed through research. The quality of the data then affects the certainty of the projections and the reliability and usefulness of the resulting plan. This is not to say that such data cannot be produced in a replicable, timely, and cost-effective manner. Indeed, the data base on such variables is constantly growing, and the generalizability of the data is also being expanded as regional variability is being studied and correlated.

Experience has also shown that at least two planning horizons should be employed, one for forecasting demand and assessing scenarios and the other for assessing the actions contemplated by the utility. The first horizon should recognize the limitations on foreseeing the future; it should be limited to the period for which reasonably accurate estimates can be produced. The second should recognize that any power plant that is constructed is going to be around for quite a while; it should be long enough to encompass the lifetime of such a plant.

In addition to these two planning horizons, an action plan should be formulated. This action plan should specify all of the resource acquisition and allocation that the utility plans to accomplish in the near future (i.e., the next two years). This action plan provides the utility a workable roadmap to follow for the next couple of years, and it provides the commission a benchmark against which to judge the utility's subsequent actions.

The development and availability of commercial and public-domain software for carrying out specific tasks have also simplified least-cost planning and lessened the uncertainty associated with it. Such software is available for risk and uncertainty analysis, demand forecasting, production-cost modelling, energy-use modelling, econometric modelling, uncertainty analysis, end-use modelling, cost-effectiveness testing, decision analysis, financial analysis, and rate designing.

Having these tools available, however, does not absolve the planner from understanding how they are used and when they should be used. In particular, the planner should be careful not to use inconsistent methods of analysis for supply-side options and demand-side options. Such use of different methods can bias evaluations. All resources,



whether supply- or demand-side, should be assessed in a comparable and consistent manner.

Once a least-cost plan has been prepared, its provisions can be converted into reality in a variety of ways. Pilot programs can be used to research the effectiveness of the plan and the technologies it uses, to produce information on program costs and benefits, and to introduce a program and establish its delivery system. Market-based procedures can be employed, such as allowing different providers of electricity and other energy services to bid against each other for the right to provide that service. And regulatory actions can be used to encourage utilities to adopt least-cost paths by allowing the utility to recover its investment in demand-side projects (and perhaps even realize a profit) through expensing or rate basing.[1]

In summary, the analytical tools and methods of least-cost planning allow utilities and regulators to project and assess the effects of a utility's future actions, such as retiring old generating plants, constructing new base-load plants, constructing new peak-load plants, using various mixes of fuels, using purchased power strategically to meet demands, realigning or upgrading distribution systems, setting rate structures, encouraging conservation, and offering incentives for actions that will moderate the daily and seasonal load shapes. The results of these analyses will, in turn, allow planners (utility and regulatory alike) to select the mix of available options that will best suit the needs and interests of customers, the power industry, government, and society in general.

## END NOTE

[1]See for example the paper contained in the proceedings of the NARUC's Least-Cost Planning Conference held in Aspen, Colorado, April 10-13, 1988 delivered by Commissioner David Moskovitz titled, "Will Least-Cost Planning Work Without Significant Regulatory Reform?". Copies of the proceedings are available through the NARUC.

## A Least-Cost Planning Handbook
## for Public Utility Commissions

### I. INTRODUCTION

Today, electric utilities operate in a world far different from that of the past. Demand growth rates are lower, economies of scale are not as predictable or as pronounced, planning is subject to greater uncertainty, competition is stiffer, and more players crowd the field. As a result, regulators and utilities must be able to anticipate changes in technology and the economy rather than just react to them. And they must be able to cope with and take advantage of the broad range of resources (fuels, power-generation technologies, conservation techniques, etc.) now available to electric utilities.

Least-cost planning (LCP) is a planning process that can be used by utilities in forecasting needs, assessing uncertainties, and hedging risks. The planning process can then be reviewed and used by regulators to help judge the suitability of proposed changes in the utilities' operations.

Least-cost planning has been called by a number of names, such as least-cost utility planning, least-cost energy planning, integrated resource planning, or combinations of these. As described in this handbook, LCP is a strategy whose goal is to provide reliable electrical services at the lowest overall cost with a mix of supply-side and demand-side resources, a flexible system that helps utilities and regulators to respond to uncertainties and to cope with risks.



Least-cost planning methods can help regulators attain their traditional goals, including economic efficiency, adequate and reliable service, environmental quality and safety, and equity among interested parties:

> Least-cost planning strives to satisfy the expected demand for energy services from the least costly mix of supply additions and energy-efficiency improvements, thus resulting in economic efficiency.
>
> Least-cost planning can result in a flexible and diversified plan able to respond to uncertainty and to minimize risk by using both short- and long-lead-time responses to current needs and expected demands. This flexibility and diversity helps to ensure adequate and reliable service.
>
> Least-cost planning attempts to meet demand at the lowest cost. The lower costs incurred by a utility because of LCP should make it easier to strike a balance among the revenue contributions of the various customer classes. At the same time, the risk sharing and risk management built into LCP should help achieve perceived equity among the utility, its shareholders, its customers, and other involved parties.

Because of these advantages, LCP is being used more and more as a planning technique. Nearly two-thirds of the states have some least-cost activity underway. According to a survey conducted in 1987 by the Arizona Corporation Commission,[1] 17 states are involved in LCP, 4 include LCP elements in other programs, 8 are developing an LCP program, and 4 are considering undertaking such a program.

This broad interest by regulatory commissions prompted the NARUC Committee on Energy Conservation to suggest the preparation of an LCP handbook. The U.S.

Department of Energy provided a grant to fund this activity.

This handbook is designed to answer three basic questions for commissioners and utility-commission senior staff:

1. What is LCP?
2. How does LCP work?
3. Why should utilities and commissions undertake LCP?

It then provides general guidelines on how to prepare and implement an LCP.

## END NOTE

[1]Arizona Corporation Commission, "Regulatory Institutions for Least-Cost Energy Planning," Appendix I in 1987 Report of the Committee on Energy Conservation, National Association of Regulatory Utility Commissioners, Washington, D.C., 1987, p. 59.



# II. WHAT IS LEAST-COST PLANNING?

## TRADITIONAL VS. LEAST-COST PLANNING

With traditional utility planning, the planner takes into consideration the demand to be met, the reliability to be achieved, and the applicable state and federal regulations regarding safety and the environment to be complied with. Then he or she selects the types of fuels, power plants, distribution systems and patterns, and power purchases that will meet these objectives with the minimum revenue requirement. Two aspects of this type of planning should be noted. Demand is taken as a "given" as opposed to a variable that can be altered. And options are selected only from the supply side (as opposed to the consumption or "demand" side) of the electricity system. Traditional utility planning makes no attempt to integrate supply and demand-side options.

Least-cost planning attempts to take this traditional concept several steps further. It strives to:

1. minimize costs to all stakeholders;
2. evaluate all options, from both the supply and demand sides, in a fair and consistent manner; and
3. create a flexible plan that allows for uncertainty and permits adjustment in response to changed circumstances.[1]

Examples of the options that traditional utility planning and LCP draw upon and choose from are listed in Table 1 on the following page.

**Table 1**

**Examples of resource options**

| Supply-side options | Demand-side options |
| --- | --- |
| **Conventional plants:** | **Energy-efficiency options (customer):** |
| Large fossil-fueled | Home weatherization |
| Nuclear | Energy efficient appliances and lighting |
| Small combustion turbines | High efficiency heating, ventilating, and A/C |
| Life extensions of existing plant | Passive solar modifications |
| Transmission expansion or upgrade | **Energy-efficiency options (utility):** |
| **Non-utility-owned generation:** | More-efficient motors |
| Cogeneration | Reduced transmission losses |
| Small-scale hydro | Advanced transformers |
| Self-generation | Load Management |
| Independent power producers | Utility control of appliances |
| **Purchases:** | **Rates:** |
| Requirements transactions | Time-of-use |
| Coordination transactions | Interruptible |
| **Renewables:** | Incentive |
| Geothermal | |
| Solar | |
| Wind | |



## THE BENEFITS OF LEAST-COST PLANNING

The traditional goals of utility regulation are economic efficiency, reliable service, environmental protection, and equity. Reliable service necessitates the balancing of customer and investor interests (i.e., balancing the quality of service against cost). Equity necessitates the additional balancing of the interests of the various customer classes as well as of the interests of present and future generations.

Least-cost planning makes it easier to strike a balance among these traditional goals by considering all supply and demand options as potential contributors and by integrating them into a common framework. The result is an opportunity to achieve lower overall costs than might result from just considering supply-side options. Further, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.

