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# Technical competence of integrated resource plans prepared by electric utilities

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Integrated resource planning is a new way for electric utilities and state regulatory commissions to cost-effectively meet future energy-service needs. As part of this process, many utilities prepare long-term plans that integrate demand-side programs into the utility's mix of resources. This paper discusses guidelines for the preparation and review of utility reports on their resource plans, focusing on the technical competence of the underlying analysis. Load forecasts, demand-side resources, supply resources, integration of resources, and treatment of uncertainty are discussed.

## 1. Introduction

Many electric utilities throughout the U.S periodically prepare long-term resource plans, often in response to requirements from state public utility commissions (PUCs). These plans inform regulators and customers about the utility's analyses of future demands for electricity, alternative ways to meet customer energy-service needs, and the utility's preferred mix of resources to meet those needs. The plan is an opportunity for the utility to share its vision of the future with the public and to explain its plan to implement this vision.

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PUC requirements provide one yardstick with which to judge these plans. However, the data list or cookbook approach sometimes prescribed by PUCs is not sufficient to assess whether these plans enhance utility decisions on resource acquisitions or whether they adequately inform the public. A more analytical approach is needed.

This paper discusses guidelines for long-term resource plans. The purpose of these guidelines is to assist PUC staff who review plans and utility staff who prepare such plans. These guidelines are based on discussions with staff in utilities and PUCs and on reviews of formal plans and related planning documents prepared by more than 30 utilities and government agencies.

The 'goodness' of a plan can be judged by four criteria:

- the clarity with which the resource plan, the procedures used to produce it, and the expected outcomes are presented;
- the technical competence (including the computer models and supporting data and analysis) with which the plan was produced;
- the adequacy and detail of the short-term action plan; and
- the extent to which the interests of various stakeholders are addressed.

These criteria are summarized in table 1 and detailed in Hirst et al. (1990).

Although this paper focuses on the utility's formal plan, recognize that the written plan is a snapshot of an ongoing, dynamic integrated resource planning (IRP) process. Indeed, the ensuing discussions deal with the planning process as well as the final product. IRP includes the utility's departments and people, analytical methods, and data as well as inputs from customers, non-utility energy experts, and the PUC. The process is a blend of quantitative data and analysis, qualitative assessments, and judgments reflecting alternative points of view. IRP differs from traditional utility planning in that it (1) explicitly includes energy-efficiency and load-management programs as energy and capacity resources, (2) considers environmental and social factors as well as direct economic costs, (3) involves public participation, and (4) carefully analyzes the uncertainties and risks posed by different resource portfolios and by external factors (table 2). Cavanagh (1986), Hirst (1988), and the National Association of Regulatory Utility Commissioners (1988) describe various aspects of IRP. None of these authors, however, discusses standards against which to assess long-term resource plans.

The remainder of this paper deals with technical competence, the second of the four criteria identified in table 1. The other issues are omitted only because space does not permit comprehensive treatment of all four issues.

The amount of information that must be processed to prepare integrated resource plans is daunting. Computer models are routinely used to manage these data for load forecasting; screening of demand and supply resources; and analysis of production costs, revenue requirements, electricity rates, and other financial parameters. These models are used to analyze a wide range of

Table 1

Checklist for a good integrated resource plan.

Clarity of plan – adequately inform various groups about future electricity resource needs, resource alternatives, and the utility's preferred strategy

- Clear writing style
- Comprehensible to different groups
- Presentation of critical issues facing utility, its preferred plan, the basis for its selection, and key decisions to be made
- Logical report structure

Technical competence of plan – positively affect utility decisions on resource acquisitions and regulatory approval thereof

- Comprehensive and multiple load forecasts
- Thorough consideration of demand-side options and programs
- Thorough consideration of supply options
- Consistent integration of demand and supply options
- Thoughtful uncertainty analyses
- Full explanation of preferred plan and its close competitors
- Use of appropriate time horizons

Adequacy of short-term action plan – provide enough information to document utility's commitment to acquire resources in long-term plan, and to collect and analyze additional data to improve planning process

Fairness of plan – provide information so that different interests can assess the plan from their own perspectives

- Adequate participation in plan development and review by various stakeholders
- Sufficient detail in report on effects of different plans

plausible futures and resource mixes in developing the utility's preferred resource portfolio.

