LEAST-COST UTILITY PLANNING

A HANDBOOK FOR PUBLIC UTILITY COMMISSIONERS

VOLUME 2

THE DEMAND SIDE: CONCEPTUAL AND METHODOLOGICAL ISSUES

National Association
of Regulatory Utility Commissioners

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I. INTRODUCTION

Currently, seventeen states require least-cost planning in the utility sector. Many other states are establishing similar planning procedures and regulations. These developments represent a trend toward greater regulatory and public participation in resource planning. As a result of this trend, regulators need a better understanding of the technical-methodological aspects of least-cost planning.

The experience so far with least-cost planning (LCP)[1] has highlighted many areas where technical-methodological issues need to be resolved if we want to effectively implement least-cost planning policies. These issues can be grouped into three broad areas:

1) Quantification, comparison and integration of supply options;

2) Quantification, comparison and integration of conservation and load management options; and

3) Comparison and integration of demand-side with supply-side options.

Complexities and uncertainties on the supply side may, on the whole, be larger than those on the demand side, though both are significant. On the supply side, some of the difficulties arise from economies and diseconomies of scale, lead times, construction cost escalation, unit sizes, reliability, availability, fuel prices and escalation, patterns of electricity output over time, environmental impacts, etc. The problem of environmental and other externalities makes the costing of supply sources especially uncertain.

[1] We speak of integrated least-cost utility planning to clarify that investment options on the supply side and on the demand side are both part of the least-cost planning process. We use the terms "least-cost utility planning," "least-cost planning," "integrated least-cost utility planning," and the acronyms "LCP" and "LCUP" interchangeably.

On the demand side, there is also a broad list of complicating factors: measurement of program-related savings, loadshape impacts, program costs, predictability of customer acceptance and participation rates, persistence of savings, etc.

Finally, integrating demand-side resources into a traditionally supply-oriented planning framework brings up many specific issues, which include choosing appropriate cost-benefit tests, defining and calculating avoided costs, evaluating risks, and choosing modeling tools suitable for planning under uncertainty.

The present publication is the second volume of the NARUC Handbook on Least-Cost Utility Planning. While the first volume gave a general introduction and overview to Least-Cost Utility Planning, the second volume is oriented toward the demand-side component of LCUP.

A special focus on demand-side resource issues is warranted not because these resources are more important to the least-cost planning approach than supply-side resources, but because they represent its most novel component. Because of this novelty, many utilities and regulatory commissions are unfamiliar with the technical and policy problems of demand-side resources.

Volume Two is also different from Volume One in that it is more of an in-depth technical discussion than a general introduction. Because of the technical depth, no attempt is made to comprehensively address all the conceptual and methodological problems encountered in integrating demand-side or conservation and load management (C&LM)[2] resources. Instead, we limit ourselves to a subset of demand-side issues, notably the areas of economic tests, avoided cost definitions, and modeling approaches for integrated resource planning. We also cover in

[2] We use the acronyms C&LM and demand-side resources interchangeably. In the case of sales-reducing demand-side measures, we generally speak of efficiency investments rather than conservation investments, since conservation connotes, in some contexts, the curtailment of energy services.

detail the policy issues associated with the choice of economic test perspectives.

Other important issues may be taken up in later publications. Among them are the specific measurement issues associated with demand-side programs, and the "loose cannon" of least-cost planning, i.e., the difficult to quantify environmental and other "externalities", and the role LCP could and should play in achieving environmental normative policy goals at least economic cost.

We begin with the fundamentals (Section II): the reasons that demand-side resources exist in the first place and the special role of utility programs in mobilizing them.

From there, we move to the test issues. The economic tests used for the evaluation of utility demand-side programs have been a central issue in LCUP regulatory efforts. In the new demand-side field, they are the first area in which a standard practice approach is emerging from workshops between utilities and regulatory agencies in individual states. In this Volume, we formally review and define the key tests, including formulas (Section III).

While the standard-practice approach has more or less settled the *definitions* of the different economic perspectives, considerable debate surrounds the issue of how to *balance* the different perspectives. This debate often involves abstract arguments that are not sufficiently connected to the typical circumstances in which utilities and regulators may find themselves. Therefore, in Section IV we present not only an overview of the general arguments, but also concrete quantitative examples that illustrate pragmatic balancing of the perspectives under various circumstances.

In Section V, we give a brief overview of measurement issues involving the methods and data used to calculate the inputs for the economic test formulas. Standardizing the calculation of these inputs is important for making LCP practice more uniform and consistent. In this report, we address in detail only the issues of proper determination of avoided costs.

- respond to whatever price signals they receive with a level of demand-side investments that is consonant with average returns on capital realized in the economy as a whole.

Distortions in price signals are usually attributed to such factors as neglected externalities (or better, difficult-to-quantify costs), subsidies, or insufficient competition among suppliers. In the utility sector, the rate-setting process presents additional and unique impediments to marginal cost pricing (Landsberg 1979).

From this pricing-oriented perspective, the type of program needed to mobilize demand-side resources would be rate reforms that establish electricity prices based on marginal cost and time of use. Only where rate-setting inadequacies prevent the alignment of rates with marginal costs would incentive payments to customers be called for, and the magnitude of these incentives should then be limited to the gap between average rates and marginal costs.

Deficiencies of the Conventional Model

Underlying the conventional model is the assumption that market imperfections or barriers are negligible or affect only small numbers of electricity customers. Over the last decade, however, extensive research[1] has shown that the diffusion of efficiency technology is severely impeded by many factors other than price distortions, notably institutional barriers, inconvenience, risk perceptions, and limited access to capital and information.

The evidence for large, unrealized opportunities for cost-effective demand-side investments stems from research on the following three questions:

1) How does the average energy efficiency of new buildings and equipment as currently built and purchased compare with the most energy-efficient, cost-effective technology, specifically, the most cost-effective commercially available models?

2) What kind of economic payback requirements are being used by customers -- either explicitly or implicitly -- when they face choices about investments in end-use efficiency?

3) What specific institutional and socio-economic factors other than price (if any) influence or determine these investment decisions?

[1] See, for example, the discussions in Stern and Aronson 1984, Blumstein *et al.* 1980, and EPRI 1987. Many other references documenting and analyzing these issues are quoted below in the discussion of the payback gap.

The following sections review the most important findings from this research.

The Efficiency Gap

A number of studies[2] have investigated the unrealized potential for electricity savings through increased end-use efficiency. Though estimates vary, these studies agree that the gap between the energy efficiency of the average new investment, and that of the best available and cost-effective technology on the market, is large. The gap is even greater if best available technology is defined to include near-commercial prototypes or improvements using materials already available, proven electronic components, and standard but unrealized engineering approaches that could enter the market during the 10-20 year time horizon of utility resource planning, and that are expected to provide savings with good economic returns.

In utility planning, it is customary to only consider commercially-available and mass-produced equipment or well-established building techniques. Even with this constraint, potential savings identified in the above-mentioned analyses are fifty percent or more in a number of end uses, such as residential and commercial lighting, refrigeration, water heating, etc. These technical

[2] See, for example, SERI (1980) for all sectors of the U.S. economy as a whole, Usibelli *et al.* (1985) for the commercial sector, Hunn, Rosenfeld *et al.* (1986) for the residential and commercial sectors, Geller *et al.* (1986) and Krause *et al.* (1987) for the residential sector, based on baseline data from service territories in Texas, California, and Michigan.

analyses also find that the average cost of conserved energy[3] obtained from investments in these commercially available demand-side technologies are often significantly lower than current electricity rates.

To understand how a demand-side resource is specified, it is useful to relate the concept to conventional utility forecasting terms. Figure II-1 shows four types of projections that illustrate the method, based on a recent least-cost planning exercise in Michigan.[4]

The topmost curve, labeled *frozen efficiency forecast*, projects electrical demand assuming no technical efficiency improvements at all : i.e., the evolution of demand is driven only by the development of household size and number, growth in personal income (or, in the industrial sector, economic growth in value added by SIC group), and end-use and equipment saturations.

The second line, labeled *business-as-usual forecast*, incorporates projections of efficiency improvements as a function of current market trends and other known factors, such as schedules for efficiency standards.[5]

The third line, labeled *program-based scenario*, relies on the same forecast but assumes implementation of a variety of utility programs that would speed up and ensure the penetration of more efficient demand-side technologies. The supply curve in Figure II-2 shows the costs of the programs included.

[3] The cost of conserved energy (CCE) is the levelized capital and maintenance cost of an efficiency investment over its useful life, divided by the energy savings (Meier 1982). In a similar manner, one can define the cost of conserved peak power (CCPP), see (Krause *et al.* 1987).

[4] Michigan Electricity Options Study (MEOS) 1987. The figure shows results from the residential sector study as submitted by LBL (Krause *et al.* 1987).

[5] The business-as-usual forecast, shown here for the residential sector, was prepared on the basis of estimates and projections by utility staff participating in the MEOS least-cost planning project, and information from the Association of Home Appliance Manufacturers (AHAM). It includes the anticipated savings from implementation of the National Appliance Efficiency Standards of 1987.

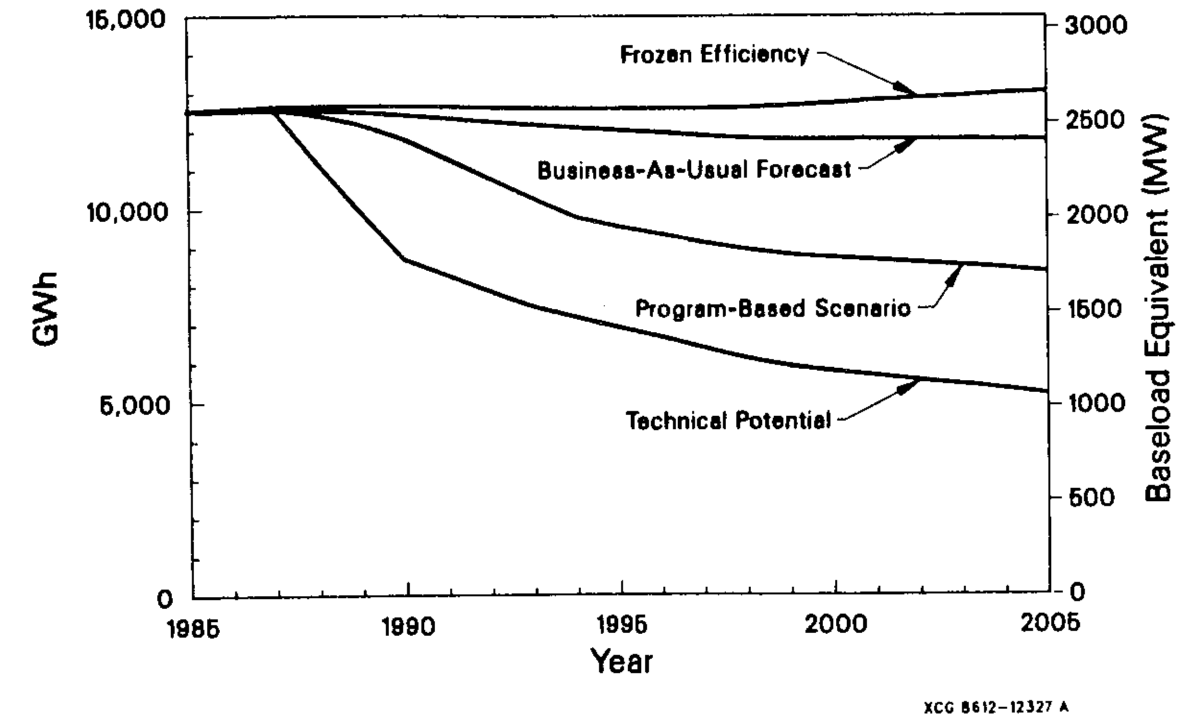

Figure II-1. **Demand-Side Resources in Michigan's Residential Sector, 1985-2005. Source: Krause, *et al.* 1987.**

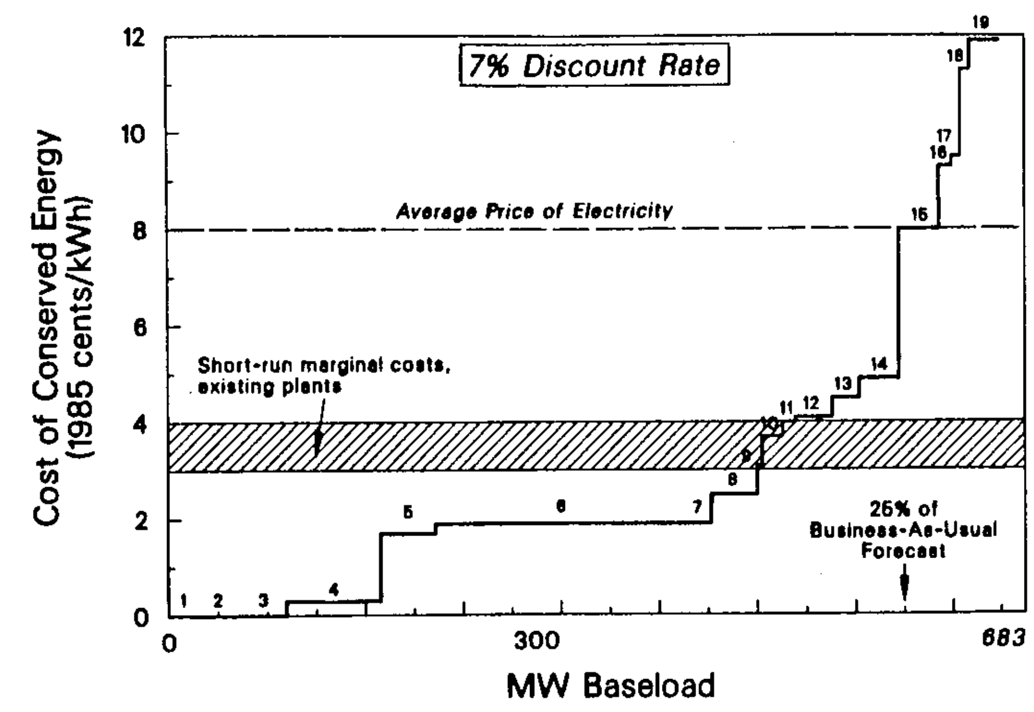

Figure II-2. **Curve of Annual Residential Sector Electricity Savings in Michigan, Year 2005. Source: Krause, *et al.* 1987.**

The fourth line, labeled *technical potential*, shows the hypothetical demand that would result if the most efficient device or technology on the market were fully utilized in each replacement purchase or new addition of buildings and equipment. Costs for this technical potential are generally structured as in Figure II-2, but because of the full penetration assumed, the savings available at each cost step are larger.

Figure II-1 shows that if all residential customers in Michigan were to buy the best commercially-available technology (the technical potential), residential electricity demand would be about 56 percent lower than conventional forecasts for 2005. This finding illustrates that, extrapolating from current purchasing and investment patterns, most consumers would forego energy-efficient models and technologies. The *lower limit* of savings that could be reliably obtained with large-scale utility incentive programs was estimated as 29 percent.[6] In other words, programs could implement at least about half the technical potential. This is a conservative figure that could be improved, judging from experience with aggressive programs that rely on direct delivery and installation at no cost to consumers, and achieve as much as 85-90 percent participation in a period of a few weeks to two years.[7]

The cost structure of demand-side resources, expressed in terms of cents per kWh saved and based on societal discount rates, is illustrated in Figure II-2. The figure shows a supply curve of conserved energy for the Michigan residential sector; it is the cost per kWh of implementing the

[6] This estimate excludes electricity savings that could be cost effectively obtained from switching water heaters, stoves, and dryers to gas. The technical potential of these fuel-switching measures was found to be about as large as that from all the electricity measures combined in the program-based scenario. Mainly in the case of cooking, customer preferences may prevent the utility from fully realizing that potential. The large size of the potential fuel-switching resource illustrates, however, that the least-cost planning framework should be expanded to include fuels other than electricity.

[7] Examples are the Hood River residential building retrofit program which was specifically designed to test the gap between technical and program-based achievable potential (Hirst *et al.* 1989), and a number of lighting programs (Krause and Vine 1989).

measures and programs assumed in the program-based scenario in Figure II-1.[8]

The supply curve in Figure II-2 reveals a large cost differential between most demand-side measures and current typical residential electricity prices of about 8 cents/kWh (dashed line). The figure also shows a cost band for the short-run marginal costs of producing power from *existing* baseload and cycling plants, which range from 3-4 cents/kWh (including line losses). Note that a large portion (about 70 percent) of the demand-side resource costs less than operating existing plants. The average cost of this portion of the supply curve is significantly below the cost of producing electricity from *existing* baseload powerplants. Table II-1 gives the numbers for the average costs of each major segment of the supply curve, and the average cost of the demand-side resource as a whole. As can be seen, the average cost of the total demand-side resource (including program administration costs) in Figure II-2 is 2.9 cents/kWh at a 7% utility discount rate. For the portion of the supply curve that falls below the band of short-run marginal costs, the average is 1.4 cents/kWh (Krause *et al.* 1987). Note that a seven percent real discount rate is an unfavorable assumption for demand-side investments, given that an equivalent rate of return in utility power plant investments is only realized on equity capital. Debt financing and AFUDC substantially reduce the applicable average discount rate. For example, at a 3% real discount rate, the average cost of the supply curve is only 2.0 cents/kWh. The portion that falls below the 3.0 cents/kWh threshold grows to 75 percent of all savings, and the average cost of conserved energy of that portion becomes 1.1 cents/kWh.

[8] Cost figures include the full cost of the demand-side investment plus the administration costs of demand-side programs, equivalent to the cost of the demand-side resource to ratepayers if the ratepayers were to provide rebates covering the entire extra first cost of choosing greater efficiency in demand-side investments.

Table II-1: Curve of Annual Residential Sector Electricity Savings in Michigan, Year 2005: 7% Discount Rate

Rank	End Use Measure	Annual Savings over Business-as-Usual (GWh)	Cost of Conserved Energy (Total Resource Cost) (¢/kWh)
1	Air Cond.	114	0.0
2	Furnace Fans	173	0.0
3	Temp.Setback	191	0.0
4	Hi-Eff.Showers & Faucets	385	0.3
5	2nd Units	226	1.7
6	Lighting	1123	1.9
7	Exis. EHH, Block 1	13	2.3
8	Frost-Free 1992 Std.	189	2.5
9	Auto-Defrost.Low Tech.	20	3.1
10	New EHH, Block 2	83	3.7
11	Exist. EHH, Block 2	52	4.0
12	Frost-Free Low Tech.	149	4.1
13	Clothes Washers	112	4.5
14	Manual Low Tech.	162	4.9
15	Eff. Water Heaters	168	8.0
16	Std. 1992/Low Tech.	51	9.3
17	Exist. EHH, Block 3	36	9.5
18	Low-Income Programs	38	11.3
19	New EHH, Block 3	124	11.9
	All measures < 3.0 cents/kWh	2414	1.4
	All measures 3.0-4.0 cents/kWh	155	3.7
	All measures > 4.0/cents/kWh	840	7.1
	All measures	3408	2.9

It should be noted that these results for Michigan are at best suggestive of the results that might be expected in other regions. They cannot be automatically transferred to other service territories and states. Other regions of the U.S. vary significantly in climate, types of buildings, statistical weight of end uses, hardware prices and labor costs. For these reasons, the quantification of demand-side resources and their cost structure should always reflect real conditions in each region.

The Payback Gap

Findings such as these have drawn attention to the slow penetration of commercially available energy-efficient technologies into the building and equipment stock, despite highly favorable costs of conserved energy. This discrepancy can be related to an underlying *payback gap*, i.e. a gap between the economic criteria used by energy suppliers and energy consumers. The term "payback gap" was first introduced by Cavanagh (1983).

According to extensive surveys of customer choices, consumers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. Moreover, this behavior is not limited to residential customers. Commercial and industrial customers implicitly require as short or even shorter payback requirements, sometimes as little as a month. The phenomenon is not only independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved.[9]

[9] For general reviews, see e.g., Train 1985, CPUC 1984, Hirst *et al.* 1983, Stern and Aronson 1984, Kempton and Neimann 1987, Stobaugh and Yergin 1981. For energy-efficiency investments in residential buildings, see Corum and O'Neal 1982, Vine *et al.* 1987, Stern *et al.* 1986, Oster and Quigley 1978. For residential appliances, see Ruderman *et al.* 1984. For the commercial sector, Barker *et al.* 1986, Manitoba Conservation and Renewable Energy Office 1984, Rosenfeld and de la Moriniere 1987, EPRI 1987. Recent experience with commercial lighting efficiency choices in Nevada implies a one month payback requirement (Wellinghoff 1988). For the industrial sector, see ASE 1987.

This short-term perspective of energy consumers, in turn, leads to inflated demand growth and forces utilities to undertake compensating supply-side investments. Utility investments are, however, based on long-term planning with real rates of return in the neighborhood of 5-7% on equity, and about 2-4% on debt-financed investments. They are expected to pay back over 10 to 20 years or more. The general picture that emerges is thus one of a large asymmetry between economic investment criteria for the demand side and the supply side. The size of this asymmetry is so large that it outweighs otherwise significant demand-side variations in implicit payback requirements by customer class, end-use and technology.

To illustrate this payback gap in more concrete terms, consider as a typical example an efficient refrigerator that provides energy savings at a cost of 2.5 cents/kWh (assuming a 20 year life and a utility real discount rate of 3%). Compared to average electricity rates of about 7 cents/kWh, a cost of conserved energy of 2.5 cents/kWh would make this model a bargain. Table II-2 shows the conversions between rates of return and payback times as a function of investment life (Wisconsin PSC 1985, Plunkett 1988), For an investment life of 20 years, we find a 3.1% discount rate to be equivalent to a 15 year payback.

Now consider customers implicitly requiring a 2 year payback. Again, making use of Table II-2, we see that these customers implicitly apply a discount rate of 64% to the refrigerator investment. At this discount rate, the cost of conserved energy is higher in proportion to the shorter payback period, or by a factor 15/2=7.5. This yields a *perceived* cost of conserved energy of about 2.5x7.5=18.8 cents/kWh. This is more than twice as high as the average U.S. electricity rate. Put another way, a 2-year-payback customer paying average rates of 7 cents/kWh can be expected to forego demand-side measures with costs of conserved energy of more than 7/7.5=0.9 cents/kWh.

Table II-2. Implicit Real Discount Rates (%/yr)

PAYBACK (Y)	INVESTMENT LIFETIME (Y)							
	3	5	7	10	15	20	25	30
1	146.5	159.8	161.5	161.8	161.8	161.8	161.8	161.8
1½	68.4	87.3	91.2	92.3	92.5	92.5	92.5	92.5
2	33.5	55.5	61.3	63.5	64.0	64.0	64.0	64.0
2½	13.3	37.2	44.4	47.6	48.6	48.8	48.8	48.8
3	0.0	25.1	33.4	37.5	39.0	39.3	39.3	39.3
4		9.7	19.4	24.9	27.5	28.1	28.3	28.3
5		0.0	10.7	17.2	20.7	21.6	21.9	22.0
6			4.6	11.9	16.0	17.3	17.8	18.0
7			0.0	7.9	12.6	14.2	14.8	15.1
8				47.7	9.9	11.8	12.6	12.9
9				2.2	7.8	9.9	10.8	11.2
10				0.0	6.0	8.3	9.3	9.9
12					3.1	5.8	7.1	7.7
15					0.0	3.1	4.6	5.5
20						0.0	1.9	3.0

Source: Plunkett (1988)

Suppose policy-makers wanted to create price signals sufficient to stimulate a 2-year-payback customer to undertake all efficiency investments that would be cost effective from the utility perspective against current average revenue requirements (again assuming a 7% discount rate): For this to occur, price signals of 7x7.5=52.5 cents/kWh would appear to be required.

