A New Utility DSM Strategy Using Intensive Campaigns Based on Area-Specific Costs

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SYNOPSIS

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1. ABSTRACT

This paper describes a utility demand-side management (DSM) strategy, built on intensive campaigns with limited geographical coverage, rather than conventional DSM programs with broad coverage but modest impact. Recent analytic advances in accurately determining utilities' area-specific costs have important implications for DSM design. Unlike the system-level utility costs, which are most sensitive to costs of generation and bulk transmission costs, area-specific costs depend most on distribution and local transmission costs. For utilities with relatively slow total load growth, the latter costs can represent a large share of their current investment needs. If utilities know what their area-specific costs are, they will know where and when their costs are significantly higher than the system average. The timing is important, because costs must be forward-looking: once costs are sunk, the opportunities to reduce or defer them are lost. Thus, high-cost areas move around in space and time.

Higher costs mean higher avoided costs for DSM, allowing more expensive measures and therefore larger energy and demand savings to be cost-effective. These high cost areas justify intensive DSM investments - "blitz" programs to capture a large energy-saving fraction - in certain places at certain times. With area-specific cost information available, an improed DSM strategy can expoit these opportunities fully where and when they occur, rather than doing broad-based programs that achieve small savings and low participation rates. After doing a "blitz" in one target area, one can identify different areas to "blitz" later. This DSM strategy gives large savings per customer, and large participation rates in the target areas, thus large total savings in that area. This strategy is also shown to be more promising than the conventional approach for maintaining incentives for DSM under utility deregulation.

2. INTRODUCTION

One of the problems with most utility-sponsored demand-side management (DSM) programs is that they are designed to cover a large share of the eligible customers, resulting in low participation rates, low energy-savings per customer and high administrative costs. Loan programs have often been disappointing, as relatively low numbers of customers are typically willing to take on debt in order to save energy. Rebate programs, although more reliable than loan programs, do not provide the utility with direct control over the level of energy or peak demand savings, and these programs sometimes suffer from high administrative costs, especially in the residential sector (see, for example, Nadel 1992).

This paper describes a utility DSM strategy, built on intensive campaigns with limited geographical coverage, rather than conventional DSM programs with broad coverage but modest impact. The rationale for such a strategy is that some geographical areas within a utility's service territory are more expensive to serve than others. This means that DSM programs in some areas have higher avoided costs and therefore higher cost-effectiveness thresholds compared to other areas, and compared to the system average. Although utility DSM has been implemented mostly in North America, and the examples given in this paper are from US utilities, the methods we use and the implications of our results can be applied more generally, in particular to utility systems introducing deregulation and competition.

Recent analytic advances in accurately determining utilities' area-specific costs therefore have important implications for DSM design. The key difference compared to traditional utility costing practice is to apply area- and time-specific marginal costs (ATSMC), rather than system-average marginal capacity costs (MCC) and marginal energy costs (MEC) to determine the avoided cost for a DSM program or distributed supply resource. This area-specific costing work allows the precise targeting of programs in areas where the avoided costs are relatively high.

It may seem curious that utilities do not already have a very detailed understanding of ATSMC analysis. However, for several reasons, in the past utilities have had little use for such information, which is very data-intensive and analytically demanding to obtain. First, distribution and local transmission costs were small compared generation and bulk transmission costs, and were viewed as unavoidable components in the expansion of the generation network, the cost of which drove other system costs. Second, utilities have generally been prevented from using differential rates among their customers, even though this practice would be economically efficient when the cost of service varies across customers. Finally, the powerful economies of scale that reduced generating costs steadily until about 1970 focused utility planning methods and decisions on large central generation (see Hyman 1988).

In recent years, however, most of these conditions have changed, making ATSMC information increasingly relevant and useful in utility planning. Transmission and especially distribution costs are becoming a more important component of utility costs. Deregulation is making it more feasible (although no more equitable) to apply differential rates across customers, making ATSMC estimates useful in pricing.