The models should accurately simulate the processes under study and should use realistic assumptions to derive their results. The structure of the models, the data and assumptions on which they are based, how data passes from one model to another, and the inputs used in each model should be clearly explained in the IRP report.

In the following sections, technical competence is discussed for load forecasts, demand-side resource screening and assessment, supply resource screening and assessment, integration of resources into a comprehensive plan, and uncertainty analysis.

## 2. Load forecasts

Forecasts of annual electricity use and of peak demand (e.g., in Gwh and MW) for each customer class should be presented, and the basis for each forecast should be clearly explained. A reference document (e.g., an appendix) should explain the forecasting methodology, input data, and historical

Table 2

Key elements of integrated resource planning.

| |
|---|
| *Integrate resources* |
| Supply, demand, transmission, distribution, and pricing |
| *Integrate people and departments* |
| Cooperation, coordination, and communication |
| *Treat uncertainty explicitly* |
| Alternative resource portfolios |
| Factors external to the utility |
| *Involve the public in the planning process* |
| Customers, nonutility experts, independent power producers, and PUC |
| *Consider environmental factors* |
| *Implement plan* |
| Acquire demand and supply resources |
| Collect and analyze additional data |
| *Continue planning process* |
| Feedback from implementation to planning |
| Develop new plans |

performance of the forecasting models. Because future conditions are inherently uncertain, a range of load forecasts is desirable.

Meaningful links between the annual energy and peak-load forecasts are needed. Some utilities develop detailed energy forecasts, while the peak-load forecast is based on a simple model that is not coupled to annual energy use. This approach is not tenable unless the consistency of the two sets of models can be demonstrated. Serious consideration of demand-side management (DSM) resources requires detailed analysis of both the energy and load-shape effects of these resources and of the consequences of these effects on the power-supply system.

The utility should explain how the effects of projected changes in electricity price (outputs from resource integration) are fed back into the load-forecasting models. This feedback loop is especially important if the prices initially used as inputs to the load forecasts were quite different from those resulting from the resource-integration process.

The relationship between the forecasting process and forecasts on the one hand and the utility's DSM programs on the other hand needs to be clearly explained. In particular, it is essential to know whether (as well as how) the forecasts include the effects of demand-side activities. Such activities include the company's energy-efficiency and load-management programs, government appliance-efficiency standards and building codes, and other DSM programs, as well as changing fuel and electricity prices. Without quantification of

existing DSM activities, it is impossible to establish a baseline for the acquisition of additional DSM resources.

End-use forecasts are desirable because they provide much more detailed estimates of future electricity use than do traditional econometric models. This detail is needed to assess the effects of past and current DSM programs and the likely effects of future programs. For example, federal standards for refrigerators and freezers, issued in November 1989, will cut their average electricity use by more than 25%. Forecasting models that lack end-use details cannot account for such changes in future electricity use.

Also the link between DSM potentials and load growth needs to be made explicit. In particular, the size of the conservation potential in new buildings increases with increasing economic and load growth [Ford and Geinzer (1988), Northwest Power Planning Council (1989a)].

Dworkin (1989) discusses the role of end-use models in load forecasting:

> ...historical demand forecasts, which directly influence the timing and composition of supply requirements, are methodologically independent of the underlying structure of energy end-uses. Consequently, existing forecasting methods prevent utilities from explicitly linking the baseline consumption of buildings targeted for efficiency programs with future consumption projections.
>
> The resulting gap between program planning and demand forecasting introduces considerable uncertainty in the integration of demand-side and supply-side resources. This risks double-counting savings from demand-side programs that are already included in demand forecasts; it also invites utilities to dismiss certain efficiency measures or programs on the unsubstantiated presumption that their forecasts incorporate savings from such measures.