These figures illustrate why the payback gap makes policies based only on pricing ineffective unless they are combined with programs that address the market and institutional barriers encountered by energy consumers who are trying to make economically rational investments.

Market and Institutional Barriers

Detailed investigations by research institutions and utilities have shed much light on the reasons for this payback gap.[10] They reveal a complex web of micro-level considerations and constraints that differ greatly by customer group and end use, though their effects on implicit discount rates are quite universal and comparable in size to one another. The following factors can be distinguished:

- *Split incentives.* Imagine that energy users follow the same long-term economic rationality that is used by utility and other long-term investors, are well-supplied with information and access to capital, have had a chance to test the risks of efficiency technologies and are satisfied they work; these consumers may still not undertake all cost-effective efficiency investments because they are faced with institutional barriers in the form of split incentives. The most prominent one is that in many demand-side investments the user of the equipment or building does not do the purchasing, but the landlord or builder does. Even in absence of these factors, energy users, including home owners, may rationally choose not to invest in energy efficiency if they are uncertain about how long they will stay in a particular building.

[10] See, for example, the many articles found in the Proceedings of the ACEEE Summer Study (1986, 1988).

- *Limited access to financing and protection from financial risk.* Energy users may also face limited access to financing or may feel economically too exposed if they were to sink scarce cash or credit into investments with payback periods of several years.

- *High information and transaction costs.* Energy users may face not only the economic costs of demand-side investments, but also high transaction and information costs, e.g., research to find out about the availability of efficient technologies, to assess and verify vendors' claims, to find qualified architects, installers, and technical personnel, and to judge the uncertainties involved with equipment reliability.

- *Irreducible but hidden indirect costs.* There may be hidden costs of demand-side resources that are not sufficiently captured by the price of efficiency investments but are not transaction costs or the result of information barriers. They include technical risks that are real, i.e., not just perceived risks based on inadequate information, or loss of convenience or comfort.

- *Non-economic consumer rationality.* Energy users often do not mainly follow economic rationality in their demand-side investments, but are governed by such intangibles as appearance, fashion, the opinions of peer groups, personal obligation, trust in sources of information, and the momentum of habit. They may only try to avoid hassles, do nothing until they perceive a critical need and then do only enough to let the problem recede from attention (Stern *et al.* 1986).

- *The "Catch-22" effect.* Due to the payback gap itself, manufacturers have a much reduced incentive to market high efficiency devices that could deliver energy services at least cost.

Economic theory holds that true societal costs include only those input requirements for providing a given quantity of service that cannot be reduced. If it costs a utility 2 cents/kWh to install a lighting measure, and customers 20 cents/kWh when doing it on their own, the true societal cost is still 2 cents/kWh. Only one factor of the previously mentioned barriers and costs -- irreducible hidden costs -- cannot be immediately influenced by demand-side programs, though utility programs would likely stimulate the design of new and better technology once they become a predictable feature of energy service delivery. Unfortunately, verifying and measuring such hidden costs is complex and usually cannot be done reliably, short of undertaking a pilot program. Energy users who suffer from the above-mentioned market and information barriers are not only likely to be *un*informed about such hidden costs, but may also be *mis*informed about them, for various reasons (e.g., experience with early versions of a new technology). Similarly, these same barriers are likely to prevent customer awareness of hidden benefits in convenience that could bring a net increase in consumer surplus.

For example, compact fluorescent lightbulbs are one of the most highly cost-effective demand-side investments. But at a typical first cost of $8-17, which is 10-20 times the cost of a standard bulb, they are not perceived to be a bargain. Also, they are less conveniently sized than incandescents. Though fixture manufacturers are responding to new lamps with new designs, this size differential may present a real loss of convenience in many applications. But, contrary to outdated information, models with electronic ballasts do not flicker as standard fluorescent tube fixtures do, and with the introduction of new, warm-light phosphors, their color rendition now approaches that of incandescents.

Conclusions: the Limits to Pricing Policies

The short payback requirements for efficiency investments usually result from different combinations of these factors. But the multitude of dynamics involved explains why the payback gap is not just found for particular end uses or particular customer groups, but is so universal. It also explains why consumer investments in efficiency and load management are not governed solely or even mainly by an economically efficient response to prevailing prices. For these reasons, the redesign of utility rates alone, or any other strategy limited to the correction of prices only, is insufficient to mobilize the bulk of demand-side resources. Direct intervention is needed to strengthen market mechanisms and remove institutional and market barriers.

This is not to say that efforts to correct prices are not important. On the contrary, the more that market and institutional barriers are removed, the more that prices will govern demand-side investments, and the more important it is that energy prices and electricity rates appropriately reflect marginal costs.

Utility Roles in Mobilizing Demand-Side Resources

Utility programs are not the only and not necessarily the best-suited approach to reducing market imperfections. Building codes, equipment efficiency standards, other regulatory action (appliance and building efficiency labels, sliding scale hook-up fees, changed mortgage lending practices, etc.), legislative action (tax credits, energy taxes, loan programs, state-financed conservation services and banks, etc.), and private energy service companies (ESCos) all can work toward these aims.

In weighing the advantages and disadvantages of each approach, one must take into account different perspectives (societal, consumer, utility) and a number of practical issues. These include the manner in which demand-side measures are selected, the organization and administration of customer participation and program delivery, the relative cost-effectiveness of each approach, the predictability of customer participation and of impacts on utility loads, the degree to which these impacts can be flexibly shaped, etc. Other issues include the degree to which end-uses involve homogeneous or widely differing applications, the degree to which suboptimal investments in demand-side efficiency would create long-term lost opportunities, and the extent to which each form of program creates real or perceived inequities among participants and non-participants (due to asymmetrical barriers to participation), and the implication of alternative approaches for utility investor earnings.

While a full discussion of these trade-offs is beyond the scope of this handbook, we can say that it would be unwise to make utility programs the only vehicle for market correction. On the other hand, the inverse is also true: not conducting utility programs would introduce significant handicaps and inefficiencies in addressing market barriers. Least-cost analysts have identified a number of utility program advantages that complement those of non-utility programs (Schultz 1986, Ruff 1987, NWPPC 1988):

- Utility programs put the cost of avoiding additional supply investments onto the direct beneficiaries of such action, i.e., the ratepayers in each region. This establishes symmetry with the supply-side. Power plants are not built with taxpayer money either, but with ratepayer money.
- When the cost of acquiring demand-side resources is recovered from ratepayers, including participants, payment is based on how much electricity they use. This is more equitable than purchasing demand-side resources with general tax revenues raised from income taxes, purchases of goods, and property values.

- Utility incentive programs rely on voluntary participation and are thus a non-coercive means of introducing the societal least-cost perspective into customer efficiency decisions.
- Because of the established supply, metering, and billing relationship with their customers, utilities are particularly well positioned to provide customers with information, to recruit program participants, and to reduce the transaction costs of demand-side investments.
- Utility programs offer greater flexibility. Unlike regulatory or legislative action, they can be modified quickly and tailored continuously to customer needs. Pilot programs are a reliable, empirical way of testing for hidden technology costs and benefits, and thus ensuring consumer surplus.
- Whereas efficiency standards are most suited for raising the efficiency floor of the market by eliminating the worst appliances, buildings, and other equipment, utility incentive programs can create or stimulate markets in the higher efficiency brackets that standards tend not to reach. They can thus complement the market push of standards with a market pull, increasing the total demand-side resource accessible to society.
- The choice of technologies and the timing of programs can be tailored to the specific circumstances of individual utility systems to assure optimal impacts on load factors and additional capacity requirements over time.
- Utilities and their ratepayers, as the supplier of last resort, are forced to pick up the cost of non-adoption of cost-effective demand-side resources.

- Utility demand-side programs may be a required element of least-cost pollution abatement strategies for acid rain and global climate warming because such programs can be most flexibly tailored toward individual regions and companies.

Equally important, utility and non-utility approaches can work together, and such joint approaches may yet prove to be the most powerful policy for overcoming the payback gap. Already, utilities are enlisting private performance contractors or energy service companies in their programs because such companies are often more adept at identifying the latest technology in their specialized field and at maintaining energy-saving investments over time. ESCos, on the other hand, are finding that the endorsement of the utility greatly facilitates their efforts to enlist customers. Direct payments from the utility to the ESCo, rather than from the customer under shared savings arrangements, greatly simplifies demand-side investments. Moreover, joint utility-ESCo programs do away with the pressure on private energy service companies to concentrate only on the largest customers and on the quickest-payback items, which customers are most likely to do on their own, particularly once ESCo activity has shown them how attractive they are.

Similarly, utility programs can make regulatory approaches more effective and palatable, by bearing some of the costs of compliance and enforcement, for example in buildings. Also, utility programs can increase the market penetration of new technologies to the point where they are used by the majority of customers and standards can take over, a point that might not be reached until years later without programs. In the area of pollution abatement, a number of studies have explored how utility demand-side programs can supplement emission standards and other mitigation strategies.

III. COST-BENEFIT TESTS FOR UTILITY DEMAND-SIDE PROGRAMS

A special set of cost/benefit tests for demand-side resources is needed for two reasons:

1) With the exception of some forms of load control, the physical devices producing demand-side savings do not usually belong to the utility, but to its customers. The total costs and benefits of demand-side resources are thus distributed differently.

2) The operating characteristics, system impacts, and availability of demand-side resources are quite different from those of utility-owned generating sources.

This section provides a formal review of the four most important perspectives: participant, non-participant, utility, and total resource/society, while only briefly mentioning other perspectives that are essentially subsumed by them.

We begin with definitions of these four perspectives and the related cost-benefit tests. In using these perspectives and tests, least-cost planners have often been faced with ambiguous, contradictory, and changing definitions of key terms. Recently, two publications attempted to reduce these ambiguities with definitions that would establish a standard practice. They are California's Standard Practice Manual for Economic Analysis of Demand-Side Management Programs (referred to as the California Standard Practice manual) (CPUC 1987) and the Electric Power Research Institute's TAG Technical Assessment Guide, volume 4, Fundamentals and Methods, End-Use (referred to as the TAG manual) (EPRI 1987). In our review, we cross-reference these sources to allow consistent use of their definitions, rather than developing new definitions.

Table III-1. Summary of Economic Benefit-Cost Perspectives

Economic Perspective	Benefit Components			Cost Components		
	Utility Avoided Costs	Customer Bill Savings	Utility Incentive Payment	Utility Program Administration[1]	Customer Direct Costs	Customer Bill Savings
Participant		X	X		X	
Non-Participant	X			X		X
Utility	X			X		
Total Resource[2]	X			X	X	

1. Includes incentive payments.
2. Elements of the total resource are contained in the Societal Perspective, which also includes indirect economic and other non-quantifiable or difficult-to-quantify economic and non-economic impacts.

Definition of Cost-Benefit Perspectives

The goal of a cost-benefit test is to provide a consistent framework for quantifying the benefits and costs of a demand-side program. Cost-effective outcomes may be expressed either as having a positive net present value (NPV) or as having a benefit-cost ratio (BCR) in excess of one. In both cases, the basic idea is simple: a program is cost effective if and only if benefits outweigh costs.

Formally:

$$\mathrm{NPV} = \mathrm{B} - \mathrm{C} \qquad [1]$$

or

$$\mathrm{BCR} = \frac{\mathrm{B}}{\mathrm{C}} \qquad [2]$$

We proceed now to introduce and define these components of benefit and cost for each economic perspective. As described previously, convenience often dictates that these definitions be restricted to readily quantifiable, direct economic benefits and costs, although we will note exceptions.

Participant Perspective

The goal of the participant perspective is to measure how a customer's self-interest will be affected by participating in a demand-side program. When the basic economics of the program are insufficient to induce participation, evaluating the participant perspective can serve to identify appropriate incentives to stimulate participation. The perspective is relevant only for evaluating demand-side interventions because it is generally assumed that all customers are "participants" in supply-side programs.

The participant perspective is defined as the difference between the costs incurred by a participant in a demand-side program and the subsequent value received by that participant. The participant's costs include all costs that are associated with installing and operating a particular demand-side measure and that are borne by the participant. The cost to the utility of program administration, for example, is not included. The value of the program usually consists of only the direct economic benefits received by the participant. These benefits include incentives from the utility or other sources (e.g., federal tax credits), and the value of changes in the participant's utility bills. One can also identify other less quantifiable costs or benefits resulting from changes in the participant's comfort or lifestyle as a result of a program (see the discussion of consumer surplus impacts in Section II), but these impacts are typically ignored for pragmatic reasons. For example, the recent California Standard Practice Manual restricts the participant perspective to include only readily quantifiable costs and benefits (CPUC 1987)[1].

We define the benefits and costs for the perspective formally, as follows:

$$B_p = \sum_{i=1}^{N} \frac{I_i + \sum_{j=1}^{M} (\Delta E_{ij} * P_{ij})}{(1 + DR_p)^i} \qquad [3]$$

and

$$C_p = \sum_{i=1}^{N} \frac{DC_i}{(1 + DR_p)^i} \qquad [4]$$

Where:

B_p = Participant benefit
C_p = Participant cost
ΔE_{ij} = Change in energy use in year i for fuel j

[1] End-use forecasting models (described in section VI) can, in principle, capture one such effect, the so-called "rebound" effect, in which subsequent consumption decisions are affected by increases in real income resulting from energy bill reductions.

P_{ij} = Price of energy in year i for fuel j
I_i = Incentives received in year i
DC_i = Direct costs of participation in year i
DR_p = Participant discount rate, expressed as a decimal fraction
N = number of years
M = number of affected fuel types

Incentives can include payments from the utility or indirect incentives from the government in the form of tax credits or loan guarantees. Incentives (I_i) and direct costs (DC_i) generally occur only in the first year of a program (i=1). Exceptions are, however, not unusual. Examples include ongoing maintenance costs in addition to first-year direct costs, and monthly bill credits in addition to, or in place of up-front payments as an incentive for participation.

Estimating the value of energy savings is complicated by difficulties in[2]:

1) measuring the savings attributable to participation;
2) determining the relevant price of energy;
3) estimating the bill impacts of these prices; and
4) meaningfully specifying the appropriate participant discount rate.

There are two major sources of uncertainty in forecasting electricity prices: 1) the well-known volatility of the factor inputs to the production of electricity, such as fuel prices, and 2) the need to forecast a theory of regulation. That is, the analyst must make implicit or explicit assumptions about how changes in the utility's unknown future costs will be translated into specific retail rate tariffs for consumers, some of whom are the participants in the programs. A complicating consideration is the need to account for feedback effects that are related to the size of the

[2] A full discussion of the methods for addressing these measurement problems is beyond the scope of this handbook. With these few points, we highlight the need for a thorough treatment of inputs to the test formulas.

demand-side program. Essentially, trajectories of two price streams are required, one with and one without the program. This latter issue is directly related to the non-participant perspective, and will be addressed more fully in that subsection.

If energy is priced using a flat rate, estimating the bill impacts is trivial. The process becomes complicated when the customer's tariff has block-rate, or, for electricity, time-of-use or demand charge provisions. Under a block-rate tariff, the analyst must be able to allocate energy savings to different blocks of consumption, each of which has a different price. Under a time-of-use tariff (which includes both time-of-day and seasonal tariffs), an allocation of energy savings must be made to different periods of time during the year. When demand charges are present, the analyst must account for changes in recorded demands and, if present, the impact of these changes on billing ratchets.

Typically, these complications are ignored in favor of a simplifying assumption about an annual average flat rate. The simplification can be justified when two conditions are met: 1) the load shape impact of the demand-side program is relatively undifferentiated in time than rough the year; and 2) the energy-use profile of the participants is relatively homogeneous with respect to the assumptions used to derive the annual average price. Significant deviations from these two assumptions will skew results from their true impacts on participant's bills.

In order to trade off future changes in energy bills against current net costs or benefits, the analyst must express the differences between future energy bills with and without the program as present values. The difficulty lies in specifying the appropriate discount rate. Empirical evidence on consumer discount rates does not yield conclusive results, yet the choice of discount rate is crucial for evaluating programs that have consequences which last for many years.

Finally, our discussion of the cost effectiveness of programs from an individual customer's

standpoint tends to obscure the need to acknowledge the diversity of customers participating in program. That is, a program affects many customers simultaneously and their individual responses (e.g., bill impacts, discount rate) can vary considerably. The "average" participant assumed in most evaluations is a convenient fiction, so generalizations can be misleading.

Non-Participant Perspective

The goal of the non-participant perspective is to measure the distribution equity impacts of demand-side programs on non-participating utility ratepayers. At issue is the degree to which non-participating customers must pay or benefit from a demand-side program. For this reason, evaluation of the perspective is often termed the "no losers" test. As with the participant perspective, the test has historically only been applied to demand-side programs.

The concept originated in a paper by K. White (1981), but is most widely known as a result of the original California Standard Practice manual (CPUC 1983). In their most recent version of the manual, California regulators have recast the formulation of the non-participant perspective calculation and now call it the Ratepayer Impact Measure Test (CPUC 1987). The differences from the earlier definition do not affect the principle under consideration.

The basic idea of the non-participant perspective is to assume that regulators will keep the utility "whole." As such, changes in revenue requirements resulting from a demand-side program will be borne by or accrue to non-participating customers. The components of changes in revenue requirements consist of the program costs to the utility in the form of incentives and administration, resulting changes in utility production costs, and revenue changes that are due to an altered pattern of sales. In the case of a new conservation program, for example, the utility will avoid having to generate power, but it will also fail to collect revenues (also referred to as "lost revenues'') and, to achieve this result, will have to administer a program not previously funded.

The term ''lost revenues'' comes from a view of least-cost planning in which demand-side programs represent perturbations to a pre-existing forecast of sales. According to that forecast and its associated generation expansion plan, a trajectory of average revenues is modified by the implementation of a demand-side program. Thus, if sales are reduced through a demand-side program, sales will be ''lost'' relative to this pre-existing forecast. For this reason, the sense in which revenues are lost at all is somewhat artificial. The term is used broadly to refer to any impact on utility revenues from changes in sales. For example, a promotional program to sell additional electricity will change the sign of the lost revenue term (as well as that of the ''avoided'' cost).

In the non-participant perspective, a program is cost-effective if it reduces revenue requirements. If revenue requirements increase, the assumption that regulators will keep the utility whole means that the resulting increase will be recovered in the form of higher rates for non-participants. To the extent that regulators do not keep the utility whole, losses or gains will accrue to utility shareholders in the form of changes in net income.

Generally speaking, the distinction between participants and non-participants is not made rigorously. In practice, net impacts on revenue requirements usually affect all ratepayers, whether or not they participate. The EPRI TAG manual defines a non-participant perspective that explicitly excludes participants; nevertheless, it also assumes participants will contribute to any revenue shortfalls. In principle, reallocations could also be made among customer classes.[3]

[3] See, for example, the original California Standard Practice manual (CPUC 1983).

We define the components of the non-participant perspective formally, as follows:

$$B_{np} = \sum_{i=1}^{N} \frac{(\Delta E_i * AC_i)}{(1 + DR_{np})^i} \quad [5]$$

and

$$C_{np} = \sum_{i=1}^{N} \frac{(\Delta E_i * P_i) + PA_i)}{(1 + DR_{np})^i} \quad [6]$$

Where:

B_{np} = Non-participant benefit
C_{np} = Non-participant cost
ΔE_i = Change in energy use in year i
AC_i = Avoided cost of energy in year i
P_i = Price of energy in year i
PA_i = Program administrative costs (including incentives) in year i
DR_{np} = Non-Participant discount rate, expressed as a decimal fraction
N = number of years

The non-participant perspective is generally evaluated separately for each fuel type because it is assumed that the fuel suppliers are distinct companies or, in the case of combined gas and electric utilities, that no transfers take place across the different lines of business. Program administrative costs include all costs to the utility of running a demand-side program, including incentives. The utility's weighted average cost of capital is typically selected for use as the non-participant discount rate because it is the rate that the utility uses in determining revenue requirements.

With respect to the participant perspective, lost revenues are just the aggregate impact of savings by individual participants on the utility. Accordingly, the difficulties involved with evaluating the bill savings for participants are identical in evaluating the non-participant perspective. They include the effects of demand charges for electricity, and time-of-use and block rates. The basic issue is that meaningful calculation of lost revenues requires that the analyst estimate lost sales on a scale commensurate with the tariff structure faced by the participants.[4]

Utility Perspective

The utility perspective can be defined in one of two ways: as an accounting of utility costs that is generally consistent with the approach taken in non-participant perspective, or as a stockholder perspective focused on opportunities to earn a return. Adequate treatment of the utility stockholder perspective is complicated, which explains why it has not been incorporated into standard practice definitions.

The components of the conventional treatment are essentially those of the non-participant perspective. However, under the assumption that regulators will keep the utility whole, lost revenues are not included, since they are simply transfer payments between participating and non-participating ratepayers[5]. Thus, the utility perspective measures only the difference between the utility's avoided costs (see section V) and the utility's cost to implement the program. The costs of the program borne by the participant are not included. The California Standard Practice manual refers to the perspective as the Utility Cost Test (CPUC 1987). The EPRI TAG refers to this perspective as the Revenue Requirements Perspective (EPRI 1987).

We define the utility perspective formally, as follows:

$$B_u = \sum_{i=1}^{N} \frac{(\Delta E_i * AC_i)}{(1 + DR_u)^i} \qquad [7]$$

[4] See Kahn (1988) for an example of the calculation of lost revenues under block rates.

[5] This assumption also means, that in principle, there is no relevant shareholder perspective, since the utility's earnings are un-affected.

and

$$C_u = \sum_{i=1}^{N} \frac{PA_i}{(1 + DR_u)^i} \qquad [8]$$

Where:

B_u	= Utility benefit
C_u	= Utility cost
ΔE_i	= Change in energy use in year i
AC_i	= Avoided cost of energy in year i
PA_i	= Program administrative costs in year i
DR_u	= Utility discount rate, expressed as a decimal fraction
N	= number of years

As with the non-participant perspective, the utility perspective is evaluated from the perspective of a single fuel type.

Using this definition of the utility perspective, demand-side programs, traditionally conceived, will almost always be cost-effective. The reason is that, under the traditional conception, the direct cost of customer participation is borne by the customer. As such, an often large component of total cost is excluded from the equation. The utility perspective asks only whether what the utility must put up to induce participation exceeds the reduction in revenue requirements through avoided production costs. Only when the utility bears the full cost of participation does the perspective begin to capture the net impacts of a demand-side resource acquisition.

In principle, supply-side alternatives can be addressed by this version of the utility perspective. That is, there are a range of technologies (on both the supply- and demand-side) available to meet future projected demands and a revenue-requirements perspective requires that the one with the lowest cost to the utility should be chosen. Demand-side programs, however, will have a decided advantage over supply-side resources, if the utility bears only a fraction of the cost of demand-side programs.

The second, more rigorous definition of the utility perspective, which considers the preferences of utility stockholders explicitly, is difficult to estimate with precision. This perspective will often reflect utility management's preference for traditional supply-side investments on which the utility will earn a return, as opposed to demand-side investments where the regulatory treatment of program costs may be less well-defined. Internal to the company, a regulatory treatment of the utility's program costs (expensing versus capitalization) must be determined. External to the company, the impacts of programs on a company's valuation by the financial community must be considered.

Societal/Total Resource Cost Perspective

The societal and total resource cost perspectives eliminate distinctions between participants and non-participants (and the more restrictive definition of the utility perspective). The goal of these perspectives is to determine whether a program is cost-effective to society based on the total costs and benefits of a program, independent of their precise allocation to shareholders, ratepayers, and participants. The difference between the societal and total resource cost perspectives is the boundary between the utility and its participants, and society as a whole; the societal test incorporates externalities in the cost/benefit analysis.

