Estimation of Avoided Costs for Electric Utility Demand-Side Planning

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Avoided costs originated with federal laws designed to encourage renewable energy and small power production. When estimated properly, they provide an unbundled characterization of the short- and long-run cost structure of a utility. We review current practices for estimating avoided costs for use in electric utility demand-side management (DSM) resource planning. For large DSM resource options, using avoided costs to estimate value is more accurate than using short-run marginal costs; avoided costs are simpler to use than traditional supply planning methods. We describe various administrative approaches for estimating avoided power generation costs and discuss modeling issues that arise in the estimation process. We also discuss emerging, market-based approaches for estimating avoided costs and describe current estimation practices for the additional, often substantial, non-generation-related costs avoided by DSM programs. Finally, we discuss special considerations in using avoided costs to estimate the system value of DSM.

Keywords avoided costs, demand-side management, electric utility, power generation

Traditional utility resource planning methods were developed primarily to evaluate the economics of trade-offs in the timing, size, and operating characteristics of various options for generating power. Integrated resource planning (IRP) requires that a utility consider a wide variety of options for meeting customers' energy service needs, including demand-side management (DSM) programs, which were previously not widely considered (Hirst, 1988). DSM refers to utility-initiated actions to modify the energy use patterns of customers as an explicit resource alternative to other supply options (which could typically be owned by the utility, e.g., new generating plants). Individually, DSM resource options are small in comparison to the supply options traditionally considered in utility resource planning.

When the resource contribution from DSM programs is expected to be large, which is typical in many IRP processes because substantial untapped DSM resources exist (Krause & Eto, 1988), it is important to use avoided costs to estimate their system value to the utility[1] for screening the myriad DSM options available and identifying the most promising options. Avoided costs are more accurate than short-run marginal costs (the most well-known alternative) for this purpose be-

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[1] In this article "system value," refers to the value to the utility system.

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cause avoided costs explicitly account for both short- and long-run cost effects of large DSM resources.

Current practice in estimating avoided costs varies considerably, and little published information exists on the strengths and limitations of different approaches. In addition, avoided costs are used differently in DSM planning. The scope of these additional costs includes transmission and distribution system investments and losses; alternative supply options generally avoid only generation investments and operational costs.

This article addresses all aspects of avoided cost estimation for demand-side planning. In the following section, we elaborate on the intermediate screening function in demand-side planning and describe the origins of the avoided cost concept. Then we discuss various approaches for estimating avoided short-run generation costs (in the short run, the capacity of the supply, transmission, and distribution system is fixed) and long-run avoided generation costs (in the long run, the capacity of the supply system is allowed to change). We review procedures for allocating long-run avoided costs between energy and capacity, which typically require the use of production cost models; we discuss some of the differences among models (with reference to how they are used). We discuss the administrative determination of avoided costs and describe the emerging practice of developing avoided costs through market-based approaches, such as competitive solicitations. We then compare the methods and review progress in the new area of estimating transmission and distribution capital, and environmental costs associated with generation avoided by demand-side programs. Finally, we describe the methods required to disaggregate avoided costs into tariff-like schedules for use in valuing DSM programs and summarize our findings regarding avoided costs in valuing DSM.

Demand-Side Resource Planning, Avoided Costs, and Marginal Costs

When a utility engages in resource planning, it traditionally calculates a risk-adjusted revenue requirement for a handful of supply options (see, for example, Stoll, 1989). The risk-adjusted revenue requirement represents the net present value of all costs associated with each option. The calculation requires detailed production cost and financial information. The goal is simply to choose the option that minimizes life-cycle revenue requirements. This option typically consists of a trajectory of future supply plants (and retirements or life-extensions to existing plants), to be built and brought on-line at specific times. In this process, the size, operating characteristics (e.g., heat rate), and optimal timing for a number of plants are considered simultaneously. The process is computationally intensive, so modern resource planning models often feature optimization routines to assist in conducting the analysis (see, for example, Caramanis et al., 1982). These methods limit the number of options that can be considered at any one time.

Determining the appropriate role for demand-side programs in a utility's resource portfolio is similar to the supply planning process but with added complications. Selecting among demand-side resources is difficult because they are by nature, diverse, diffuse, and decentralized. Compared to the number of supply options traditionally considered by utilities in resource planning, there are many more demand-side options to choose from. Analyzing each option in the same detailed manner as supply options would quickly tax the staff and computational resources of even the largest utility. Each option, moreover, is much smaller than a typical supply option. Even if analytic resources were unlimited, the resolution of traditional supply planning and optimization models is too coarse to capture the effects of the comparatively small load impacts of individual DSM resources. Finally, it may take several years to "ramp-up" large-scale demand-side resources. While utilities often have control over the construction lead times associated with supply resources, the ramp-up time for DSM resources may not be controllable by utility management. However, the load contributions from demand-side resources will begin to accrue during the ramping-up period, which is not true for supply resources.

The problems associated with the number and small size of individual DSM options are addressed by bundling the options together into larger resource blocks, which reduces their number and makes them more manageable in the resource planning process. This process requires screening criteria to determine appropriate bundles of options. Standardized benefit cost methods have been developed (California Public Utilities Commission and California Energy Commission (CPUC/CEC), 1987). Once the DSM resource bundles are defined, aggregated bundles can generally be accommodated by traditional resource planning approaches, although important integration issues remain (Hill, 1991; Environmental Defense Fund, 1992).

Typically, DSM program screening relies on short-run marginal cost. We believe this practice can lead to large inaccuracies in the DSM resource planning process. Our reasons can be best understood by examining the difference between marginal and avoided costs.

Economists agree that desirable welfare efficiency benefits result from using marginal costs (as opposed to average costs) to price utility services (see, for example, Crew & Kleindorfer, 1986). These benefits derive from the idea that consumers will make better choices (as measured by the efficiency of the resource allocation process) when the price of utility services reflects the cost of the next unit of production (i.e., the marginal cost of production). In the late 1970s, electric utilities undertook a massive research program to describe methods for applying the formal economic concept of marginal cost to electricity pricing (see National Economic Research Associates (NERA), 1977a).

The formal idea of avoided costs was created by the Public Utilities Regulatory Policies Act (PURPA), passed in 1978. Section 210 of PURPA called for a dramatic change in utility policies toward nonutility generators (Devine et al., 1987). The law required utilities to interconnect with unregulated renewable, waste, and cogeneration electricity generators on a nondiscriminatory basis and pay these providers on the basis of the generating costs that utilities were able to avoid by using the energy supplied by these non-utility producers. The rules promulgated by the Federal Energy Regulatory Commission (FERC) held that "...under the full avoided costs standard, the utilities' customers are kept whole, and pay the same rates as they would have paid had the utility not purchased energy and capacity from the qualifying facility (QF)" (FERC, 1981). Implementation of the FERC rules has typically led to the development of tariff-like payment schedules for the QFs (e.g., $/kWh or $/kW, on-, off-peak).

Avoided costs, as defined by FERC, differ from marginal costs in important ways. Marginal costs do not consider the size of the load over which changes in costs are measured. According to the economics literature, marginal costs technically refer to infinitesimal changes in costs associated with infinitesimal changes in production. In contrast, avoided costs require explicit consideration of the change in cost associated with a finite change in load (in this case, the utility load reduction represented by the output of the qualifying facility). Thus, while marginal costs depend only on the timing of loads, avoided costs depend on both the timing and magnitude of load changes.

When loads change, the optimal resource mix and its dispatch can be affected. In the short run, the capacity of the supply system is assumed to be fixed, so that changes in load only affect the dispatch of existing units. Differences between short-run avoided costs and short-run marginal costs can be significant, depending on the size of the load changes over which the cost changes are estimated and on the fuel mix of the generating system. In the long run, the capacity of the supply system is no longer fixed, and changes in load influence the timing and choice of future resource additions. Avoided costs can, in principle, capture short- and long-run changes in a manner consistent with the expected load impacts of the DSM resources under consideration.