The Northwest Power Planning Council (1989a) uses its demand models to produce three types of forecasts. The frozen-efficiency forecast (top curve in fig. 1) estimates electricity use assuming that no further improvements in energy efficiency will be made. The price-effects forecast (middle curve in fig. 1) shows the effects of increasing electricity prices on electricity use. The difference between the price-effects forecast and the sales forecast (bottom curve in fig. 1) represents the effects of utility programs.

## 3. Demand-side resources

A broad range of demand-side resources (both energy efficiency and load management) should be considered to balance the traditional emphasis on utility-owned power plants. These programs should include all customer classes, all major end uses, and a variety of current and emerging technol-

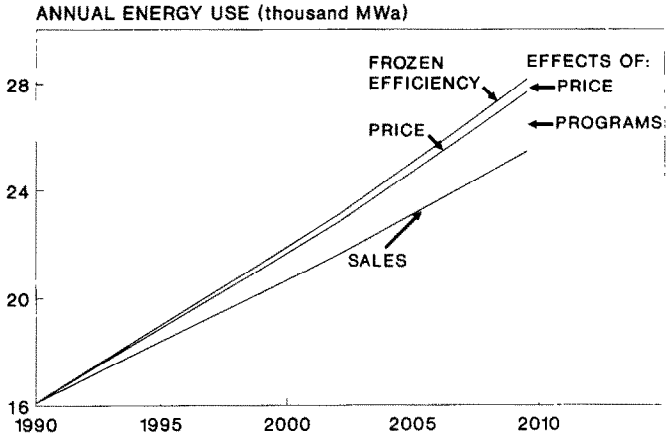


Fig. 1. Electricity-use forecasting concepts used by the Northwest Power Planning Council (1989a). One average MW (MWa) equals 8.76 GWh.

ogies. DSM resources that are slightly more expensive than supply resources under baseline conditions should not automatically be rejected at this point. These DSM options may later turn out to be attractive as the integration and uncertainty analyses proceed.

This portion of the report should begin with a review of the company's past and ongoing DSM programs. The discussion of each major program should include: program description, annual utility budgets, program participation rates, estimated energy and load effects (and the basis for these estimates), and analysis of program cost-effectiveness. The estimated effects on electricity use should distinguish between net and total savings. (Net savings are those directly attributed to the program, while total savings include market-induced as well as program-induced effects.) The utility should show what evaluations and market research support its knowledge about the process and performance of existing programs.

The utility should then discuss new program possibilities, building on its existing programs and a comprehensive assessment of DSM resources in its service area. The results of such an assessment are summarized in conservation and load-management supply curves, which show the amount of resource available at various costs (in ¢/kWh and $/kW). Because much more is known about the residential sector than about the commercial and industrial sectors, special emphasis should be placed on collecting information on the DSM potentials in the latter sectors [Goldman and Kahn (1989)].

As part of its plan update, Wisconsin Electric Power Company (1989) reviewed energy audits of commercial and industrial facilities. These audits

had been conducted as part of their DSM program, which began in 1987. These audits identified new conservation and load-management opportunities that were unknown to the company at the time it had prepared its previous resource plan. By the year 2000, new programs intended to capture the additional DSM potential identified in these audits are expected to cut peak demand by 289 MW, in addition to the 167-MW reduction expected from existing programs.

New programs can include modifications of existing programs (e.g., to gain more participation from existing target markets, to reach new market segments, or to change financial incentives) and initiation of new programs (new end uses, new technologies, or new market segments). DSM options (e.g., electric heat pumps, high-efficiency lighting systems, and industrial cogeneration) should be combined into program designs because that is what the utility delivers to its customers. It is not enough to analyze the costs and electricity savings of high-efficiency lights and motors for commercial buildings. The combination of these measures and the utility's delivery system (e.g., marketing approach and audit cost) is what is relevant. The analysis should build on experience with current programs to develop estimates of administrative costs, program participation rates over time, and energy and load reductions. The utility should also review the experience of other utilities with similar programs.