These externalities are often difficult to quantify (e.g., acid rain).[6] They are also borne by different groups within society (e.g., ratepayers within the service territory might not be affected, while those living outside the service territory may be). In the extreme, "society" stands for the global community as a a whole, as in global warming impacts of electricity use. Because benefits and costs are difficult to quantify, the societal perspective is often approximated with the

6 Hohmeyer (1988) attempted this quantification and found great extremes in the ranges of estimates.

total resource cost perspective. Some jurisdictions, however, have begun to incorporate these important benefits and costs explicitly, notably Wisconsin, Illinois, and the Pacific Northwest.

The components of the perspectives are the costs avoided by the utility, less the costs borne by both the utility and participants. The total resource cost perspective is, essentially, the sum of the non-participant and participant perspectives; the bill savings and lost revenues cancel out of the equation. A supply- or demand-side program is cost-effective if it can provide an energy service at a cost lower than the cost for the utility to provide the service using the existing set of resources.

We define the total resource cost perspective formally, as follows:

$$B_{tr} = \sum_{i=1}^{N} \frac{\sum_{j=1}^{M} (\Delta E_{ij} * AC_{ij})}{(1 + DR_{tr})^i} \qquad [9]$$

and

$$C_{tr} = \sum_{i=1}^{N} \frac{DC_i + PA_i}{(1 + DR_{tr})^i} \qquad [10]$$

Where:

B_{tr}	= Total Resource benefit
C_{tr}	= Total Resource cost
ΔE_{ij}	= Change in energy use in year i for fuel j
AC_{ij}	= Avoided cost of energy in year i for fuel j
DC_i	= Direct costs of participation in year i
PA_i	= Program administrative costs in year i
DR_{tr}	= Utility discount rate, expressed as a decimal fraction
N	= number of years
M	= number of fuel types

In principle, the total resource cost will also capture other less readily quantifiable benefits and costs, such as the impacts on consumer surplus identified for the participant perspective. It could also capture the analogous impacts on utility surplus, such as the planning benefits from reduced demand growth uncertainty.

IV. POLICY ISSUES IN THE CHOICE OF LEAST-COST TESTS

The formulas and definitions of the cost-benefit tests as outlined in the previous section are well on the way to becoming standard practice guidelines in most states with formal LCP processes. However, debate continues about the proper interpretation, application and balancing of the various perspectives. The core of this debate include questions such as these:

- Should revenue requirements (average bills) be minimized, should rates be minimized, or should total societal costs be minimized?
- Should utilities' "lost revenues" be counted as part of the total cost of demand-side resources?
- Would the payment of utility incentives up to avoided costs, and in particular, the purchase of demand-side resources through bidding, overstimulate demand-side investments?
- Are load-building programs compatible with LCP?

Demand-side programs reshape the nature of the utility business. Most importantly, they can cause revenue shortfalls or *lost revenues* because utility rates are calculated on the basis of a specific forecast of demand, and, in some cases, on the basis of both sunk and planned supply investments to meet that demand.

In a capacity-short/significant growth situation, the sales-reducing impact of demand-side investments[1] can usually be absorbed by adjustments in the forecast and resource plan before

[1] In this chapter, we will use the terms demand-side measure or demand-side investment narrowly to mean (sales reducing) energy efficiency (or, in conventional parlance, conservation) investments, as opposed to load management measures. Though load management measures present similar problems in principle, the policy debate centers on demand-side programs aimed at reducing electricity consumption.

capital is sunk into new plants, and the lost revenue issue may become less important.

The lost-revenue issue becomes more significant where demand-side programs reduce revenues to cover sunk investments. The most typical situation where this may occur is when overcapacities exist and growth is slow or stagnant. This shortfall is not a loss to society but will nevertheless have to be allocated among utility stockholders and ratepayers. In making this allocation, regulators can pursue, individually or in combination, four basic options:

- Allocate lost revenues to all ratepayers, by raising rates sufficiently to keep utility revenues unchanged.
- Allocate lost revenues from each program only to that subgroup of customers that is eligible for the program, by means of rate redesign.
- Allocate lost revenues to the program participants themselves, by billing them both for kWh purchased and for kWh saved.
- Allocate lost revenues to utility stockholders by reducing their earnings.

The distributional issue can also be looked at from the point of view of the benefits of demand-side investments. Depending on program design, the fraction of customers enjoying direct benefits through participation can be large or small, and the direct benefits may be shared in different ways between utility stockholders, participants, and non-participants.

Either way, the introduction of demand-side programs changes the nature of the utility business, including opportunities for making or losing profits. These implications are of direct concern to utility stockholders and managements, ratepayer organizations, industries, community planners, and environmental and other public interest groups. As is to be expected, these constituencies favor widely different cost/benefit trade-offs and resolutions, and they will invoke philosophical principles justifying competing decision-making rules. Not surprisingly, the various proposals

are sometimes plainly ideological. Often, they are also tied to abstract principles without sufficient examination of their likely impacts under actual circumstances.

To develop a regulatory perspective on these questions, it is helpful to examine the likely quantitative ramifications of each perspective under practical circumstances. It is also useful to establish how each element in the current debate relates to the perspectives and definitions developed in Sections II and III. At bottom, the entire debate is fueled by the competition between decision rules based on the societal perspective and decision rules equivalent to the non-participant perspective. If the various proposals and arguments are organized as presented, the debate can be conveniently grouped into five major component areas:

1) The first component of the debate, and in many ways the primary issue, has already been mentioned. It addresses directly how to distribute the burden of lost revenues among ratepayers, participants and non-participants, and whether utility stockholders should be held neutral. The focus of this debate is whether the societal/total resource cost test should be the principal cost/benefit perspective for accepting or rejecting demand-side programs, or whether the non-participant ("no-loser") test should be the primary criterion. Here, one issue is whether use of the non-participant test would in effect create a double standard by giving different regulatory treatment to equity impacts from demand-side investments and supply-side investments. More recently, the utility competitiveness issue has also become prominent (see item 4).

2) A second component centers on whether the payback gap is mainly a result of market barriers or failures, or mainly a reflection of losses in consumer surplus that are not captured in engineering-economic analyses of demand-side investments (see also Section II). The driving concern is that if hidden costs were the cause of the payback gap,

incentives payments would not offset market failures but would possibly overstimulate demand-side investments, the so-called *double-payment issue*: Participating customers would receive a utility incentive for their energy efficiency investment, plus the savings on their bills, and would use both combined to purchase demand-side resources whose total (direct and hidden) cost is higher than avoided cost. The claim, then, is that the total resource cost test could be misleading because demand-side resource costs are inadequately defined. To avoid societally inefficient outcomes, it is proposed that bill savings (revenue losses) should be counted as a societal cost of demand-side measures. This procedure would transform the total resource cost test into the non-participant test.

3) The third component of the debate is another version of the double payment argument. This version of the argument is not concerned with the possibility that demand-side resource costs might be inadequately accounted for. Rather it raises a double payment issue specific to *demand-side bidding*. The concern is that in an attempt to obtain the advantages of competition, the rules for demand-side bidding would not be structured to ensure societal efficiency. Assuming that a separate test for the societal cost-effectiveness of proposed demand-side investments is not part of the bidding scheme, a double payment issue could arise if bidders were to combine utility incentives with bill savings to invest in societally inefficient demand-side measures. This has led to proposals to structure bidding schemes in such a way that demand-side bids would, in effect, be governed by the non-participant test.

4) As with the no-loser issue, the fourth component of the LCP debate has its origin in the allocation problem of revenue shortfalls. It is driven by concerns that rate impacts associated with societally efficient demand-side programs could negatively affect *utility competitiveness* vis-a-vis self-generators, other utilities, and non-utility suppliers. The two dominant issues are: under what conditions would rate impacts be large enough to have such an effect? And could such impacts be avoided through an appropriate structuring of utility programs short of reverting to the non-participant test?

5) Finally, regulators have become concerned that current rate-of-return regulation is inadvertently making demand-side programs less profitable for shareholders than supply-side investments, and that this reduced *profitability* might discourage vigorous utility efforts on the demand-side. The debate centers around various regulatory proposals that would make utility earnings neutral to this choice, either by decoupling utility earnings from utility sales or, going further, by making demand-side activities more profitable for utilities than conventional supply investments.

The discussion in this Section will explore each of these issue areas in more detail. We also discuss a number of practical approaches regulators and utilities have tried, or could pursue, in balancing or reconciling competing perspectives. Because it is difficult to assess trade-offs among basic perspectives without having some feeling for the magnitude of impacts on revenue requirements and total resource costs, we provide a set of illustrative quantitative examples. The concluding section deals with the profitability issue.

The Societal/Total Resource Cost Test versus the No-Loser Test

Economic efficiency as measured by societal cost effectiveness is used or advocated as the primary criterion of least-cost planning by three groups:

(1) utility commissions and other jurisdictions that use the total resource cost test[2] rather than the non-participant test as a basis for accepting or rejecting demand-side programs (e.g. Bonneville Power Administration, Northwest Power Planning Council, Massachusetts DPU, Idaho PUC, Wisconsin PSC, Nevada PSC, District of Columbia PSC);

(2) a number of neoclassical economists and other analysts involved in the least-cost planning debate, who argue on the basis of neoclassical economics (for example, Joskow (1988), Baker (1988), Lovins & Gilliam (1986), Cavanagh (1986), Plunkett (1988) Ciccetti & Hogan (1988); and

(3) a number of environmental and other public interest groups that advocate the inclusion of currently neglected social costs in utility investment decisions.

These groups share the view that the principal measure of cost effectiveness for least-cost utility planning should be the minimization of total societal cost. The basic argument is that without this measure, LCP would be meaningless because it could not reliably work to maximize social welfare. Demand-side investments would either not reach, or exceed, welfare-maximizing levels.

From the societal perspective, a demand-side program is cost-effective if marginal supply-side costs including externalities, are greater than the costs of the demand-side program borne by both the utility and the participants, including the externalities associated with the program.

[2] This group comprises, at one extreme, jurisdictions that lean more toward the revenue requirements perspective as an approximation of the societal perspective, whereas other jurisdictions have attempted to move closer to the true societal perspective. The use of the revenue requirements perspective instead of the total resource cost perspective is sometimes presented as reflecting the statutory limits of electric utility regulation, but is less easily justified on practical grounds. The approximation is equivalent to using the total resource cost test where utilities are paying 100% of the demand-side measure cost, as e.g., in direct installation programs, or where program experience and engineering analysis have shown that demand-side investments are significantly cheaper than marginal cost.

This cost difference can easily be as large as the current price of electricity.

By contrast, the no-losers test would limit utility incentives for demand-side investments to the difference between (higher) marginal costs and average rates. Being a difference between two large numbers, this figure can be negative if large overcapacities are paired with stagnant growth, meaning no demand-side programs would be cost-effective, and is small in magnitude in most other cases. The ceiling on demand-side investments is therefore very different under the two tests.

The basic rationale for the non-participant test is distributive, i.e. to protect ratepayers from rate increases. More recently, the non-participant test has also been advocated to prevent possible adverse impacts on utility competitiveness from higher rates.

Typically, one or several of three arguments are presented against reliance on the non-participant test:

(1) As the name implies, the purpose of the non-participant test is to measure distributional impacts and not economic efficiency. A distributive perspective is therefore seen as incompatible with economically efficient, welfare-maximizing capital allocation.

(2) The non-participant test is seen by many as introducing distributional criteria on the demand side without an equivalent treatment of equity impacts on the supply side.

(3) The distributional objectives the no-losers test is to serve are seen by many as attainable through strategies that do not constrict demand-side efficiency investments (e.g. maximizing participation opportunities and targeting low-income consumers).

Proponents of the societal perspective therefore unanimously reject the principle of minimizing rates as a primary goal for least-cost planning. The fact that several of the above-mentioned analysts propose limits on utility demand-side incentives identical to those of the non-participant test is incidental to their argument, which is based on the perception of a double-payment problem and not on distributional concerns.

Loss of Efficient Capital Allocation

The first objection raised against the non-participant test is based on conventional neoclassical economic theory. In the so-called non-participant or "no-losers" test, revenue shortfalls experienced by utilities as a result of demand-side programs are counted as part of the cost of demand-side resources. Lovins & Gilliam (1986) point out that this reasoning cannot be reconciled with the basic least-cost tenets of economic efficiency and welfare maximization. In neoclassical economic theory, welfare is maximized if society chooses in each instant to invest in the option of lowest marginal cost. Lost revenues exist only in relation to sunk costs already incurred by utilities. They are thus not marginal costs. If, for example, a unit of energy service can be supplied at lower marginal cost through a demand-side measure than through generation from existing supply facilities, the economically efficient, welfare-maximizing choice is to invest on the demand side. The sunk capital on the supply side, Lovins and Gilliam argue, has in this instance simply become obsolete. It is not part of the cost of demand-side resources.

Asymmetric Treatment of Equity Impacts

The second objection raised against the non-participant test is that it introduces an asymmetry in the treatment of distributional impacts from supply-side investments versus demand-side investments: non-participants are always required to pay for capacity expansions of the supply system, even though the need for such expansions is mainly caused by distinct subgroups of ratepayers, i.e. people and businesses that expand their power needs, or newcomers to the service territory. A major reason for this treatment of the rate impacts of demand growth is that not doing so

would lead to grave inequities in access to electricity service, and would exacerbate differences between the economically well-off and low income groups. In conventional resource planning, no distinction is therefore made between marginal and non-marginal customers; there is just marginal consumption.

The non-participant test would, in effect, introduce such a distinction in the case of demand-side programs. But customers not only differ significantly in their ability to *pay for* electricity services; they also differ markedly in their ability to *avoid* the cost of new power plants. As Cavanagh (1988a) points out, barriers to demand-side investments, while faced by all customers, are disproportionately more severe for low income people, for the smallest commercial customers, and for people who depend on electricity-intensive equipment for their livelihood or comfort.

The same argument is raised against another proposed treatment of the non-participant issue in which rate impacts from demand-side programs would be limited to the class of ratepayers for which they have been designed. Opponents of this approach argue that rate impacts from new power plants are not assigned to specific rate classes or marginal customers either. This treatment would therefore introduce an uneven treatment of supply-side and demand-side investments.

Inefficient Capital Allocation Through Load Building

Many utilities with excess capacity are interested in load-building, either by promoting electric end-use technologies, or creating special incentive rates and industrial customer contracts, or both. So long as these forms of load building cover the short-run marginal costs of operating existing capacities and do not create the need for new capital investments, they can reduce average rates by spreading existing fixed costs over more kWh sales.

Proponents of the societal least-cost perspective raise a number of objections to these load-building programs. One is that significant demand-side resources may exist that cost less than short-run marginal costs from existing capacities (see Section II). A second objection is that utility load-building programs are not sufficiently integrated in overall long-term resource plans to prevent such load-building from increasing long-term capacity requirements. They are thus likely to advance the need for new, more expensive capacity, which would force a greater increase in revenue requirements over the longer-term than would have been the case without load-building. On a net present value basis, these cost increases in the longer-term could be far greater than short-term savings.

Load building programs would also produce welfare losses due to lost opportunities for efficiency investment. Many decisions about energy efficiency are essentially irreversible over the lifetime of the equipment concerned. The Northwest Power Planning Council actually defined such lost opportunities as a special demand-side electricity resource that should be explicitly considered in power planning (NWPPC 1987).

A further objection (Cavanagh 1988a) is that load building would increase the emission of carbon dioxide and acid rain emissions while accelerating the depletion of fossil fuel reserves. In a number of service territories, surplus capacities are very "dirty" coal plants with high operating costs. Cost-effective efficiency investments could avoid these impacts and risks. Cavanagh also points to the increased volatility and uncertainty of demand associated with load building.

The Societal Test versus the Total Resource Cost Tests

Regulatory commissions typically use the total resource test or the all-ratepayers test as a proxy for the societal test. The principal motivation for substituting the total resource cost test for the societal test is that so-called externalities or indirect cost such as acid rain damage, climate warming, or nuclear accident and proliferation risks are difficult to quantify.

As pointed out by environmental groups and others, the total resource cost test tends to overestimate the net costs of demand-side resources because it ignores many savings from avoided indirect impacts and risks, both environmental, economic, and social. Also, utility discount rates used in calculating program costs from the total resource cost or all-ratepayer perspective are higher than societal discount rates. These proxies may thus lead to a substantial reduction of cost-effective demand-side resources to a level below the societally efficient optimum.

While these indirect costs are inherently difficult to quantify, and in many cases defy all attempts at quantification, it is nevertheless possible to establish at least a lower limit estimate. Such an estimate concentrates on those portions of known externalities that can be reasonably well quantified. Recently, the European Economic Community commissioned a study pursuing this approach (Hohmeyer 1988). It found a range of 2.5 cents/kWh to 6 cents/kWh for the calculable portion of the externality cost of electricity production, using the Federal Republic of Germany as a case study. Compared to the average electricity price in the U.S. of 6.7 cents/kWh (US EIA 1987), this would be 40-90%.

Of course, an assessment for the U.S. would be necessary to establish the applicability of this range. But should these orders of magnitude apply, they would indicate that current attempts to incorporate externalities in the context of least-cost planning may be highly insufficient. For example, some jurisdictions have given demand-side resources a 10% cost bonus in resource integration exercises. Similarly, the proposed all-resource bidding scheme of Orange and Rockland Utilities proposes to allocate 7% of total bid evaluation points to externality benefits, so that the advantages of demand-side resources over other resources could be up to 7% (ORU 1988).

The magnitude of these correctives would appear too low to achieve societal efficiency.

The more narrow interpretations of the societal test also exclude the consideration of fuel-switching. But, as pointed out in an early report on LCP by the U.S. Department of Energy (TBS 1986), optimal resource allocation cannot be fully achieved if the least-cost principle is applied only to the electricity sector. LCUP as currently practiced can optimize the provision of energy services through electricity, but may or may not achieve the least-cost provision of energy services from all fuel sources. Therefore, from a societal perspective, fuel switching from electricity to gas or to fuels not supplied by utilities, and the converse switch from other fuels to electricity, should also be included in least-cost planning. Regulatory commissions are increasingly confronted with this issue, when, for example, utilities propose incentives for cool storage in commercial buildings that compete with gas-fired absorption cooling options. Similar dilemmas arise in residential water heater programs and industrial programs. The Nevada and District of Columbia regulatory commissions are already mandating LCP for gas utilities.

Is there a Double Payment Issue?

Several authors (Joskow 1988, Ruff 1987, Ciccetti & Hogan 1988) have argued that utility incentives up to avoided costs could lead to societally inefficient outcomes by overstimulating demand-side investments. This issue has become known as the double-payment argument. To avoid excessive incentives for demand-side investments, these authors arrive at the decision rule that incentive payments should be no larger than the difference between marginal cost and current rates. This is, of course, no different from the non-participant test, but this outcome is incidental to their argument.

Their common conclusions notwithstanding, there are important differences involved in each

author's line of reasoning. To assess the relevance of the double payment argument, these need to be understood.

The Payback Gap: Market Barriers versus Hidden Costs

According to Ruff (1987), the lost revenue of the utility from reduced sales should be counted as part of the costs of the demand-side resource, not just under the non-participant perspective, but also in the societal perspective.

The core argument advanced for this treatment of lost revenues is a reinterpretation of the payback gap. Ruff assumes that consumers operate in more or less perfect markets, and that market barriers are the exception rather than the rule. With this assumption, Ruff interprets the pervasiveness of the payback gap to mean that consumers are foregoing highly cost-effective demand-side investments because of real but hidden or indirect costs, such as high transaction and inconvenience costs, loss of comfort, and technical risks. He further sees most of these indirect costs as inherent to the technologies involved and generally not reducible by programs.

From there he goes to argue that the price of electricity paid to the utility by consumers should be seen as reflecting these indirect costs. In other words, the price of electricity measures the consumers' real opportunity cost, and the payback gap is only apparent. Consumer choice is in equilibrium with the sum of direct and indirect costs of demand-side resources.

Based on this view, he then argues that consumers already have an effective incentive, in the form of the prevailing electricity rate, to invest in demand-side resources. If consumers were given an additional incentive through a utility program, which could be as large as the full avoided cost of supply, this could then about double the incentive and greatly overstimulate demand-side investments. To prevent this, Ruff argues that the electricity bill saving should be counted as part of the demand-side cost, just as it is under the non-participant test.

Joskow (1988) develops the same line of argument but is much more cautious about dismissing market barriers. He concedes that market barriers could be the dominant force behind the payback gap, in which case the double payment argument as advanced by Ruff would not apply. Joskow's main concern is that not enough is known about why barriers exist or how to minimize their effect on decision-making. He feels that the individual circumstances should be carefully examined before programs are undertaken. In this context, he endorses[3] the detailed market research, program experiments and planning procedures used by the Northwest Power Planning Council. His major concern is that in demand-side bidding schemes, such careful analysis would be displaced by the seeming elegance of this market mechanism. (The double-payment issue in the context of bidding is taken up below).

As discussed in Section II, the most logical response to uncertainty over the causes of the payback gap is to engage in systematic market research and pilot program experimentation. The Northwest Power Planning Council staff (NWPPC 1988) point out that both Joskow and Ruff seem to ignore or be unaware of the large and growing body[4] of utilities' own market research, focus groups, trade ally experiments, and pilot programs.[5] These have supplemented earlier published research with ever richer documentation of the causes and pervasiveness of market failures.

Ruff's exclusive emphasis on the hidden costs of demand-side programs is countered by Plunkett (1988b), who argues that contrary to Ruff's bias, energy-saving investments have indirect consu-

[3] Joskow clarifies this and a number of other positions of his in a letter responding to a critique of his testimony by staff of the Northwest Power Planning Council.

[4] A prominent example is the NORDAX regional program experience data base recently created by New England utilities with seed money from the Department of Energy. The project is being coordinated by C. Sabo of New York State Electricity & Gas Co.

[5] For example, neither Joskow nor Ruff references the research on market barriers quoted in Section II or provides empirical support for their own view of market failures.

mer *benefits* as well as indirect costs. In many utility programs, these non-monetary benefits have proven ultimately decisive for program success. This observation affirms that indirect costs must be taken into account as Ruff argues, but contradicts his bias toward negative costs. In well-designed programs, consumer surplus benefits are clearly identified and actively marketed.[6] In other cases, utility programs were instrumental in making large numbers of customers familiar with the comfort benefits of sponsored technologies, such as the noise and draft reduction provided by improved, multi-paned windows and the thermal comfort from improved building insulation in general.

A further indirect benefit of demand-side efficiency investments is the lessening of uncertainty of future energy demand and its attendant economic and financial costs and risks.

NWPPC staff conclude that, contrary to the perception their publications might have created, Joskow and Ruff do not offer any insights that would require a revision of the standard societal test definition. At the same time, they reiterate that a careful step-by-step procedure for program research, planning, and monitoring should be used in applying the societal/total resource cost test.

Demand-Side Bidding and the Societal Test

Recently, a growing trend can be observed to introduce demand-side bidding. This trend is partly a response to similar initiatives on the supply side. It also is driven by the hope that bidding schemes could provide an elegant, hands-off, market-based tool to ensure the most efficient provision of demand-side resources.

[6] For some of the many reports on this subject, see e.g. the Proceedings of the biennial Summer Study of the American Council for an Energy Efficient Economy (ACEEE 1984, 1986, 1988), the Proceedings of EPRI's First National Conference on Demand-Side Management (EPRI 1987b), and EPRI's Customer Acceptance project (EPRI 1987a).