How LCP makes it easier to strike balances among and between goals can be seen by comparing how each approach treats reliability. Traditional planning defines reliable service as the ability to meet demand at all times. In an engineering sense, this means maintaining sufficient generating reserves to meet a perceived cost-effective reliability criterion, generally defined as an outage once in ten years, or a loss-of-load probability of 0.1. Least-cost planning, however, views demand as a manipulable variable; demand does not always have to be met. Rather, rate options (such as interruptible rates for large users) might be used as a cost-effective substitute for a portion of the generating reserves. Such a strategy trades off a constant meeting of demand for savings in the required capital investment in generating plants and transmission facilities.

All utility plans must deal with risk. Risks arise from uncertainties, which range from the nature of future acid rain legislation to the actual performance characteristics and ultimate cost of resources. In many instances, the risks from various uncertainties will overlap. For example, the risks associated with future inflation and interest rates play an important role in the perceived risks regarding the future cost of new power plants.

The planner must manage uncertainties so that exposure to risk is minimized. Techniques for managing uncertainties include hedging, risk sharing, diversification, and flexibility. Supply-side planning can provide a measure of each of these attributes. For example, a utility might include combustion turbines in a predominantly coal-fired system in partial substitution for efficiency improvements. Such a step might be taken despite that fact that it is not the lowest-cost economic alternative because it would assure reliability and provide fuel diversity. The diversity, in turn, could also serve as a hedge against changes in clean-air requirements, in fuel costs, or in fuel availability.

Least-cost plans usually allow greater diversification because they draw upon a larger number of options. Also, the contribution of each resource tends to be smaller because more resources are sharing the load. With smaller contributions from each resource used, subsequent changes can be made with little or no detrimental effect. This diversity and flexibility permit modification, over time, to take account of events not envisioned when the plan was instituted.

The role played by a commission in least-cost planning is similar to that played in traditional planning. The commission is still charged with issuing the "rules of the game" and overseeing the implementation of those rules. But traditionally, regulation has examined utility costs (exclusive of plant construction) after the expenditures had been



made. Under least-cost planning, the investment proposals of the utility are scrutinized before they occur. This prior review and approval has many benefits.

An important benefit for the utilities is that the increased regulatory involvement in the planning process together with commission approval of the least-cost plan may limit the regulator's subsequent willingness or ability to disallow an investment that is consistent with the plan.[2] On the regulatory commission's side, this perceived reduced ability to disallow expenditures is compensated for by shared planning responsibility between the regulator and the utilities and greater access to the planning process for the regulator and the public.

The insertion of the commission and the public into the process should improve the quality of planning by introducing new perspectives. For example, in Wisconsin a utility group proposed 352 miles of new 345-KV lines to bolster system reliability. A comprehensive transmission planning and evaluation effort involving interveners, the utility, and commission staff found that lower voltage lines could be upgraded and the 345-kV transmission construction could be reduced to 35 miles with no loss in reliability. Savings were estimated at $80 million.

In another case, the Nevada Public Service Commission (PSC), as part of its review of the Nevada Power Company's least-cost plan, rejected a proposal to purchase 100 MW of the Hunter III coal-fired unit in Utah and to construct connecting transmission lines. The commission felt this was not the least-cost alternative. A year later, Nevada Power amended its resource plan to include a significantly less expensive transmission-purchase option than the original Hunter III proposal. As a consequence, southern Nevada ratepayers will realize significant cost savings as the plan is implemented.

## BARRIERS TO LCP

Commissions seeking to develop a LCP process must address several threshold issues: developing an operational definition of "least cost," getting utilities to recognize the benefits of LCP and to cooperate in the preparation of an LCP, and finding the proper role of the public utility commission under LCP.

### The Meaning of "Least Cost"

Different versions of LCP are used by different utility commissions. The common elements in these various approaches include the point that both supply-side and demand-side options should be considered and that these should be assessed in a consistent, integrated manner. These elements can be seen in the definition of LCP of the PSC of Wisconsin: "... a process in which all reasonable options for both supply and demand are assessed against an array of cost-benefit considerations which are defined as broadly as possible."[3] This sounds like a simple and straightforward definition of LCP, but other regulatory commissions could interpret it in a different manner than the Wisconsin PSC does. The major difference among the regulatory bodies is the criterion used to measure least cost. Even though differences in LCP interpretation can exist among jurisdictions, 2 States, Wisconsin[3] and Nevada[4] as conveyed in Table 2 (page 17) utilize on a general basis a common approach.

### The Cooperation of Utilities

Some companies may be suspicious of LCP and uncertain of its advantages. Involving them in the procedure at an early date may help to allay those fears and result in more-enthusiastic future participation. This involvement can be accomplished through conferences, workshops, and meetings.



Despite the best efforts of the regulators to involve the utility in the preparatory phases of a least-cost plan, the company may find it difficult to comply because of institutional problems. An example of such an institutional problem would be poor relations and little cooperation between a utility's management and a commission. Another would be the case where a utility's engineering department spent five years on the design, site selection, and preliminary acquisition activities for a new coal-fired plant just to be confronted with another department's suggestion that demand-side actions be taken to eliminate the need for the new plant. To combat such difficulties, a commission may find it necessary to work with the utility's top management in an effort to assure

**Involving the Utility in LCP: A Case Study**

Before issuing its first LCP rule in 1984, the Nevada PSC held a pretrial conference in September 1983 to establish the hearing schedule and to present an outline for discussion in subsequent informal workshops. Three workshops were held: one on demand issues, one on supply planning issues, and one on regulations proposed by the Office of Consumer Advocate.

The workshops were followed by a second pretrial conference in October. At that meeting Sierra Pacific Power Company was designated to develop a first draft of the regulations based on an outline of the Consumer Advocate's proposal. Other parties also prepared drafts. A hearing on the various proposals was held in November; post-hearing comments were due in early December 1983.

A proposed rule was issued by the commission in mid-December with comments from the parties due in January 1984. A hearing was held in February, and the final rule was issued in March 1984.* This process permitted the active involvement of all of the parties in the preparation of the order, thus encouraging their support in its implementation. Several aspects of this case history are notable. (1) The deadlines imposed on those involved in the process were tight, but were met by the participants. The scheduling probably produced an effort at organization and a feeling of determination that otherwise might not have been observed. (2) A high degree of cooperation occurred among the participants, and differences in perspectives and interests were worked out in a timely and civilized manner. And (3), probably the most important, a feasible rule was produced.

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*Source: In The Matter of Rulemaking Proceedings Regarding Resource Plans of Major Electric Utilities Pursuant to Senate Bill 161.

their support for the process. If management's enthusiastic support for LCP can be enlisted, a greater probability of success will result.

A utility's integration and parity may also be lacking. Those who work on the supply-side planning effort tend to be engineers, while those involved in demand-side planning tend to be more customer oriented, less technical, and often not as familiar with the electrical system. A mutual suspicion of the motives and abilities of each group may exist. The two camps must be melded into a working group able to respect each other's views and to work effectively toward a common goal. To achieve this melding, the utility may need to reorganize its planning activity.[5]

**The Commission's Role**

Although a commission's role under LCP is essentially the same as it is under traditional planning and review, it is sometimes conceptually difficult to fit the rules of the old order to the new. To what degree does the commission have the right (or duty) to determine what the utility will do? To what degree should the commission review the planning procedures of the utility? And to what degree should the utility determine the depth and breadth of the plan?

The Wisconsin and Nevada commissions expect utilities to consider a broad array of factors such as the ones listed in Table 2. Pennsylvania has attempted to clarify the role of the commission by providing its regulators with both decision-making access and ratemaking flexibility. However, the informedness of the commission and its regulatory power are kept strictly separate. The PUC staff is required to evaluate the plans submitted by the utilities, but the planning law stipulates that no action of the commission is to constitute approval or acceptance of the plans.[6]



**Table 2**

**Wisconsin & Nevada Approaches to a Definition of Least-Cost Planning**

| | |
|---|---|
| ECONOMICS: | Present-value life-cycle revenue requirement |
| FACTORS: | Reliability |
| | Risk |
| | Uncertainty |
| OTHER FACTORS: | Customer economics |
| | Safety |
| | Environmental concerns |
| | Health aspects |
| | Societal impacts |
| BENEFITS: | Allows tradeoffs among factors considered |
| PROBLEMS: | Some factors difficult to quantify |

On the other hand, the Wisconsin Commission approves a new 20 year plan every two years. Subsequent commission certification of generation or transmission projects depends on their being a part of the approved plan. Thus, discussion of the desirability of a project is a part of the plan approval process. Once approved, it is understood that any subsequent prudence review will be limited to the implementation of the project, and not to its initial desirability.