Each DSM program should then be assessed using standard economic tests, such as those developed by the California Commissions (1987). These tests assess the benefits and costs of DSM programs from the perspectives of participating customers, non-participating customers, the utility, and society in general (table 3). The plan should clearly state which tests are used, how they are used for resource screening and selection, and the sensitivity of the results to the input assumptions. Assumptions concerning program costs, participation rates, and changes in marginal energy and capacity costs are especially important.

This step should result in the selection of a set of DSM packages (say four to eight). Each package would include several programs aimed at a common objective. The packages could differ by cost-effectiveness and by goal (e.g., cut summer peak vs improve overall energy efficiency). These aggregated program packages would then be used in the resource integration process.

The documentation for these DSM program packages should include information comparable to that provided for supply resources. Such information includes program participation goals, program budgets, anticipated total and net energy and load-shape effects, and the expected lifetimes of these energy and load reductions. The relationships between new and existing programs and the load forecast should be explained clearly. To the maximum extent possible, the results of program evaluations should be used to develop the estimates of performance for planned programs.

Table 3

Economic tests proposed by the California Public Utilities Commission and the California Energy Commission for use in assessing DSM programs.

| Benefit or cost component | Perspective | | | |
|---|---|---|---|---|
| | Participant | Rate-payer | Utility | Society |
| *Benefits* | | | | |
| Avoided supply costs (fuel and capital) | | X | X | X |
| Participant incentives | X | | | |
| Participant bill reduction | X | | | |
| *Costs* | | | | |
| Program costs | | X | X | X |
| Participant incentives | | X | X | |
| Lost revenue[a] | | X | | |
| Participant costs | X | | | X |

[a]Lost revenue is equal to the participant bill reduction.

*Source*: California Public Utilities Commission and California Energy Commission (1987).

## 4. Supply resources

The list of supply resources considered should be as complete as possible, including purchased power (from other utilities, facilities that qualify under the federal Public Utility Regulatory Policies Act, and other independent power producers), alternative energy sources (such as photovoltaics, wind, and geothermal), life extension and repowering of existing plants, as well as utility construction of power plants. New or upgraded transmission facilities should be included also.

The data sources used to estimate construction times, construction costs, and operating costs should be listed in an appendix. The relationships between these assumptions about future resources and the costs and performance of existing generating units should be specified. It is especially important to assess the possibility and consequences of higher-than-anticipated construction and operating costs caused by stricter environmental regulations and public opposition to construction of power plants and transmission lines.

Analysis of customer supply options, such as self-generation, needs to be consistent with the load forecast. The same issues of agreement arise here as do in analysis of DSM resources. The Public Utility Commission of Texas (1989) carefully assessed the potentials for co- and self-generation because this is a large resource in Texas, 17,000 MW as of 1986. The commission analyzed cogeneration costs as a function of plant size and capacity factor and compared these costs with industrial rates for different utilities. These results were summarized in supply curves for individual utilities.

The Northwest Power Planning Council (1989b) discussed ways to improve efficiencies within a utility's transmission and distribution (T&D) system:

> Replacement of transmission and distribution system components, such as transformers and conductors, with components having lower electrical losses.
>
> Modification of system operating conditions, such as lowering nominal voltage levels, to reduce losses. (This option is sometimes called conservation voltage reduction.)
>
> Reconfiguration of the transmission and distribution system. An example is reconfiguring distribution feeders to reduce the average distance, and therefore losses between the substation and its loads.

Unfortunately, most utilities do not consider T&D improvements as a resource. Of the plans we reviewed, only Green Mountain Power (1989) dealt explicitly with losses in the T&D system.

Green Mountain Power (1989) was unique also in its assessment of resources from independent power producers. The company issued a request for proposals in May 1988 and received 24 proposals in July. The six most promising proposals, primarily for gas-fired combustion turbines, were reviewed in the company's 1989 resource plan.

The benefits and costs of diversity (in fuel mix, production technology, and power-plant ownership) should be assessed. In addition, the financial and regulatory risks of different resource-acquisition strategies should be considered.

The criteria used to screen supply resources and to select those for further analysis (in the integration phase) should be consistent with the criteria used for demand-side programs. These criteria should be defined explicitly and their sensitivity to key assumptions qualified.