Reflecting this motivation, both Joskow (1988), Ruff (1987), and Ciccetti & Hogan (1988) make the assumption that the bidding scheme would not be accompanied by supplemental, non-bidding based screening tests to ensure societal cost-effectiveness. This assumption is key to understanding their entire argument. It is assumed that conformity with efficient capital allocation would be ensured by the bidding process itself, as an endogenous outcome.[7]

Joskow and Ruff further assume that bidding occurs in an integrated auction in which both demand-side resource bids and supply-side options could each be awarded up to full avoided costs. They point out that such an all-source bidding auction would create an asymmetry due to a double payment problem on the demand-side. This is so because, in absence of supplementary regulations, the bid price would include only those portions of the demand-side resource paid for by the utility, not the portion paid for by the customer. The bidding process would not measure the total resource cost of the demand-side resource, but only the portion paid for by the utility. The result would be that of applying the all-ratepayers test to the demand-side, while using the total resource test for supply investments. But if supply- and demand-side integration is to follow societal least cost, it requires that full resource costs be measured in each case.

As pointed out by Ciccetti & Hogan (1988), the net result would be the same in either case so long as the total resource cost of demand-side investments is less than avoided cost. However, trouble could arise if a winning bidder were to offer a demand-side investment that costs somewhat more than avoided costs, say 8 cents/kWh instead of 7 cents/kWh, at a little less than avoided cost, say 6 cents/kWh. If average rates are 5 cents/kWh, the bidder could use 2 of the 5 cents saved on the electricity bill to compensate for the shortfall in the utility payment, and would still have a surplus of 3 cents/kWh. The result would be a societally inefficient outcome

[7] In their discussions of demand-side bidding, the authors also accept, if only for the sake of argument, that the bidding program would address real market barriers.

due to a double-payment effect.

In this example, the double payment issue would be real. Whether the danger of societally inefficient outcomes is indeed significant will depend on circumstances. The analysis of the payback gap in Section II suggests that, faced with an average rate of 5 cents/kWh, the high implicit discount rates of typical customers would lead them to forego savings opportunities costing significantly less than 1 cent/kWh. One would thus expect to find significant low-cost savings opportunities throughout the service territory. These would not be fully depleted until existing capital stocks have turned over. Bidders would have an incentive to offer the cheapest available demand-side resources first, because these offer the greatest potential for profit. It could therefore very well be that, at least in the initial years of bidding activity, bids would primarily be based on societally efficient measures.[8]

However, bidding rules should be structured to ensure societally efficient outcomes in any case. Here, Joskow and Ruff argue that the double payment problem can be endogenously avoided only if the maximum bid price is limited to the difference between marginal costs and current rates. This decision rule is again equivalent to the non-participant test. Joskow doubts that such a cap on demand-side bids would be politically feasible in the context of an all-source bidding scheme. He also is concerned that an exogenous control for societal cost-effectiveness, i.e. monitoring and screening efforts that could ensure societal cost-effectiveness, would not be used. What makes him skeptical is, in part, that many proponents of demand-side bidding precisely hope to make such efforts unnecessary. He therefore opposes all-source bidding schemes.

[8] We are not dealing here with the rate impacts of such low-cost resources. If the bidding scheme does not achieve perfect competition, bidders might very well bid close to avoided cost in an attempt to capture most of the economic rent for themselves. This might mean that demand-side measures would be purchased by the utility at a cost far greater than the total resource cost. Thus, rate impacts could be significant irrespective of the total resource cost of the measure, and they could be greater under bidding than in conventional programs.

A number of utilities and commissions experimenting with bidding acknowledge the need for screening and monitoring procedures to ensure societal cost effectiveness but do not see the same practical difficulties in implementing them as Joskow. In its Power Partners Program, Central Maine Power Co. has developed the concept that such constraints on demand-side resource bids should be viewed as equivalent to the practice on the supply-side, in which diversification of fuels, environmental concerns, and reliability factors are routinely used as criteria for narrowing the field of least-cost competitors.

So far, two approaches have been implemented to respond to this need. The first approach, which was used by New England Electric System is to tie the bidding process to a preselected group of technologies that have, through careful analysis, been identified as meeting the societal least-cost test (NEES 1987). The second approach, which was pursued by Central Maine Power, was to make demonstrated societal cost effectiveness a precondition for all bids, without preselecting technologies (CMP 1987). Both approaches avoided having to limit demand-side bid prices to the equivalent of the non-participant test.

By contrast, the integrated bidding program of Orange and Rockland Utilities proposes a ceiling price mechanism equivalent to the non-participant test (ORU 1988).

Unbundled All-Source Bidding

The most recent proposal to endogenously control for societal cost-effectiveness is that of Ciccetti & Hogan (1988). The authors recognize the unpalatable aspects of directly limiting demand-side bid prices to the difference between marginal cost and average rates. While their proposal would basically have the same effect, this feature is the net result of a so-called unbundling arrangement. This unbundling consists of treating the customer (or the ESCo intermediary and the customer combined) as a resource supplier in one part of the transaction, and as a consumer of energy services in the other part.

As a supplier, demand-side bidders would have full standing in the all- source bidding scheme. Thus, they would be eligible to win prices up to full avoided cost. As consumers of energy services, they would be billed for the same level of energy services as was supplied before the demand-side investment. The new bill of a winning bidder (or the winning ESCo's customer) would consist of a (reduced) number of kWh of electricity actually used, plus a bill component exactly equal in kWh to the estimated savings bid and paid for in the auction. This "energy service component" of the bill would be paid at normal tariff rates.

While the concept is a creative and elegant idea, it remains doubtful whether it would in practice solicit a more positive result than the direct non-participant cap on bid prices suggested by Joskow and Ruff. The scheme might best be described as a bidding-based version of the nonparticipant test. The advantage of offering up to full marginal costs for demand-side bids is only obtained at the expense of concentrating the burden of lost revenues entirely on the program participant. This is a much more severe application of the "no-loser" test than the traditional one used in utility-run programs. In the traditional non-participant test, the lost revenue burden is spread among all ratepayers before the test is applied. By contrast, Ciccetti and Hogan would concentrate the incidence of the lost revenue burden directly onto the participant. For example, under the unbundling scheme, a bidder saving 50% of energy might only get a 10% bill reduction, whereas in a traditional utility program, the participant would get the entire bill reduction of 50%. In the unbundling scheme, the bidder also bears the entire risk of estimating the size of the savings. These factors might turn out to be strong disincentives, reducing participation below that obtainable with traditional utility programs.

Strategies for Minimizing Rate Impacts while Improving Societal Efficiency

Demand-side programs may raise average electricity rates. If the utility is to be kept "whole", rates would have to rise whenever, as a result of demand-side programs, sunk fixed costs need to be spread over fewer kWh than originally planned. The non-participant test would limit demand-side programs to levels that do not raise rates.

There are several reasons for the utilities' interest in the non-participant test. One is that the mechanism by which the recovery of utility program expenses occurs is perceived as disadvantageous or uncertain. Another is that demand-side investments don't generate the same rate of return to stockholders. For example, a unit of energy saved does not earn a rate of return under expensing, and recovery of expenses may be delayed until the next rate case. Another is uncertainty over the approval of higher rates that would result from utility programs. If rate impacts are sufficiently large, utilities fear public response could put pressure on regulators. Finally, utilities may be concerned that increases in rates, if sufficiently large, will encourage competitive customers to move toward self-generation. This concern has become more prominent in the wake of greater competition in the power industry.

Regulatory commissions must also consider rate impacts for equity reasons. Just like supply-side investments, demand-side programs bring with them specific equity issues. If a utility runs only a few programs and focuses on subgroups and end-use devices not owned by all or most customers (e.g. programs that benefit owners of air conditioners in an area where only a minority of customers own them, or programs for homeowners without comparable programs for rental buildings), this cross-subsidization involves real inequities. Similarly, program activities that are offered only temporarily can create inequities over time. For example, an appliance rebate program will only benefit those customers whose appliances are up for replacement in the years

the program is offered. But it may take fifteen to twenty years to replace all appliances of that type. If programs are not carefully designed, inequities may be enhanced by free riders, i.e. participants who would have undertaken the demand-side investment in absence of the program incentives.

The same kinds of equity issues arise with supply-side investments and the traditional demand-side activity of load-building. As discussed above, ratepayers and commissions accept major income transfers all the time in paying for grid expansion investments that benefit people and businesses in limited localities and power plant investments that bring the greatest benefits to future ratepayers. Still, it is generally recognized that demand-side inequities cannot be ignored just because similar inequities exist on the supply side. Even regulatory commissions favoring the societal perspective as the primary test acknowledge the need to reduce inequities as much as possible.

There are a number of approaches to reconcile rate impacts, distributional equity, and utility competitiveness on one hand with with economic efficiency on the other. They include:

- Offering efficiency programs in lieu of promotional industrial rates;
- Moderating the timing of demand-side resource acquisition;
- Minimizing utility incentive and administrative costs through improved delivery;
- Sharing savings between ratepayers and program participants;
- Constructing a low-impact DSM plan by mixing programs with positive and negative rate impacts; and
- Offering a broad set of programs which allow all to participate.

Offering a Diverse Set of DSM Programs

Many jurisdictions have sought to minimize income transfer effects by designing programs that offer opportunities for all customer classes and affect the variety of end uses and technologies used by each of them. Here, programs for low-income customers are especially important. Another equity-promoting approach is to offer programs over a long enough time period that customers who cannot or do not participate immediately have a chance later on.

Joskow (1988) is concerned that this striving for equity through program diversity might result in support for programs where no real barriers to efficient customer investment exist, and thus lead to societally inefficient use of capital. Underlying this concern is the assumption that barriers are an exceptional circumstance found only in a few customer subgroups and end uses.

The Northwest Power Planning Council and other jurisdictions using a broad-based approach, agree that programs should not be undertaken where they do not induce additional demand-side investments. They point, however, to evidence showing that market barriers and opportunities for increased energy efficiency can be found in virtually all end uses and among all customer classes, as discussed in Section II. Furthermore, market barriers tend to be most severe for low-income groups. As a result, a diversity of programs would be expected to accelerate the move toward economically efficient capital allocation rather than distracting from it.

To achieve equity through equal-opportunity program design does not require that everyone be offered the same percentage savings. Customers should have the opportunity to save as much money as other programs might raise rates.

Timing DSM Programs

In this approach, acquisition of demand-side resources is timed so that rate increases stay below the threshold where industrial customers might leave the grid or non-participants would feel rate

shock. This approach is explicitly recognized in the revised California Standard Practice Manual. Here, the non-participant test has been replaced by a Rate Impact Measure (RIM) test. The RIM test calculates the percentage increase in rates instead of automatically failing programs on the basis of cost-benefit ratios less than one, no matter how close they are to this ratio.

An important consideration in planning the timing of programs is how program costs enter the stream of revenue requirements. In many states, utility C&LM outlays are expensed rather than rate-based. Because expensing involves more or less immediate cost recovery, it has a front-loading effect on revenue requirements. Near-term negative rate impacts could thus occur mainly for accounting reasons.

Minimizing Program Delivery Costs

Experience with utility incentives programs has shown that with the exception of low-income groups, customers can be induced to make efficiency investments with incentives substantially less than the full extra first cost of the measure. Often, the method of program delivery (door-to-door canvassing, dealer rebate programs, other trade ally involvement) can maintain or increase participation rates over those for conventional customer rebate programs while reducing the incentive needed per customer investment. Although some of these program approaches may increase program administration costs, and thus may have an on influence total societal cost, this impact appears to be limited. For example, recent systematic comparisons of alternative lighting programs by New England Electric System Co. suggest that in well-designed programs, administration costs can be as low as 5-20% of total resource costs (see, e.g. Nadel 1988, Krause *et al.* 1989). If the total resource cost under alternative program designs remains relatively constant, the number of demand-side measures passing the societal test will not change significantly either. On the other hand, changes in program design may effect a much larger reduction in revenue requirements (i.e. program administration plus incentives), reducing rate impacts proportionately. In pursuing these improvements, care must be taken that they do not produce a regressive distribution of program benefits.

Demand-Side Programs versus Industrial Incentive Rates

Utilities often propose preferential "development rates" or contracts for industrial customers. These incentives are either aimed at preventing self-generation or at load-building in the industrial sector. Usually, this kind of load building is seen as a means of reducing rates because short-run marginal costs are less than industrial rates and/or the loss of large industrial customers would increase fixed costs for the remaining ratepayers.

As an alternative to this practice, Cavanagh (1988a) and Lovins & Gilliam (1986) have proposed that utilities offer industrial firms bill reductions through industrial efficiency grants of net present value equivalent to rate discounts. Cavanagh and Lovins also argue that in the face of industrial bypass, load-building in the industrial sector will not necessarily lower system average rates. Special development rates would create a rate burden on ratepayers at large just as industrial DSM programs do. The California Public Utility Commission (CPUC 1988) is now requiring utilities to offer customers a menu of conservation options as alternatives to rate discounts. The Connecticut Department of Utilities has adopted a similar approach.

The authors also argue that the burden on ratepayers overall could be lower with such programs than with promotional tariffs. If promotional tariffs are offered, there is no guarantee that industrial customers will stay or that economic development benefits will be realized. The industrial customers might still leave the grid at a later time. System-wide slackening of investments in efficiency could bring about rate pressures from new construction on a magnified scale, and at an earlier date than might have been the case otherwise. Efficiency programs would not have

this effect.

Relatively less experience exists with industrial demand-side programs. Available evidence (ASE 1986) suggests that only the largest industrial firms engage in systematic in-house energy efficiency programs. Most firms could thus benefit from industrial DSM programs. The initial challenge for utilities is to acquire the expertise to develop programs that industrial firms will find attractive. In fact, many utilities are quite adept at running industrial programs. Recruiting customer service representatives with process engineering or other appropriate backgrounds has long proven an effective approach in dealing with industrial customers. Other utilities have chosen to hire energy service companies and consulting firms to conduct their industrial programs. More systematic pilot program activities need to be undertaken in this area.

Shared-Savings Arrangements

Rate impacts due to the lost revenue problem can be addressed by arrangements that allow non-participant ratepayers and utility stockholders to share in the participants' savings. In many cases, such investments in efficiency improvements could, if properly structured, contribute to utility margins as well as reduce customer bills and societal costs.

In the shared-savings approach the utility sells the energy service the customer wants at close to current rates, and it finances the demand-side investment as though it owned the facility or equipment itself. The arrangement is similar to the third-party approach that has been used to finance solar and other similar investments. Customers would be motivated to participate because of the no-hassle, hands-off, low-risk manner in which they can obtain modest but guaranteed financial savings without upfront costs of their own, and choose this option over the higher-risk, more-hassle alternative of buying and installing the efficiency device on their own.

For the shared-savings program to work, the utility would, in most cases, have to be content with recovering only a portion of the lost revenues. Even then, such an arrangement would minimize the net cost of the program to the utility, and could thus help keep rate impacts below the threshold of concern. At this point it is too early to say to what degree this approach would reduce program participation or complicate the utility's marketing efforts.

Constructing a Low-Impact DSM Plan from a Mix of Programs

Utilities may be able to combine programs from a set of societally cost-effective measures in such a way that programs with rate-reducing impacts partially or wholly compensate for programs that would increase rates. This cross-subsidization may be possible among the end uses of a particular rate class and would thus not necessarily alter established cross-subsidization patterns.

What Rate Impacts Can be Expected from these Strategies? Some Quantitative Illustrations

To better understand the rate impacts that efficiency options might produce in practice, it is useful to examine some simplified quantitative examples. Below, we have constructed such examples based on two kinds of prototypical situations. The first set of examples shows how generation strategies compare with demand-side strategies in an excess capacity situation when only the short term is considered. The second set of examples examines a capacity shortage situation and also uses a longer time horizon. Most utilities will find themselves somewhere in between these two conditions, moving from one into the other over time.

In Table IV-1 below we summarize several paths for resource acquisition that could be pursued in each situation. The examples, which build on similar exercises in NWPPC (1988), Plunkett

(1988a), Lovins & Gilliam (1986), and Costello (1985), are constructed to illustrate the various approaches and issues discussed above.

Our base case is a utility with an installed capacity of about GW, producing 100,000 GWh annually. The fixed cost of generation from existing plants is taken to be 3.5 cents/kWh, equivalent to the short-run marginal costs including costs of distribution losses. Operating costs are assumed to be 3.5 cents/kWh, for a total current rate of 7.0 cents/kWh. These proportions are roughly equivalent to the average U.S. electricity rate.[9] Demand-side resource costs are based on the rough proportions of the supply curve shown in Section II, which is based on a detailed analysis with real utility data. For modest amounts of savings (5% of load, their total resource cost is assumed to be 1 cent/kWh. For 10% savings, it is 2 cents/kWh, and for 25% savings it is 3 cents/kWh. The utility cost of this resource ranges from 0.5 cents/kWh to 3 cents/kWh.[10]

We analyze each strategy in terms of its impacts on rates, on the total present value of revenue requirements, and on the present value of total resource costs. The present value costs are calculated for a 5 year and a 15 year horizon in a simplified procedure.[11] Total revenue requirements are equal to the sum of direct costs *to the utility* for generation and demand-side resources. Total resource cost, used here to approximate societal cost, is equal to the present value of revenue requirements plus the customer costs for the demand-side resources.

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[9] According to data from the U.S. Energy Information Administration (U.S. EIA 1986, 1987) about 44% of average rates projected for 1990 are capital-related and about 56% are fuel- and O&M-related. Average rates were 6.7 cents/kWh for investor-owned utilities.

[10] Readers who wish to test different cost assumptions for demand-side resources can easily generate new results from Table IV-1 by means of a pocket calculator.

[11] This procedure aims to facilitate comparisons rather than capture the exact cost path involved in each strategy. The state of the system in years 5 and 15, respectively, is evaluated as though each represents the new steady state for the utility system. This steady state is then net present valued over 5 or 15 years, respectively. The resulting difference in present value costs is larger than would be obtained from a detailed analysis of the actual transition path to each end state. On the other hand, the freezing of the end state of the system after year 5 or year 15 neglects the fact that cost differences among the strategies would grow larger over time.

Table IV.1 Impacts of alternative resource acquisitions on rates and revenue requirements

System data	Base year	5-Year Time Horizon 1.a Generation strategy	2.a Demand-side strategy Non-part.	3.a Demand-side strategy Soc. Test
Existing load (GWh)	100000	100000	100000	100000
Load growth (GWh)		10000	10000	10000
DS-resource (GWh)		0	0	5000
Gen. resource (GWh)		10000		5000
Total load (GWh)		110000		105000
Existing rate (cents/kWh)	7	7	7	7
fixed costs (cents/kWh)	3.5			
operating costs (cents/kWh)	3.5	3.5	3.5	3.5
Existing annual rev.requirement ($ billion)	7	7	7	7
Addl. generation (GWh)		10000	10000	5000
Cost of addl. generation (cents/kWh)		3.50	3.50	3.50
DS-resource cost (cents/kWh)				1.00
Utility program cost (cents/kWh)				0.50
Customer cost (cents/kWh saved)				0.50
Addl. generation rev. requirements ($ billion/year)		0.35	0.35	0.175
DS rev. requirements ($ billion/year)				0.025
Avoided rev. reqs. f. depreciation of net plant in service ($ billion)				
Avoided revenue requs. through shared savings ($ billion)				
Total annual rev. requirement($ billion)	7.00	7.35	7.35	7.20
Average rate (cents/kWh)	**7.00**	**6.68**	**6.68**	**6.86**
Index	*100*	*95*	*95*	*98*
Total present value @ 12.35%	5 years			
rev. requirement ($ billion)	**25.02**	**26.27**	**26.27**	**25.73**
Index	*100*	*105*	*105*	*103*
Total annual resource cost($ billion)	7.00	7.35	7.35	7.23
Index	100	105	105	103
Present value @ 12.35%	5 years			
Total Resource Cost ($ billion)	**25.02**	**26.27**	**26.27**	**25.82**
Index	*100*	*105*	*105*	*103*

Table IV.1 Impacts of alternative resource acquisitions on rates and revenue requirements (cont.)

System data	1.b Generation strategy	2.b Demand-side strategy Non-part. test	3.b Demand-side strategy Societal test	4.b Improved programs Societal test	5.b Shared savings Societal test
Existing load (GWh)	100000	100000	100000	100000	100000
Load growth (GWh)	20000	20000	20000	20000	20000
DS-resource (GWh)	0	10000	30000	30000	30000
Gen. resource (GWh)	20000	10000	-10000	-10000	-10000
Total load (GWh)	120000	110000	90000	90000	90000
Existing rate (cents/kWh)	7	7	7	7	7
fixed costs (cents/kWh)					
operating costs (cents/kWh)	4	4	3.5	3.5	3.5
Existing annual rev.requirement ($ billion)	7.5	7.5	6.3	6.3	6.3
Addl. generation (GWh)		20000	10000	-10000	-10000
Cost of addl. generation (cents/kWh)	8.50	8.50			
DS-resource cost (cents/kWh)		2.00	3.00	3.00	3.00
Utility program cost (cents/kWh)	1.00	3.00	2.00	3.00	
Customer cost (cents/kWh saved)		1.00	0.00	1.00	6.00
Addl. generation rev. requirements ($ billion/year)	1.70	0.85			
DS rev. requirements ($ billion/year)		0.10	0.90	0.60	0.90
Avoided rev. reqs. f. depreciation of net plant in service ($ billion)		-0.10	-0.10	-0.10	
Avoided revenue requs. through shared savings ($ billion)					-0.90
Total annual rev. requirement($ billion)	9.20	8.45	7.10	6.80	6.20
Average rate (cents/kWh)	**7.67**	**7.68**	**7.89**	**7.56**	**6.89**
Index	*100*	*100*	*103*	*99*	*90*
Total present value @ 12.35%	Base 15years	46.80			
rev. requirement ($ billion)	**61.51**	**56.49**	**47.47**	**45.46**	**41.45**
Index	*131*	*121*	*101*	*97*	*89*
Total annual resource cost($ billion)	9.20	8.55	7.10	7.10	7.10
Index	100	93	77	77	77
Present value @ 12.35%	Base 15years	46.80			
Total Resource Cost ($ billion)	**61.51**	**57.16**	**47.47**	**47.47**	**47.47**
Index	*131*	*122*	*101*	*101*	*101*

Excess Capacity/Five-Year Horizon

In this scenario, load grows in 5 years by 10%, which the utility is able to meet with existing capacities.

Strategy 1a: Generation/Load Building Strategy. Here, the utility is able to meet additional demand with existing plants and may actually pursue load building. The marginal cost of generation (including distribution losses) is 3.5 cents/kWh. Annual revenue requirements increase by $350 million, and rates decline by 5%. Total present value revenue requirements (here identical with total resource costs) increase by about $1.25 billion or by about 5%.

Strategy 2a: Demand-Side Programs Subject to Non-Participant Test. The utility explores demand-side resources. Though these are cheaper than short-run marginal costs (see Section II), the difference between short-run marginal cost and average rates is negative. As a result, demand-side programs do not pass the non-participant test. Strategy 2 becomes identical with strategy 1.

Strategy 3a: Demand-Side Programs Subject to Societal Test. The utility finds that the demand-side resources that could be put in place within 5 years are more than enough to compensate for expected demand growth (see Section II). The utility aims to reduce demand growth only by half or 5,000 GWh. This also allows the utility to concentrate on the lowest cost demand-side resources first. It is able to buy the targeted savings at program costs of 0.5 cents/kWh saved.[12] As a result, annual revenue requirements for additional generation are $175 million, while demand-side resources supplying as much electricity as the generating facilities add another $25 million. Total annual revenue requirements rise to $7.2 billion. Rates drop 2%

[12] This rate of growth reduction and cost of conserved energy are roughly the same as those achieved by Southern California Edison Co. in its large-scale programs of the early 1980s.

to 6.86 cents/kWh. Compared to the generating strategy, rates are 2.7% higher. Total present value is $540 million less or 2.1% lower than in the generation strategy.