Many variations on these two very different themes are used by different states across the nation. The extent of cooperation between and interdependence of utilities and utility commissions in the least-cost-planning process may be influenced by the political temperament of each state's legislature among other factors.

## END NOTES

[1]"Least-Cost Planning: Much Ado about Nothing?" Electrical World 201 (6), 17-18 (June 1987).

[2]Lisa Shapiro, Paul Markowitz, and Nancy Hirsh, A Brighter Future: State Actions in Least-Cost Electrical Planning, The Energy Conservation Coalition, Washington, D.C., December 1987, p. 14.

[3]Findings of Fact, Conclusion of Law And Order, Docket 05-EP-4, Public Service Commission of Wisconsin, Madison, Wisc., August 5, 1986, p. 3.

[4]General Order Number 43, Public Service Commission of Nevada, Carson City, Nev., March 19, 1984, pp. 23-28.

[5]Dale A. Landgren, Wisconsin Electric Power Co., Direct Testimony Before the District of Columbia Public Service Commission, Formal Case 834, Phase II, District of Columbia Public Service Commission, Washington, D.C., February 1987, pp. 2-5; and Eric Hirst and Corey Knutsen, Developing an Integrated Planning Process: An Electric Utility Case Study, ORNL/CON-247, Oak Ridge National Laboratory, Oak Ridge, Tenn., January 1988, p. 5.

[6]Lisa Shapiro, Paul Markowitz, and Nancy Hirsh, op. cit., p. 65.



# III. COMPONENTS OF A LEAST-COST PLAN

Utilities prepare least-cost plans for their service areas. Regulators then review these plans and approve, reject, or modify them. In some jurisdictions, a comprehensive statewide plan is also prepared by a state agency and regulatory agencies have to ensure that the individual plans of the utilities conform to and advance the statewide plan. Regulators, therefore, do not have to know how to produce an LCP or the "nuts and bolts" of its operation, but should understand and be able to evaluate the purposes, means, and contents of a complete and effective least-cost plan.

## THE BASIC ELEMENTS

Least-cost planning usually consists of a number of discrete steps:

1. Identifying the objectives of the plan (e.g., reliable service, minimal environmental effects, low cost of environmental controls, meeting peak demand in a cost-effective manner, and a reasonable price for consumers).

2. Developing one or more load forecasts.

3. Determining the levels of capacity expected for each year of the plan.

4. Identifying needed resources (e.g., fuels, generating capacity, distribution capability, a manageable load shape, and perhaps periodic decreased demand) needed to bridge the gap between expected loads and capacities (see Table 1 on page 10).

5. Evaluating all of the resources in a consistent fashion.

6. Selecting the most promising options for fashioning an effective, flexible, and responsive plan.

7. Integrating methods of supplying needed power with methods for controlling and moderating demand.

8. Constructing scenarios, pitting the selected mixes of options against possible economic, environmental, and social circumstances.

9. Evaluating the economic and technical success of each mix of options under the circumstances of the various scenarios.

10. Analyzing the uncertainties associated with each possible plan of action.

11. Screening the alternatives to eliminate those that are not suitable.

12. Rank ordering of the alternative courses of action.

13. Testing each alternative for cost effectiveness from a variety of viewpoints (e.g., the utility, ratepayers of different classes, and society).

14. Reevaluating the alternatives considering economic, environmental, and societal factors.

15. Selecting a plan for implementation, one that most nearly satisfies all the objectives of the plan.

16. Developing a plan of action.

17. Implementing the plan of action to bring about the least-cost provision of electric power.

18. Monitoring and evaluating the operation of the utility under the plan and revising the plan as necessary.

## THE WISCONSIN MODEL

Although abstract rules and analyses are very helpful in understanding complex processes like LCP, it may be useful to review the procedure actually followed by one utility, Wisconsin Electric Power Company, in producing a least-cost plan.[1]



Wisconsin Electric develops a base case that assumes there are no demand-side programs. The case examines the projected demands of the residential and commercial sectors by end use, and models the industrial sector at the two-digit Standard Industrial Classification level. The effects of technologic trends are factored into the determination of future demand. The expected quantities of cogeneration and alternative energy sources are then estimated for the planning period. These additional sources of electricity are then subtracted from the base-case demand levels to determine the new capacity required. The least-costly mix of supply-side options is identified, and production costs are computed.

Energy-efficient end-use technologies that are cost-effective for the customer are identified, and their costs and usage characteristics are determined. Demand-side planners then estimate the kind and level of incentives needed to encourage customers to adopt these technologies. They also estimate customer acceptance. Cost-benefit analyses are performed, and program characteristics and timing planned. Alternative supply-side options are developed in a similar manner. In addition, needed system improvements, such as efforts to reduce transmission and distribution losses, are identified by type and cost.

The annual load shape impact for various demand options is computed and fed into the Load Management Strategy Testing Model[2] (LMSTM), which calculates the energy-use pattern. Production costs are computed for discrete time periods, and these are then aggregated to produce yearly data. Rebates and administrative costs are then taken into account, and the energy, demand, production costs, capacity costs, and revenue for the demand-side case are compared against the base case with a spreadsheet overlay.

Supply options are analyzed with the Power Technologies, Inc., (PTI) production cost model. The output from this model is used to calculate revenue requirements and financial data using the Utility Planning Model developed for EPRI.[3] To assure comparability in the comparison of supply and demand options, production costs from the LMSTM model are calibrated against those from PTI.

> Planning models are in fairly widespread use among the utilities and are being adopted by various state commissions. These models are useful in testing alternative assumptions, preparing state-wide plans, and testing the utility plan. The variety of models that commissions use is evident in the following sample:
>
> Wisconsin.......Production cost model
> Michigan........Integrated resource planning and Financial models*
> Maine............Integrated planning model
> Nevada..........Integrated planning model
>
> *Integrates supply and demand options, minimizes long-term costs given the selected set of alternatives, and computes financial data and average electricity rates. Source: Michigan Department of Commerce, Electricity Options for the State of Michigan: Results from the MEOS Project, Executive Summary, September 1987, p. 71.

The data from the preceding analyses are used to compute benefit-cost ratios for each supply and demand option from the perspectives of the participant, nonparticipant, utility revenue requirement, and society in general. The societal-perspectives test currently does not include such externalities as environmental factors, jobs, and safety; Wisconsin Electric is working on a methodology to include these.

Finally, the uncertainties associated with forecasts, customer acceptance, technologic advances expected, etc. are analyzed, and their effects considered.

The process followed by Wisconsin Electric is indicative of what is needed to create a least-cost plan, but not necessarily what is done by others. Least-cost planning is an



evolving art, and advances are being made constantly. Each state and utility has to find the procedure that fits its particular circumstances, within the planning methodology available at the time.

## END NOTES

[1]Dale A. Landgren, Wisconsin Electric Power Co., Direct Testimony Before the District of Columbia Public Service Commission, Formal Case 834, Phase II, District of Columbia Public Service Commission, Washington, D.C., February 1987, pp. 6-20.

[2]Decision Focus, Inc., User's Guide to the Load Management Strategy Testing Model, EPRI EA-3653-CCM, Electric Power Research Institute, Palo Alto, Calif., August 1984.

[3]Arthur Anderson and Co., Utility Planning Model (UPM) Version 2.0, System Documentation and User's Manual, EPRI EA-4807, Electric Power Research Institute, Palo Alto, Calif., September 1986.

## IV. ISSUES ENCOUNTERED IN LEAST-COST PLANNING

Listing a series of tasks for carrying out LCP is relatively straightforward. However, as soon as one starts to prepare a plan, a host of questions arises about how to perform those tasks: What data should utilities be required to gather and to use in their planning? What time horizons should be used in the planning? How can one assure that the demand forecasts used in the plan are sufficiently accurate and reliable? How should uncertainty be dealt with? Should options that do not hold promise for producing least-cost operation of a utility be screened out, and if so, how? How should a possible option be tested for cost effectiveness? How can a particular mix of resources be selected in an objective and balanced manner to produce a course of action that will have the least overall cost? When and how should models be used to estimate the consequences of possible actions?

Although each application of LCP is different, it need not be approached and solved as though it is a totally new and unique situation. Commissions and utilities have tackled these problems in innovative and effective ways, and others can learn from their experiences.

### DATA REQUIREMENTS

Preparing a least-cost plan requires obtaining and handling very large quantities of complex data, such as load shapes, load levels, capital stocks and their efficiencies, and market research data. The task, however, is not insurmountable or unique. Utility operations, as well as regulation, are complex, technical, and data-intensive. As a consequence, much of the required data is already available within the utility, although efforts may be necessary to obtain additional information.