In summary, avoided costs are a more comprehensive measure of the value of DSM resources because they can better account for the value of the load that will be avoided by the DSM resources under consideration. Short-run marginal costs, by definition, cannot account for the fact that the value to the utility system of the DSM resources depends on their size. In practice, the use of avoided costs will lead to increased accuracy in the DSM option screening process whenever the difference between short-run marginal and avoided costs is large, as measured by the differences in the amount of DSM resources that are economical under each set of costs. That is, the difference between short-run marginal and avoided costs will always increase as the size of DSM load impacts increases. However, the magnitude of these increases depends on the total size and cost of the DSM resource potential.

Short-Run Avoided Generation Costs

Estimating avoided generation costs for electricity requires distinguishing between the short run in which the capacity of the supply system is held fixed, and the long run, in which capacity is allowed to change. Economic theory holds that the short run and long run are equivalent in an equilibrium condition. However, because capacity is indivisible (i.e., new power plants are "lumpy"), this equivalence does not hold for the electricity industry (Andresson & Bohman, 1985).

In this section, we discuss various approaches for estimating short-run generation avoided costs, in which the supply system capacity is fixed. We follow conventional practice by distinguishing between avoided energy and avoided capacity costs. The approaches that we review for estimating avoided energy costs currently involve production cost models; we discuss some of the differences between methods by reference to the use of these models. Several modeling issues, which are generic to both short- and long-run generation cost methods, are discussed separately below.

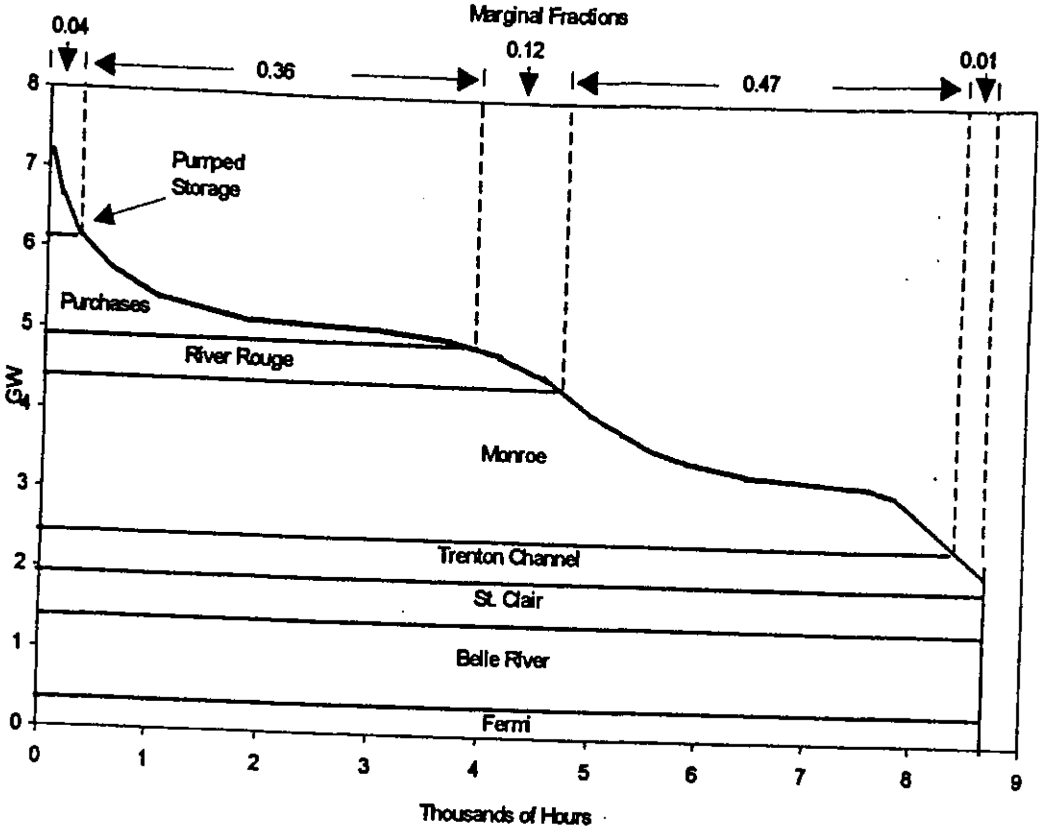

Figure 1. Fully dispatched load duration curve. Generating units are dispatched in merit order starting from lowest to highest variable cost. Units dispatched above the knee of the load duration curve are considered marginal. Marginal cost is estimated by calculated average operating cost of marginal units, weighted by percentage of time they are marginal.

Avoided Energy Costs

There are three short-run approaches to calculating avoided energy costs: instantaneous, increment/decrement, and QF (or DSM) in/out. Implementation of the methods is best depicted through the use of a load duration curve.[2] Under the load duration curve shown in Figure 1, electricity generating resources are dispatched in order, according to their technical and economic characteristics. This merit order fills under the load duration curve from the bottom with the least-variable-cost resources loaded first, and the highest-variable-cost resources loaded last. In general, baseload plants operate under the "knee" of the curve (i.e., up to the lowest load level shown at the extreme right in the load duration curve), while intermediate and peaking plants tend to operate above this point on the curve. These latter plants constitute the marginal plants in this system.

Instantaneous. The instantaneous approach considers what cost changes result from an infinitesimal change in load. In other words, avoided costs are set equal to short-run marginal energy costs. In Figure 1, we see that a small change in load

[2] A load duration curve is a rearrangement of a chronological load curve in which loads are re-sorted from the highest to the lowest load.

results in changes in electricity production from only the plants operating on the margin (i.e., above the "knee" of the load duration curve). The overall cost changes resulting from those production changes can be approximated as an average of the operating costs of the marginal plants weighted by the percent time each plant appears on the margin (as shown at the top of the figure).[3] Short-run marginal costs calculated in this way are often a standard output of utility production cost models. Customarily, they are based on a single production cost simulation of the base case supply plan, although arguments have been made in favor of basing them on a simulation of the plan that includes the alternative resource (in this case, DSM) (Parmesano, 1987). See discussion of in/out, below.

Because the instantaneous approach equates avoided cost with marginal cost, its appropriateness as a method for estimating avoided cost is questionable. That is, changes to the electricity system from alternative resources are not infinitesimal, as assumed in the definition of marginal cost, but finite. In this short-run framework the instantaneous approach will be most inaccurate either when there is a large gradient in costs at the margin or when relatively large perturbations in load are anticipated. The next two short-run methods avoid this limitation by using finite load changes to estimate cost impacts.

Increment/Decrement. Also known as the zero-intercept method, the increment/decrement method is a logical extension of the instantaneous method. It requires two simulations. In one simulation, load is incremented by a fixed amount. In the other simulation, load is decremented by the same amount. Avoided cost is calculated by dividing the difference in costs between the two simulations by the difference in energy. Thus, in contrast to the instantaneous method, the increment/decrement method measures cost changes by considering finite load changes about a base case set of loads.

In/Out. The in/out approach is a variant of the increment/decrement method and comes the closest to accurately estimating the likely cost consequences of a change in load resulting from DSM. Like increment/decrement, in/out uses two simulations and a finite load change. However, depending on the type of DSM, one simulation is either an increment (for DSM that builds load) or a decrement (for DSM that reduces load). In both cases, the second simulation is the base case. Thus, in/out gives an estimate of avoided energy cost from a discrete change in load *from* the base case, while increment/decrement gives an estimate of avoided energy cost *about* the base case. This is a subtle distinction, but it can produce different outcomes.

Because the in/out method is in principle the most accurate of the three given above for estimating the value of DSM to a utility system, we describe its operation step by step. Figure 2 shows a schematic load duration curve with generation resources (G_1, G_2, etc.) dispatched under the curve. This represents the "out" case. The dashed line represents the load duration curve of the "in" case, where DSM is expected to reduce loads the same amount in each hour (i.e., baseload DSM). The avoided production is the area between the solid and dashed curves. Avoided cost is the difference in production costs between the "in" and "out" cases, divided by the difference in loads.

[3] Bloom (1984) provides a formal definition of this intuitive description.