The present value of customer costs for demand-side investments is only $90 million. As a result, total resource costs are still about $450 million or 2% lower than in the generation strategy.

Capacity Shortage/Fifteen-Year Horizon

In this scenario, load growth and market-driven efficiency improvements increase demand by 20%. The reference plan is to meet this load growth with new capacity.

Strategy 1b. The entire demand is met with new capacity costing 7.5 cents/kWh. The regulatory commission adds an externality surcharge of 1 cent/kWh, for a total cost of 8.5 cents/kWh. Fuel prices for existing facilities also rise, resulting in an average short-run marginal cost of 4 cents/kWh. As a result, annual revenue requirements for producing electricity the base-year level of the base year rises from $7 billion to $7.5 billion. The new capacity adds another $1.7 billion, for a total annual requirement of $9.2 billion. Rates rise 10% compared to the base year, to 7.67 cents/kWh. Total present value revenue requirements rise from $46.8 billion to $61.5 billion, which is 31% higher than in the base-case system.

Strategy 2b. Under the non-participant test, the utility can spend up to 8.5/7.5 = 1.0 cents/kWh on demand-side resources. The utility finds from studies by others and its own pilot programs that it could buy most savings with a *total* resource cost of 2 cents/kWh or less for a *program* cost of 1 cent/kWh. It also finds that, in its service territory, these resources comprise a significant portion of the supply curve and could deliver about 10,000 GWh. By buying these resources for an annual revenue requirement of $100 million, total annual revenue requirements are lowered to $8.45 billion. Rates are the same as in strategy 1b. Total present value revenue requirements are lowered by $5.0 billion or 8.2% below those of the generation strategy. On a total resource cost basis, the strategy still saves $4.4 billion over the generation case.

Strategy 3b. Using the societal test, the utility can spend up to 8.5 cents/kWh on demand-side resources. In this case, resources which cost less than 8.5 cents/kWh saved, have an average cost of 3 cents/kWh (see Section II). Due to risks of global warming, the utility seeks to lower total demand to 90% of the base year level. Lacking experience with the incentives required to bring about larger amounts of demand-side investments, the utility decides to play it safe and offers approximately 100% of the total resource cost, or 3 cents/kWh on average. (Note that this average includes programs with significantly higher unit costs.) Annual revenue requirements for the demand-side investment then amount to $900 million. With these incentives, the utility lowers demand to 90% of the base-year level.

Because of the load reduction, the utility is able to retire units with above-average operating costs. This reduces average operating costs in existing plants to 3.5 cents/kWh. The annual revenue requirements for generation decline to $6.3 billion.

The utility's resource plan also assumes that demand will be held at or below the 90% level over the long-term, because of large untapped demand-side resources, continuing technology innovation in the market, concerns over global warming, and improved programs. The utility and the commission therefore decide to recycle to ratepayers some portion of rates that would have paid for depreciation of net plant in service for the unneeded capacity. The annual amount returned is $100 million.[13] Total annual revenue requirements thus drop to $7.1 billion. This translates into

[13] To estimate a lower limit for this factor, we assume a rate of depreciation based on 30 years, straight line. In 15 years, plant would depreciate by half. We consider only the 10% of plant in service that is permanently displaced by demand-side management. Upon completion of this displacement in year 15, revenue requirements would then be lower by $3.5 billion x 0.10 x 0.5=$0.175 billion. Of this total, only the generation-related portion is counted, since grids and other equipment are governed more by the number of customers than by the number of kWh sold. We assume that this portion is $100 million. As with all the other parameters, a more detailed

a rate of 7.89 cents/kWh, or an increase of 3% over the generating strategy.

Meanwhile, total revenue requirements (which are in this case identical with total resource costs) drop by $14 billion or 23% below those of the generation case.

Strategy 4b. In this scenario, the utility fine tunes the delivery mechanisms of its demand-side programs and lowers the financial incentives required to induce customer investments. Consequently, the average cost of its programs drops to 2 cents/kWh. Rates drop by 1.5% below the generation case to 7.56 cents/kWh. Total present value revenue requirements drop by $16.1 billion or 26% below those of the generation strategy. They are even 3% lower than they were in the base case. Total revenue requirements are also about $2 billion lower than total resource costs, which are the same as in strategy 3b.

Strategy 5b. In this approach, the utility is encouraged to pursue demand-side investments on a shared-savings or equipment-leasing basis. As in other third-party programs, the utility offers to provide a portion of the customer's electricity needs through demand-side investments, for a reduced rate of 6.0 cents/kWh. The customer receives a rate reduction of 1.6-1.8 cents/kWh compared to cases 1b-4b. The utility incurs the total resource cost of the savings as in case 3b, but also earns 3 cents/kWh saved. This additional revenue from shared savings reduces total annual revenue requirements to $6.20 billion. Rates drop by 10% to 6.89 cents/kWh. Total present value revenue requirements drop by $20.1 billion or 33% below those of the generation strategy. Total present value resource costs are the same as in Strategies 3b and 4b.

Discussion

It should again be pointed out that demand-side resource cost data, and thus the percentage rate impacts, can differ significantly from these cases. Commissions and utilities should always

analysis is needed to go beyond this order of magnitude estimate.

ascertain the supply curve structure of their demand-side resource potentials before adopting the conclusions stated below. The cost proportions assumed in the above analysis were based on a detailed case study for Michigan (described in Section II). With this assumption, the following general trends can be observed:

- The losses to society from using the the non-participant test to select programs can be very significant. Even if excess capacities exist and only a short-run perspective is considered, these losses can amount to hundreds of millions of dollars in a large service territory (3a vs 2a). If a (more appropriate) long-run view is taken and the need for new capacity is accounted for, these societal losses can reach the $10 billion range in present value in just one large service territory (3b, 4b, and 5b vs. 1b and 2b).
- Although the use of the revenue requirements (all ratepayers) perspective will underestimate the societal cost of demand-side resources; this practice is unlikely to lead to a societally inefficient outcome so long as the average total resource cost is low. In many cases, this average cost may be lower or no more than short-run marginal cost.
- Even when the difference between average rates and long-run marginal costs is small, i.e. on the order of 1 cent/kWh, significant savings may nevertheless pass the non-participant test (2b). This is true because of two characteristics of the demand-side resource: (1) utilities can often induce customer investments at a fraction of the total resource cost of demand-side investments; (2) supply curves of conserved energy tend to be rather flat over most of their range (see Figure II-2 in Section II).
- Where these structural characteristics of the demand-side resource prevail, the differences in rate impacts between using the societal test or the non-participant test may be

less important so long as marginal vs. average cost differences are in the range of 1-2 cents/kWh or more (2b vs 3b and 4b).

- For the same reasons, incorporating environmental costs in the marginal cost definition for electricity supplies is very important in least-cost planning. As illustrated in strategy 2b, relatively small marginal cost corrections (on the order of 1-2 cents/kWh) may greatly expand the size of the demand-side resource that could be purchased without raising rates noticeably. Again, this result applies where supply curves for demand-side resources are approximately shaped as shown in Figure II-2.
- Where excess capacities exist, the difference in rates resulting from load-building versus demand-side efficiency improvements may turn out to be small, of the order of a few percent (3a vs. 2a).
- Put another way, in excess capacity cases, rate impacts from programs that satisfy the societal test but not the non-participant test may be no more than a few percent (3a vs 2a).
- Should environmental or technical factors lead to permanent reductions of demand, rate impacts could be reduced somewhat by returning set-asides for plant replacement to ratepayers (3b, 4b, and 5b).
- Refinements in program delivery and efficacy can reduce rate impacts significantly (4b and 5b vs 3b). The most powerful approach to eliminating rate impacts under the societal test could be the shared-savings concept (5b vs 1b-4b). Under favorable conditions, shared savings may contribute as much to covering fixed costs as sales would.
- With such program designs, utilities could pursue aggressive demand-side programs aimed at overcompensating demand growth (e.g. for environmental reasons) while

keeping rates below those of the unperturbed growth path (4b and 5b vs 1b).

The above examples underscore the need to choose an appropriate time horizon for calculating avoided cost. Static analyses based on the near term ignore the fact that, over time, avoided costs may rise. If an appropriate time horizon is chosen, C&LM programs may decrease average rates to below those for a case without programs. This issue, along with other avoided cost issues, is taken up in Section V.

Detailed Analyses of Timing, Uncertainty, and Risk

The above examples have the advantage of transparency, but do not rely on detailed, dynamic simulations. We therefore review two recent analyses that investigate the issue of timing of demand-side programs in a more sophisticated way. One is a series of detailed analyses based on the Conservation Policy Analysis Model (CPAM) of the Bonneville Power Administration, summarized in Ford and Geinzer (1986). Another is the DSM analysis contained in PG&E's most recent filing under California's Common Forecasting Methodology process (1986).

Both studies are significant not only because of their detailed treatment of program impacts but because they also address a fundamental issue that is not captured at all in the standard practice cost-benefit tests: the extent to which demand-side programs may be suited to minimize the risk to ratepayers from uncertainty about future economic and other developments.

Ford and Geinzer found that even in a situation where capacity surplus exists for ten years or more, non-participants would receive rate benefits from all but the more aggressive demand-side programs because negative rate impacts in the early years were compensated for by lower rates in later years. Ford and Geinzer focus their CPAM analysis on the more aggressive programs.

They use rate impacts (average over the 20 year period) and societal cost impacts to compare a "blitz" strategy with a "balanced program" strategy. The "blitz" strategy assumed a package of

residential, commercial, and industrial programs in which the utility pays for the total cost of the demand-side measures, which results in higher participation rates than the "balanced program" produces; the "balanced" strategy relies on the same package, but assumes smaller incentives and therefore more modest participation rates. This modest participation stretched out program impacts over time.

The "blitz" policy saved $1.4 billion in societal cost, but increased rates slightly, by 0.075 cents/kWh or about 1.5%. The "balanced program" reduced societal benefits by approximately 30% to $1 billion, but also reduced rates by 0.01 cents/kWh or about 0.2%.

To further refine the picture, Ford & Geinzer performed an uncertainty analysis, in which regional growth, electricity exports, composition of the region's industries, and other factors were allowed to change avoided costs. Here, the "blitz" policy showed more variable societal savings and rate impacts. At some point, the advantage of the "blitz" strategy over the "balanced program," strategy may increase or disappear. Under a "balanced program" rate increases would be limited, even in the most extreme case, to only 0.018 cents/kWh.

Overall, Ford & Geinzer found that widespread improvements in the efficiency of new buildings in the Bonneville Administration's system offer the prospect of 24% less uncertainty about loads than in the reference case, and 22% less uncertainty about future rate levels.

The PG&E analysis used an uncertainty approach similar to Ford and Geinzer's. Rather than developing a plan for demand-side programs that performed well in a specific future situation, it developed plans that perform well over a wide range of assumptions. One hundred scenarios were analyzed with and without programs to create a map of this range. Specifically, a fixed deployment plan for a set of DSM programs was compared with a flexible deployment plan.

PG&E's results showed that, with flexible deployment, rate increases could be limited to 0.1% or so during the initial 10 year period, with significant rate drops during the second 10 year period. The fixed deployment plan created rate increases of about 1% during the first decade. Rate reductions during the second decade were the same.

Both studies underscore the idea that negative rate impacts from demand-side programs can be largely or entirely avoided if programs are matched by type, timing, and magnitude to resource needs.

Summary

These examples suggest that the conditions under which C&LM programs could push up rates can be more restricted and the sizes of rate impacts more limited than commonly thought. In reviewing demand-side management plans and analyses of rate impacts, particular attention should therefore be paid to these issues:

- What is the structure of the supply curve for efficiency improvements? While overcapacities exist, utility programs might focus on the lowest-cost portion of the resource.
- Have shared savings been explored as an option? This approach could provide rate relief that would compensate for less favorable but still societally cost-effective programs.
- Are avoided costs defined with a correct time horizon? This time horizon should be at least as long as the lifetime of the C&LM measures, which in many cases is as long as typical planning horizons (15-20 years).
- Are the dynamic impacts of growth, plant depreciation, and operating costs accounted for? If not, rate impacts may be overstated.
- Have risks been included in the analysis, and, if so, how does that change the importance of distributional impacts and concerns over competitiveness?

Profitability of Demand-Side Programs

Many regulatory commissions have observed that despite the above options to avoid or minimize rate impacts of demand-side programs, utilities are on the whole unenthusiastic about fully mobilizing the cost-effective potential of demand-side resources. Regulators and other analysts have concluded that the broad-based implementation of least-cost planning may depend in large part on regulatory reforms that will improve the profitability of demand-side investments for utility stockholders (Wellinghoff 1987, Moskovitz 1988, Whittacker 1988, NARUC 1988). As a position paper of NARUC's Conservation Committee puts it:

> "A utility's least-cost plan for customers should be its most profitable plan. However, because incremental energy sales increase profits, traditional rate-of-return calculations generally provide substantially lower earnings to utilities for demand-side resources than for supply-side resources. For this reason, the profit motive generally encourages utilities to invest in supply-side resources even when demand-side alternatives are clearly identified in its resource plan as being the least-cost resource.
>
> The loss of profits to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning. This obstacle to least-cost planning should be addressed. There are identified mechanisms for offsetting the profit-erosion problem.
>
> Therefore, it is the position of the Energy Conservation Committee that state commissions:
>
> - should require their utilities to engage in least-cost planning;
> - should consider the loss of earnings potential connected with the use of demand-side resources; and
> - should adopt appropriate mechanisms to compensate a utility for earnings lost through the successful implementation of demand-side programs which are a part of a least-cost plan and seek to make the least-cost plan a utility's most profitable resource plan."

The Committee has identified several mechanisms for offsetting the profit erosion problem. These range from removing disincentives by unlinking company profits from short-term sales to allowing electric utility companies to earn a profit from providing services on the customer's side of the meter. Table IV-2 provides a list of possible mechanisms identified by NARUC.

Table IV-2. Summary of Policy Options for Ratemaking

Option	Definition
Conventional R.O.R. Regulation without California-type ERAM	Conventional rate of return (R.O.R.) regulation establishes rates based on the formula: revenue requirements = expenses + (rate base * rate of return) Consequently, the more investment a utility has in rate base the higher will be its rates and its profit, except in the unusual circumstance where the company's short run marginal costs exceed its rates. Furthermore, between rate cases the rates don't changes. Consequently, the more kilowatt hours of electricity or therms of gas that are sold the higher will be a utility company's profit.
Conventional R.O.R. Regulation with California-type ERAM	This is the same as conventional R.O.R. regulation except that the utility's rates are later adjusted on the difference between predicted and actual sales, to ensure that unexpected changes in sales volumes do not affect earnings.
Separate R.O.R. for C&LM Investment	Here the rates are set and maintained in the same manner as conventional R.O.R. regulation except that the rate base investment for conservation and load management is accounted separately and in a rate case is calculated to earn a higher rate of return.
R.O.R. Adjustment for Low Bills	This is the same as conventional R.O.R. regulation except that the rate of return in the revenue requirement formula is adjusted based on the ratio of the average annual utility bill for a set of comparable utility companies to the average annual total bill for the subject utility company.
Performance Bonds	Here regulation is the same as conventional R.O.R. regulation except that a third term is added to the revenue requirement formula used in a rate case. As an alternative, the R.O.R. in the revenue requirement formula could be adjusted. In either case, the adjustment is based on some measure of the effectiveness of the utility's management in achieving least-cost planning goals and is presumably at the discretion of the commission.
Share C&LM Savings	This is the same as conventional R.O.R. regulation except that a third term is added to the revenue requirement used in a rate case. That added term is a pre-determined percentage of the calculated savings that the utility can demonstrate from its conservation and load management programs.
Bounty on C&LM Savings	This is the same as the previous option except that the adder to revenue requirements is not a percentage of the savings. It is instead a pre-determined dollar amount dependent on the achievement of certain goals set by the company and/or commission.

Wiel (1988) identifies a number of conditions a new ratemaking formula should ideally satisfy: It should not reward increased investment for increased sales and it should reward improvements in energy efficiency sufficiently to overcome the lost opportunity for profits from ineffective investments and from sales for inefficient use. In addition, a change in ratemaking formula should avoid potential biases from forecast errors, fuel price fluctuations, and weather fluctuations. It should also avoid the opportunity for cheating by either the utility company or its customers. It must not be overly subject to Commission discretion, and must pass the "front page test" of customer acceptability. And, of course, it must not discourage the use of electricity for providing new services.

At this time, it is not clear which of the proposals identified in Table IV-2 could best satisfy these conditions, though some differences are discernible. For example, the ERAM approach would remove disincentives to demand-side investments, but would not necessarily make the utility prefer them over generation investments.

V. AVOIDED COST CALCULATION: PRINCIPLES

Measurement Issues in the Application of Cost-Benefit Tests

The perspective and test definitions of the EPRI and California manuals, as synthesized in Section III, represent a major step toward standard practice in at least one area of least-cost planning. However, for many other areas, a standard-practice approach is still needed. The conventions by which the inputs to cost-benefit tests are generated are as important as the definitions of these tests. The methods used to generate inputs are equally important to utilities preparing least-cost plans, as well as to regulators reviewing such filings. The issue is well-recognized on the supply side where fuel-price forecasts, projections of capital costs and construction times, availability and reliability of powerplants, and other uncertainties can greatly influence cost-effectiveness evaluations.

We focus our attention on the primary benefits of demand-side programs; specifically, on approaches for estimating utility avoided costs. Prior to this review, we identify key issues that arise in quantification of the cost of demand-side resources per unit of energy or peak power saved. A detailed discussion of these issues is beyond the scope of this report.

In defining the *cost of demand-side resources*, the following issues typically crop up:

- Does the utility have satisfactory data on the baseline conditions in the end uses for which programs are examined? (Data could include detailed surveys of the energy-consuming stock of buildings and equipment in the service territory, not only of energy consumption by end use but also by type of technical equipment; share of total stock by efficiency, load profiles by end use; sub-metered data at the end-use level versus conditional demand estimates versus simulation/engineering judgement).

- Does the utility have sufficient data to reasonably project market-induced efficiency gains? (Data could include surveys of efficiency of currently purchased technology, projections by product industry analysts of future efficiencies, their load shape impacts, the future market share of each efficiency category, average service life and rate of turnover of existing stock).

- Are assumptions and data reasonable regarding the performance of demand-side technologies? (These could include engineering estimates versus field measurements, costs as a function of whether the utility or the customer does the buying, feedback loops between utility programs and efficiency product price).

- Are program impacts monitored and evaluated using a consistent framework? (Reasons for incorrect measurements of impacts could include inadequate baseline data, actual persistence of installed measures versus technical life, free riders, and free savings from spillover effects of programs on non-participants and efficiency-product distributors).

A similarly broad list of issues emerges in quantifying the *benefits of demand-side resources*. They often center around the proper calculation of avoided costs, including the use of proper modeling techniques, a topic which we discuss in detail. Estimation of avoided costs has impacts that extend beyond the specifics of the demand side to include the broader issue of integration of demand-side and supply-side resources.

Approaches to Avoided Cost Calculations: Overview

The costs avoided by a utility because of a program are the primary quantifiable benefit from the non-participant, utility, and societal perspectives. This section reviews types of costs that may be avoided and common methods for calculating them. Section VI will identify computer models suitable for some of these calculations.

We use the term "avoided", rather than "marginal" cost, to emphasize the necessity of considering the size of demand-side programs in an evaluation. For example, the cumulative impact of a group of demand-side programs will often exceed that of a single program evaluated in isolation, because, taken as a group, the programs may warrant deferral or even cancellation of a future generating unit. In this situation, the appropriate avoided cost is the long-run marginal cost of generation. It would be inappropriate to use a short-run marginal cost (essentially, consisting of only fuel and variable O & M costs) to value each individual program and ignore their cumulative impact on system demands.

Generally, there are two approaches to calculating the costs avoided or incurred by a demand-side program: 1) direct measurement; and 2) application of tariff-like, unitized values. The first approach is theoretically superior because changes in utility costs are estimated directly through an analysis of total supply-system costs with and without the demand-side program. However, this method is more difficult to employ, especially, when attempting to evaluate many programs because it requires consistent treatment of vast amounts of information, some of which is expensive to obtain. Instead, avoided costs, expressed in a tariff-like fashion (e.g. \$/kWh or \$/kW, on-, off-peak, etc.), are more commonly used. In this approach, the value of a program is measured simply by multiplying the appropriately aggregated load shape change by its value. We will focus on this latter method.

Techniques used to estimate avoided costs were developed initially for power purchases from non-utility sources. Early efforts to calculate avoided costs were the result of the Public Utility Regulatory Policies Act (PURPA) requirement that utilities purchase power from non-utility sources at a price equal to the costs avoided because the utility does not produce the power. Operationally, there is an identity between power generated by non-utility sources and the effects of demand-side programs; both options result in the utility avoiding the cost of producing a certain amount of power. Most avoided-cost offers take the form of tariffs with unitized values for power.

The danger in relying on the simplification provided by using tariff-like values arises when the load impact of a demand-side program (or the non-utility generation of power) is dissimilar to the assumptions used to calculate the avoided cost. For example, failure to consider the size of the demand-side impact could skew an evaluation. There could also be timing mismatches between the introduction of demand- and supply-side programs. The basic issue is whether the initial calculation of these quantities sacrifices too much of the consistency that the direct estimation approach attempts to guarantee.

There are three major components of the costs avoided (or incurred) by a utility through the actions of a demand-side program. First, there is the distinction between energy and generating capacity costs. Second, although most evaluations focus on generation costs, transmission and and distribution costs may also be avoided. Third, we can distinguish between a long- and short-run perspective for each these costs. In a final section, we will discuss the development of avoided-cost tariffs.

Avoided Energy Costs

Avoided-energy costs for purchases of non-utility power and demand-side program evaluations are typically set equal to short-run marginal energy costs. These costs are usually calculated using production cost simulation models (see Section VI). We will not repeat the extended discussion in that section about the importance of benchmarking and calibrating the inputs and outputs of these models prior to use in LCUP evaluations. We note, however, that the effects of methodological differences in avoided energy calculations can be dwarfed by the effects of an improperly calibrated model.

In the traditional definition of the short run, plant capacity is assumed to be fixed. Changes in output must be met with existing capacity in the form of increased variable operating costs. Given this general framework, at least three methodologies have been developed to measure the value of these changes.

In the first method, marginal cost is reported directly by the model as a standard output, on either an hourly or on a more aggregated basis. The marginal energy cost reported is the incremental cost of producing a single, additional kWh and, for this reason, may be quite inappropriate for valuing large blocks of avoided-power generation. If the cost structure of the utility is quite stable over large variations in output, however, this instantaneous measure is an acceptable approximation.

A second approach is the increment/decrement method in which discrete changes in load shape are used to calculate marginal cost. The calculation is typically done in two steps. First, as the name suggests, the loads from a base case are separately incremented and decremented by a fixed amount. Next, the differences in total cost from the two runs are divided by the differences in energy generated. The result is a marginal cost estimated by a discrete load shift around a base value.

The third method, called zero-intercept, comes closest to the spirit of a direct measurement approach. It is similar to the increment/decrement method, except that the increment case is replaced by the base case (e.g, without DSM). The difference in total cost between the base case and the decrement case (e.g., with DSM) is divided by the difference in energy generation. Zero-intercept typically assumes a generic load shape change, in contrast to direct measurement attempts to reflect the exact change resulting from a program (and of course there is no longer a need to re-express cost changes on a per unit basis).

The basic issue in all methods is whether the analysis has been performed consistently with respect to the demand-side programs to be evaluated. For example, in California, substantial debate takes place about the size of the decrement for the zero-intercept method. For a program with large load shape impacts, the appropriateness of the load variation evaluated must similarly be addressed. If the load impact is substantial, the use of any method with a short-run perspective is probably inappropriate.