Residential data may be available from the U.S. Census and from company hook-up records. Because many residential end uses of energy are new or developing, end-use metering on a sample basis may be required to obtain needed data.

Commercial-sector data may be available from hook-up records, from local construction agencies, and through special metering. A detailed customer survey updated by a load-research sample may be helpful. End-use data for the industrial sector is virtually nonexistent.[7]

Different public utility commissions find different types of data suitable for their purposes. For example, North Carolina has proposed requiring from its utilities:

1. documentation of load forecasts including end use data;
2. a resource integration plan including a risk and reliability assessment;
3. a list of plants planned for retirement during the next 15 years;
4. a 15-year projection of fuel use and purchases for existing plants along with power plant performance and operating-cost data;
5. a 15 year projection of alternative energy sources and costs;
6. data on cost-effective conservation and load management; and
7. end-use data for residential, commercial, and industrial customers including appliance type, fuel, efficiency, total energy consumed, and contribution to peak load.

As another example, Pennsylvania requests from its utilities

1. the historical and forecast demands for energy, expressed as peak demand and number of customers;
2. the resources, demand, and reserves for the next 10 and 20 years;

3. the existing generating capability;
4. the planned generation during the next 20 years, including installation, changes, and retirements;
5. the availability of cogeneration, renewables, and small power production;
6. a breakdown of the generating capability for 20 years by fuel type along with data on imports and exports;
7. a breakdown of net generation by fuel for 20 years;
8. the demand, resources, and energy produced for the past year;
9. the conservation and load management potential for 20 years; and
10. a comparison of annual costs of the preferred plan with alternative plans.

The differences in the requested data reflect the different interests and concerns of the two utility commissions.

**THE TIME HORIZON**

Long-term information is often relevant to relatively near-term decisions. For example, a decision regarding the construction of either a 138 kV or 345 kV transmission line may hinge on what will happen 20 years from now. And those distant events would have to be fully evaluated to make an informed decision today.

How far ahead should the utilities and their regulators be looking and planning? Part of the answer to that question is determined by what type of planning one is talking about. At least two horizons should be considered. One is the planning horizon for use in forecasting demand and assessment of scenarios. The second is the analysis horizon over which options are assessed.



The planning horizon (often 10 to 15 years) should be long enough to cover the costs of, benefits of, and anticipated changes in the system as planned by the utility. The planning process not only identifies what is and is not known but also helps determine what the planner needs to know. When a full set of facts is available, decisions can then be made and plans created to provide low-cost reliable service over a wide range of possible futures.

The analysis horizon (often 20 to 30 years) will vary with the resource under consideration. The horizon should be long enough to cover the period during which costs and benefits will accrue, which in most cases is the period that the resource is expected to be in use. That is, its life cycle. For example, a conventional power plant is generally expected to operate for 40 years, so it would be evaluated over that period.

The plan based on these horizons should be updated and resubmitted every few years. This makes the process dynamic rather than static, allows the incorporation of new developments, and gives all parties an opportunity to discuss goals and objectives at regular intervals.

Several commissions, such as Illinois and Nevada, require a 20-year planning horizon with periodic revisions. Illinois requires revision every two years,[2] and Nevada recently changed its requirement from two to three years.[3]

**DEMAND FORECASTS**

Standardizing efforts. The demand forecast is a critical portion of any least-cost plan. Any error in the demand forecast will have serious effects on all the rest of the plan and its use. Regulators, therefore, must be assured that the demand forecast is sufficiently accurate and reliable. Several approaches can be taken to gain this assurance. These approaches range from careful review of the methods used by a utility to forecast demand to specifying the general methods to be employed in forecasting demand to naming the specific techniques and data sets to be used in forecasting demand. Whatever approach is used, however, the objective is the same, to permit both the utility and its regulators to better understand how future events may affect load growth and to develop a dynamic, flexible plan capable of adapting to circumstances over time.

The system that allows the utility the greatest latitude is one in which the commission chooses simply to require extensive documentation about the assumptions, sensitivity, demographics, usage patterns, etc. used in the forecast. Such documentation permits the regulator to determine whether the forecast is logical and allows the utility to select the methods, data sources, and interpretations that are best suited to their situation.

At another level of involvement, the regulators may wish to prescribe the general method to be used in the forecast. This prescription might include the detail of the data to be used, the analyses and tests to be conducted, etc. Such specification allows the commission to standardize the analyses of different utilities, to compare them, and to review them more easily and evenhandedly.

At a high level of involvement, the commission may wish to specify the specific computer models to be used in carrying out the analyses. Such a specification ensures that models that have proven to be reliable are used and that results from one utility are comparable to those from another.

Dealing with uncertainty. No one knows the future with certainty, and a least-cost plan must consider the effects of possible future events on demand. One way to do this is to require several forecasts reflecting the different probabilities. These usually take the form of high, low, and probable forecasts with an explanation of why a specific forecast was



chosen as the planning goal. Some commissions, such as Pennsylvania's, also require an explanation of what modifications to the resource plan will be needed in the event either of the other scenarios come to pass.[4]

Modeling. Prior to 1970, electric-load forecasting was a relatively simple affair because demand tended to grow at a predictable rate. In some cases, forecasts were made with a ruler and semi-log graph paper. Once demand growth became a matter of considerable uncertainty, more-sophisticated methods had to be introduced. Their major contribution is to provide more information and encourage greater knowledge of trends, thus improving the accuracy of the forecasts.

Three types of computer models are used in the production of demand forecasts: econometric, end-use, and combined models.

Econometric models attempt to relate electricity demand and significant economic and demographic factors. These factors may include electricity prices, relative gas prices, gross state product, time, manufacturing indices, population, personal income, and degree days. The specific factors chosen are those that exhibit a statistically high degree of correlation with demand. In some cases only one variable is used; in most cases, a number of variables are used in the model.

These econometric models may be designed to provide a forecast for each of the principal customer classes, such as the residential, commercial, and industrial sectors. Each of these sectoral models is based on those economic and demographic factors correlated with demand in that sector and produces a demand forecast for that sector. The projections for all the classes are combined to produce the total forecast.

Econometric models generally lack detail and, because of their dependence on historic data, do not do a good job of predicting change, particularly that associated with technological modifications. Thus, econometric models have difficulty in grappling with demand-side options, such as efficiency improvements, because they represent a change in technology and a change in the relationship between demand and the factors selected as predictors.[5]

End-use models analyze each end use, such as heating, cooling, lighting, and water heating. They forecast consumption based on the number of units of each type of appliance and the electricity use per unit. The aggregate consumption by each type of appliance is often expressed in terms of dwelling or plant type. Data for these models is derived from market surveys and appliance-usage studies. The use of end-use models may be limited to a specific customer class where data are more easily available and uses are more homogeneous. For example, in its original LCP order, the Nevada PSC required end-use forecasts for the residential and commercial sectors while permitting econometric forecasts for the industrial sector.[6]

End-use models are better able to grapple with behavioral responses to changes in technology and policy, but require significant investments of time and money to develop an adequate database. They also have difficulty in capturing the effects of economic factors, such as price and income, on appliance usage intensity.[5]

Combined models have been developed to improve the ability to capture the effect of both economic and technological factors. Combined models may be developed by adding economic variables, such as income, price, or capital investment, to an end use framework. Alternatively, end-use equations may be added to an existing econometric model.[7]



Econometric models are based more on data describing the supply side of the utilities industry, whereas end-use and combined models permit a better understanding of those factors that contribute to demand. As a consequence, the regulator is better able to target policy and incentives with end-use and combined models. Some popular combined forecasting models are REEPS,[8] COMMEND,[9] and INDEPTH,[10] which were developed under EPRI sponsorship for the residential, commercial, and industrial sectors, respectively.

**EVALUATING THE OPTIONS**

Under LCP the options available to meet future demand are many and are on both sides of the meter. They include additional increments of supply (such as conventional generating plants, non-utility-owned generation, life extension, purchases, and nonconventional sources) as well as demand-side resources (such as energy efficiency and load management).

Not all of these options will be useful in all cases. Therefore, they should be screened to eliminate those that are not suitable. Screening at the outset reduces the number of options that must be evaluated in subsequent steps. Doing so, however, may result in the elimination of resources that a full evaluation would indicate should stay in, and vice versa.

Any screening should use a predetermined set of evaluative criteria applied equally to each option. A partial set of criteria is as follows:

1. Is the option based on unproven technology or does it lack adequate technological development?

2. Does the state or region lack a resource base to support the option?

3. Will the option detract from the ability to meet the planning objectives, such as load-shape, environmental-quality, or system-reliability requirements?