Perhaps most importantly, the economies of scale that previously characterized generation technology have been eroded severely. Decentralized options, including DSM technologies for energy efficiency and load management, as well as smaller-scale gas-fired and renewable generation technologies, are now becoming cost-effective alternatives. In addition, the trend toward deregulation will tend to accentuate the advantages of decentralized resources by shortening the time-horizon for planning and increasing the risk of large stranded investments in supply capacity (Swisher 1994a; Wiel 1994).

3. AREA- AND TIME-SPECIFIC UTILITY COSTING

Unlike the system-level utility costs, which are most sensitive to costs of generation and bulk transmission costs, area-specific costs largely depend on distribution and local transmission capacity costs. A simple expression for a utility's marginal costs, and therefore the avoided cost for a DSM program or distributed supply resource, is:

$$\text{ATSMC} = \text{MEC dkWh} / \text{crf} + \text{MCC dkWsys} + \text{MDCC dkWarea} \qquad [1]$$

where: MEC = marginal energy cost (depends on amount of system-wide energy reduction)
MCC = marginal system-level capacity cost (depends on system expansion plan)
MDCC = marginal distribution capacity cost (depends on local area expansion plan)
dkWarea = savings in distribution capacity (depends on time of area peak demand)
dkWsys = savings in system-level capacity (depends on time of system peak demand)
dkWh = savings in annual energy use (depends on load-factor of affected end-use)
crf = capital recovery factor (depends on discount rate and amortization time)

In practice, each of the terms in Equation 1 is evaluated for each hour of the year, and the results are summed to estimate the full marginal costs. The first two terms in Equation 1 are familiar components of a system-level avoided energy- and capacity-cost calculation. These cost components are usually determined by production-cost models that minimize variable operating costs by optimal dispatch of generating sources, subject to accepted system reliability criteria. A common reliability criterion is the maximum annual loss-of-load probability (LOLP) (Crane and Roy 1992).

For a given level of kW of load reduction, the avoided marginal energy cost depends on the usage hours or load-factor of the affected end-use, and on the amount of system-wide load reduction. Once the most expensive marginal supplies are removed or deferred, the marginal cost savings of additional DSM or other load reductions are diminished (see, for example, Swisher 1991). Hourly marginal energy costs come directly from production-cost models and are adjusted upward to account for transmission losses.

The avoided marginal system-level capacity cost depends on the coincidence of the load reduction with the time of system peak demands, and on the time-proximity of investments in generation and transmission capacity expansion. The need for imminent expansion tends to increase the marginal capacity costs. Thus, even conventionally-defined marginal capacity costs are time-specific, but they are not area-specific, except to the extent that local load profiles are different (for example, due to a different climate) from the rest of the system. The annual capacity cost is allocated to each hour of the year according to the hourly contribution to the annual LOLP (Vardi 1977).

In addition to the system-level energy costs and (generation and transmission) capacity costs, the ATSMC includes the area- and time-specific value of the marginal costs of distribution and local transmission capacity (MDCC).

Estimating the MDCC requires the development of the local distribution supply and expansion plan. To develop such a distribution plan, utility planners evaluate each area's future load growth and related investments in capacity expansion. Because distribution planning is performed on a rather ad hoc basis, some utilities do not even have their planning areas clearly defined.

An area-specific distribution supply plan is developed using the following steps: (1) subtract present load from present area capacity to determine excess capacity, (2) divide excess capacity by the area's forecasted annual load growth to determine the time when present capacity will be exceeded, (3) prepare a least-cost capacity expansion plan to satisfy the forecasted load growth under accepted engineering reliability criteria. A common approach is to use two contingency security criteria (Crane and Roy 1992). The normal criterion is that forecasted loads can be met without overloading any facility in the system, and the emergency criterion is that the failure of any facility can be compensated by other facilities without exceeding their emergency capacity for a limited time. The expansion plan includes the required timing and mix of investments in poles, conductors, substations, etc. The schedule of these investments provide the cost data from which the MDCC can be estimated.