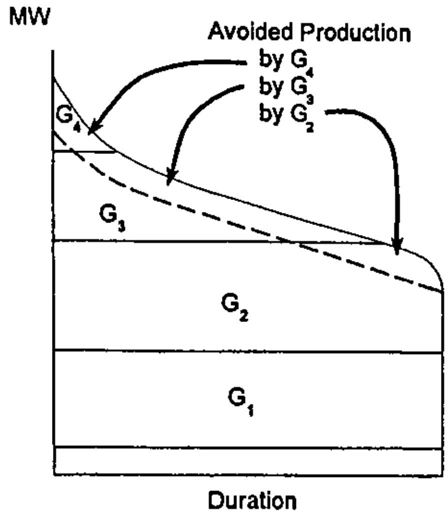

Figure 2. Schematic representation of the DSM in/out calculation. Two production cost simulations are run, one with a base case set of loads, one with loads decremented by the expected load impact of DSM. Avoided cost is calculated by dividing the difference in total production costs between the two runs by the difference in energy.

Figure 3 shows all three methods superimposed on the same load duration curve. Arrows point to the load representations used in the simulations that underlie each method. The three methods are most appropriate for different applications. The instantaneous method is the simplest and will be reasonably accurate when the DSM resources under consideration are small. The increment/

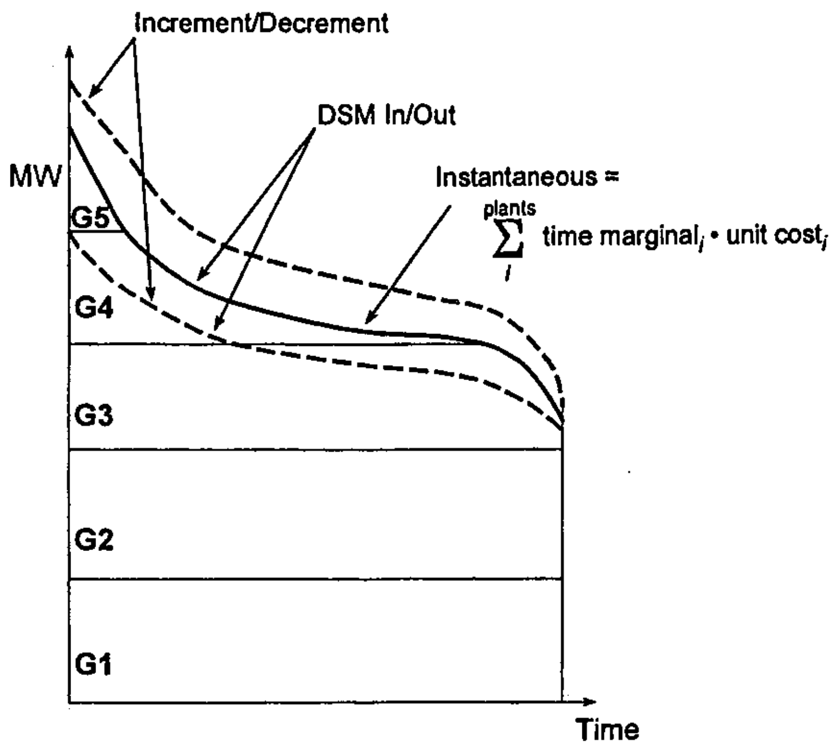

Figure 3. Schematic representation of the relationship between instantaneous, increment/decrement, and DSM in/out avoided cost calculations. Differences between methods depend on whether one (instantaneous) or more (increment/decrement and DSM in/out) production cost simulations are required to calculate avoided cost. Differences between methods requiring two simulations depend on whether load variations are considered about the base case (increment/decrement) or from the base case (DSM in/out).

decrement and in/out methods both require two simulations. Increment/decrement may be a reasonable compromise when both load-building and load-reducing DSM resources are being screened. In principle, in/out is the most accurate method in all cases. For both increment/decrement and in/out, care must be exercised to ensure that the load increments or decrements are consistent with the expected aggregate load impact of the DSM resources.

Avoided Capacity Costs

In contrast to avoided energy costs, avoided capacity costs are incurred to ensure 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 how reliable the system wishes to be. Generally speaking, if utility loads are reduced through a demand-side program, the utility can plan for smaller capacity reserves. However, controversy exists regarding the value of increased system reliability for utility systems with substantial excess capacity.

U.S. utilities traditionally plan for generation systems to experience outages no more than 1 day in 10 years. This target is a rule of thumb developed along with the use of increasingly sophisticated methods to probabilistically calculate a generating system's reliability.[4]

From a marginal-cost perspective, the least expensive short-run investment to increase the reliability of a power system is usually measured by the capital cost of a combustion turbine. It is important to recognize that this convention is frequently violated in practice,[5] and thus combustion turbine costs are more appropriately referred to as a proxy for the least expensive incremental addition to capacity to increase reliability (National Economic Research Associates, 1977b).

The appropriateness of the combustion turbine proxy has been questioned by some utilities with reserves in excess of their planning criteria (see, for example, Southern Company, 1991). They argue that excess capacity means that, in the short run (under 5 years, for example), no capital expenditure is required to increase the reliability of the system because the existing plant is underutilized.[6] Underlying this reasoning is an assumption of a defined level of reliability (e.g., 1 day in 10 years) that the system currently exceeds. California regulators, among others, have accepted these arguments and permit adjustments to the full value of the combustion turbine proxy based on 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

[4] In principle, the desired level of reliability is appropriately measured by customers' demand for uninterrupted electric service. The Pacific Gas and Electric Company (PG & E) (1991) has devoted considerable effort to estimating the value of service through surveys and experiments with customers. This pioneering work has not yet been widely incorporated into system planning.

[5] From an optimal generation expansion perspective, the marginal physical plant capacity that a demand-side program allows a utility to avoid may be a baseload power plant. This possibility dramatizes the importance of considering both long- and short-run avoided generation costs. See the following section.

[6] Some jurisdictions cite recent capacity transactions between utilities as *de facto* evidence of short-run capacity value and use them as the basis for avoided capacity costs (New York Public Service Commission (NYPSC), 1991). We take this issue up in Section 5 where we discuss market-based approaches to estimating avoided costs.

capacity costs. The details of the adjustment are quite technical, relying upon "expected unserved energy," which is another reliability index commonly calculated in planning models (PG & E, 1991).

Long-Run Avoided Generation Costs

In this section, we discuss approaches for estimating long-run avoided generation costs; the capacity of the power system is allowed to change in these approaches. In other words, both operating costs and capacity costs can change in response to the introduction of alternative resources. As a result, avoided generation energy and capacity costs are intertwined. For our purposes, they must be unbundled so we can estimate the value of resources with different energy and capacity impacts.

Methods for Calculating Long-Run Avoided Costs

We describe three methods for estimating long-run avoided costs: proxy embedded cost, proxy deferral, and differential revenue requirements. Each of these methods represents increasingly more involved approximations of the long-run change in supply system costs in response to load changes. The accuracy of these methods, in turn, depends on the representativeness of these approximations.

Proxy Embedded Cost. A proxy plant is a generating plant that represents the costs avoided when alternative resources are introduced. The proxy can be a plant just completed, one planned in the future, a hypothetical plant, or a composite of several plants. The analytical challenge is in choosing the proxy plant. Identifying an appropriate proxy plant is more art than science; the plant must closely match the size, duty cycle, and timing of the alternative resource under consideration. Otherwise, the proxy plant method itself is straightforward; it involves calculating busbar cost or some equivalent unit cost measure for the proxy and designating that cost as the avoided cost. The proxy embedded cost method implies that the alternative resource will completely displace the proxy and that this is the only cost change to the supply system as a result of the alternative resource. This assumption is rarely realized in practice.

Proxy Deferral. The proxy deferral method considers a more realistic situation in which the need for a particular new supply plant is delayed because of the introduction of a new resource. If the plant were not just deferred but canceled, this method would be equivalent to proxy embedded cost.

The proxy deferral method is based on an economic motivation for adding new resources. New resources are added when their introduction into the supply mix lowers operating costs sufficiently to offset the added cost associated with a new plant (otherwise, it would be cheaper to meet loads with the existing supply system). In the case of DSM, reduced loads lower operating costs because the most expensive plants operate less. When a new plant is deferred, operating costs rise for the opposite reason. The proxy deferral method seeks to find the introduction date for the new plant when these two effects cancel out one another. The value of the load reduction is expressed directly in the proxy deferral, which can be monetized as follows (adapted from Kahn, 1989).