After the initial screening, the remaining options need to be evaluated in terms of the various economic, environmental, and societal parameters. The options that best meet the need should then be selected for inclusion in the least-cost plan.

## TESTING FOR COST EFFECTIVENESS

Initial evaluation. A number of tests can be used to check cost effectiveness.[11] These tests measure the costs and benefits of the various options from a number of perspectives: those of the utility, the nonparticipant, the participant, the ratepayer, and society.

The utility perspective is represented by the revenue requirements test. This has been used for years to evaluate generating alternatives, and is built into many of the generation planning models. This test computes the net present value of the revenue requirements for a given resource option, calculated over the life cycle of the option.

The nonparticipant perspective or no-losers test is one of the more controversial tests in use. Under the terms of this test, if the costs to those who do not participate in a given program exceed the benefits they obtain, the option fails. As applied, the test asks if rates will rise because the resource option is used. The nonparticipants test has been applied primarily to demand-side options. It results in a heavy weight being assigned to the losses suffered by a specific group (nonparticipants). If the nonparticipants suffer even small losses, an option may be rejected despite large gains made by the participants.

Many regulators believe that any test intended to measure the comparative cost effectiveness in choosing among several options, must be equally applicable to both supply side and demand side measures, otherwise it is impossible to compare their relative merits.



For this reason, a number of jurisdictions such as the District of Columbia and Massachusetts, do not permit the use of this test for screening purposes.[12] Other states, such as California, use it as a measure of rate impact, and have renamed it the rate impact measure test.

Other perspectives are represented by the participant and the total-resource tests. The participant test compares utility bill savings against out-of-pocket participation costs, while the total-resource test compares avoided supply costs to total program costs. The total-resource test measures the cost to all ratepayers of participation in demand-side programs. It indicates which resources will minimize costs for all customers, not just some subset, such as nonparticipants.

The difficulty with these tests is in their application. Users tend to apply different tests to demand-side resources than to supply-side options. The use of different methods for different options can introduce bias into the evaluation. The major criterion should be that all resources, whether on the supply or the demand-side, should be assessed in a comparable and consistent manner.

To achieve consistency, some states depend on a single test; others require a number of tests to reap the benefit of various perspectives. California, for example, recommends[13] the use of four tests reflecting four perspectives. The suggested tests are the participant, ratepayer impact measure, utility cost, and total resource cost tests. A societal cost test is considered as a variation on the total resource cost test. The ratepayer impact measure test is a variation on the nonparticipants test, and the utility cost test is a renamed utility revenue requirements test.

All four tests can be applied to each option to facilitate trade-offs between the various perspectives and to show whether an option is cost effective. The tests will not, however, indicate whether an option is more or less cost effective than another, whether a different mix is more desirable, or whether a given level of participation in the program is optimal.

Follow-up evaluation. Once the initial evaluation has been completed, other factors (economic, environmental, and societal) should be considered individually. Such a reevaluation prevents the rejection of options that may have high costs in one set of factors, such as economics, but strong countervailing benefits in others, such as environmental impacts.

Among the factors that require evaluation are the option's effects on reliability, rates for all customers, financial stability of the utility, and the environment. Many of these factors have costs associated with them, making their evaluation straightforward. The non-cost factors can be evaluated with a number of sophisticated methods. One of theses methods is decision analysis, which determines the variability of the factors, assigns probabilities to a number of circumstances, and computes an expected value for the factor with statistical techniques. With decision analysis and related techniques, alternative scenarios can be analyzed and compared to determine the effects of a factor.

In evaluating the non-cost factors, a number of sophisticated methods are available including decision analysis. In general, decision analysis determines the variability of the factors, assigns probabilities to them, and then computes an expected value using statistical techniques. It is also possible to analyze and compare alternative scenarios to determine the effect of these factors. These methods are beyond the scope of this handbook, but



regulators may want to assure themselves that appropriate methods have been used. The essential point is that the impact of the factor and the probability of its occurrence, and its consequent importance, is a necessary ingredient in determining effectiveness.

## SELECTING THE LEAST-COST MIX

Once cost-effective options are identified, the combination of those options that will result in the lowest-cost electricity production must be determined. A number of approaches can be followed to this end. Each involves the collection and assessment of data related to the options and the development of estimates of exogenous factors. This information needs to be sorted and evaluated to arrive at the appropriate least-cost mix.

With the brute-force approach, the cost-effective options are tried in varying combinations in an iterative process until a least-cost grouping is determined.

A more direct approach is the two-part procedure used by the New York PSC staff.[14] In the first part, the various supply and demand options are ranked. The ranking is accomplished either by computing the levelized cost per kWh or per kW or by testing each option against a base case for its impact on revenue requirement and reliability.

In the second part, the least-cost options are grouped by utility and public policy objectives. These groupings are assessed to determine the options that best accomplish the planning objectives. The resulting resource plans are evaluated for their effect on customers, investors, and the environment. This evaluation includes sensitivity and uncertainty analyses as well as a determination of the impact of each plan on the load forecast. The plan best able to maintain adequate reliability levels, ensure the financial integrity of the utility under uncertainty, provide flexibility, and fulfill policy and regulatory objectives is considered to be the least-cost plan.

## MODELS

The evaluation and integration of options can also be accomplished through the use of various commercially available models. Electric utility models are designed as operations, engineering, or planning software. The first two deal with the analysis of system performance and the design and specification of components, respectively. These need not concern us here.

Planning models are tools for identifying and selecting the most economical alternatives. These models may be restricted to specific applications, such as production costing, or may be integrated programs including a number of analytic modules. An integrated planning model may include modules for production costing, financial analysis, load forecasting, and rate design. The distinction between application and integrated models, however, is fast disappearing. Many of the production-cost models now include financial modules and other analytic tools. A detailed discussion of the various types of models will be found in Volume II (forthcoming from Lawrence Berkeley Labs).

Caution is necessary in using models in least-cost planning. One must understand what the particular model can and cannot do, what assumptions are integral to the model, what other models may be required for specific phases of the process, and what is needed to interface the various models.

A variety of models are readily available for use in LCP, among them PROMOD, ELFIN, MIDAS,[15] LMSTM,[16] EGEAS,[17] and UPLAN.[18] The UPLAN model is an integrated planning system that runs on a personal computer and is able to evaluate both demand-side and supply-side resources. UPLAN can analyze production costs, load shapes, demand-management options, and supply options. The effects of demand-side management



programs are simulated through the manipulation of load shapes. With a financial planning routine, but not a load forecasting program, UPLAN has most of the components necessary to analyze the separate and combined parts of a least-cost plan, including sensitivity and scenario analyses. It cannot, however, be used to optimize the mix of options.

The use of these models is a great convenience and permits the exploration of a larger number of scenarios than might be possible without them. Their use, however, does not eliminate the need for judgment in interpreting and evaluating the results in combination with other available information.

## END NOTES

[1]Dale A. Landgren, Wisconsin Electric Power Co., Direct Testimony Before the District of Columbia Public Service Commission, Formal Case 834, Phase II, District of Columbia Public Service Commission, Washington, D.C., February 1987, pp. 21-23.

[2]Rulemaking Implementing Section 8-402 of the Public Utilities Act, Least-Cost Energy Planning, Appendix, Docket 87-0261, Illinois Commerce Commission, Springfield, Ill., January 20, 1988, p. 16.

[3]General Order 43, Docket No. 87-151, Public Service Commission of Nevada, Carson City, Nev., December 21, 1987, p. 11.

[4]Amendments to the Commission Regulations, 52 Pennsylvania Code, Chapter 57, to Implement a Least-Cost Planning Strategy for Electric Utilities, Annex A, Pennsylvania Public Utility Commission, Harrisburg, Penn., November 13, 1986, pp. 1-2.

[5]Booz, Allen & Hamilton, Inc., Electric Load Forecasting: Challenge for the 80's, EPRI EA-1536, Electric Power Research Institute, Palo Alto, Calif., Sept. 1980, p. IV-19.

[6]In the Matter of Rulemaking Proceedings Regarding Resource Plans of Major Electric Utilities Pursuant to Senate Bill 161, Docket 83-713, Public Service Commission of Nevada, Carson City, Nev., March 19, 1984, p. 9.

[7]Booz, Allen & Hamilton, Inc., op. cit., p. IV-4.

[8]Cambridge Systematics, Inc., REEPS Code: User's Guide, EPRI EM-4882-CCM, Electric Power Research Institute, Palo Alto, Calif., January 1987.

[9]R. B. Lann et al., An Implementation Guide for the EPRI Commercial Sector End-Use Energy Demand Forecasting Model: COMMEND, Vol. 1, Model Structure and Data Development, EPRI EA-4049, Electric Power Research Institute, Palo Alto, Calif., June 1985.