Economically meaningful estimates of MDCC require a costing method that captures the area- and time-specific nature of distribution investments, which are inherently "lumpy," in that they come in only a limited range of discreet sizes. Transformers, for example, typically have 10, 25, 37,5, 100, 176, 250, 333 or 500 kVA capacity (Pansini 1992). The appropriate method uses a present-worth approach, which determines the value of deferring a local expansion plan for a given time period (see Orans 1989). A one-year deferral value equals the difference between the present value of the expansion plan and the present value of the expansion plan deferred one year, adjusted for inflation and technological progress. The value of deferring capacity for s years is:

$$\text{and } MDCC = s \underset{t}{[\, K_t / (1+r)^t \,]} - s \underset{t}{[\, K_t (1+i)^s / (1+r)^{t+s} \,]} \qquad [2]$$

where: K_t = investment in year t
- i = inflation rate net of technological progress
- r = utility's weighted-average cost of capital
- s = (peak load reduction) / (annual load growth)

The MDCC varies by area because the method is applied at the local level to individual area-specific distribution supply plans, which can include a wide divergence of distribution investments by area and time (Woo et al 1994). The time variation arises because the present-worth approach is forward-looking, i.e. it ignores past investments and applies a high value to imminent investments needed to prevent an approaching capacity shortage. Once an investment is in place and its cost is sunk, the resulting excess capacity pushes future investments farther away on the planning time-horizon, and the present worth approach gives a marginal capacity cost of almost zero.

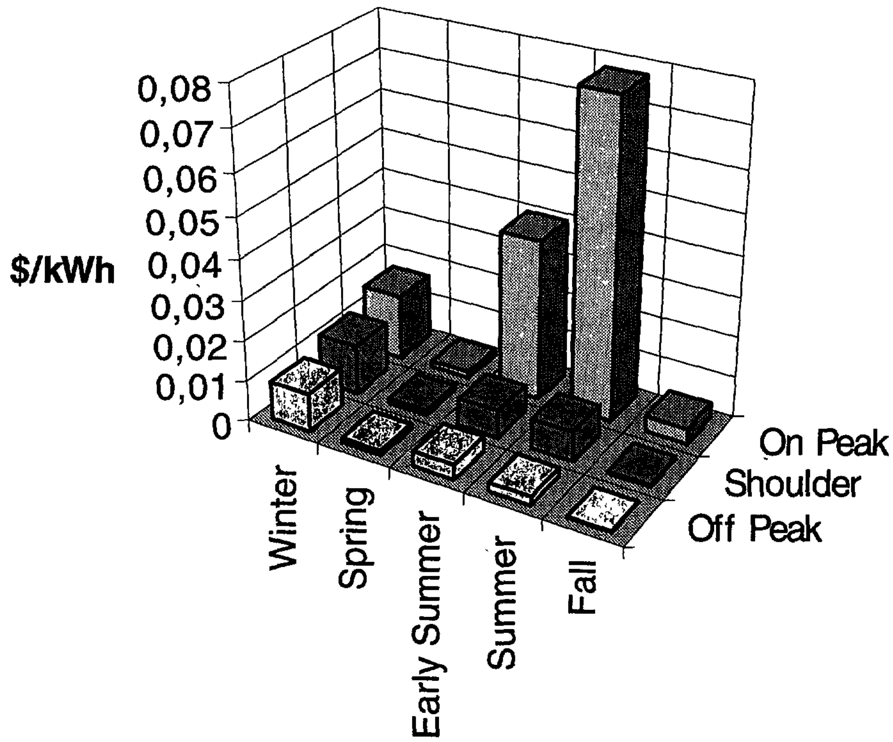
The MDCC is usually allocated to the 60-100 hours per year of maximum area-specific demand, which are the hours that influence the distribution capacity. It is important to note that the need for distribution supply expansion, and thus the MDCC, is driven by the area-specific demand peak, rather than the system-wide peak. These two peaks are often highly coincident, but they can also occur at different times or even different seasons. This type of divergence would indicate that different types of DSM programs, especially those involving load management, would be encouraged more by ATSMC methods than by traditional costing methods.