Figure 4 illustrates the steps involved in valuing the proxy deferral. In the top panel the base case load forecast and supply plan are simulated, including the proxy plant addition. In the second panel the load forecast is reduced by the block of DSM resources, followed by the proxy deferral. The correct timing of the deferral is found when the present value of the stream of system operating costs over the study time horizon is equal between the deferred case and the base case. The bottom panel shows the base case loads simulated with the modified supply plan including the proxy deferral. The value of the deferral (and hence the avoided cost) is the difference in present value system operating costs between the base case (top frame) and the deferral case (bottom frame).

This method can be more complicated and subtle than our abstract description reveals. When load impacts are large, or the supply plan is growing rapidly in response to expected high load growth in the base case, it becomes necessary to choose multiple plants and deferral paths, which introduces complications such as

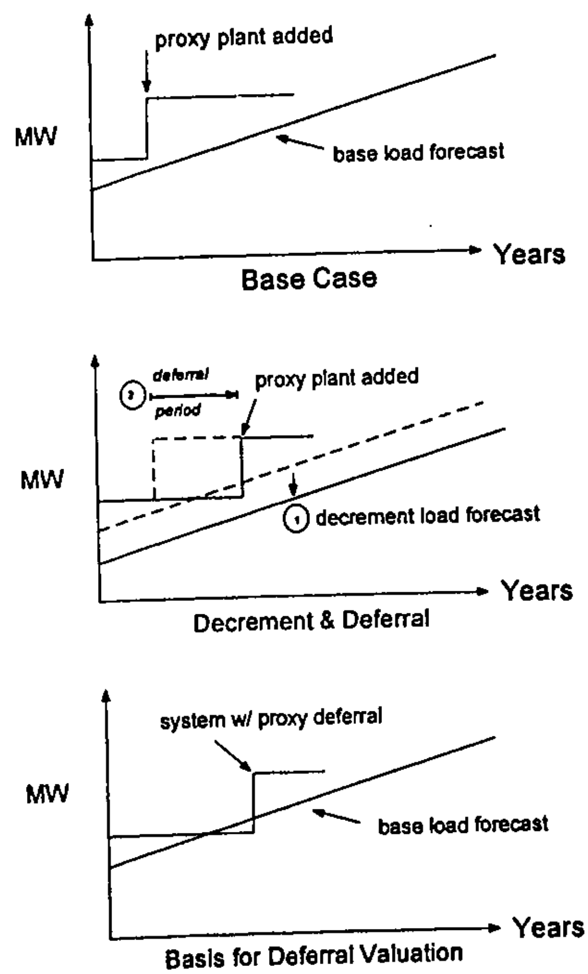

Figure 4. Proxy deferral method. The deferral period is determined by calculating the revenue-neutral period over which plant construction can be delayed due to a decrement in load from that assumed in a base case (not including DSM) supply plan. The value of deferral is measured by the difference in revenue requirements between the base case plan and the deferral case plan, altered to use the base case (rather than deferral case) load forecast.

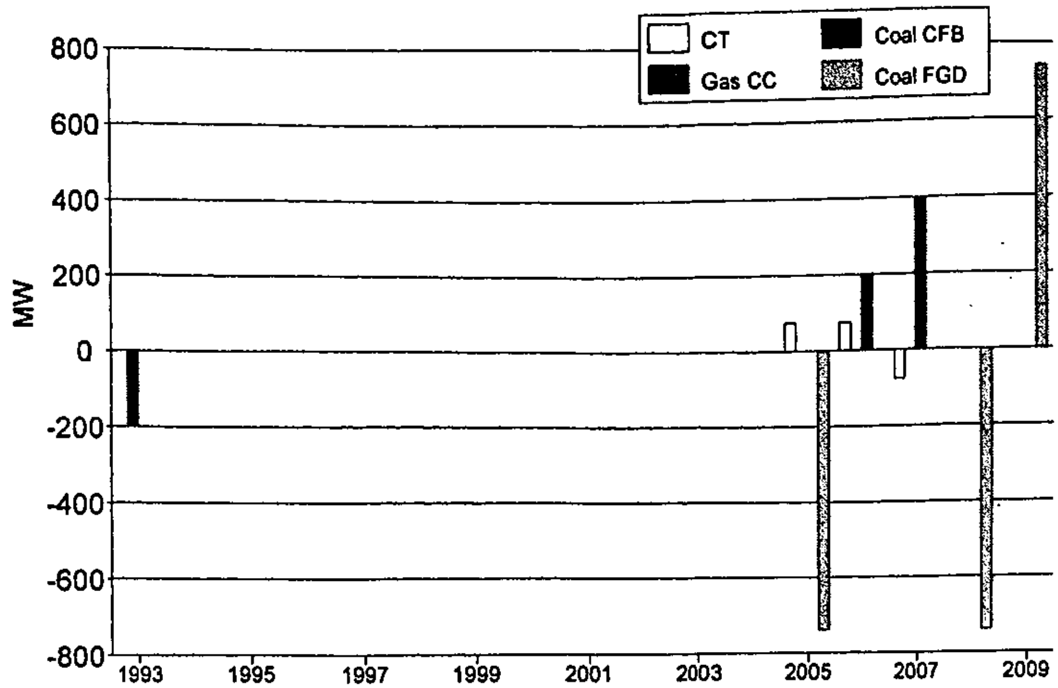

Figure 5. Net changes in capacity expansion due to a load decrement. Added units, indicated by type, are listed above the horizontal axis, while deleted units are indicated below the axis. This example shows that the effect of a load decrement is to change the timing, size, and type of a set of generating plants that were found to be optimal in a base case load forecast.

maintaining reliability equivalence among all simulations (Busch, 1992) and essentially amounts to manual optimization. The next long-run avoided cost technique addresses these limitations.

Differential Revenue Requirements. The method of differential revenue requirements (DRR) is the most computationally intensive and perhaps the most rigorous approach to calculating avoided cost. It involves an explicit reoptimization of the system when the alternative resource is added to the mix, and therefore, in principal, it most accurately captures the full cost implications of such a change.

A good example of the DRR approach comes from an avoided cost study conducted by the Virginia Electric and Power Company (1988). Although this example describes a supply-side resource avoided cost calculation, the approach is easily adaptable to demand-side resources. Virginia Power used the DRR approach for estimating avoided costs for capacity only, but the approach could be used for estimating avoided energy cost as well.

Using a capacity expansion model, two simulations were conducted: a base case and a case with an additional costless 200-MW generating resource. If the alternative resource is large enough, then significant differences in the type and timing of future resources may appear between the two cases. For Virginia Power, this was the case, as Figure 5 illustrates. The figure shows the net capacity expansion changes during the planning period in terms of MW of resources of various types added or removed in each year. Avoided capacity cost is then based on the cost differences of the net capacity changes. Specifically, avoided capacity cost, as calculated by Virginia Power, is the fixed portion of the net revenue requirements of the displaced units. Figure 6 shows the pattern of annual net revenue requirements during the planning period; the lumpiness of capacity additions and subtractions is apparent in large annual changes in revenue requirements and both positive and negative values. The second curve in Figure 6 is the translation of this stream of revenue requirements into a steady, increasing stream of equivalent present value. This latter curve is calculated using the economic carrying charge rate presented in the section below on valuing DSM programs with avoided costs.

Disaggregating Energy and Capacity Avoided Cost

In the example above, Virginia Power assumed that the fixed costs of resources are equivalent to their capacity value. This assumption ignores the fundamental rationale of substituting capital for energy that underlies the economics of baseload generation. For instance, the relatively higher capital intensity of coal or nuclear plants is typically justified on the basis of lower operating costs. Following the rationale presented earlier for developing short-run capacity value, it is common practice, consistent with marginal cost theory, to assign capacity value as the cost of a combustion turbine (CT), with the remainder of costs assigned to energy. This remainder above the cost of a CT is known as energy-related capital (Kahn, 1988).