## 5. Integration of demand and supply resources

The selection of resource portfolios can be based on many different criteria (e.g., to minimize revenue requirements, capital costs, or average electricity prices; to ensure adequate reserve margins and the ability to meet high load growth; to maintain certain financial ratios; or to reduce environmental effects of electricity production). The utility should clearly specify what criteria it used in selecting individual resources and choosing among alternative resource mixes. For example, Carolina Power & Light Company (1989) used several economic, financial, strategic, and reliability factors in assessing resource portfolios; each attribute was assigned a numerical weight used to rank alternative plans. These criteria included revenue requirements,

Table 4

Resource additions (1989–1998) and 1998 electricity prices for alternative paths analyzed by Southern California Edison.

| | Energy conservation | Managed demand | Energy productivity | Energy marketing |
|---|---|---|---|---|
| Demand additions (MW) | | | | |
| Conservation | 900 | 200 | 300 | 100 |
| Cool storage | 400 | 200 | 400 | 700 |
| Air-conditioner cycling | 300 | 0 | 300 | 300 |
| Interruptible rates | 400 | 400 | 400 | 400 |
| Subtotal | 2,000 | 800 | 1,400 | 1,500 |
| Supply additions (MW) | | | | |
| Qualifying facilities | 1,250 | 1,250 | 1,250 | 1,250 |
| Firm purchases | 400 | 750 | 750 | 850 |
| Oil/gas units returned to service | 0 | 450 | 450 | 700 |
| Other | 250 | 750 | 850 | 1,400 |
| Subtotal | 1,900 | 3,200 | 3,300 | 4,200 |
| Total additions, 1989–1998 (MW) | 3,900 | 4,000 | 4,700 | 5,700 |
| Average price in 1998 (¢/kWh) | 13.0 | 12.3 | 12.0 | 12.1 |

percent of construction internally funded, dividends, construction expenditures, electricity price, annual use of oil for electricity generation, and reserve margins.

Results for different combinations of supply and demand resources should be shown explicitly. Southern California Edison Company (1989) identified four customer-service strategies; these paths emphasized energy conservation, managed demand, energy productivity, and marketing. The company developed resource plans, including both demand and supply options, to meet each load-growth path and assessed the cost and rate impacts of each path (table 4). Forecasted sales ranged from 75,000 to 90,000 GWh in 1998 across these four paths. The company selected the energy productivity path as the preferred choice for the next decade.

The methods used to integrate supply and demand resources often involve linkages among several planning models [Eto (1989)]. In general, screening models are used to develop a short list of resources that are then subjected to more detailed analyses, both individually and in various combinations.

The screening process and criteria have important effects on the final mix of resources chosen for integration. For example, Pacific Power & Light Company (1989) used an estimate of the cost of a coal plant (5.5 ¢/kWh) to screen DSM programs. After taking all DSM programs with a levelized cost less than this hurdle rate, supply resources were used to meet the remaining

gap between projected demands and existing resources. This approach may bias resource selection decisions. In this case, if supply options were available at less than 5.5¢/kWh, too much demand resources would have been chosen. On the other hand, if supply resources cost more than 5.5¢/kWh, then too few demand resources would have been chosen. The use of a hurdle rate makes practical sense, but uncritical use of such a factor can lead to biased results. A particular subtlety in this example is that the value of DSM resources diminishes as more of these resources are chosen because the reductions in demand reduce marginal costs (i.e., the appropriate hurdle rate).

A related problem in the analysis of DSM programs is that, taken one at a time, they may not warrant adjustments to the utility's capacity-expansion plan. However, in aggregate, their effect may be large enough to defer or cancel some future power plants [Kahn (1989)].

The general issue underlying these observations is that utilities must use a rigorous analytical process that both integrates and incorporates feedbacks among different aspects of the planning problem. In this regard, the planning models used by Seattle City Light (1988) are noteworthy. The process links several detailed models into an integrated whole, which includes inputs of regional and local economic and demographic determinants of electricity use and wholesale electricity prices from the Bonneville Power Administration. Analyses of electricity demands, production costs, revenue requirements, and electricity prices proceed in an integrated and recursive fashion.