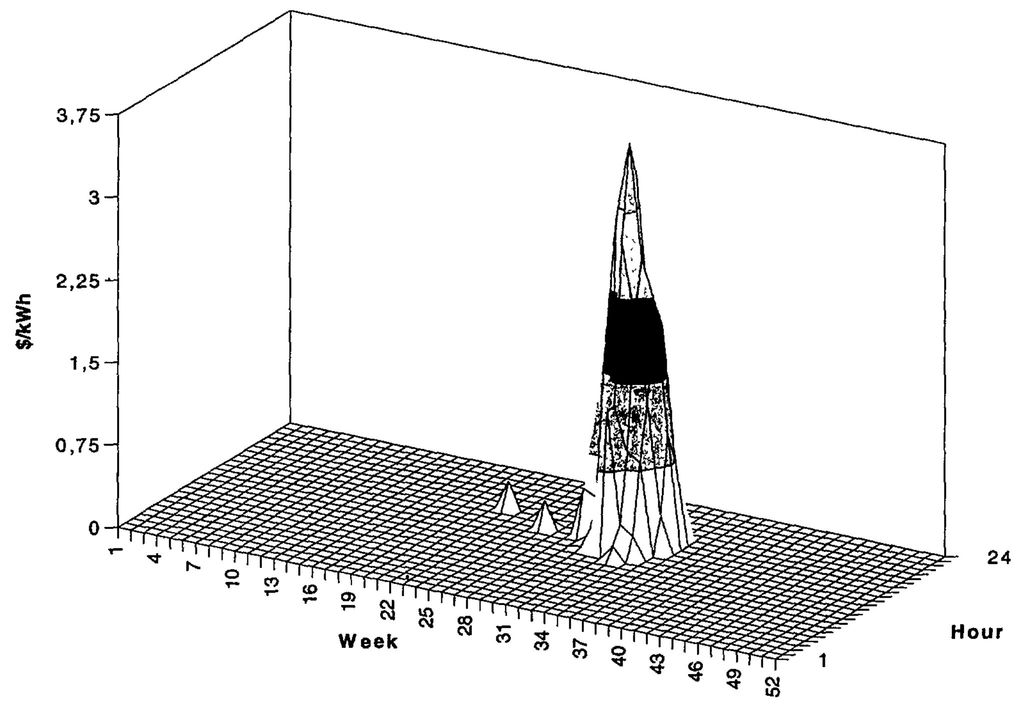
For utilities with relatively slow total load growth, distribution and local transmission capacity costs can represent a large share of their present investment needs. This means that the MDCC can be a large share of the utility's avoided capacity costs, especially for areas with relatively high values of MDCC. If DSM programs are to offer the potential to avoid capital investment costs, these local investments may be the most important costs that can be avoided, i.e. deferred or obviated via energy efficiency or load-management. DSM may have a particular advantage compared to "lumpy" distribution capacity costs, because DSM programs can be implemented in a relatively flexible manner (Hirst 1991).

If utilities know what their area-specific costs are, they will know where and when their costs are significantly higher than the system average. The timing is important, because cost estimates must be forward-looking. Thus, high-cost areas can move around in space and time, and some utilities will have many such areas, while others will have few, if their general level of excess distribution capacity is relatively large.

4. VARIATIONS IN AREA-SPECIFIC COSTS

The variation in ATSMC values within one utility is illustrated by comparing Figure 1, which shows system-average marginal costs for Pacific Gas and Electric (PG&E), and Figure 2, which shows ASTMCs for one of PG&E's high-cost planning areas. While the system-average values reach a maximum of about ECU 0,065/kWh ($0,08/kWh) during summer afternoon demand peaks, the ASTMC values reach nearly ECU 2,5/kWh ($3/kWh) on the same utility system.





A recent study of four US utilities illustrates the variation in MDCC by time and location, both within and between different utilities (Heffner et al 1994). The four utilities, PG&E, Public Service of Indiana (PSI), Central Power and Light (CP&L) and Kansas City Power and Light (KCP&L), vary from each other by location, customer mix, load profile and size. PG&E, for example, is larger than many national utilities, with annual sales of about 75 TWh (75 billion kWh). The range and variation of MDCC within and between these four utilities is shown in Tables 1 and 2, which show the utilities' MDCC estimates for 1994 and 1999, respectively.