Avoided Generation Cost Modeling Issues

This section provides a general overview of utility generation planning models and issues that arise when they are used in avoided cost procedures. Because electricity production is technically complicated, computer simulation models are required to gain meaningful insight into the process. Computer planning models are tradition-

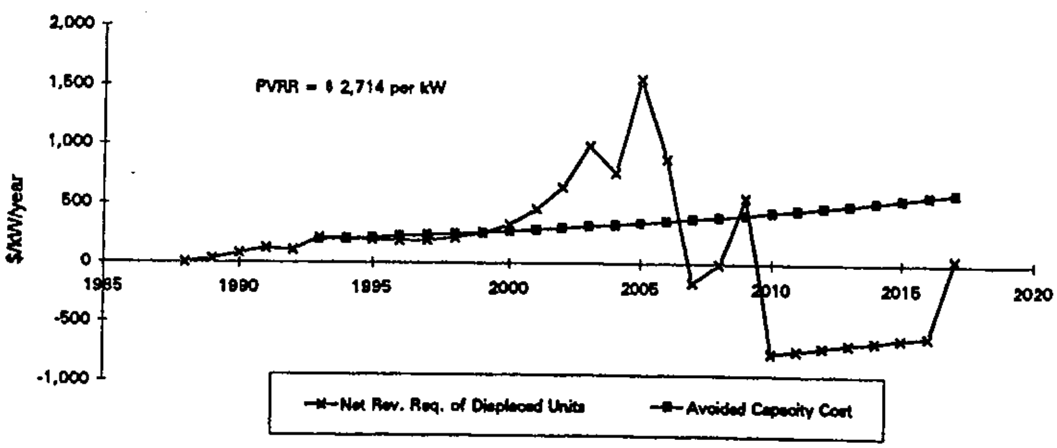

Figure 6. Translation of net revenue requirements of displaced and added generating units into a stream of avoided costs. The actual time pattern of revenue requirement changes depends on whether units are displaced or added. For planning purposes, it is useful to convert this pattern into a uniform stream of capacity values or payments. In this case, an economic carrying charge is used to ensure that the real escalation rate for the stream is zero (see section on valuing DSM programs with avoided costs for discussion of this levelization method).

Table 1
Model types and capabilities

Model type	Typical time horizon	Unit commitment representation	Outage treatment	Fixed cost treatment
Long-term optimization (e.g., EGEAS)	10–30 years	none	probabilistic convolution	integrated trade-off of many alternatives with dispatch effects
Production simulation: Load duration curve (e.g., PROMOD)	1–20 years	reserve margin heuristics	probabilistic convolution	none
Production simulation: Chronological (e.g., IRP Manager)	1 year	heuristic using minimum up/down times, ramp rates, spinning reserve	Monte Carlo	none
Unit commitment (e.g., benchmark)	1 week	optimized	none	none

ally used in the management function of electricity firms. As the industry has evolved, computer simulation models have assumed a greater role in the regulatory process. Nowhere is this more evident than in the calculation of avoided energy costs. Modeling issues related to short-run avoided energy costs have been the subject of extensive litigation because of their importance for QF pricing (Kahn, 1993).

Table 1 shows a typology of utility system planning simulation models used for calculating avoided cost (Kahn et al., 1990). Each type of model has certain advantages and disadvantages, reflecting trade-offs between level of detail and amount of computation necessary. The typology distinguishes among four kinds of models: long-term optimization (or capacity expansion), production simulation based on the load duration curve and chronological loads, and unit commitment. The defining characteristics of the models include the time horizons they are designed to cover (which is strongly linked to the kind of problem each was originally designed to address), and how unit commitment, forced outages, and fixed costs are handled by the model. Unit commitment and forced outages are real phenomena that are represented differently in different models; these differences strongly influence results.

The fundamental problem solved by long-term optimization models is how to determine the trade-off between fixed and variable costs of power plants. Optimization models are often used to study alternative capacity expansion plans. In order to reduce their run time, optimization models usually employ simplified production costing routines that ignore many operating constraints on the system.

Production simulation models are designed to study power system operation in the medium to long term. They typically incorporate many of the operating constraints of real systems. The major distinction among types of production simulation models is in how loads are represented; the load duration curve described earlier is the most commonly used approach. Chronological models can, in theory, better represent some operating constraints that are inherently chronological in nature, such as power plant ramping and minimum up and down times, or peak-shaving DSM, but at the cost of significantly greater computation and data requirements. Production simulation models of either type are used for fuel budgeting, contract evaluation, marginal costing, or evaluating a small number of resource alternatives.

Unit commitment models are the most detailed of the four types and most accurately represent operating constraints. Accordingly, the time horizon over which they are typically used is about 1 week. Unit commitment models are designed for operations planning and not for addressing other planning issues at the level where avoided cost pricing takes place (Jackups et al., 1988).

Kahn (1993) describes the controversy over the modeling conventions used to determine avoided costs for QF pricing in California. Here, the unit commitment feature of models and the way this feature is represented in the context of avoided cost analysis illustrate the impact of a fine delineation of operating conditions on the bottom line. The basic phenomenon underlying unit commitment is that thermal power plants need significant periods of time to warm up and cool down when cycling their operations. In order to meet high demands, thermal plants must often be kept running at some minimum level (i.e., committed) during low load conditions even though they are relatively inefficient at low output levels, and other resources would be cheaper to operate. Figure 7 depicts the supply and demand balance for an actual utility system during the course of a week. The upper curve shows the total nameplate capacity on-line, ready to meet loads at each point in time, while the lower line shows fluctuating demand. The amount of capacity on-line, especially during weekdays, is relatively insensitive to the daily load swings because of unit commitment.

The unit commitment constraint causes total system costs to be higher than they would otherwise be, and the constraint has particular influence on what happens at the margin. Because it forces more expensive generation lower in the loading order, less expensive generation is pushed up and operates a larger fraction of the time on the margin. This reduces the cost of generation at the margin even though total costs are higher. For similar reasons, unit commitment also reduces avoided energy costs.

In California this phenomenon has been the focus of extensive debate among QFs (who were receiving payments for their generation on the basis of administratively determined avoided energy costs) and utilities (who were paying those bills). Production simulation models based on the load duration curve were being used to estimate avoided energy costs. Disputes focused on how the models represented unit commitment and what particular inputs were assumed in applying those features. The standard for acceptable treatment of unit commitment in the models became increasingly stringent. Not surprisingly, the parties involved tended to promote the features and input parameters that furthered their own financial interests, which in this context amounted to tens of millions of dollars in utility payments to QFs, based on modeling results.

Table 2 shows a sample calculation of the effect of unit commitment on avoided energy cost. In this stylized version of the instantaneous method, we compare two simulations: one with and one without unit commitment. Comparing

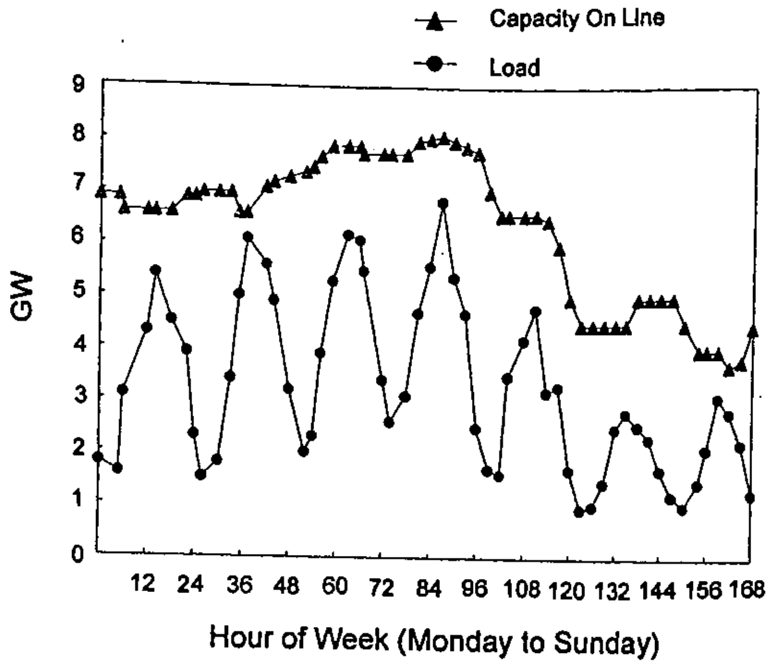

Figure 7. Comparison of the aggregate generating capability of on-line units to actual loads. For reliability purposes, excess capacity is always placed on-line as spinning reserve. Due to operating constraints related to time required to start and stop units, it may be economical to dispatch substantial excess capacity during low nighttime load periods in order to have sufficient capacity available on-line to meet high daytime loads.