Duke Power Company (1989) begins its integration process by preparing a reference supply-only resource plan. This plan is developed with a large capacity-expansion model that produces the least-cost mix of supply options to meet future load growth consistent with the existing mix of power plants. Duke then adds each candidate DSM program to the resource mix to assess its cost effectiveness relative to the optimized supply-only plan. Those DSM programs that are cost effective are then combined into various packages, and the packages are tested against the supply-only plan. The final plan includes those DSM programs that are more cost effective than the reference supply plan and those supply resources that were still cost effective after addition of the DSM programs.

Other utilities, including New England Electric, Puget Power, and Pacific Power & Light test various combinations of demand and supply alternatives in the search for a preferred mix of resources. Rather than begin with an optimized supply plan, they combine demand and supply options from the beginning.

Regardless of the type of models or particular approach used, it is not sufficient to treat demand as a subtraction from the load forecast and then analyze supply options only, as some utilities do (top part of fig. 2). Subtracting DSM-program effects from the forecast and using the resultant

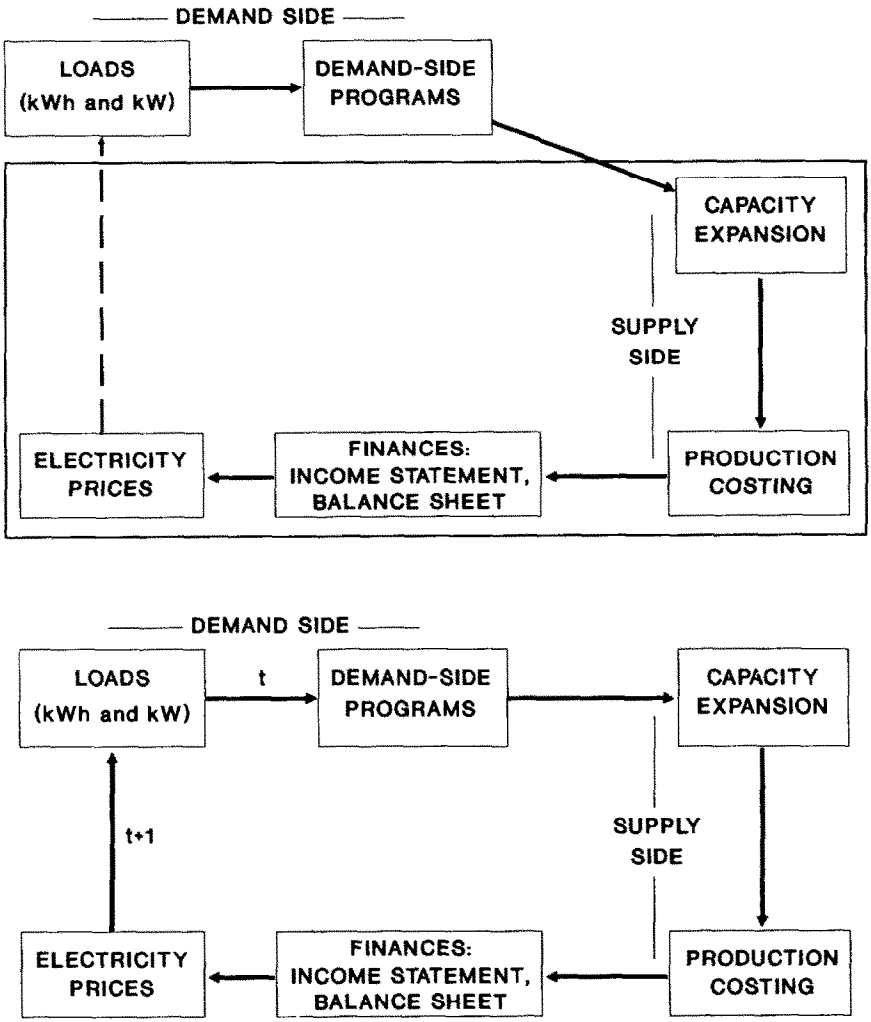


Fig. 2. Different approaches used to assess demand and supply resources. The top part shows the traditional approach, still used by some utilities. The bottom part shows an integrated approach, embodied in several recently developed planning models. In this figure, $t$ refers to the year of analysis.