In applying avoided energy values to specific demand-side program impacts, care must be taken to ensure consistency between the load shape impacts and time-differentiation in the avoided energy values. For example, average annual avoided energy costs will be inappropriate for valuing the load shape impacts of, say, high-efficiency air conditioners.

Short-Run Avoided Capacity Costs

Short-run avoided capacity or capital costs have taken on a stylized definition in the literature of avoided costs. Typically, the capital costs of a combustion turbine is used as a proxy to measure avoided-capacity costs. Long-run avoided energy and capacity costs, on the other hand, are calculated based on the deferral or cancellation of baseload powerplants.

In contrast to avoided energy costs, avoided capacity costs are the costs that would go toward ensuring that the electrical system can satisfy the maximum loads placed on it by customers. Because electricity cannot be stored readily, the utility must have capacity available in excess of anticipated demands; the amount of excess capacity required depends on the desired reliability of the system. If utility loads are reduced through a demand-side program, the utility can plan for smaller capacity reserves.

Utilities traditionally plan for the generation system to suffer an outage no more than one day in ten years. This target is a planning rule of thumb, developed with probabilistic techniques to compute generating system reliability. In principle, the desired level of reliability is appropriately measured by customer's demand for uninterrupted electric service.

From a marginal-cost perspective, the investment in additional plant capacity to increase the reliability of the system is measured by the installed cost of the least expensive supply alternative, conventionally, a combustion turbine. Nevertheless, from an optimal generation expansion perspective, the marginal, physical plant capacity that a demand-side program allows the utility to avoid could be a baseload powerplant. For this reason, the combustion turbine is more appropriately referred to as a proxy for the least expensive incremental addition to capacity to increase reliability (National Economic Regulatory Associates 1977).

The most controversial issue in the calculation of the cost of increasing system reliability is the relevance of the term for a system with substantial excess capacity. For, example, the appropriateness of the combustion turbine proxy has been questioned by some utilities with excess capacity (notably, California and New York). They argue that excess capacity means that, in the short-run (under, say, five years), no capital expenditure is required to increase the reliability of the system, since the existing plant is underutilized. Of course, additional capacity will always improve reliability; the point is that the system is currently and will remain reliable with the existing capacity despite load increases. Underlying this reasoning is an assumption of some target level of reliability (e.g., one day in ten years), which the system currently exceeds.

California regulators have accepted these arguments and now adjust the full value of the combustion turbine proxy by the deviation of the system from some target level of reliability. The adjusted value is best thought of as a short-run measure of avoided capacity costs. The details of the adjustment are quite technical. Currently, ''expected unserved energy'' is the basis for the adjustment; previously, ''loss-of-load-probability'' was used.

In using avoided capacity costs to value demand-side programs, we must ensure consistency between the load shape impact and the capacity costs avoided. In particular, the coincidence of the load shape impact with the system peak demand must be accounted for. Similarly, a program will be undervalued if the reduction in utility reserve margin requirements is not included in capacity savings.

Long-Run Avoided Generating Energy and Capacity Costs

In the long run, plant capacity is not held fixed. Increases in demand can be met with either changes in the operation of existing plants or increases in plant capacity (i.e., new construction). The use of the installed costs of a combustion turbine as a proxy for the marginal cost of generation capacity is an attempt to isolate a reliability-related component in the decision to increase generating capacity. We now turn to methods that evaluate both the energy- and reliability-related components of long-run avoided costs.

The importance of these methods is that comprehensive least-cost planning efforts must acknowledge the potential for demand-side programs to affect long-run decisions about expanding generating capacity. Serious treatment of demand-side options will consider large-scale programs that can displace supply-side investments. A short-run perspective, in which the generation expansion plan is fixed, cannot capture this effect, and, as a result, seriously underrepresents the value of demand-side programs. Figure V-1 illustrates how dramatically these perspectives can differ.

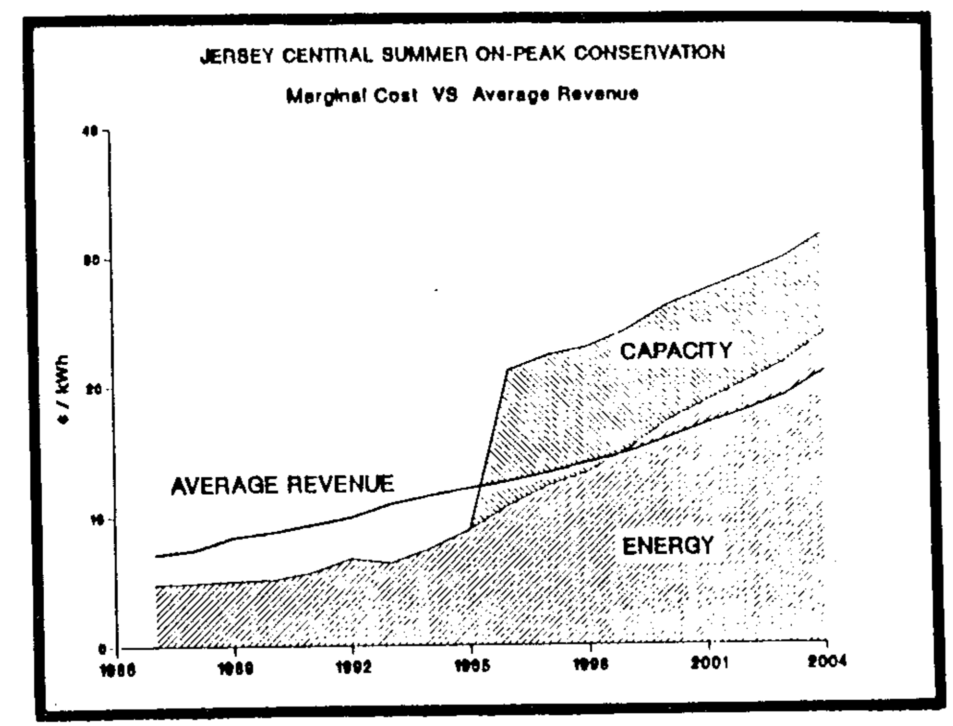

Figure V-1. **Relationship Between Short-Run Avoided Energy, Long-Run Avoided Capacity Costs and Average Revenue. Source: Roddy and Bloom 1987.**

We are familiar with at least two approaches for measuring long-run avoided costs. In general, the two approaches come very close to methods that would be used in the direct measurement approach to valuing demand-side programs. The difference is in the use of generic load shapes (rather than specific ones) to develop aggregate long-run values and then unitizing these values for evaluating specific demand-side programs.[1]

The first method involves estimating the direct capital cost savings resulting from pushing back the on-line dates of future generation additions. The calculation is relatively straightforward; it is simply the present value of differences in capital expenses between two alternative supply plans. Once calculated, the total value can be again spread over time and unitized by time of use or season.

This approach has been adopted by several state commissions. The primary problem is specification of the appropriate deferral period. In the extreme, an entire plant may be canceled, although typically the delay is for some number of years. In principle, the number of years should be related directly to the size and expected duration of the load shape impacts.

The second method for measuring long-run avoided costs attempts to estimate the deferral period directly. Once the deferral period is estimated, there is no need for a capital cost evaluation because the evaluation is implicit in the determination of the appropriate deferral period. The method defines the appropriate deferral as the cost-neutral change in future generation expansion resulting from the effects of the demand-side program.

The method relies on iterative simulations of the supply system. The goal is to find a supply plan (using loads modified by the generic load shape change) with a deferral period that results in a present value of operating costs equal to the present value of operating costs from the base

[1] See Kahn (1986) for additional details of both approaches.

case. An added condition is that the two systems have comparable levels of reliability. Since these two supply/load growth scenarios (base case and deferral supply with new loads case) have the same operating costs, an optimal or cost-neutral deferral period has been determined. The value of the deferral is the difference in present values between the base case and the deferral supply case with the base case loads.

A variant of both approaches separately identifies a reliability component from the deferral by subtracting the value of a combustion turbine from the total value of the deferral. In this case, the remaining value from the deferral is referred to as the energy-related capital component of the original generation expansion decision.

Avoided Load Distribution Costs

Avoided transmission and distribution expenses may also be offset by demand-side programs. Unfortunately, the techniques for estimating avoided transmission and distribution expenses are crude compared to the elaborate production cost simulation techniques often used in valuing generation.

NERA developed guidelines for estimating marginal transmission and distribution expenses (National Economic Regulatory Associates 1977). As a first approximation, these guidelines are appropriate for avoided cost determinations. The suggested technique is to convert past and future expected expenses into current year dollars and regress them on the corresponding annual increases in load. The method requires judgment about appropriate expenses and loads to use in the regression.

For distribution expenses, in particular, there is substantial controversy on the issue of marginal customer costs. In general, demand-side programs will not reduce customer costs, unless they reduce the number of customers. NERA, however, recommends subtracting incremental or marginal customer costs from incremental distribution expenses prior to the regression. Without an agreed-upon estimate for marginal customer costs, however, net distribution expenses cannot be determined.

The difficulty in measuring marginal customer costs is primarily the metric used. Typically, analysts assume that costs which cannot be assigned a demand- or energy-related function must be customer-related. The metric chosen is cost per unit customer. Although some customer-related costs vary by the number of customers, some costs vary more appropriately according to the geographic dispersion of customers. Unfortunately, analysts tend only to consider these costs on a per customer basis, because geographic discrimination among groups of customers is an unpopular ratemaking concept.

The relevant annual increases in load used for the analysis of marginal transmission or distribution expenses tend not to be annual increases in system peak loads. As a general rule, the closer the analysis gets to end use of power, the more important it becomes to consider non-coincident loads. There is, essentially, a continuum between the generation system and the customer in which differing degrees of coincidence and non-coincidence reflect the appropriate avoided load on the T&D system.

In some cases, proxy plant methods that examine deferral of identifiable T&D investments may be preferable to avoided cost determinations based on NERA guidelines because proxy plant methods avoid some of the measurement problems described above. The identification of specific, deferrable investments can eliminate the need to rely on statistically-based correlations of expenses and loads.

Using Avoided Costs to Value Demand-Side Program Benefits

One advantage of the direct measurement approach for avoided costs is that, once measurements are made, the analyst's job is complete. When using hypothetical, generic load shape changes to represent the gross impact of demand-side programs, however, the analyst must convert these gross values into specific, tariff-like quantities. Then, to value individual programs, the analyst must multiply these quantities by and sum them over the relevant load impacts. The task is disaggregation along several dimensions of space and time.

The spatial dimension is most easily addressed through the application of loss factors to convert customer savings (at the relevant distribution voltage level) into generation costs avoided at the point of generation or busbar of the utility. An added complication is that these losses are rarely constant over time; these variations in losses are usually ignored.

The degree of time disaggregation required is dictated by the characteristics of the demand-side programs under evaluation. If their load shape impacts are homogeneous relative to the generic load shape assumed in the avoided cost analysis (both for each hour within the year and for each year evaluated), then little disaggregation is required. In the general case, however, we need to evaluate programs with very different load shape impacts, all of which have different lifetimes, and so substantial disaggregation is necessary if we are to use the avoided costs meaningfully.

Rectifying timing mismatches across years is the logical first level of disaggregation. The goal is to re-express avoided costs that span years as annualized values to evaluate programs whose lifetimes (and beginning dates) do not coincide with the assumptions used to develop the avoided cost.

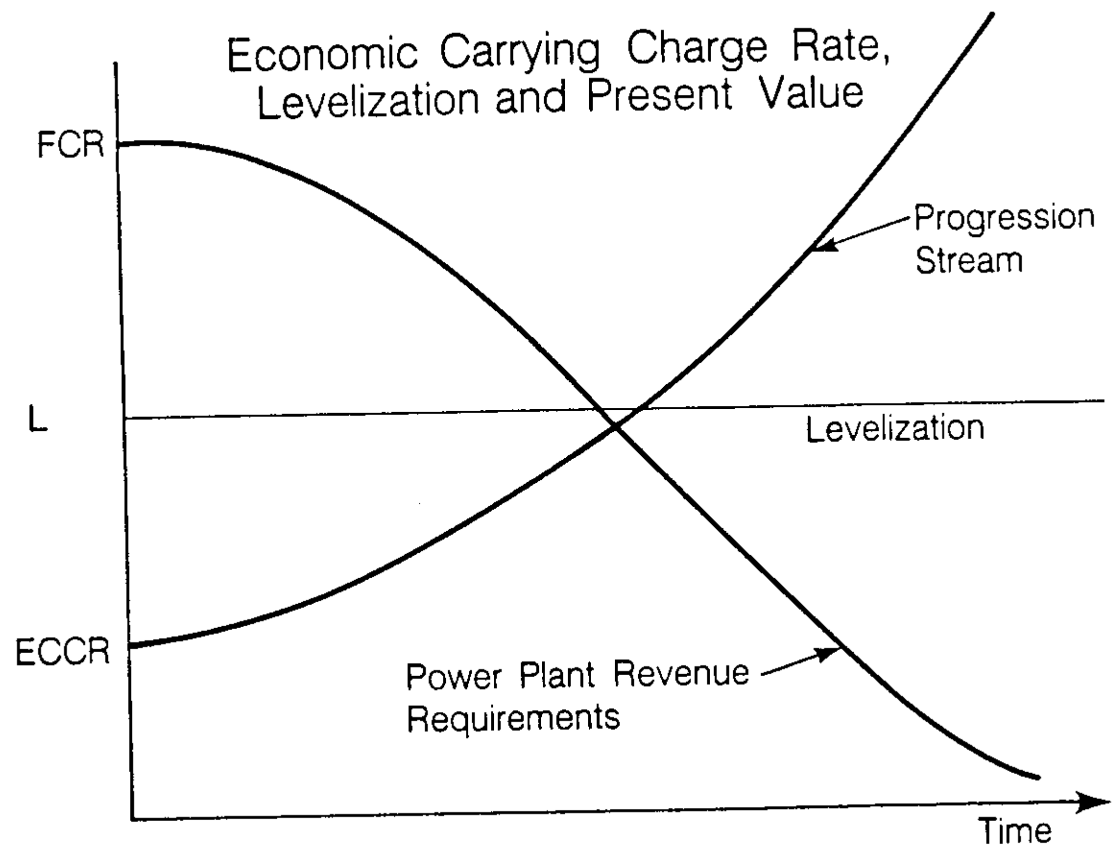

Figure V-II. **Comparison of Levelization, Economic Carrying Charge, and Traditional Utility Amortization Techniques. Source: Kahn 1988.**

Two methods are widely used to annualize multi-year avoided costs; one involves levelization and the other uses a concept called the economic carrying charge rate (ECCR). With levelization, the present value of a quantity is spread over the assumed lifetime of the investment in equal, nominal dollars. The resulting stream, when discounted, leaves the original present value unchanged. Given some positive discount rate, the real worth of the annual values declines over time. Levelization results in ''front-loading'' of the stream of benefits; the bulk of the present value is received in the first half of the investment lifetime, resulting from the effects of a positive discount rate.[2]

The second method holds the real worth of the annual values fixed with respect to inflation. Thus, assuming some positive rate of inflation, the present value is spread in an ever-escalating stream of nominal dollars over time. Since the real value for each year is identical, this method avoids the front-loading feature of the levelization method.[3] Figure V-2 illustrates the relationship between levelization and the use of an economic carrying charge rate, and compares them to traditional capital cost recovery by utilities (fixed charge rate or FCR), which is extremely front-loaded.

Additional disaggregation, within a year, is always warranted for load shape impacts that are not uniformly distributed over the year. In principle, the disaggregation could extend to each hour of the year; in practice, this is rarely necessary and seldom worth the additional effort.

The most important criterion for chosing a disaggregation method considers both the reliability of the disaggregation inherent in the estimation of demand-side program impacts and the variability in the supply system cost structure. Disaggregation techniques differ somewhat for

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[2] Formulas for levelization can be found in the EPRI TAG manual (1987).

[3] See NERA (1977) for a discussion of the rationale underlying this approach.

avoided energy and capacity costs. For avoided energy, a logical starting place is a simple seasonal distinction (winter and summer). The next most important level of disaggregation is time of day, or on- versus off-peak energy use. Beyond these minimum levels of disaggregation, the analyst is generally limited to to whatever additional levels of disaggregation are featured in the individual modeling techniques being used. For avoided capacity, much finer time-steps must be examined. Our discussion of T&D avoided capacity costs described some of the measurement problems that stem from the need to combine varying degrees of coincident and non-coincident demand. In this discussion, we consider solely the problems associated with measuring demand savings in order to value avoided capacity costs for reliability.

The first measurement issue is the well-known need to establish coincidence factor relationships between class (or individual customer) peak demands and system peak loads. Without some measure of this relationship, customer class peak-load savings cannot be meaningfully translated into utility system capacity savings.

The second issue tends to reduce the importance of determining an exact coincidence factor. The advent of probabilistic reliability indices[4], such as loss-of-load-probability (LOLP) and expected unsecured energy (EUE), established an analytical basis for assigning capacity cost responsibility to more hours than the system peak hour. Coincidence of class and system loads is still important; the difference is that a wider bandwidth of system peak hours is now the target for the coincidence factor relationship.

The final issue for avoided generation capacity costs is similar to the earlier discussion of the utility's generation capacity planning goal. In addition to assigning appropriate loss and coincidence factors to a demand-side program, a reserve margin credit should be added to the total.

[4] See Bhavaraju (1982) for a discussion of these indices.

That is, without the demand-side program, not only would capacity be required to serve load, additional capacity would be required to provide a reserve margin for the now avoided load. Thus, a reserve margin credit should be added to the direct avoided capacity kWs.

VI. INTEGRATED EVALUATION METHODS AND MODELS

Least-cost utility planning involves substantial modifications and expansions of traditional utility filings. It confronts regulators with the difficult task of evaluating plans that use conventional modeling tools in new ways, as in the calculation of avoided costs from production cost models, and it introduces a new generation of planning tools specifically designed to deal with the complexities of demand-side resource quantification and demand-/supply-side integration. For example, EPRI's Demand-Side Information Directory lists 80 computer models for demand-side management and its integration into resource plans (Battelle Columbus 1985).

But models and other analytical tools have value for LCUP only to the extent that they facilitate planning by manipulating data in ways that are meaningful, understandable, and helpful to decision makers. That value stems largely from the the rigid structure provided by a modeling framework. Technically, the structure serves to define the range and manner in which issues can be addressed. Institutionally, the structure promotes the use of a common set of definitions and, as such, can be extremely effective in building consensus in the planning process and in identifying areas for conflict resolution.

At this time, the inherent limitations and relative accuracy of available modeling tools are insufficiently understood. For example, no comprehensive comparison has been performed between the major production cost models that are widely used in the industry. Even less understood are the differences in results that alternative applications of existing and new modeling tools might yield in the expanded, LCUP form of utility resource planning[1]. These problems are overshadowed by even larger uncertainties in the input data required by the models. The data required

[1] A limited review of some available models has been prepared by Stone and Webster (1988), with funding from DOE.

by most models are more detailed than most currently available data, which often leads to use of default values or, essentially, judgment calls by the model user. The cumulative impact of these values may be difficult to evaluate.

A related problem is the need in sophisticated least-cost planning efforts to link a number of models with each other. Extensive calibrations may be needed to make models compatible with each other, both in terms of data detail and formats. Utilities that have invested in a particular production cost model or other expensive planning tool may find themselves confronted with the need to make large additional investments in staff training, data generation, and calibration. The appropriate linking of models and their associated data sets to arrive at least cost integration is another area where good judgment is required and the impacts of methodological choices may not be sufficiently understood.[2]

Regulators and utilities must contend with these uncertainties while making high-stake planning decisions. However, these difficulties are no excuse for postponing least-cost planning efforts. There was no world of perfect information in the past, and it is unlikely that there will ever be one. The main thrust of regulatory review and oversight should probably be to assure that least-cost filings reflect as closely as possible the current state of the art and to create an informed dialogue between utilities and commissions that will ensure the constant improvement of their least-cost planning procedures. Improvement may not just mean a move to ever greater detail and comprehensiveness, but also the development of acceptable approximations; the effects of which are understood by all parties and which keep filing requirements tractable.

It is necessary, however, to continue to engage in further extensive efforts of model and data development. The following discussion of models used in least-cost planning is a cursory road

[2] See, for example, Synergic Resources Corporation (1985) and Eto (1986).

map illustrative of the large range of capabilities available in current planning models and the major conceptual distinctions among them.

One of our goals is to describe some of the complexities that LCUP adds to the use of models as used in traditional, supply-side utility planning. Procedurally, we start from a sketch of the major steps in LCUP and highlight some of the complexities involved. We then discuss various approximations to this ideal that can be achieved with existing modeling tools. Moving from the most sophisticated approach, the linking of a number of detailed, specialized models, we discuss successively simpler modeling approaches and the compromises they involve. In all our discussions, emphasis is on the issues raised for LCUP by these compromises, to pinpoint sensitive areas. We discuss some utility planning exercises performed by LBL as part of its LCUP research, and the practical difficulties encountered in these exercises.

The discussions are not exhaustive, nor are they to be construed as an endorsement of one vendor's product over another. Accordingly, while these discussions are accurate portrayals of the models, given available reference materials, they cannot account for changes to subsequent versions of these same products, which can differ considerably. The interested reader is advised to contact vendors directly for the latest information about products.

Least-Cost Planning Process Overview

LCUP requires evaluation of at least six subjects: load forecasts of energy and load shapes; cost and performance of demand- and supply-side options; consumer acceptance of these options (primarily of those on the demand side); long- and short-run utility production costs; impact on a utility's financial position; and interaction effects between *and* within the above five items. The sixth subject, regulatory environment, of course, underlies all of these subjects.

The societal perspective also encompasses analyses of the broader consequences of demand- and supply-side activities. These can include regional economic studies, environmental impact analyses, lifestyle assessment, etc. In the present work, we focus on the more limited topic of models and methods for measuring direct economic impacts.

Several important methodological issues arise in the context of integrating demand-side resources in what has traditionally been a supply-side planning exercise. These issues include:

1) Consistency between estimation of demand side program load shape impacts and the overall system energy/load shape forecast. Does the model account for the interactive effects of several programs or the effect of a single program on other components of the forecast? Does the model simply subtract demand-side program load shape impacts from a base-line forecast in a way that may overcount or undercount load impacts?

2) Integration of demand-side programs into the generation expansion plan. Are demand-side programs large enough to alter the timing or size of future supply additions?

3) The relationship between demand-side programs, load shapes, and rate design. Are demand-side programs large enough to alter retail rates, and, if so, how exactly are rates affected? How do rates, in turn, affect load shapes?

4) Representation of demand-side programs that rely on prices, not technologies to modify demands. Can the demand forecast reflect the impacts of differing rate structures?

5) The role of uncertainty in all facets of the planning process. Can the models used adequately capture the range of uncertainty underlying the data used in the planning process?

Linked, Detailed Models

The most complicated evaluation method for LCUP involves linking the inputs and outputs of individual, detailed models into an integrated process. The method is attractive because the detailed models selected are generally already in use as chief analytical tools for different utility departments. Institutionally, the results from these models will tend to carry with them the support of their host departments.

The primary difficulty of the model-linking approach stems from the fact that the models were not designed to be linked. Instead, they were designed to stand alone with their own unique sets of inputs and outputs and corresponding data conventions. A potential benefit of this approach is that the process of linking model inputs and outputs may require more explicit review and analysis of the data.

Generally speaking, there are models for each step of the LCUP process, including load-shape forecasting, generation planning, production costs, financial analyses, and rates. We will focus our attention on models developed for the first three areas, since the application of these models is central to the demand-side aspects of LCUP evaluations. In addition, we will also discuss several detailed models that are often used to develop inputs for load-shape forecasting models. Following these discussions, we will describe an example of the model linking approach with highlights from an LBL case study of the utility impacts of residential appliance efficiency standards.