The MDCC variations can be dramatic: 73% of PSI's planning areas have zero MDCC over the 20-year planning horizon, while 75% of CP&L's planning areas have MDCC values greater than ECU 225/kW ($270/kW). The MDCC distributions vary substantially by utility. The MDCC for KCP&L ranges from ECU 50/kW ($60/kW) to only ECU 195/kW ($233/kW) in 1994, while the range for PG&E is from zero to almost ECU 1000/kW ($1200/kW). The mean MDCC in 1994 varies from ECU 53/kW ($64/kW) for PSI to ECU 450/kW ($550/kW) for CP&L (Heffner et al 1994). The relatively low mean MDCC values imply that little DSM would be cost-effective if implemented system wide at PG&E and especially at PSI, unless system-level avoided costs are large, which is unlikely because these utilities have excess generating capacity and slow system-wide load growth.

Although the system-average MDCC estimates are similar in 1999 compared to 1994, the individual area-specific values fluctuate considerably over time. Few of the high-cost areas in 1994 continue to be high-cost areas in 1999, rather they are replaced by other planning areas that become high-cost areas as a result of imminent distribution capacity expansion. This finding has important policy implications for resource planning: the benefit of a DSM program is time-dependent, and determing the least-cost mix of DSM options can require dynamic optimization techniques (see Orans, Woo and Horii 1994). A dynamic model can adjust MDCC values to account for DSM programs already implemented, and such adjustments should also be made at the system level, where widespread application of DSM can influence the MEC and MCC (Swisher and Johnson 1992; Orans, Woo and Horii 1994).

Tables 1 and 2 illustrate the potential importance of MDCC information to evaluating the cost-effectiveness of DSM programs. For example a DSM measure with a cost of ECU 210/kW ($250/kW) in 1994 would be cost effective in more than 75% of CP&L's planning areas on the basis of MDCC alone, while it would only be justified in about half of PG&E's areas, less than 10% of PSI's areas, and not at all for KCP&L. A measure with a cost of ECU 420/kW ($500/kW) in 1999 would be cost-effective in more than half of CP&L's planning areas but in less than 10% of the other three utilities' areas.

Table 1. *Descriptive Statistics for 1994 MDCC ($/kW) by Utility*

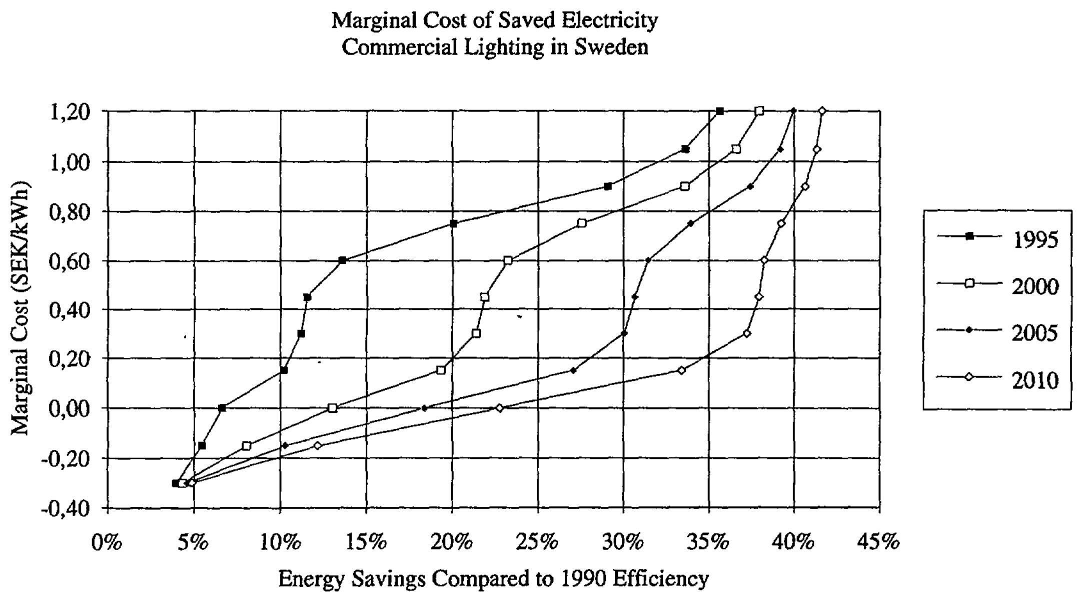
Utility	Number of Areas	% of Areas with $0/kW	First Quartile	Median	Third Quartile	90th Percentile	Maximum	Mean	Standard Deviation
PG&E	201	19%	$166	$240	$303	$392	$1173	$230	$156
PSI	152	73%	$9	$0	$28	$197	$1040	$64	$169
CP&L	17	0%	$269	$344	$712	$1638	$1801	$550	$659
KCP&L	6	0%	$78	$129	$162	$201	$233	$130	$67