[10]Battelle Columbus, Industrial End-Use Planning Methodology (INDEPTH): Demonstration Design, Vol. 1-3, Interim Report, EPRI EM-4988, Electric Power Research Institute, Palo Alto, Calif., December 1986.

[11]In addition to the present discussion, an extensive discussion of methodology is provided in Electric Power Research Institute, TAG-Technical Assessment Guide, 4 vol., EPRI P-4463-SR, Electric Power Research Institute, Palo Alto, Calif., 1986-1987.

[12]Opinion and Order, Formal Case No. 834, Phase II, In the Matter of Application of Potomac Electric Power Company for Changes to Electric Rate Schedules, Order No. 8974, Public Service Commission of the District of Columbia, Washington, D.C., March 16, 1988, p. 46.

[13]Standard Practice Manual for Economic Analysis of Demand-Side Management Programs, California Public Utility Commission, San Francisco, Calif., and California Energy Commission, Sacramento, Calif., November 1987.



[14]Staff Report to the Administrative Law Judge on the Work of the Integrated Planning Committee, New York Department of Public Services, Albany, N.Y., November 27, 1987, pp. 32-40.

[15]Temple, Barker & Sloane, Inc., and M. S. Gerber and Associates, Inc., Multiobjective Integrated Decision Analysis System (MIDAS), Vol. 1: Model Overview, EPRI P-5402, Electric Power Research Institute, Palo Alto, Calif., April 1988.

[16]Decision Focus, Inc., User's Guide to the Load Management Strategy Testing Model, EPRI EA-3653-CCM, Electric Power Research Institute, Palo Alto, Calif., August 1984.

[17]EGEAS: The Electric Generation Expansion Analysis System, Vol. 1-6, EPRI EL-2561 (RP1529-1), Electric Power Research Institute, Palo Alto, Calif., April 1987.

[18]UPLAN: The Electric Utility Planning System, Utility Software and Modeling Center, Los Altos, Calif., 1988.

# V. GETTING STARTED[1]

A regulatory commission must have the legal authority to undertake least-cost planning. Such authority may accrue under a variety of mechanisms (such as statutory specification) or duties vested in the commission (such as rate proceedings, internal investigations, generic proceedings, and rulemaking). Before it undertakes any LCP, the commission must determine what authority it is charged with and what regulatory approach is suitable for that situation.

## STATUTORY FRAMEWORK

The legal authority to order least-cost planning may be derived from specific instructions from the state legislature or from the interpretation of other legislation.

Specific LCP legislation is the most straightforward means of allowing LCP and the most resistant to challenge and delay. It sanctions the need to institute LCP, and it usually establishes the responsibilities of both the commission and the utilities and sets limits on what can be done. The enabling legislation should be specific enough to guarantee that those involved in the process will be legally bound to follow a comprehensive least-cost strategy. The act should provide regulators with specific authority (1) to require the utilities to submit long-range plans; (2) to approve, modify, or reject those plans; and (3) to enforce their decisions. In reviewing the plans, the commission should have the right to use a broad set of criteria, such as economic, engineering, environmental, health, reliability, and safety factors.



It would also be useful for the legislation to provide a link between the least-cost plan and other regulatory activities.[2] For example, the act might forbid the granting of construction permits to a utility by any state agency unless the proposed construction conformed to the plan previously agreed to by the utility and the commission. The commission could also be empowered to consider a utility's conformance to the plan in subsequent rate cases. Under such a situation, the commission could disallow additions to the rate base or adjustments to the allowed rate of return that did not conform with the plan.

Where statutory specificity does not exist, LCP may be instituted under one or more existing acts. In some cases, an individual act already affords opportunities for requiring least-cost planning of public utilities. In other cases, a variety of laws might contribute discrete requirements that add up to a least-cost plan.

In some cases, a state legislature may grant planning authority to an agency other than the PSC. For example, Massachusetts requires utilities to submit load forecasts and supply plans, including demand-side options, to the Energy Facilities Siting Council each year. The Department of Public Utilities (DPU), however, oversees rate setting. This separation of oversight and rate-setting duties requires a close cooperation between the utility regulators and the other agency. Although not required to do so, the DPU does consider the least-cost plans filed with the Siting Council as a factor in rate cases. A bill recently introduced in the Massachusetts legislature would make approval of a resource plan by the Siting Council a precondition for filing a rate case with the DPU. It would also mandate that the DPU assure that utility investments are consistent with the approved plan.

A regulatory body may also be granted the authority to require least-cost planning as a consequence of the "sunset" legislative review process. Here, the effectiveness of previous legislation can be evaluated, problems with extant legislation can be identified, and new approaches to regulation can be adopted.

**THE REGULATORY APPROACH**

Once the statutory authority of the commission has been determined, the appropriate regulatory approach to least-cost planning can be selected. How the commission decides to implement LCP also depends on how promptly the regulators wish to start the process. The available means of implementing LCP are all the traditional regulatory methods, such as rate proceedings, internal investigations, generic proceedings, and rulemaking. Some of these methods address regulatory problems directly while others allow a period of introspection and analysis on the part of the regulatory commission.

Rate cases can be used to raise questions in regard to utility resource investments. Inasmuch as these cases are usually limited to one company, it is difficult to develop a comprehensive statewide LCP approach. The questions raised in a single case, however, can lead to the development of a more comprehensive rule. In May 1986, the Washington Utilities and Transportation Commission, as the result of testimony in a rate case, ordered Puget Sound Power and Light Company to develop a least-cost plan. Approximately one year later, the commission issued a general least-cost rule covering all electric utilities in the state. This ruling was followed by a technical paper in June 1987 detailing what is expected of utilities in the preparation of such a plan.

Internal investigations allow a commission to explore LCP concepts and processes to decide what, if anything, it wants to do. The investigation may propose legislation, offer



a statewide plan based on LCP, propose a generic rule, or call for more formal procedures and deliberations. In Missouri, a PSC staff report presented recommendations on which draft legislation was subsequently based. In Ohio, the PUC prepared a staff report on LCP and appointed utility and consumer task forces to help develop an LCP strategy. When those task forces complete their tasks, the PUC is expected to implement that strategy

Using Existing Legislation:
Wisconsin

The Wisconsin Public Service Commission (PSC) instituted least-cost planning under the state's 1975 Power Plant Siting Law. Under that act, the utilities are required to file a biennial Advance Plan. The plan must include energy and peak forecasts for the next 20 years, construction and transmission plans for 15 years, data on anticipated energy-efficiency programs, and an analysis of alternatives. During the past 10 years, the PSC has issued four orders, the most recent of which requires utilities to consider all options on an integrated and equivalent basis when preparing an Advance Plan. These orders, in conjunction with the Siting Law, have effectively produced a least-cost planning process.

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Sources: Wisconsin Public Service Commission, Advance Plan for Construction of Facilities as Filed with the Commission for Review and Approval Pursuant to Section 196.491, Wisconsin Statutes, Docket 05-ET-1, August 17, 1978; Wisconsin Public Service Commission, Advance Plan for Construction of Facilities as Filed with the Commission for Review and Approval Pursuant to Section 196.491, Wisconsin Statutes, Docket 05-EP-2, December 4, 1980; Wisconsin Public Service Commission, Advance Plan for Construction of Facilities as Filed with the Commission for Review and Approval Pursuant to Section 196.491, Wisconsin Statutes, Docket 05-EP-3, May 19, 1983; Wisconsin Public Service Commission, Advance Plan for Construction of Facilities as Filed with the Commission for Review and Approval Pursuant to Section 196.491, Wisconsin Statutes, Docket 05-EP-4, August 5, 1986; 196.491, Wisconsin Statutes.

through rulemaking.

Generic proceedings can also be used to investigate least-cost planning. For example, in August 1986 the New York PSC started a generic proceeding to investigate plans for meeting future electricity needs and issues affecting future electrical supplies, including LCP. To carry out this inquiry, the PSC established working groups to study integrated planning, deregulation, and ratemaking and finance issues. Each of these three working groups is made up of PSC staff, other state officials, utility personnel, and consumer advocates. The Integrated Planning Group is developing a least-cost planning process for consideration by the PSC.