End-Use Energy and Load-Shape Forecasting Models

Consistent and comprehensive treatment of demand-side options in a least-cost planning analysis requires the use of end-use energy and load-shape forecasting models. End-use detail is required to identify the effects of specific demand-side activities. Load shapes are required to provide a consistent basis for comparison with supply-side activities.

Although econometric forecasting models are an improvement over simple extrapolations of historic demand growth rates into the future, they cannot capture changes in the structure of demand. Without details of this structure, we cannot use these models to forecast the effects of individual demand-side measures, as is required by LCUP. Indeed, econometric models are of limited value for long-run forecasting precisely because of their inability to reflect structural changes in the composition of demand; the possibility for such large changes is essential for a rigorous evaluation of LCUP options.

End-use models attempt to represent the structure of demand directly in terms of the energy-using constituents of total energy demand. Thus, energy use for a given end use is simply the product of the number of forecasting units (e.g., businesses, households, floor area etc.) that have the end use times the average unit energy consumption (UEC) of the end use or energy utilization index (EUI). The forecast is the result of adding up the energy consumed by each end use. Within the end-use framework, econometrically estimated inputs play an important role in the energy forecast.

In the present state of the art, load-shape models are essentially post-processors to an annual electricity forecast. The models tend to rely on a combination of empirical observations and engineering relationships to allocate energy use to hours of the year.[3] We will discuss the special requirements of load management evaluations separately.

End-use models may disaggregate by sector, end use, energy source, and, less frequently, vintage and technology. At the sector level, major distinctions are made among residential, commercial, industrial, and other energy uses. Usually, separate models are used for each sector. At the end-use level, the most common set of end uses for residential and commercial sector models includes lighting, cooling, heating, ventilation, water heating, cooking, and miscellaneous. Specific energy-using processes are added to this list for industrial sector models. The most advanced models forecast all major fuel types (electricity, natural gas, oil, etc.) simultaneously and include algorithms to explicitly model fuel switching.

[3] For load management measures, this bifurcation of the energy forecast from the load shape is no longer tenable.

The available models are distinguished by the mechanisms used to predict future demand. The simplest models only multiply exogenously specified growth rates by an exogenously specified EUI. The most advanced models use inputs from econometric forecasts to relate exogenously specified macroeconomic changes (such as population growth, fuel prices, income, economic activity) to micro-economic, behavioral and structural consumption decisions at the end-use level, based on a model of consumer behavior and the options available to consumers to modify consumption. Because of the nature of current specifications of the models, most end-use models tend to be more responsive to long-run trends than short-term fluctuations in underlying economic influences.

The data requirements for end-use models can be staggering. Indeed, the availability of relevant and reliable data is often the weakest link in an LCUP evaluation. There are more data available for residential sector models than are available for commercial sector models. Not surprisingly, residential models are most highly developed, while commercial models are still relatively primitive. Load shape models are constrained solely by the current lack of measured data.

Evaluations of end-use forecasts generally consider data relevance and reliability, and benchmarking or calibration.

Data relevance is an issue because the models' large data requirements and the absence of already collected data often forces the analyst to rely on default values. Using default values is unavoidable, but a minimum set of local data is essential for meaningful analysis. The minimum data set includes local economic forecasts and gross characterizations of building stock (e.g., floor area and appliance saturations). Generally, the most difficult data to obtain include local end-use energy intensities and load shapes.

Data reliability is an issue because models can be quite sensitive to certain input values; small errors can have large impacts on the forecast. The most important input values are the choice of growth rates for the principal driving forces behind energy use, such as commercial floor area and numbers of households.

Benchmarking an end-use model to past sales is essential. The process consists of selectively calibrating inputs to produce a ''backcast'' using recorded sales. Complete calibration is impossible since historic consumption is never recorded at the level of disaggregation available in the models.

Uncertainty is also introduced by the unavoidable adjustments of the backcast or the historic data to achieve meaningful comparison. For example, an adjustment should be made for the influence of weather on energy use for heating and cooling. Past consumption will reflect the effects of past weather, but backcast consumption is usually based on assumptions of normal or average weather conditions. Some adjustment must be made, but techniques available for adjustment are crude.

Several rules of thumb can be followed in evaluating a backcast. First, calibration to shorter time intervals, monthly or even hourly (if performed in conjunction with the load shape models), will increase confidence that the appropriate relationships between the weather-sensitive and non-weather-sensitive end uses are being maintained. Second, calibration to several years of

past data will ensure that some of the structural relationships have been properly captured, which may not be true in one-time adjustment for a single year of historic data.

The origin of all current end-use forecasting models can be traced to work performed at the Oak Ridge National Laboratory in the seventies (Hirst and Carney 1978, Jackson *et al.* 1978). Currently, the most well-known end-use forecasting tools for electricity are the EPRI-sponsored models, REEPS (Cambridge Systematics 1982), COMMEND (Georgia Institute of Technology 1985), INDEPTH (Battelle Columbus 1985), and HELM (ICF, Inc. 1985). Below we highlight major features of these models.

REEPS is a residential sector forecasting model (Cambridge Systems 1982). It has one of the most sophisticated specifications of residential sector energy demand. While the end-use structure of most models is based on the notion of a single prototypical unit (a typical single-family residence, or a typical restaurant), REEPS allows for multiple prototypes to capture diversity of income, dwelling type, location and other characteristics. In addition, REEPS links appliance holdings, so that, for example, the presence of gas space heating increases the likelihood of gas water heating. Finally, REEPS includes a rudimentary load shape model. These features make REEPS, in principle, an extremely powerful tool for residential forecasting.

COMMEND is EPRI's commercial sector forecasting model (Georgia Institute of Technology 1985). EPRI's implementation includes three enhancements to the original Oak Ridge model: An algorithm to account for HVAC and fuel efficiency choices based on life-cycle economics, a load shape capability, and default values based on analyses of national data for the model's numerous inputs. As can be gathered from these enhancements, data development is one of the major issues for commercial sector models. In particular, data on energy utilization intensities and their related load shapes are generally acknowledged to be primitive. Similarly, precise measurement of the forecasting unit, commercial floor area, has been hampered by a lack of reliable record-keeping.

INDEPTH is EPRI's industrial sector forecasting model (Battelle Columbus 1985). It is a hybrid of overlapping modeling concepts that reflects the diversity of approaches available for forecasting in the sector. The first concept is a purely econometric, disaggregation by 17 industry types. The second concept focuses on specific industrial processes. Consumption decisions are a function of cost-minimization criteria applied to the range of available technologies for a given process. EPRI claims this approach is applicable for forecasting one-third of industrial electricity use. The third concept further disaggregates selected equipment types, such as motors or compressors. Here, the model addresses market penetration issues for five equipment types.

HELM is an EPRI load shape analysis tool (ICF, Inc. 1985). It is primarily a post-processor of annual energy forecasts from end-use models. It has a flexible accounting framework in which to manipulate and aggregate individual load shapes into a system-level load shape. The inputs, in addition to annual energy forecasts by end use, are dimensionless load shapes for use in allocating annual energy use to hours of the day, month, and year. In addition, the model features rudimentary capabilities for adjusting load shapes to account for weather variations and alternative rate designs. HELM, like COMMEND, is an example of the state of the art in modeling capabilities, which outstrips the availability of high-quality data. The development of meaningful load shape data is a major research issue.

Production Cost and Generation Expansion Models

Production cost models are the backbone of traditional electric utility generation planning analyses. They are used to estimate the operating costs of generating electricity, given a set of demands to be met and a series of generating resources available to meet them. They are

relevant to demand-side activities because estimates of changes in production costs measure the value of the demand-side activity. Use of these models, consequently, is central to least-cost planning evaluations.

At the same time, because of their complexity, these models are often called "black boxes." Accordingly, uncritical use or reliance on poorly documented modeling conventions and input definitions can seriously skew results. The purpose of our review is to highlight major issues to illustrate their relative importance for those who must review or use these models. We focus primarily on model features and calibration issues, but also give a brief overview of generation expansion models in the context of LCUP. Generation expansion models are closely tied to production cost models because they rely on the output of production cost simulations to optimize deployment of future supply resources.

Our discussion focuses on: 1) load representation; 2) unit representation; 3) unit commitment; 4) non-standard unit representation; and 5) calibration. Throughout the discussion, we rely extensively on a longer monograph on the subject of production cost models by Kahn (1987a).

Load Representation. Modern production cost models all take explicit account of the probabilistic nature of generator outages. In our vocabulary, load representation refers to the modeling framework used by the production cost model to capture these outages. Broadly speaking, there are two distinct load representations in current use, the load duration curve and the chronological load curve. Each has advantages and disadvantages.

The load duration curve approach developed because the transformation of loads permits the use of computationally efficient algorithms to calculate production costs and system reliability. The load duration curve is simply a reordering of chronological loads (typically hourly), into a monotonically descending order. At a time when computing power was at a premium, efficient algorithms meant that many scenarios of multi-year duration could be analyzed at reasonable cost. Consequently, the approach has been quite popular and is featured in the many current production cost models, including PROMOD (Energy Management Assoc., Inc. 1986), ELFIN (EDF, Inc. 1986), EGEAS (Caramanis 1982), and UPLAN (Lotus Consulting 1986).

The important limitation of the load duration curve is that the reordering of loads means certain chronological features of a generating system must either be suppressed, such as the interdependence of outages from hour to hour, or finessed through modeling conventions, such as the must-run designation. Some of these modeling conventions are quite powerful, however, and their existence should not be taken to imply that load duration curve models are inferior. Importantly, many of the demand-side options available for LCUP exhibit strong chronological dependences, so the impacts of these conventions can be quite important. We will describe one important convention in some detail and mention others in our discussions of unit commitment and non-standard (time-dependent) unit representation.

Sub-annual specifications for loads are often used to introduce chronological phenomena in the load duration curve approach. Production cost models typically calculate annual production costs, but many models actually perform their calculations on a monthly or seasonal basis, using separate load duration curves, so the user can introduce chronological (monthly or seasonal) features of the system directly. An example is the ability to specify seasonal fluctuations in the availability of hydrological or purchased power. PROMOD, in addition, permits specification of separate diurnal and weekly sub-periods (on-peak, off-peak, and weekend) to capture chronological phenomena on an even smaller time-step (Energy Management Assoc., Inc. 1986).

Recently, production cost models have begun to rely on chronological load curves. These models offer the potential for a more realistic representation of electric generating system operation than load duration curve models. Nevertheless, the use of load duration curve models is more widespread and use of a chronological model often begins with extensive benchmarking and calibration to results from load duration curve models. Also, despite advances in computer technology and algorithm development, the programs can still require significant amounts of computer time. Well-known models relying on chronological load curves include LMSTM (Decision Focus, Inc. 1982), BENCHMARK (Manhire 1982), and POWERSYM and its descendents (TEAM-UP Office 1981).

Unit Representation. Unit representation refers to the information needed to describe generating units. The basic information includes the rating of the generator, the fuel it burns, its fuel conversion efficiency (called heat rate), characteristics of its reliability, and maintenance requirements. Most models permit segmentation of units into blocks of capacity with different heat rates that can be dispatched separately, albeit sequentially. This convention replicates well-known properties of generating units and provides for a closer match to actual dispatching decisions than a single-block representation.

Maintenance schedules can often be assigned manually or automatically. In general, manual specification of maintenance periods is only necessary for nuclear units. Because of size and relatively low variable operating costs, the presence or absence of these units in the generation mix can have a large influence on total production costs. For most other units, automatic scheduling of maintenance is generally not a problem.

Unit Commitment. The goal of production cost models is to determine the most economic dispatch of generating units for a given load level. In principle, the algorithms attempt to determine the lowest cost combination of generating units for each load point or hour.

Unit commitment is designed to reflect certain realities of utility operation in which the relevant boundary of what is economic must be extended beyond a single hour. For example, large generating units cannot be started and stopped hourly; typically, they must be dispatched on a weekly basis. Thus, while operation of such units is economic during the day, when loads are high, operation at night is often uneconomic relative to other available, lower-cost generators. Nevertheless, the cumulative economies of operation during the day outweigh the penalties of running at night and so the unit runs during the night even though there are less expensive units available. An hourly optimization cannot accommodate this situation.

Several approaches are available to incorporate this important operating constraint in production cost modeling. The simplest is the "must-run" designation. This designation is assigned by the user to the first capacity block of a baseload unit that meets the criteria described above. The program then dispatches this portion of unit regardless of the economics in any given hour.

Uncritical use of this parameter, however, can lead to unrealistic results. In essence, the must-run designation is overriding the program's internal logic on the economic ordering of units. If the amount of must-run capacity is large relative to the loads being met, significant changes in production costs will result. It is particularly important to scrutinize the use of the must-run designation in evaluating calibration runs because selective use of the feature can guarantee a calibration run that is meaningless for other purposes.

The second mechanism for capturing dispatching decisions is a commitment target. With a commitment target, the program will "commit" units up to a target level (usually some percentage above anticipated peak loads), but run them only at minimum levels when system loads are low. Uncritical use of this feature can severely bias results. Some vendors now supply output reports documenting their program's commitment decisions. Needless to say, these reports are an important diagnostic tool for fine tuning a simulation.

Non-Standard Unit Representation. Standard unit representations for production cost models may not apply for many now important types of generation available to a utility. Economy power purchases, pondage or storage hydro, utility-dispatched load management, solar, and wind technologies all fall into this category.

Economy energy purchases are often characterized by strong diurnal fluctuations in availability. Large amounts of inexpensive energy are typically available at night and on weekends, but relatively less is available during weekdays. It is virtually impossible to model this feature in the standard load duration approach. PROMOD, as mentioned above, can model this feature using separate sub-period load duration curves for weekdays, weeknights, and weekends, by month. ELFIN also has this capability. UPLAN offers an interesting hybrid approach in which a chronological dispatch is used to determine the amount of such surplus power that would be taken. This amount is used as a load modifier in the load duration curve production cost computation. Solar and wind technologies can also be accommodated in this fashion.

The dispatch of pondage (or storage) hydro is strongly tied to times of system peak loads. Within the load duration curve format, a load modifier is the modeling convention that reflects this bias. Essentially, the convention results in a slice being removed from the top of the load duration curve starting at the peak load and extending to the capacity of the pondage hydro unit. This approach has important consequences for the program's calculation of instantaneous marginal costs. Utility dispatched load management is also represented in this fashion.

Calibration Issues. The probabilistic formulation used by production cost models means that calibration to measured data is impossible. Production cost models calculate expected values from an underlying distribution of probabilities; recorded history is just a series of random draws from this distribution.

Calibration is more meaningful when it is performed between models. Simpler models are easier to use in integrated-planning evaluations, but these evaluations are meaningless unless the simpler model has been calibrated to a more complicated (and typically pre-existing) one.

Production cost models contain many adjustable parameters. As such, individual parameters can always be adjusted to calibrate the model in a trivial sense; however, meaningful calibration results in consistency over a broad range of conditions. We identify three indicators that suggest that such consistency has been achieved.

Because of the size and position in the dispatch order of baseload units, their generation can only be considered well-calibrated when agreement to within 1-3% has been achieved. For units that are marginal, typically medium and smaller oil and gas units, good calibration for the generation of the entire group of such units is about 5-10% agreement. Model-specific options often preclude closer calibration, and calibration to the level of individual units is usually impossible; however, it is unnecessary since generating costs are nearly identical for these units. An example of such a calibration is contained in our discussion of the calibration of the UPLAN model for LBL's analysis of SCE's avoided costs (see below).

The most critical calibration metric is the comparison of marginal costs. Again model-specific idiosyncrasies and options usually preclude agreement closer than 5-10%. Broad agreement in monthly and diurnal patterns is a much more reassuring sign of calibration. As in calibrating end-use models to historic sales, calibration to many years of data is a good sign.

Generation Expansion Models

Generation expansion models rely on sophisticated mathematical optimization techniques to produce a schedule of additions to generation capacity. To perform this optimization, they must contain both financial and production cost simulation capabilities. These capabilities can be

quite detailed and usually can be used in a stand-alone mode; i.e., without using the optimization module at all. We believe there are serious limitations to the use of these models for least-cost planning. On the one hand, there is a significant question of their relevance. The models have been developed to minimize utility revenue requirements, not total societal costs. In addition, it is often not possible to represent demand-side measures properly in a format designed to select supply-side options. Both issues call into question the usefulness of these models for LCUP. Most important of all, ultimately, people make planning decisions, not models. At best, computer models can help inform these decisions, they cannot replace decisionmakers.

As strictly supply-side optimization tools, there is still reason to doubt the usefulness of generation expansion models. In particular, it is often difficult to represent the appropriate constraints to the planning problem in a meaningful way. For example, the EGEAS model, which features extensive optimization capabilities, does not have an explicit procedure for treating the limitations on utilities' ability to raise capital for new construction (Caramanis 1982). Instead, the user must artificially restrict the capacity available from capital-intensive supply options. Too often, specification of the relevant constraints requires predetermining the answer. In this case, the optimization has not provided any new insight into the problem, and its marginal worth must be scrutinized.

Specialized End-Use Models

Specialized end-use models are often required to supplement the detail and information available in an end-use energy and load shape forecasting model. For example, a building energy simulation model may be used to provide information on the load shape impacts of an innovative technology, such as thermal energy storage. Similarly, a separate analysis may be needed to develop the impacts of a water heater cycling load management program for input into a load shape model. In both cases, precise characterizations of these demand-side measures are important inputs that are not generally contained in the forecasting model. Accordingly, these details must be developed exogenously.

In this sub-section, we will introduce two major classes of specialized models: 1) the broad class of building energy analysis models, and 2) EPRI's model for evaluating residential sector responses to time-of-day pricing.

Building Energy Simulation Models. Success of demand-side programs in the commercial and residential sectors depends largely on the opportunities for changing the levels and patterns of energy use in buildings. Many computer models have been developed specifically to assess these prospects in individual buildings. In general, these models are engineering tools for assessing the thermodynamic performance of buildings, given a fairly rigorous description of their physical and operational characteristics.

Within the engineering approach, most models follow one of two major paradigms. The first relies on a steady-state formulation to the modeling problem. This assumption greatly simplifies energy calculation and, accordingly, is the approach adopted by most PC-based models, such as TRAKLOAD (Morgan Systems Corporation 1987). The second type of model relies on a dynamic formulation of the heat flow equation and uses a complicated solution. The most well-known of these models is the DOE-2 building energy analysis program developed by the Lawrence Berkeley and Los Alamos National Laboratories (LBL 1985). This program was developed for a mainframe computer, but has been adapted by private firms for PCs.

The appropriateness of a model for use in LCUP evaluations is a function of the type of demand-side program involved. Steady-state models are generally appropriate for evaluating residential buildings of low mass where diurnal fluctuations in operation are not pronounced

(e.g., single-family, wood structures, without night temperature setbacks). The construction and operation of large commercial buildings, on the other hand, warrants the use of the more detailed modeling approach. In general, steady-state models are not appropriate for evaluating the load shape impacts of modifications to the thermal integrity of buildings.

The models described above were developed for architects and engineers to evaluate their designs prior to construction. For this purpose, the pre-specification of operating patterns and controls is both necessary and appropriate. Recently, however, a new class of models has appeared that start with recorded energy use and attempt to develop statistically a model of this energy use. With these models, the actual operating behavior of the buildings is implicit, rather than pre-determined. These models are specifically designed, then, to capture the as-built and operated performance of buildings and are particularly applicable for measuring recorded rather than predicted energy savings. The most well-known of these is the Princeton Scorekeeping Method (PRISM) (Fels 1986). To date, the model has been successfully used in evaluations of energy (but not load shape) impacts of residential conservation programs.

EPRI's RETOU. Innovative tariff designs can play an important role in LCUP. Prominent among them are time-of-use rate schedules that convey seasonal and diurnal variations in the cost of power to consumers. The analytical challenge in evaluating tariffs is the development of time-differentiated price elasticity of demand.

In the seventies, many research programs measured the impacts of these rates. EPRI's RETOU program embodies the results of some of this research in a program that can be used to assess the impacts of time-of-use rates on residential electricity demand (Laurits R. Christensen Assoc., Inc. 1984).

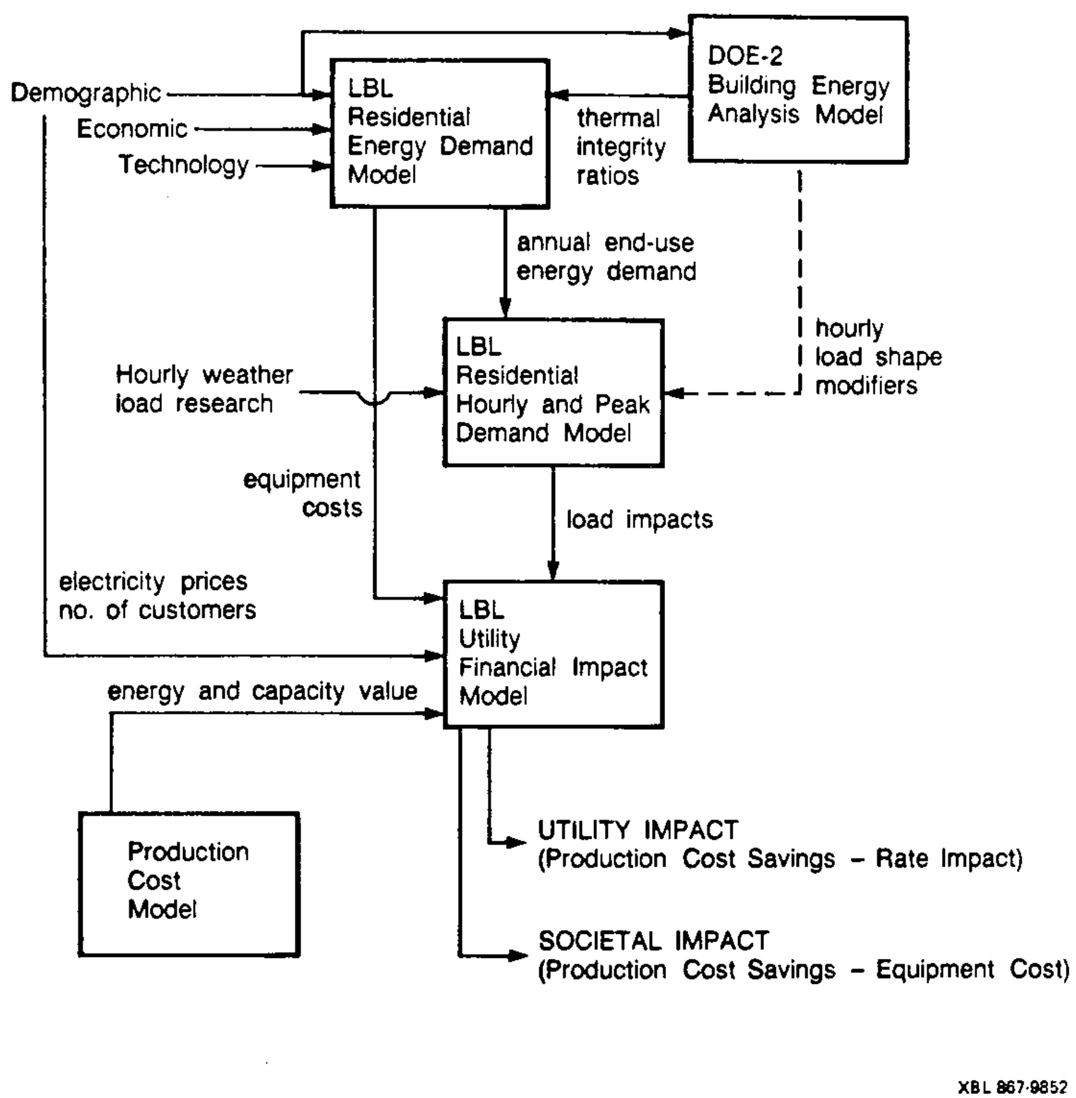

Figure VI-1. **Overview of the LBL Evaluation Method for Analysis of Residential Appliance Standards on the Nevada Power Company. Source: Eto, *et al.* 1988.**

Nevada Power Appliance Standards Case Study

To illustrate the complexities involved in the model linkage approach, we review one of LBL's five case studies of the impacts of residential appliance efficiency standards.[4] The Nevada Power Company (NPC) case study is LBL's most sophisticated attempt to use the model linkage approach (Eto *et al.* 1988, Eto *et al.* 1986). The study relied on linking four separate computer models: The LBL residential energy model (McMahon 1986), the LBL residential hourly and peak demand (Ruderman and Levine 1984), model, the DOE-2 building energy analysis model (Building Energy Simulation Group 1985), and the TELPLAN production cost simulation model (TERA 1982). Figure VI-1 illustrates these models and major flows of data between them.