Table 2. *Descriptive Statistics for 1999 MDCC ($/kW) by Utility*

Utility	Number of Areas	% of Areas with $0/kW	First Quartile	Median	Third Quartile	90th Percentile	Maximum	Mean	Standard Deviation
PG&E	201	19%	$207	$289	$335	$433	$1330	$267	$179
PSI	152	72%	$0	$0	$29	$171	$1641	$73	$217
CP&L	17	0%	$321	$534	$859	$1732	$1795	$556	$690
KCP&L	6	0%	$62	$99	$108	$146	$182	$94	$54

5. INTEGRATED DISTRIBUTION PLANNING WITH AREA-SPECIFIC COSTS

Of course, the above cost estimates are conservative because they use the MDCC as the minimum criterion for DSM cost-effectiveness, without including the MEC or MCC values. Including these system-level avoided costs will increase the cost-effectiveness threshold for DSM measures that save energy and/or reduce the system peak, depending on the magnitude of such savings and the corresponding marginal cost values. As shown in Figure 3, raising the marginal cost threshold can significantly increase the level of energy and demand savings that are cost-effective as DSM measures. One should note that the effect of MCC on the ATSMC depends on a DSM measure's coincidence with the system-wide peak, while the effect of MDCC depends on the measure's coincidence with the area-specific demand peak.



Estimates of the MDCC make it possible to extend the concept of integrated resource planning (IRP) to include distribution planning. A key element of IRP is to bring the economic evaluation of energy efficiency and other utility DSM programs onto an equal basis with supply expansion, and to consider a wider variety of supply resources, including distributed sources (see, for example, NWPPC 1991). Combining the MDCC with system-level costs to determine the full ATSMC of utility expansion is thus an extension of the IRP paradigm. In addition to weighing DSM investments on the basis of their potential to offset generation and bulk transmission costs, ATSMC evaluation accounts for the potential of DSM to offset distribution and local transmission costs, which are becoming an increasingly important part of utility investment budgets.

As an example of integrated distribution planning, a study conducted for PG&E focused on the optimal integration of DSM programs with a local distribution plan in a relatively high-cost planning area northeast of San Francisco called the Delta District (Orans, Woo and Swisher 1992). The area consists of 23.000 residential and small commercial customers served by a distribution network with five 21 kV feeders and two substations. The Delta study uses ATSMC estimates to develop an integrated distribution plan, which specifies the least-cost mix of DSM programs and the optimal timing of program implementation, subject to limitations on the rate of market penetration and equipment turnover. The study assumes that DSM only alters the timing but not the type of supply-side investment. This is in contrast to generation planning, where the least-cost system configuration may depend on the degree of DSM implementation (NWPPC 1991; Hirst 1992; Swisher and Johnson 1992).