'net' forecast for resource planning eliminates DSM programs from all integrating analysis. This approach makes it difficult to assess alternative combinations of DSM programs and supply resources and the uncertainties, risks, and risk-reduction benefits of DSM programs (e.g., small unit size and short lead time). Demand-side resources should be treated in a fashion that is both substantively and analytically consistent with the treatment of supply

resources so that demand and supply resources compete head to head (bottom part of fig. 2).

If several models are linked together to integrate resources, data transfers are an important problem. Differences among the models will probably require simplification of data transfers and clear definitions of each data element to ensure consistency across models. Using several models, with sequential model runs and transfers of data among models, is time consuming and will reduce the number of computer runs that can be conducted.

During the past few years, several computer models, some of which run on microcomputers, have been developed that perform the integration shown in the bottom part of fig. 2. Examples are described by Farber, Brusger, and Gerber (1988), Ford and Geinzer (1988), and USAM Center (1988). While these models can facilitate the integration process, potential users should be aware of the limitations of these models. First, these models often do not replace the existing, stand-alone models used by the utility. Consequently, they must be benchmarked to the stand-alone models. Second, the ability of these integrated models to represent load-shapes often outstrips the available data, which creates a reliance on defaults whose relevance to the particular utility must be scrutinized. Third, deferred or canceled power plants must be input to these models. Fourth, although feedback effects are included in the integrated models, the treatment of electricity-price changes on future demands is often primitive. Typically, load forecasts are input to the integrated model from a stand-alone forecasting model.

## 6. Uncertainty analysis

A thorough analysis of a variety of plausible future conditions and the options available to deal with them is essential to a good plan. Such an analysis would use one or more of the following techniques: scenario analysis, sensitivity analysis, portfolio analysis, and probabilistic analysis. These techniques should be used to assess uncertainties about both the utility's external environment and factors at least partly under the utility's control.

Uncertainties about the external environment include economic growth, inflation rates, fossil-fuel prices, and regulation. As Shealy (1989) showed, it is difficult to forecast fuel prices accurately (fig. 3). The consistent inability of forecasting organizations to predict accurately the trend of oil prices suggests the need for humility in estimation of future electricity demand, fuel prices, and other factors that affect the costs and amounts of resource acquisition. Therefore, the ranges (or distributions) of future values for these external factors should be quite broad.

The uncertainty analysis should also consider uncertainties about the costs and performance of different demand and supply resources [Hirst and

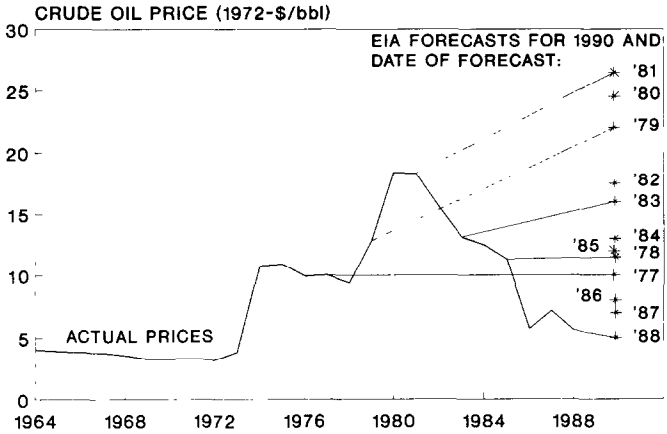


Fig. 3. Comparison of actual crude oil prices and forecasts made by the Energy Information Administration between 1977 and 1988 [Shealy (1989)]. The dark line shows actual prices from 1964 through 1988. The light lines show the forecasts of 1990 oil prices made by EIA in different years (shown on the far right).

Schweitzer (1988)]. The analysis should show how utility resource-acquisition decisions are affected by these different assumptions and show the effects of these uncertainties and decisions on customer and utility costs. Differences among resources in unit size, construction time, capital cost, and operating performance should be considered for how they affect the uncertainties faced by utilities. The assumptions must be varied in ways that are internally consistent and plausible.