The LBL residential energy model (REM) is an end-use, engineering/economic simulation that uses engineering, demographic, and economics driving forces to forecast energy use for three housing types, ten end uses and three fuel types for up to twenty years. It is similar to the EPRI REEPS model, which shares a common origin in the work at Oak Ridge National Laboratory in the late seventies (Hirst 1978). Energy use is a function of both short-run consumption and long-run stock replacement decisions. The model was originally developed to forecast national impacts of residential appliance efficiency standards, but has been adapted to model individual utility service territories. The challenge for using the model at the local level is to revise inputs to reflect local conditions. When local data were incomplete, national default values were used in this case study.

The DOE-2 building energy analysis model was used to supplement incomplete local data on the thermal energy requirements of residential buildings in the NPC service territory. For example,

[4] See Synergic Resources Corporation (1985) for another example of the model linkage approach.

NPC had data on the thermal energy requirements of the stock average, but not of new residences, as is required by the LBL residential energy model. DOE-2 runs for both a typical and a new residence were used to scale NPC's average number to estimate the requirements for a new residence.

The LBL residential hourly and peak demand (RHPD) model translates annual energy into hourly values based on empirical load research and local weather data. RHPD is similar to EPRI's HELM model, but is restricted to residential loads. These load shapes are the link for consistent treatment of demand-side interventions and supply-side responses. Also, use of this model permits highly detailed calibration. We used these results to calibrate the energy forecasts at both the monthly and hourly level. Figure VI-2 is an example of LBL's calibration for a summer peak day.

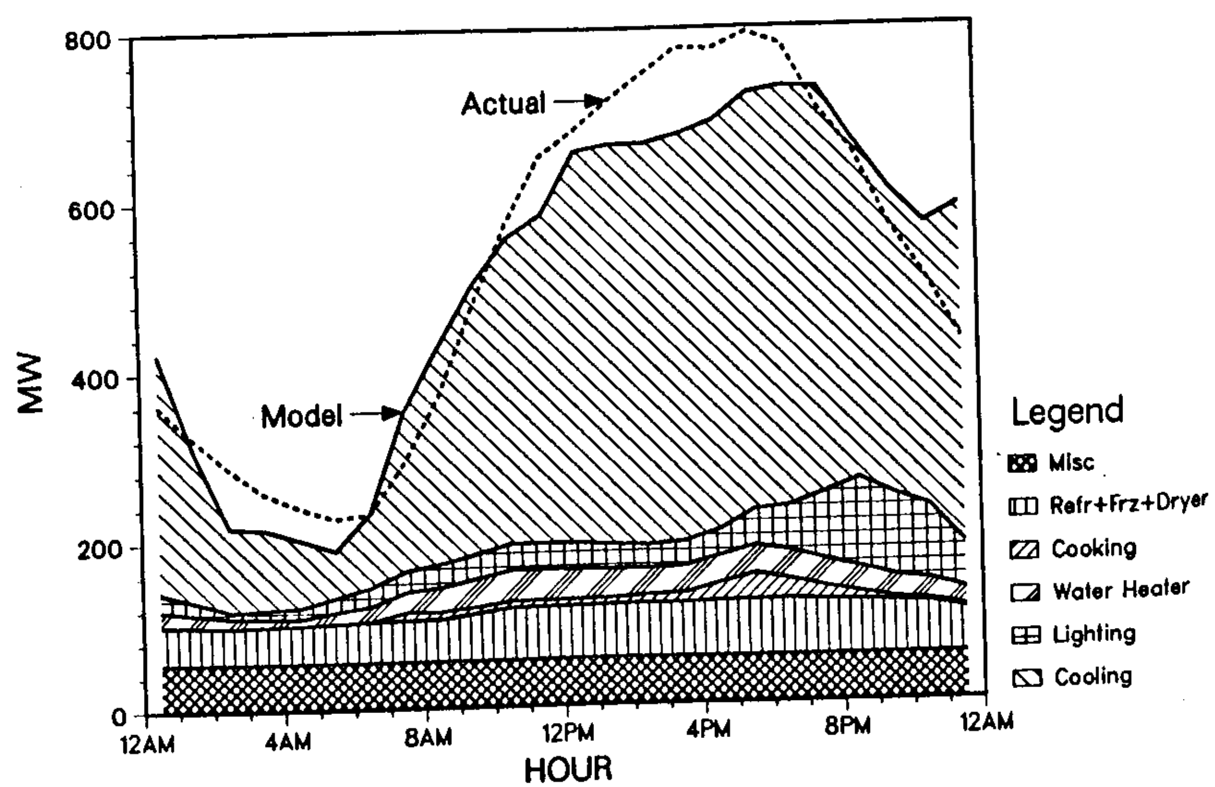

Figure VI-2. **Final Calibration of the LBL Residential Hourly and Peak Demand Model to Recorded Nevada Power Company Residential Class Loads, Summer Peak Day. Source: Eto, *et al.* 1988.**

Production cost benefits were calculated using the TELPLAN production cost model developed by TERA for EPRI. For this study, we estimated both a short- and long-run supply response to the demand-side intervention. Even a small system such as NPC requires large amounts of data to describe its supply system. Our sources were NPC supply plans and PROMOD runs filed in support of these plans.

The REM, DOE-2, RHPD, and TELPLAN models were used to calculate costs and benefits of appliance standards from both the societal and utility perspectives. The evaluation method was an analysis of impacts on utility revenue requirements and societal costs with and without the imposition of standards. The standards were modeled by constraining the equipment choice algorithms in the LBL residential energy model to select equipment of at least the minimum efficiency called for in the standard. The evaluation of the standards considered energy savings resulting from both the more efficient appliances and reductions in appliance sales because efficient appliances are more expensive.

We now describe several aspects of our evaluation that illustrate the complexities of the model linkage approach for LCUP.

For the NPC case study, the long-run production cost savings of appliance standards consisted of the deferral of future generating units. The deferral period was calculated manually through iterative simulations of the supply system. The technique, called the fuel savings approach, is described more fully in our discussion of avoided cost definition and measurement.

To simplify parametric evaluations of different standards, production cost benefits were not calculated through direct simulation of load shape changes resulting from individual appliance standards. Instead, production cost benefits were measured through the use of generic load shape changes that approximated the magnitude of those forecasted to result from the imposition of standards. This generic benefit was then re-expressed as a series of "pseudo-tariffs" for energy and capacity ($/kWh and $/kW) that were applied to the load shape changes resulting from a specific set of appliance standards. This approach is analogous to utility offers to purchase power from non-utility sources at standardized, uniform prices. We were thus able to evaluate several sets of standards rapidly without the need for a re-optimized supply response for each standard.

The decision to use generic load shape changes as the basis for production cost savings required our researchers to develop valuation rules for the appliance standard load shape changes. The first of these was to use system loss factors to increase the value of energy savings estimated at the end-use level so that they could be measured in terms of avoided generation costs at the bus-bar. The second involved determining the capacity value of the load shape changes. This determination was based on an evaluation of both the coincidence of residential class and NPC system loads and the operation of peaking plants in the NPC generating system. The evaluation concluded that the average load shape change for the highest five hundred hours of residential class loads was an appropriate measure of capacity value. To this value, a reserve margin credit of twenty percent was added to reflect NPC's reliability planning criteria.

Integrated Planning Models

Recently, a new class of integrated, least-cost planning models has been developed. These models incorporate important elements necessary for comprehensive treatment of demand- and supply-side measures, which distinguishes them from the screening tools to be described in the following section. Other resource planners may refer to integrated models as screening tools because they are less detailed than the state-of-the-art models for which integrated models can

be substituted. Examples include LMSTM (Decision Focus, Inc. 1982) and UPLAN (Lotus Consulting Group 1986), which will be discussed below.

The overwhelming advantage of these models is that they perform in a single piece of software aspects of analyses generally found in more complex, detailed models. In the model linkage approach, the major challenge is to ensure data compatibility across independent models. With integrated-planning models, major linkages are embedded in the simulation and made transparent to the user. The most important of these linkages is between the specification of the demand-side loads and the subsequent effects on production costs.

We use two criteria to distinguish integrated-planning models from screening tools. First, these models usually permit the user to specify in great detail the structure of demand. The models accept hourly load shapes that can be combined individually from the bottom up or simply subtracted from a system total load shape. Second, they also usually feature dynamic simulation of the production cost impacts based on these load shapes. These features make integrated-planning models an attractive middle ground between time-consuming linking of independent detailed models, and the great sacrifices in detail required by simpler screening tools.

The benefits of integration, however, can be compromised by the technical and institutional costs of a modeling approach that falls between these two extremes. Technically, integration results in some loss of detail at each step in the analysis. Despite substantial data requirements, simplifications are often unavoidable, and results will always be evaluated relative to those produced by the more detailed models. Thus, existing models often need extensive benchmarking and calibration (typically, to the production cost and the financial models used by the generation and financial planning departments). Institutionally, these calibration efforts are essential to give model results credibility.

Several methodological issues must be evaluated in judging any integrated planning effort. We introduced several of them in discussing challenges for the simpler screening tools but focus on them directly in this section because they are often suppressed in uncritical use of integrated models.

The first issue deals with consistent and meaningful treatment of demand-side programs in developing system-wide load shape impacts. Often, demand-side programs are represented as reductions in load from a system load shape. This technique can double-count load savings from successive, yet highly interactive demand-side measures. A chief advantage of stand-alone, end-use forecasting models is their ability—in principle—to treat demand-side measures consistently.

A second issue to judge in an integrated model is the model's ability to represent the load shape impacts of demand-side measures easily. This ability often outstrips the data available to represent these measures meaningfully. Many integrated-planning models offer sophisticated load shape handling and modification capabilities. Without reliable data on the performance of demand-side measures, use of these capabilities is difficult.

The third issue for judging an integrated model is the treatment of demand-side measures in generation planning decisions. The more limited issue for integrated planning models is that generation expansion decisions are usually specified by the user. Although treatment may be warranted for demand-side measures with small load shape impacts, serious least-cost planning efforts require consideration of large demand-side impacts that defer or displace powerplants. Typically, the user must implement these necessary modifications to a base case generation expansion plan by hand; the program will not alter a supply plan automatically.

The fourth issue for integrated models covers the effects of demand-side changes on utility rates

and the effect of these rates on future electricity demands. The effects of demand-side programs on utility rates (and finance) are generally treated very simplistically. On the one hand, forecasting ratemaking is difficult because of the need to forecast future cost-of-service relationships for all customer classes, as well as an inherently unpredictable regulatory process. On the other hand, some forecast of future rate levels and structures is crucial to forecasting future demands for electricity. In general, most integrated models, despite the rich detail available to specify system loads, do not provide for sophisticated treatment of the factors that influence these loads (such as time-differentiated prices for electricity, income, demographic change, etc.). Typically, these influences must be captured in a detailed energy forecasting model and translated into load shapes for the integrated planning models.

Least-Cost Utility Planning Study for PG&E with LMSTM

In 1987, LBL used an integrated-planning model to perform a limited, least-cost planning study for the Pacific Gas and Electric Company (PG&E) (Comnes *et al.* 1988, Kahn *et al.* 1987b and 1987c). This study illustrates some of the practical difficulties involved in introducing new integrated planning models and the reasons that adoption may take some time.

The study's goal was to measure hypothetical, large-scale, demand-side programs: a high-penetration, commercial thermal energy storage program and a minimum efficiency standard for residential air conditioners and heat pumps.

The study relied on an integrated-planning model, the Load Management Strategies Testing Model (LMSTM) developed by Decision Focus, Inc. (1982). LMSTM is a mainframe computer model. It features an extremely flexible demand-side representation, a unique chronological dispatch algorithm to calculate production costs, and a simplified treatment of utility finances and rates. LMSTM does not, however, have a very sophisticated mechanism for driving load shape changes, the generation expansion plan is fixed, and, as with most integrated-planning models, the ratemaking procedure is crude.

LBL's major challenge in using the model was to calibrate the production cost simulation module in LMSTM to the results from PG&E's in-house model, GRASS. The PG&E generating system is unique in its reliance on large amounts of hydro power, imports from out of state, and a new pumped storage facility. These circumstances result in large diurnal and seasonal cost variations. In addition, significant system boundary definition problems arise from the overlap of the PG&E system with municipal systems, whose generating facilities are often dispatched by PG&E. The substantial efforts required for the initial phase of the project resulted in a separate report that also contains valuable, widely applicable advice on calibration issues for production cost models (Kahn 1987b).

To model the impacts of the demand-side programs, our researchers bypassed the crude load shape modification features in LMSTM and developed load shape changes exogenously. To develop load shape changes for commercial thermal storage, results from building energy analysis model simulations were scaled by predefined penetration rates. To develop load shape changes for the residential appliance efficiency standard, an end-use energy and load shape forecasting model, the LBL Residential Energy Model (McMahon 1986) was used to calculate penetration rates, and the results were inserted into LMSTM.

LMSTM relies on a user-defined generation expansion plan to perform its production cost and financial calculations. To reflect the impacts of a large-scale demand-side program on future production cost and finances, the researchers had to alter the timing of future supply additions manually.

SCE Avoided Cost Estimation with UPLAN

As part of a larger study of auctions for purchases of non-utility power, LBL studied avoided costs in the Southern California Edison Company (SCE) service territory using an integrated-planning model (Rothkopf *et al.* 1985). The study was to determine the avoided generation costs associated with the introduction of large blocks of non-utility power generation. The methods used are a useful illustration of procedures for developing avoided costs (described in Section V) using an integrated-planning or production cost model.

The avoided cost study relied on the production cost capabilities of an integrated-planning model developed by Lotus Consulting Group, called UPLAN (1986). UPLAN runs on a personal computer and is executed using menu-driven screens. Its demand-side representation is slightly more flexible than LMSTM's. In addition to building up loads from the bottom, UPLAN can visually display load shapes and manipulate them on-screen through an on-line editor. UPLAN also features a fairly sophisticated production cost algorithm that is a hybrid of the chronological and load duration curve approaches. UPLAN also offers somewhat detailed financial calculations and an optimal generation expansion option; however, these options were not relevant to the LBL study.

Our major task was to calibrate the model to the outputs of SCE's own production cost model. Table VI-1 summarizes the benchmark results. Generation from baseload resources, such as Palo Verde, San Onofre, Navaho, and Mojave will agree in any set of simulations, provided consistent treatment of unit ratings and fuel prices are used. In general, input assumptions are also adjusted to guarantee the amount of generation contributed by qualifying facilities (QFs), coal, hydro, Bonneville Power Authority purchases, and other miscellaneous categories. Achieving agreement in generation from marginal resources is a more important indicator of model calibration. In the LBL study, the model showed good agreement for marginal resources, with the exception of the levels of specific economy energy purchases.

Table VI-1. **Final Calibration Results from LBL's Analysis of Southern California Edison Avoided Costs. Source: Rothkopf, *et al.* 1985.**

BENCHMARK RESULTS - 1995 in GWh

	PROMOD	UPLAN
PV/SONGS	14,563.1	14,544
Navaho/Mohave	8,361.9	8,372
Other Coal	2,291.2	2,310
QFs	17,814.6	17,842
Hydro/BPA	13,109.1	13,200
Econ CPP	1,735.6	1,720
Misc	580.1	567
Econ PNW/SW	14,144.7	14,181
Consisting of:		
PNW-on peak	1,288.3	1,421.8
PNW-off peak	2,556.6	3,579.7
SW-on peak	2,220.3	2,522.5
SW-off peak	8,079.5	6,656.8
Oil and Gas	20,931.6	20,942
Peakers	61.4	49
Other Misc	98.6	90
	93,691.9	93,688
Unserved		3.4

The calibrated model was used to calculate two different marginal costs. The first step was to identify the timing and size of a deferrable future resource addition. The calculation technique required iterative simulations to determine when the operating cost benefits associated with the addition of the resource just equaled a measure of the capital costs of the plant. This technique is described in more detail in our discussion of avoided cost calculation (Section V). The researchers found that an important component of the operating cost benefits of such an addition was the subsequent reduction in avoided cost payments to other QFs; the payments are tied to the marginal energy cost. The second marginal cost quantity calculated measured the value of additional non-utility generation beyond that of the deferred plant.

From the standpoint of an integrated LCUP evaluation, however, the model's capabilities and limitations should be borne in mind. For example, the program's highly flexible load shape editor may provide the user with too much freedom in specifying the load shape impacts of demand-side measures. That is, the program makes load shape changes easy to implement, but it does not provide guidance on their reasonableness. Without extensive cross-checks to measured or other data on the expected load shape changes of demand-side measures, uncritical use of this program capability could produce misleading results.

DSM Screening Tools

DSM creening tools address the problem of the great volume of measures available to provide energy services from either the supply or demand side. Detailed analyses of every conceivable option or combination of options would require substantial effort. The marginal benefit of these efforts may be limited because typically only a small number of options will make it into the final least-cost optimum.

Hence, the goal of these models is to provide a "first-cut" ranking of options in order to identify the most clearly beneficial measures. If we simplify many of the assumptions and suppress many of the details required by a more in-depth analysis, we can rapidly identify the most promising options. (A related reason for using these models is that it is usually quite easy to perform sensitivity analyses of key assumptions.) In general, the outcome of analysis using screening tools identifies the programs that are worth studying in detail.

Screening tools rarely include dynamic simulation capabilities[5]. The characteristics of options (e.g., performance, cost, market penetration), and generalized yardsticks for use in valuation (e.g., marginal energy costs) are specified exogenously. Typically, these data are developed from outputs of more detailed models. In essence, then, most screening models are little more than sophisticated spreadsheets, which consistently translate user-defined inputs into the cost-benefit perspectives identified in Section IV. Some models are no more than programmed sets of spreadsheet equations. DSM Planner and RDSM, for example, fall into this category (BHC, Inc. 1988, APPA 1987).

As a result of the model's spreadsheet qualities, interaction effects are usually ignored. Thus, use of such a screening model, means that the impact of a single demand-side measure will probably not account for the effect of another, logically related one. For example, a tighter building shell will reduce cooling loads, and so reduce the energy savings from an efficient air-conditioner meeting these lower loads. However, screening model generally will not be able to account for these effects. On the supply-side, a relevant example is the inability of non-dynamic models to capture the effect of increasing amounts of conservation to reduce short-run marginal costs or, alternatively, to defer or cancel future plant construction.

5 Two notable exceptions are CPAM (Bull and Barton 1986), and MIDAS (Farber, *et al.* 1988).

The benefit of ignoring these subtleties is that the models are often very user-friendly. Many models are available for personal computers and feature colorful, easy-to-use, menu-driven screens. Since the number of calculations performed is limited, these models often feature quick turn-around times that make them ideal for screening many programs, as well as testing the sensitivity of the results to changes in key assumptions. In the initial, strategic phases of an analysis of demand- and supply-side options, these features are highly desirable. The data requirements for this class of models are typically straightforward; though, they can be large.

The limitations of these models is their reliance on a necessarily simplified, non-dynamic characterization of a utility and its customers. This limitation can, however, be avoided in three ways. The first is to avoid placing undue emphasis on detailed quantitative results but to focus instead on general trends that can be addressed in detail by more sophisticated techniques. The second is to exercise substantial critical judgment in developing the inputs for use in these models. The third is to perform sensitivity analyses on key inputs.

Supply Curves of Conserved Energy

Supply-curve models were the forerunners of today's sophisticated least-cost planning tools. They produce supply curves of conserved energy and peak power across a number of end uses or whole energy sectors (SERI 1981, Meier 1982). A number of screening models on the market are based on the same concept.

Supply-curve models can define cost-effective demand-side resource for any given level of avoided costs. The procedure involves four major steps:

1) Defining the baseline in terms of current energy use intensities, load shapes, saturations, and stocks, disaggregated by individual end use and corrected for weather.

2) Developing an inventory of demand-side measures applicable to the sector and end uses under study, including involves cost data, per unit savings and load shape impacts, and interactive effects among demand-side measures. Special submodels are used to deal with interactive effects of measures in buildings and to determine savings under local weather conditions.

3) Combining this inventory with end use based growth projections to arrive at a series of macro supply curves of the demand-side resource over time. At this point, only the technical potential of the resource has been defined.

4) Using projections of program-induced penetration rates to define achievable market potentials under various assumptions of program emphasis and design. The costs of demand-side resources include program-related costs.

So far, supply-curve models lack a detailed characterization of the supply side of the utility. The supply side is represented statically, in the form of an average price or a marginal cost for electricity. These hurdle rates for cost effectiveness must be determined exogenously. Indeed, most supply-curve models do not provide sufficient detail on demand-side impacts as a function of hour, day and season to justify a more sophisticated representation of the supply side. Forecasts of saturations, fuel choice, and other growth parameters are also derived exogenously from econometric models and from trend evaluations of individual end-use technologies.

Another drawback of these models is that they have no features to deal with the interactive effects of demand-side resources on avoided costs. As demand-side options are implemented, the dispatch order, system load shape, and average generating costs on the supply side will change,

The unique advantage of supply-curve models is that they allow a highly transparent, understandable presentation of the demand-side resource. Their application for least-cost planning is thus two-fold. When used in a more or less stand-alone mode, they are limited to an initial screening for those demand-side measures that are likely to be most cost effective. As part of a sophisticated exercise, they can be used as preprocessors to provide the input for integrated evaluation of all options. In fact, they may be indispensable in this function.

Supply-curve models can also be designed to take account of interactive effects among individual demand-side measures, which are not accounted for in integrated-planning models. For example, reductions in electricity use for lighting will also reduce heat output of lighting and therefore reduce space conditioning requirements. This interaction, if not accounted for, can lead to double counting of some savings. Some supply-curve models have routines to account for these interactions.

The calculation of technical potentials can help identify assumptions about program implementation that may be too low or too high. In the absence of technical potential, it is difficult to know how to mobilize demand-side resources cheaply and effectively.

Finally, there are circumstances in which a supply-curve analysis can give reliable indications of the cost effectiveness of demand-side options under resource integration. In many instances significant demand-side resources can be bought at societal costs of conserved energy that are lower than short-run marginal costs from existing powerplants during all hours of the year. The impact of demand-side resource implementation on marginal costs can then be neglected since marginal costs cannot decline below the cost of demand-side measures in response to these savings.

The Michigan Electricity Options Study, which has been described in Section II, provides an illustration of this approach. This planning exercise involved a sophisticated integration analysis linking several models and using a special integrated-planning model to develop 20 year least-cost resource mixes. In all those end-uses where societal costs of conserved energy (including program costs) were lower than marginal costs the results of the complex integration analysis were identical with the results that would have been directly obtained from the residential sector supply-curve analysis that was used as an input (Krause *et al.* 1987).

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