If the commission's legal authority is based on a specific legislative mandate, rulemaking will probably be used to implement the Act. Even when the other regulatory approaches are pursued, virtually all of them eventually lead to rulemaking. In preparing rules, a balance must be attained. Consistency among utility plans must be assured, and each utility must be provided with adequate guidelines for use in drafting the plan. At the same time, the commission must avoid infringing on the prerogatives of utility management. These requirements can be balanced in a number of ways, ranging from a lengthy, detailed rule specifying how

Sunset Review:
Illinois

The Illinois Public Utility Act sunset review led to legislation that established guidelines for utility resource plans. The Act also required the Illinois Department of Energy and Natural Resources to prepare a statewide plan, subject to the approval of the Illinois Commerce Commission. Under the new provisions of the Act, individual utilities must demonstrate that the plans that they submit are consistent with the statewide plan.

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Sources: Public Utilities Act, Section 8-402(f), Illinois Statutes. Draft Rule, Title 83: Public Utilities, Chapter I: Illinois Commerce Commission, Subchapter c: Electric Utilities, Part 440: Least-Cost Planning for Electric Utilities, Docket No. 87-0261 (May 1988).



plans should be developed to a simple rule followed by a technical report that clarifies and explains the requirements.

The specific regulatory approach (or combination of techniques) adopted depends on a wide range of circumstances, including:

- the regulatory authority of the commission,
- the degree of cooperation forthcoming from the utility,
- the predictability and past variability of load growth,
- the presence of excess generating and transmission capability, and
- the immediacy of need for additions to or changes in the operation of the utility.

Pennsylvania

The Pennsylvania sunset review resulted in least-cost legislation that requires the utilities to file annual reports covering demand forecasts, conservation potential, integration of all options, and total costs to the customer and the utility. Once a legal basis upon which to proceed has been determined, the commission must determine how best to implement the law.

## END NOTES

[1]Much of the material in this chapter is based on Lisa Shapiro, Paul Markowitz, and Nancy Hirsh, A Brighter Future: State Actions in Least-Cost Electrical Planning, The Energy Conservation Coalition, Washington, D.C., December 1987.

[2]In 1974, California began requiring utilities to submit 20-year forecasts of supply and demand which explicitly included conservation. These forecasts are independently reviewed by the California Energy Commission and are used in assessing the need for new power plants. The California PUC uses these forecasts to determine PURPA avoided cost rates and cost effectiveness of demand side management programs. Source: California Public Resources Code Section 25300 also known as the "Warren/Alquoit Act"

## VI. IMPLEMENTATION STRATEGIES

Once a least-cost plan has been prepared, the next task facing regulators is applying the plan and bringing it to fruition. The major means of doing this are pilot programs, market-based programs, and utility incentives.

### PILOT PROGRAMS

Pilot programs are applications of the plan to a small, select subset of the population for which the plan has been designed. Applying the plan to a small test group allows the commission to see if the plan performs as expected, if it has any problems that need to be corrected, if it brings about the expected and desired results, and if it has any unforeseen beneficial or deleterious side effects. In addition to its role as a research tool, a pilot program can also serve as a source of information on program costs, as a dry run for management techniques, as a way of introducing a program, and as a means of establishing the delivery system.

Pilot programs are useful in building a data base, especially in regard to program cost-effectiveness. Such a data base is particularly important for demand-side options, many of which lack adequate data on customer acceptance and use, tangential and residual costs, and real benefits. Careful evaluation of a pilot program can yield sufficient data to accurately predict the costs and effectiveness of full-scale programs.

Pilot programs can create acceptance for demand-side programs. In many cases, the utility and its customers lack experience with these resources and techniques, and may be skeptical about including demand-side options in a plan. Several judiciously chosen pilot



programs can help to dispel the skepticism and provide the necessary experience to make such programs acceptable.

Pilot programs are also a good way to start up a new resource, such as a lighting program or a new supply technology. Pilot programs allow a utility to gain experience with a program and to eliminate any technical or managerial bugs before undertaking a broad-scale application. Ideally, a pilot program should be undertaken before the least-cost plan indicates the need for that resource option so that a proven and understood technique can be tapped when the need arises.

Unfortunately, pilot programs have a relatively high cost per decrement of capacity when compared with fully implemented programs. However, pilot programs are justified when the performance of a new technology is uncertain or when the appropriate marketing strategy is not known. In such cases, pilot programs should be as small as possible while still providing statistically significant data on the conservation potential and likely costs of a full-sized program.[1]

An example of this approach is a March 1988 order of the Public Service Commission of the District of Columbia.[2] The PSC ordered the electric and gas utilities to undertake pilot programs during the next two years to (1) determine the cost-effectiveness of demand-side options, (2) measure conservation potential, and (3) determine delivery mechanisms. The programs are to permit evaluation to account for "free riders" and "cream skimming." Free riders are those who would have implemented a conservation measure even if there were no program. Cream skimming is introducing demand-side programs only in cases that provide large savings or economic returns while refusing to serve clients or to introduce companion technologies that provide small or no financial returns. Intuitively, cream skimming projects can be expected to take all the financial rewards associated with controlling demand and to leave little or no financial incentive to introduce other, additional demand-side programs. Experience, however, has shown that this impoverishment of the marketplace does not always occur.

**MARKET-BASED PROCEDURES**

In a free-market economy, competition is seen as a mechanism producing higher-quality goods and services and lower prices. However, because of technical constraints, the nature of the distribution system, the structure of the electric utility industry, and the effects of regulation, the electric utility industry has not been a free market since shortly after its founding. In recent years, though, the industry has exhibited signs of competition, such as the presence of cogenerators and independent power producers. These competitive tendencies in some sectors of the industry may help implement a least-cost strategy.

One way to exploit this competitive environment is to employ competitive bidding in the acquisition of energy resources and services. Perhaps the best current example of free-market economics in the power industry is the two-year "Power Partners" pilot program of Central Maine Power Co., which was approved by the Maine PUC in December 1987, under which conservation projects are permitted to compete directly with supply projects. Under this program, the utility solicits proposals for demand-management programs that will yield electric energy savings in excess of 100,000 kWh or reduce peak demand by 100 kW or more. The solicitation takes place as part of the utility's purchased-energy contracting procedure. The proposals that would provide the needed resources at the lowest cost are accepted.



Recently the States of New York (by PSC order) and New Jersey (by stipulation) have initiated similar "all source" competitive bidding systems. Massachusetts permits separate bidding for demand side and supply side power purchases.

At least five states[3] use such competitive bidding to select cogenerators and small power producers.[4] The bidding (or auction) systems used vary from state to state but have several items in common: the price is usually capped at avoided cost; a set-aside is provided for very small producers, usually defined as less than 1 MW; and bids are evaluated on the basis of location, availability, reliability, and dispatchability as well as price of the electricity produced or saved.

In addition to these elements, the Maine system requires power purchases in blocks. For utilities having a peak of more than 500 MW, the block size is 50 MW. For utilities having smaller peaks, the block size is 10% of the peak. For each block, the utility calculates the avoided cost and passes this saving on to the customer. This marginal avoided cost is expected to increase as more qualifying facilities enter into service.

In California, a "second price" auction is used. Under this arrangement the price paid to all successful bidders is the price bid by the lowest losing bidder. This process is intended to eliminate strategic bidding. That is, in conventional auctions most bids cluster near the utilities' avoided cost regardless of the bidder's production cost. The second-price theory holds that the bids will reflect the bidder's actual production cost because there is nothing to gain by bidding higher; the price paid the winners will always be that of the first losing bid.[4]

As an alternative to auction systems, some states have opted for non-price-based competitive systems. For example, the Virginia State Corporation Commission authorized, in January 1988, competitive negotiation (including factors other than price) between utilities and potential suppliers. The procedural details are to be formulated by each utility electing to participate in the program. The commission will exercise oversight over the utilities' acquisition policies.[5]

## REGULATORY TREATMENT OF RESOURCE OPTIONS

Commissions wishing to implement LCP have often found it helpful to adopt regulatory mechanisms that provide financial incentives to utilities that employ LCP. Because LCP considers all resources on a comparable, equal basis, incentives for demand-side measures must be similar to those provided for supply-side resources. In other words, stockholders must share some of the benefits of LCP.[6] The regulatory treatment of supply-side resources is of long standing, but that of demand-side resources is of relatively recent vintage. Therefore, commissions may feel that they have a "road map" to follow in the case of supply-side options but that they are exploring new territory in the case of demand-side resources. However, two regulatory treatments have been adapted to the demand-side situation to allow utilities to recover their investment in demand-side projects (and perhaps even realize a profit). They are expensing and rate basing.

Expensing is the most common regulatory treatment of conservation investments. Utilities are allowed to consider investments in demand-side resources as operating expenses to be deducted from current revenues. From the utility's perspective, this method has the advantage of immediate recouping of the funds expended with a consequent reduction in long-term debt. From the regulator's point of view, it eliminates the need to calculate a rate of return on demand-side investment and the need to add the expenditures to the utility's asset base.