The MDCC for the Delta District is estimated at ECU 440/kW ($520/kW), compared to a similar value of ECU 430/kW ($510/kW) for MCC and ECU 0,033/kWh ($0,039/kWh) for MEC (Orans, Woo and Swisher 1992). The local-area peak is driven mostly by residential-sector demand, while the commercial-sector drives the system-level peak, which occurs during the same time of year but different times during the peak days. This means that the avoided costs of commercial-sector DSM measures appear more attractive from the system-level perspective, due to the importance of the MCC (dkWsys > dkWarea), while the ATSMC approach tends to favor residential-sector measures, where the MDCC has a greater impact (dkWarea > dkWsys). Thus, the integrated plan adds significant investments in residential DSM that would not be called for in the unintegrated plan for the Delta District.

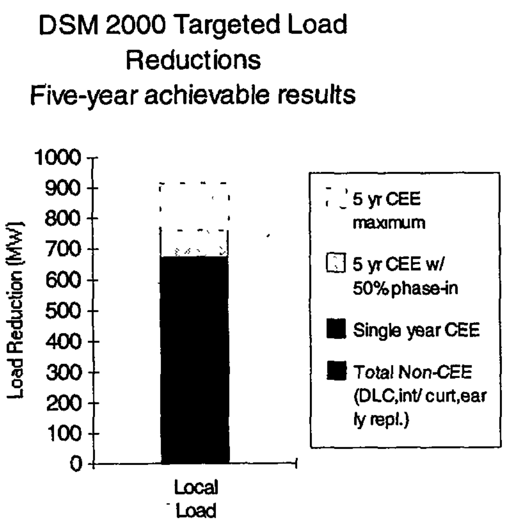
Without DSM, PG&E plans to build a new substation in the area as early as 1995, but the effect of DSM on the area's load growth could defer such investments by 6-8 years (Orans, Woo and Swisher 1992). The overall results indicate that by using ATSMCs and estimates of load by area, customer segment and end-use, PG&E could construct an integrated plan that would save about ECU 30 million ($35 million) over a 20-year period, or about 30% of the present value of the unintegrated plan for the Delta District. Extending the IRP concept further, another study uses ATSMC estimates to derive the optimal planning and pricing rules for power exchange, including DSM transfers, between utilities (Orans et al 1994).

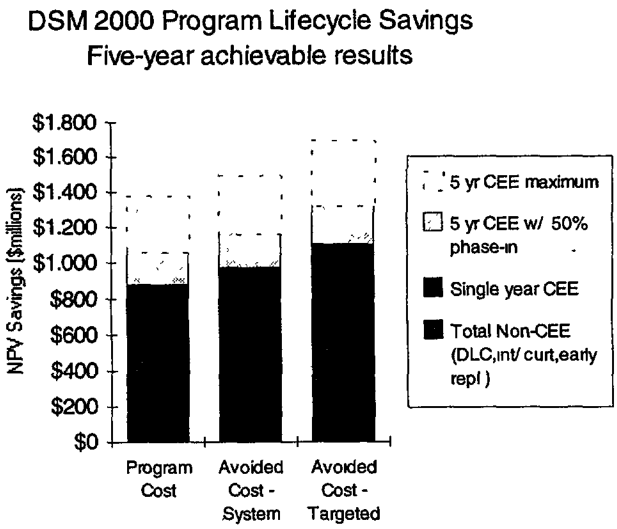
6. A UTILITY STRATEGY FOR TARGETED DSM

The large variance of MDCC over space and time motivates the use of a targeted approach to DSM. The objective of such an approach is to identify high-cost areas and implement DSM programs in time to defer planned expansions in distribution capacity. The basic methodolgy for using ATSMC estimates to target DSM program implementation involves the following steps: (1) develop ATSMC values, (2) estimate potential market penetration for each measure and customer segment, mapped according to planning area, (3) identify DSM program options and performance by planning area and market segment, and (4) estimate market potential for cost-effective DSM measures in each area.

The resulting variation of DSM market potential across areas results from variations in the MDCC values, in the performance of certain measures such as those that vary with climate, in the size of the load corresponding to different end-use measures, and in the coincidence between these loads and the area-specific peaks. In addtion, the DSM market potential also has a time variation, resulting from variations in the timing of planned distribution capacity investments. After the expansion investments have been made, or the DSM potential has been exhausted, there is no further scope for cost-effective DSM in a given area. By that time, however, other areas may be identified as high-cost MDCC opportunities.