Table 2
Sensitivity of avoided cost to unit commitment

Marginal unit	Time margin	Unit avoided cost @ \$3/MMBtu (¢/kWh)	Weighted average avoided cost (¢/kWh)	Energy revenues 50MW @ 90% CF (\$million)
		NO COMMITMENT		
G_2	0.2	×2.10		
G_3	0.65	×2.85	2.76	10.9
G_4	0.15	×3.30		
		COMMITMENT		
G_2	0.5	×2.10		
G_3	0.4	×2.85	2.52	9.9
G_4	0.1	×3.30		

these two simulations, we see that three generating units spend different amounts of time operating on the margin. Assuming all three units are fueled by natural gas at \$3/MMBtu and all have differing heat rates, the weighted average avoided energy cost is 9% lower in the unit commitment case. For a 50-MW QF operating at a 90% capacity factor, the difference is \$1 million in annual revenues. This example is hypothetical, but it highlights the fact that potentially large sums of money and important differences in allocation of resources can depend upon esoteric modeling questions underlying avoided cost estimates.

Unit commitment is by no means the only or even the most sensitive model parameter affecting avoided cost estimates. One particularly important parameter is the magnitude and shape of the alternative resource block in "in/out" or "increment/decrement" simulations. New York State's calculation of avoided costs presents a good example of the impacts from different assumptions of scale and load shapes of DSM programs (New York Power Pool, 1991). Figure 8 shows that increasing the size of the DSM resource blocks in 2000-MW increments reduces the associated avoided cost estimates for Consolidated Edison Co. Likewise, the figure shows the difference between the impacts on avoided cost of a rectangular or baseload-type load shape versus a proportional or peak-reduction-oriented load shape of the same magnitude. An interrelationship clearly exists between the amount and type of DSM resource that is assumed in the simulations and that which will be determined to be economical after DSM resources are screened using the resultant avoided costs. The equilibrium point is typically reached through iteration.

An often overlooked but fundamental assumption underlying all avoided cost estimation techniques is an optimal base case resource plan. That is, all methods

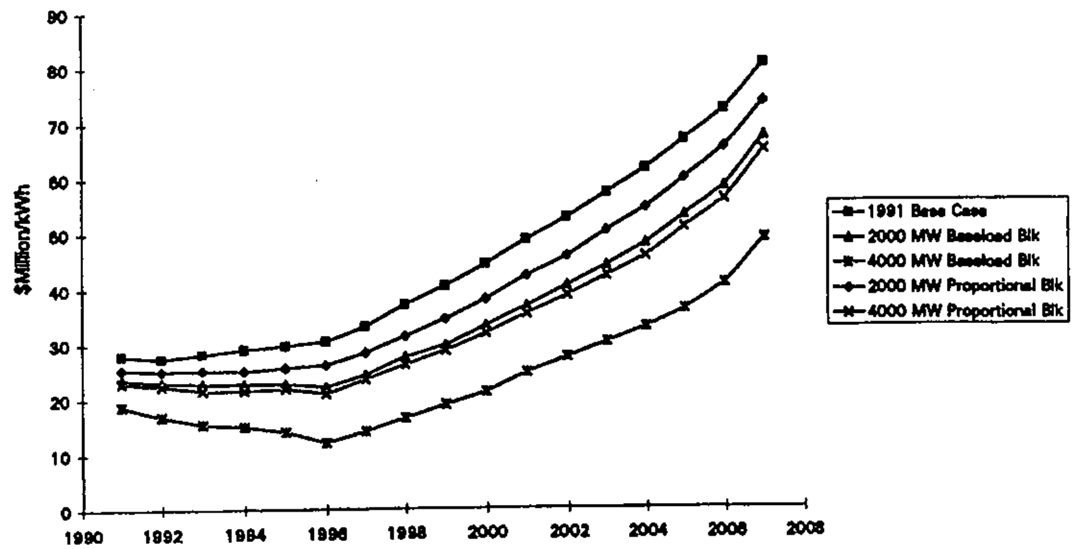

Figure 8. Avoided cost variations as a function of load decrement. Avoided costs depend on the size and shape of the load decrement considered. In this example from the Consolidated Edison Company, load decrements of baseload and proportional load shapes at 2000 and 4000 MW and were evaluated over time. The results show the characteristic reduction in avoided costs associated with increasing load decrements, as well as the greater reduction in avoided costs associated with baseload over proportional load shapes at a given decrement level.

rely upon a base case that is optimal in the sense that the mix and timing of future supply-side resources are well matched to the expected load. It is axiomatic that any avoided costs calculated on the basis of a suboptimal resource plan will differ from the true costs.

Market-Based Approaches

Market-based methods are emerging as an alternative to administratively determined avoided costs. Proponents of competitive processes in the electric utility industry argue that market forces are the best means of determining resource value. Market-based avoided costs allow us to "cross-check" avoided costs determined using "administrative" methods (such as in/out and proxy deferral). In other words, market-based avoided costs can provide a useful feedback on the administratively determined avoided costs typically used in competitive resource solicitations. Competitively determined avoided costs are not inherently short run or long run, although they tend to be most closely related to the proxy embedded cost approach, with the proxy being a competitively procured resource. While market-determined avoided costing has intuitive appeal and sounds simple, it presents many theoretical and practical questions. Unbundling is a key challenge, along with reconciling the many nonprice attributes of electricity resources that ultimately have economic value.

In New York, market prices of new generation were used to develop avoided costs (New York Power Pool, 1991). Many issues were considered to develop a methodology for utilizing competitive bidding data from the state's electric utilities; issues included (1) whether to use winning bids only or include losing bids as well, (2) how to synthesize the information from multiple bids coming from different solicitations, (3) whether to include DSM bidding information in the process, (4) whether to distinguish among bids for different types of plants (i.e., baseload versus peaking), (5) whether any adjustments to prices as bid were warranted, given that bids may reflect financing considerations or strategic bid scoring more than market equilibrium prices, and (6) whether current bids could be relied upon to represent future market conditions, especially technological change, fuel prices, and environmental and siting requirements.

The method finally adopted in New York was a hybrid of market-based and administratively determined methods. New York broke the study time frame into two periods: prior to and after the "need date" for new generation. Prior to the need date, avoided energy cost was determined using the increment/decrement method, and avoided capacity cost was based on historical transactions for off-system capacity. After the need date, data from baseload-type supply bids were used to establish total avoided cost, with CT proxy plant data used to disaggregate capacity and energy components from the total. New York chose to average the prices of the nine winning baseload bids rather than choosing either the most or least expensive plant among them as representative of avoided cost. Although bid data existed for peaking-type plants, participants felt they had too few reliable bids on which to base the avoided cost methodology.

Claiming insurmountable methodological complications, New York chose not to employ DSM bids in calculating a market-based avoided cost. The reasons given were that (1) several utilities placed a price cap on DSM bids, (2) current DSM bid prices might not represent the marginal cost of future DSM because of the sensitivity of DSM costs to penetration levels, and (3) DSM provides more than capacity and energy value, but there is no established principle for disaggregating these additional components (see section below on avoided costs unique to DSM) from a single DSM price (NYPSC, 1991).

As the electricity industry restructures and becomes more competitive, market-based avoided cost methods will undoubtedly become more prevalent. However, administratively determined avoided costs will still play a role in establishing a "reservation price" that can discourage noncompetitive pricing behavior.

Avoided Generation Cost Methods Compared

There is no ideal method for estimating avoided generation costs; each method has its strengths and weaknesses. Different approaches will be appropriate to different situations. Below we describe in very broad terms the pros and cons of methods drawn from the literature, anecdotal evidence, and our own experience.