Demand-side expenditures can also be rate based so that the utility earns a rate of return on its invested capital. Although the immediate recovery of outlays under expensing might seem more attractive than recovering the investment by factoring it into the rates charged, an analysis by the Wisconsin PSC[7] indicates that a utility should not care which method is used as long as the rate of return accounts for perceived project risk or equals the cost of money. That study also pointed out that rate basing is more equitable than expensing because conservation investment is amortized during the period of the benefits; new customers will pay a share of the costs while enjoying the benefits of those expenditures.

Rate basing can also be useful when the regulator perceives a market failure. When the marketplace would not provide a suitable return to the investor for implementing the program that is socially optimal, rate basing permits the commission to provide an additional financial incentive to the utility. Through rate setting, the rate of return can be put at a level sufficient to overcome the market failure.

The rate of return can also be adjusted up or down to encourage a utility to get the most from a demand-side investment. The Wisconsin PSC has used such a performance-incentive system in which a special "conservation rate base" is created for qualifying conservation investments. The utility receives a higher rate of return on that rate base if conservation savings exceed stipulated levels. Under the system used for one utility, the energy-efficiency investment earns the current approved rate of return. It can then earn an additional percentage point for every 125 MW of peak demand saved.

The balancing account can be somewhat of a hybrid between expensing and rate basing. Under this treatment, energy-efficiency investments are accumulated in a balancing, or escrow, account. The balancing account can be considered as a modified form of expensing in the sense that the investments in energy efficiency are segregated and not used in the rate base as part of the utility's assets. It can also be considered as a form of rate basing in the sense that the utility could be allowed to earn a rate of return on its conservation investment. It is, therefore, somewhere in between capitalization and expensing of conservation investments. Wisconsin, Minnesota, New Jersey, New York, Ohio, and South Dakota use the balancing account. Maine and Nevada also use this approach for planning and pilot stages.[8]

It is not necessary to select a single method; various combinations are possible. For example, part of the expenditures could be recouped through expensing, and part through rate basing. The type of incentive selected is dependent on the needs of the particular utility and the commission's perception of what is equitable.

The diversity of methods used to treat demand-side investment is shown in the results of a survey conducted by the Nevada Public Service Commission in October 1986 (Table 3). These different ways of treating investment in demand-side options have been reviewed and assessed by Michael Reid of the Alliance to Save Energy.[9] As can be seen in the table, most commissions treat demand-side expenditures as an operating expense with a smaller number permitting capitalization. Relatively few use the balancing account or rate of return as an incentive.



TABLE 3

COMMISSION TREATMENT OF INVESTMENT IN

DEMAND-SIDE OPTIONS

PROGRAM STAGE- NO. OF STATES

| | Planning | Pilot | Implementation |
|---|---|---|---|
| Operating Expense | | | |
| Future Test Year | 9 | 9 | 10 |
| Historic Test Year | 12 | 15 | 17 |
| Capital Expense | | | |
| Future Test Year | 1 | 1 | 1 |
| Historic Test Year | 5 | 8 | 11 |
| Balancing Account | 6 | 7 | 5 |
| Rate of Return | 2 | 2 | 4 |
| Surcharge/Independent Organization | 1 | 2 | 1 |

Source: 1987 Report of Committee On Energy Conservation, Appendix H, National Association of Regulatory Utility Commissioners, Washington, D.C., September 1987, p. 55.

## END NOTES

[1]Opinion and Order, Formal Case No. 834, Phase II, In the Matter of Application of Potomac Electric Power Company for Changes to Electric Rate Schedules, Order No. 8974, Public Service Commission of the District of Columbia, Washington, D.C., March 16, 1988, p. 77.

[2]Ibid., pp. 76-80.

[3]California, Connecticut, Maine, Massachusetts, and Texas.

[4]Ronald L. Lehr and Robert Touslee, "What Are We Bid? Stimulating Electric Generation Resources Through the Auction Method," Public Utilities Fortnightly, Nov. 12, 1987, pp. 11-16.

[5]Mary Nagelhout, "Competitive Bidding in Electric Power Procurement: A Survey of State Action," Public Utilities Fortnightly 121 (6), 41 (March 17, 1988).

[6]Jon B. Wellinghoff, "The Forgotten Factor in Least-Cost Utility Planning: Cost Recovery," Public Utilities Fortnightly 121 (7), 9-16 (March 31, 1988).

[7]Steve Kihm and Paul Newman, Ratebasing of Conservation Costs in Wisconsin, Wisconsin Public Service Commission Staff, Madison, Wisc., undated.

[8]1987 Report of the Committee on Energy Conservation, Appendix H, National Association of Regulatory Commissioners, Washington, D.C., pp. 53-58.

[9]"Conservation in the Rate Base: A Review of Regulatory Practices and Implications"; forthcoming from the Alliance to Save Energy, Washington, D.C.



## VII. ACTION PLANS AND MONITORING

The key measure of the success of a least-cost plan is the extent to which resource decisions are made and actions are taken in response to its recommendations. The long-term resource plan must be translated into a short-term (e.g., two-year) action plan that specifies the utility's commitments to implementation during the following years.

The action plan is likely to have two components. One will call for acquisition of specific supply, transmission, distribution, and demand resources. This portion of the plan could include:

- a commitment to begin construction of a new transmission line to import power from another region,
- a plan to expand an existing program aimed at improving lighting efficiency in commercial buildings, or
- a pledge to prepare a new time-of-use rate filing.

The second component will call for additional data collection and analysis on promising resources. This portion of the plan might include:

- initiation of a pilot program to assess the cost effectiveness of a utility rebate program intended to increase the efficiency of new residential appliances,
- an investigation of alternative coal-combustion technologies in anticipation of a need to construct a coal-fired power plant, or
- a detailed review of natural gas price forecasts in anticipation of new contracts to purchase gas for the utility's gas combustion turbines.

The commission will want to assess the action plan to ensure that it is consistent with the long-term plan. In addition, the commission will want to monitor implementation of the action plan to be sure that the utility fulfills its commitments.

In addition to checking whether a utility is meeting its near-term commitments, monitoring should determine whether a least-cost plan is accomplishing its fundamental objective: acquiring lower-cost resources before higher-cost options. Monitoring also permits adjustments to be made to the plan as uncertainty becomes certainty. To keep the plan responsive to the needs of the present, a continually updated, dynamic process is required. Monitoring helps assure such a dynamic process and provides the ability to respond to change through periodic revisions and updates. Without an adequate and aggressive monitoring system, LCP may become just one more plan on the shelf.



## VIII. SUMMARY

Least-cost planning is a process by which a utility considers all reasonable options open to it to meet the need for electricity. These options include both those from the supply side (e.g., new generating facilities) and those from the demand side (e.g., conservation programs). Within the LCP process, different mixes of these options are considered and analyzed to see how well and at what cost they will meet the anticipated demand. From these mixes, one can be selected that promises to satisfy the projected demand with manageable capital investments and operating expenses for the utility, affordable rates for subscribers, and a reasonable return on investment for shareholders. Moreover, the analyses that are carried out also identify alternative planning strategies that might be employed if the operating environment (e.g., fuel prices) of the utility changes.

With LCP, the role of utility commissions remains regulatory. Utilities prepare the plan, and commissions can review it and consider how well that plan meets the needs of the power users, producers, and investors. Depending on the legislative authority under which it operates, a commission might be able to accept or reject a plan devised and offered by a utility. In fact, a commission may be empowered to develop a statewide plan for utility development and be able to require that each utility's plan complement the statewide plan. Whether that authority is present or not, commissions have a number of techniques available to encourage utilities to develop and adopt least-cost plans (e.g., by making the scheduling of rate reviews contingent upon the existence of a plan).

Developing, submitting, and adopting a plan, however, is not enough. Each short-term action plan (what the utility actually intends to do in the next few years) must be checked against the least-cost plan to ensure that each component of the action plan is in harmony with and contributes to the least-cost plan. Moreover, the least-cost plan must be periodically reviewed (1) to ensure that its assumptions accurately reflect the current realities of fuel costs, demand, etc., and (2) to guarantee that the strategies of the plan actually lead to the lowest-cost methods of achieving the goals of the utility, the shareholders that invest in it, and the society that supports it and is served by it.

A dynamic planning process like LCP has the potential of changing regulation from an after-the-fact adjudication procedure to a system able in large part to avoid future major errors. LCP is, in many ways, a partnership between the utility and regulatory communities. It provides a continuously updated view of what is coming and offers a menu of adjustments to help minimize the risks accruing from an uncertain future. It is a much needed successor to traditional planning methods.



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