Pacific Power & Light Company (1989) developed different, scenario-specific mixes of DSM programs, power purchases, cogeneration, alternative schedules for plant maintenance, renewable resources, and improved operation of existing power plants. The scenarios dealt with increased competition, oil-price shocks, limits on carbon-dioxide releases, and the baseline forecast of load growth. For each scenario, results were presented on the amounts of each resource acquired; utility operating revenues; average electricity prices; and emissions of sulfur dioxide, nitrogen oxides and carbon dioxide.

While many utilities consider uncertainties about supply resources, few pay explicit attention to uncertainties about DSM programs (in part, because of the models that utilities use for such analyses; see fig. 2). New England Electric (1989) conducted probability analyses as part of its IRP. Staff from various departments assessed the probabilities associated with the performance of the different demand and supply resources being considered. The purpose of this analysis was 'to provide an estimate of how certain [New England Electric] can be that a given resource plan will meet future needs'. The probabilities of meeting target conservation and load management MW

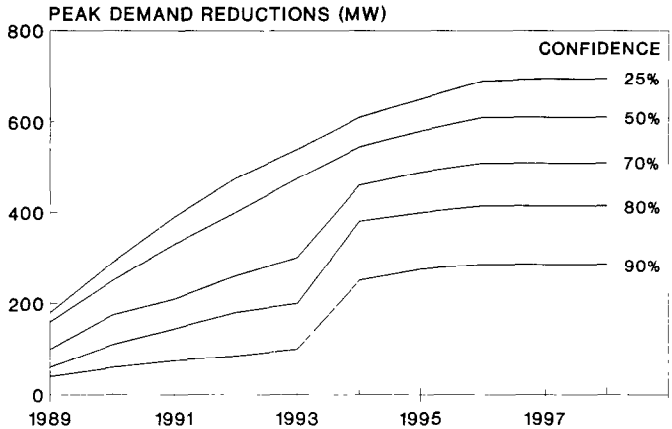


Fig. 4. Probability analysis of the performance of planned DSM programs to be run by New England Electric (1989). Each curve shows the minimum amount of peak demand reduction expected for each year for a given confidence level.

reductions are shown in fig. 4. For example, DSM programs have an 80% chance of reducing peak demands by at least 400 Mw in 1995 and a 50% probability of cutting demands by at least 580 MW that year. The company selected as a planning goal an 80% probability that, in the first five years (i.e., through 1995), planned resources will meet or exceed projected requirements. This analysis was especially appealing because it combined scenario and probability analyses to develop useful results.

That some uncertainties are much more significant than others and that some can be influenced by the utility is often lost in the details of analysis. A reasoned treatment of the most important uncertainties that the utility can influence is far more valuable than an exhaustive treatment of all uncertainties with little regard for their importance.

Finally, the links between the results of these uncertainty analyses and the utility's resource-acquisition decisions must be demonstrated. The uncertainty analysis should demonstrate the robustness of the selected resource plan. The mix of resources selected should be able to withstand the shocks of different futures and should minimize the risks associated with various adverse outcomes (e.g., rapid increases in oil prices or a moratorium on nuclear power).

## 7. Conclusions

Integrated-resource planning is a new and powerful way for utilities to provide desired energy services to their customers at reasonable cost. IRP

includes a broad array of supply and demand resources, explicit treatment of uncertainty, environmental costs as well as direct economic costs, and public involvement. Because of these features, IRP is likely to yield a better mix of resources and fewer protracted controversies among the utility, its regulator, and the public than would traditional planning approaches.

The long-term resource plans filed by utilities with their public utility commissions represent key outputs from this IRP process. It is therefore important to develop criteria to use in preparing and assessing these plans. The guidelines discussed here focus on the analytical rather than prescriptive aspects of these long-term resource plans. Although readability, specificity of the action plan, and responsiveness to different stakeholders are all important, this paper dealt with the technical basis (data, models, and analysis) for the plan.

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