- The principal advantage of the short-run methods is the ease with which time differentiation can be accomplished because of their reliance on production cost simulation models. Fluctuations in value for both energy and capacity can be distinguished down to an hourly time step. The main disadvantage of short-run methods is the difficulty in establishing the boundary between the short run and the long run. In particular, these methods may be inappropriate for evaluating large perturbations to the base case, as when large DSM programs are under consideration.
- Proxy methods have transparency and simplicity as their main advantage (Yokell & Marcus, 1984). The embedded cost approach does not even require the use of utility computer planning models, although this advantage is waning as computer hardware and software evolve and become common. The difficulties of proxy methods are the decisions about the type and timing of the proxy plant (Kroll & Rosen, 1994; Parmesano, 1987). With the embedded cost method, in particular, an additional disadvantage is that system impacts of load changes are ignored. With the deferral method in particular, the advantage of valuing systemic structural change by instituting the proxy deferral involves significant increases in the time and effort spent on computation.
- The differential revenue requirements method is intuitively appealing because it explicitly recognizes the need to reoptimize a system in response to large load changes. This method acknowledges that the type and timing of new resources may be significantly different between the base and decrement cases, and avoided costs reflect the cost implications. Because each case is optimized with respect to fixed and variable costs of future resources, this method also appears to be more accurate than the others. The main disadvantage (and the reason that its accuracy may only be apparent) is that the optimization models are extremely complex and challenging to master. Even more than production cost models, they have a certain mysterious, "black box" quality that makes oversight of their use in regulatory contexts difficult.
- Market-based methods have the advantage of potentially reflecting economic efficiencies of competition (as opposed to planning and regulatory outcomes

that the other methods approximate). However, these methods generally share with the embedded proxy method the disadvantage of not capturing the impacts of a particular resource (i.e., the proxy or the market-based unit) on the rest of the utility system.

Table 3 summarizes these broad comparisons.

To provide a sense of how the different methodologies compare quantitatively, in Table 4 we present results from estimates using the instantaneous, DSM in/out, and proxy deferral methods. All estimates are drawn from the same hypothetical utility system, loosely based on a New England utility, simulated using the IRP-Manager integrated planning model. Avoided costs derive from a DSM load decrement that is 10% of the base case system loads with the same load factor. In this stylized example, only 5 years of annual results are compared.

Annual average instantaneous marginal cost for the base case and the DSM "in" case are shown in Table 4. The marginal costs from the DSM case are lower than those from the base case because the DSM case allows cheaper generation to operate on the margin. The results for DSM in/out and proxy deferral, shown in Table 4, are functionally identical except for the first 2-year period during which a supply resource was deferred in the proxy deferral case, which raised costs because more expensive generation was used in its absence. DSM in/out and proxy deferral avoided costs are higher than instantaneous avoided costs in part because operating constraints, such as unit commitment, raise costs in the in/out and proxy deferral methods, which rely upon cost differences between two simulations.

These stylized results are not definitive; they merely illustrate that choosing a particular avoided cost methodology can influence the bottom line, in addition to having theoretical and practical implications.

Avoided Costs Unique to DSM

In this section, we review progress in estimating nongeneration avoided cost components that apply to demand-side management resources. Historically, avoided generation energy and capacity costs have received most of the attention because they typically represent 60–70% of electricity costs. However, as utilities and public

Table 3
Pros and cons of avoided cost methods

Method	Pros	Cons
SRMC	ease of time differentiation	short-run vs. long-run controversy
Proxy	transparent	type and timing of proxy controversial
DRR	intuitively appealing apparent accuracy	black box, computationally intensive
Market	reflects economic efficiencies of competition	system costs not captured

SRMC, short-run marginal cost; DRR, differential revenue requirements.

Table 4
Illustrative comparison of avoided costing results (¢/kWh)

Year	Instantaneous		DSM in/out	Proxy deferral
	Base Case	DSM Case		
1998	4.1	3.7	4.7	5.0
1999	4.4	4.1	5.1	5.4
2000	4.8	4.4	5.6	5.6
2001	5.3	4.8	6.1	6.1
2002	5.8	5.3	6.7	6.7

utility commissions (PUCs) have gained experience, avoided costing has become more sophisticated, and includes other cost components. These additional cost components can equal or exceed avoided generation costs and so substantially increase the value of DSM programs compared to supply alternatives.

Avoided Reserve Margin Capacity Requirements

Electric power systems are designed with capacity in excess of loads to allow for unplanned outages of supply resources. Demand resources are not as unreliable as supply resources. Therefore, DSM should be credited for saving unneeded reserve capacity as well as unneeded actual generating capacity. Any uncertainties in the DSM resource estimate should also be taken into account.

Avoided reserve margin is based on the reserve margin (expressed as a percentage of peak load) that met reliability planning criteria in the base case. Avoided reserve margin is expressed on a per-unit capacity basis.

Avoided Transmission and Distribution Energy Costs

Losses occur in moving electricity from point of production to point of use. DSM can avoid these transmission and distribution (T & D) losses. Loads connected at the distribution level generally experience greater losses than those connected at the transmission level. Avoided energy costs should be increased by the amount of the appropriate T & D losses, depending on where the load connects to the T & D grid; these losses are usually expressed as a percentage of total generation. Avoided T & D losses are expressed on a per-unit energy basis.

Avoided Transmission and Distribution Capacity Costs

For many U.S. utilities with excess capacity, expenditures for T & D capacity are substantially higher than those for generation capacity. Like investment for new generation, load growth drives investment for T & D. DSM targeted to areas where new T & D projects are planned could defer or cancel them (Energy and Environmental Economics (EEE) and PG & E, 1992).

In the past, techniques for estimating marginal T & D investment relied on regression techniques using historical expenses and corresponding load increases on a systemwide basis (NERA, 1977b). However, the relevant annual increases in load used for analyzing avoided transmission or distribution investment tend not to be annual increases in system peak loads. As a general rule, the closer an analysis gets to the end uses of power, the more important it becomes to consider noncoincident loads.

Other problems with the regression technique are that it does not recognize the geographic specificity and "lumpy" nature of T & D investments, the timing interactions between DSM and T & D investments, or the particular planning process of the utility (Williams, 1994). T & D marginal costing methodologies have evolved to try to address these shortcomings (Orans et al., 1994). Application of a method by PG & E, which values the cost of deferring planned capital expenditures for T & D resulting from a change in load (expressed on a per-unit capacity basis), yielded a wide range of marginal T & D costs among 200 distribution planning areas, from $0/kW-year (where no load growth was expected) to $200/kW-year, as shown in Figure 9 (Williams, 1994). These costs, when aggregated into 13 planning divisions, still differed in magnitude by a factor of 2.

Avoided Externalities

Externalities are any costs associated with the consumption of a product or service that are not reflected in the price. In the electricity industry, environmental externalities have received considerable recent attention, particularly for air emissions of generating stations (Office of Technology Assessment, 1994; ECO Northwest, 1993). In spite of federal, state, and local regulation of power plant air emissions, they remain a significant contributor to acid rain, smog, and greenhouse gases. Several state PUCs have instituted or considered rules requiring utilities to explicitly account for the costs of residual emissions (Fang & Galen, 1994).

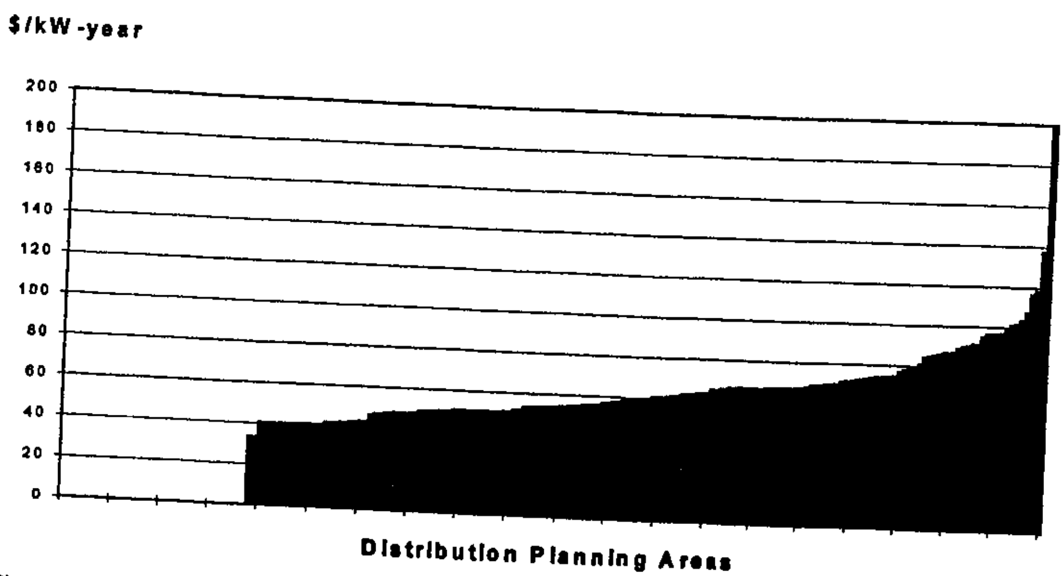

Figure 9. Cost of distribution capacity. Unlike supply alternatives, DSM can offset distribution system reinforcements; however, the need for these reinforcements varies within the service territory. In this example from the Pacific Gas and Electric Company, avoided distribution capacity costs from 201 distribution planning areas are ranked from lowest to highest, ranging from $0/kW where there is substantial distribution capacity, to nearly $200/kW where reinforcements are imminent.

Environmental externality costs can be incorporated into resource decision making as a qualitative or quantitative factor. They can only be incorporated into avoided costs when they are quantified. However, current estimates are controversial, and the range of estimates in the literature for a given externality is large. Quantification techniques include percentage and monetized adders to the costs of resources where the latter are based on estimates of damage or control costs of specific pollutants on a per-unit basis.

To the extent that DSM programs avoid generation, they will also avoid the environmental by-products of generation. When quantified, these costs can be added to avoided energy costs used in DSM resource evaluation. The simplest approach to estimating avoided emissions is to multiply the system average emissions of a given pollutant per unit output by the generation savings. A more precise approach would use the capability of production simulation models to compare the emission changes directly with and without the DSM. Either way, the emissions reductions resulting from a load decrease are multiplied by their corresponding monetized adders and summed over all criteria pollutants to arrive at the total avoided environmental externality cost (expressed on a per-unit energy basis).

Valuing DSM Programs with Avoided Costs

In this section, we discuss the transformation of avoided costs into tariff-like schedules that make DSM resource evaluations more manageable. The task consists of disaggregating avoided costs along several dimensions of space and time, resulting in a schedule of avoided costs (e.g., $/kWh or $/kW, on-, off-peak). The value of a demand-side program is measured simply by multiplying the appropriately aggregated load shape change by its value.

The spatial dimension is most easily addressed through application of avoided T & D costs described in the previous section. 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 usual case, however, we need to evaluate programs with very different load shape impacts, all of which have different lifetimes, so substantial disaggregation is necessary if we are to use the avoided costs meaningfully. It is useful to distinguish between methods for disaggregation *across* years from disaggregation *within* a given year.

Ensuring consistency between the life expectancy of DSM resources and avoided costs across years is the logical first level of disaggregation. The goal is to re-express avoided costs that span years as annualized values, so we can evaluate programs whose lifetimes (and beginning dates) do not coincide with the assumptions used to develop the avoided cost.

Two methods are widely used to annualize multiyear 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" the stream of benefits; the bulk of

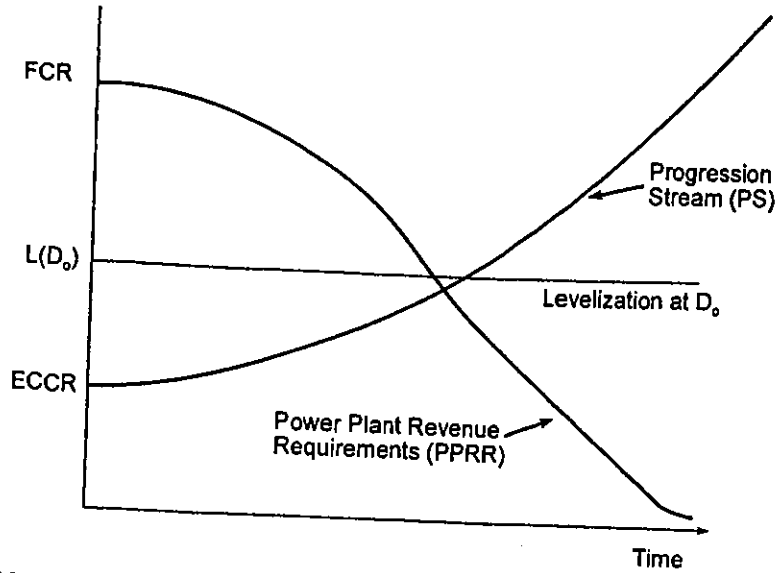

Figure 10. Alternative patterns for allocating capital costs over time. Three progression streams of equivalent present value are shown. The economic carrying charge rate (ECCR) produces a stream of payments that increase at a constant rate. This is compared to the traditional rate-basing approach based on declining revenue requirements over time and the fixed charge rate (FCR), as well as levelized payments.

the present value is received in the first half of the investment lifetime, resulting from the effects of a positive discount rate.[7]

The second method holds the real worth of the annual values fixed with respect to inflation. Thus, if we assume some positive rate of inflation, the present value is spread in an ever-escalating stream of nominal dollars over time. Because the real value for each year is identical, this method avoids the front-loading feature of the levelization method.[8]

Figure 10 illustrates the relationship between levelization and the use of an ECCR 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, disaggregation could extend to each hour of the year; in practice, this is rarely necessary and seldom worth the additional effort.

The most important criteria for choosing a disaggregation method considers how reliable is the disaggregation that takes place in the estimation of demand-side program impacts, and how variable is the supply system cost structure. Many of the principles involved are well established from the literature on traditional rate-making practices (National Association of Regulatory Utility Commissioners (NARUC), 1992). Disaggregation techniques differ somewhat for 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

[7] Formulas for levelization can be found in the Electric Power Research Institute (EPRI) (1991) guide.

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

day, or on-peak versus off-peak energy use. Beyond these minimum levels of disaggregation, the analyst is generally limited 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 result from the need to combine varying degrees of coincident and noncoincident demand. In this discussion, we consider only 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 measurement issue tends to reduce the importance of determining an exact coincidence factor. The advent of probabilistic reliability indices,[9] such as loss-of-load probability (LOLP) and expected unserved 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 in creating a tariff-like schedule is incorporating the additional avoided cost components for DSM. In most cases, an annual average will be accurate enough to characterize avoided energy cost for T & D and, to a lesser extent, avoided environmental externalities. Values that are more time differentiated are usually required for avoided reserve margin capacity and T & D capacity costs.

Summary

The need for calculating avoided costs for DSM resource planning arises because traditional resource planning approaches were originally developed to evaluate alternative utility-owned supply options. These approaches suppressed many aspects of a utility's cost structure because the resource alternatives being compared were relatively small in number and large in size. With the advent of integrated resource planning, a broader spectrum of resource options, including those on the demand side, must be considered. Avoided costs are a useful approach for analyzing demand-side resource options because they can account for the likely load impacts of DSM in a systematic fashion. Marginal costs, often used as an alternative to avoided costs, are inherently incapable of measuring the value of large-scale DSM resources. Thus, using avoided costs increases the accuracy of the planning process.

Procedures for estimating generation-related avoided costs for DSM resource planning are based on methods developed originally to establish payments for purchases from nonutility power producers. These methods rely on complicated

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

computer simulations of utility operation and have undergone considerable refinement since the avoided cost concept was first introduced in the late 1970s. More recently, market-based approaches have emerged as an alternative to administrative determination of these costs. The critical issue is ensuring that the load impacts used to estimate avoided costs are consistent with those expected of the DSM resources.

DSM resource planning also requires analysts to consider additional nongeneration capital and operating costs avoided by DSM resource options, such as reserve margin capacity requirements, T & D losses and investments, and environmental externalities. These costs can easily exceed generation-related avoided costs, so their omission from the avoided costs used in a DSM planning process can dramatically understate the system value of DSM resources.

As long as utilities actively engage in resource planning, avoided costs will play an important role in assessing all resource alternatives, not just those on the demand side. That is, for any resource acquisition process, using either competitive solicitations or other approaches, avoided costs are the reservation price against which the reasonableness of alternatives is judged.

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