A follow-up study to PG&E's Delta study applied a similar approach to the full PG&E service territory, using ATSMC estimates and DSM programs segmented according to climate and customer category (Orans, Woo and Horii 1994). The DSM options include not only customer energy efficiency (CEE) measures, but also load management options such as direct load control (DLC), thermal energy storage (TES), interuptible rates, etc. Unlike the Delta study, there are both high-cost and low-cost areas, the latter offering little potential for targeted DSM. However, like the Delta study, the overall result is that the integrated plan using targeted DSM based on ATSMCs saves about ECU 220 million ($260 million) in present-value investments, compared to about ECU 85 million ($100 million) for the plan based on system-level avoided costs (see Figure 4).





Higher ATSMC values mean higher avoided costs for DSM, allowing more expensive measures and therefore larger energy and demand savings to be cost-effective in high-cost areas. These high-cost areas justify intensive DSM investments -- "blitz" programs to capture a large energy-saving fraction -- in certain places at certain times, based on ATSMC estimates. Only a few such programs have been implemented, based on direct installation of DSM measures by the utility or by contracting with an energy service company (Esco). Direct installation programs are more expensive than utility incentive programs, but they have the potential to be simpler, and they avoid the problem of consumers' lack of information, which is a serious barrier to most energy efficiency programs.

Direct installation programs have greater consumer participation rates than incentive programs. For example, more than 90% participation was achieved in residential retrofit programs in Hood River, Oregon in the mid-1980s and more recently in Espanola, Ontario (Goeltz and Hirst 1986). Other examples of high-participation programs include British Columbia Hydro's efficient industrial motors program, which used both customer and distributor incentives to increase the market share of efficient motors from 4% to 64% in three years, and New England Electric System's (NEES) commercial-sector lighting retrofit program, which offers financing and training to electrical contractors for advanced lighting systems, increasing the contractors' ability to apply efficient technology in their work outside the DSM program as well (Nelson and Ternes 1993; Miller et al 1992).

Despite the success of such programs in term of high participation rates, their costs could be considered too high to justify widespread utility investments. However, with ATSMC information available, a targeted DSM strategy would identify high-cost areas where these opportunities are relatively cost-effective and exploit them fully where and when they occur. As demonstrated by the PG&E case studies, the potential for using this stratergy, rather than doing broad-based programs to achieve small savings and low participation rates, appear very promising. After doing a DSM "blitz" in one target area, one can identify different areas to "blitz" later. This DSM strategy gives large per customer savings and participation rates in the target areas, thus large total savings in such areas, and little or no savings (or program costs) in relatively low-cost areas.

Because DSM measures must be implemented in a fixed time interval to defer construction of new supply capacity, estimates of energy-efficiency potential and demand reduction must evaluate the achievable market penetration over time and include the administrative costs and uncertainties associated with implementation (see NWPPC 1991; Swisher and Johnson 1992). For US utility DSM programs, administrative costs add on average 10-30 percent to the technology costs (Berry 1989, Nadel et al 1993). However, these costs vary widely and tend to decrease with increasing participation rates, which reduce the number of customers to whom a program must be marketed and dilute the impact of fixed program costs (see Hirst 1991). Thus, a targeted strategy of DSM "blitz" programs, based on ATSMC analysis, should be relatively efficient, achieving high participation rates and low marketing and administration costs. Note that very high participation rates may lead to decreasing returns that again drive adminstyrative costs costs upward.

Evaluation costs and the reliability of DSM results is a growing concern in DSM program design (see Hirst and Reed 1991). Targeted DSM implementation could also reduce evaluation costs, because the total load reductions in the target areas could be large enough and achieved fast enough to measure the savings directly from the utility's area load profile, rather than relying on billing data and statistical techniques to separate relatively small customer load reductions on a system-wide basis. The resulting energy and load savings should also be more certain and reliable.

By enabling relatively high marginal-cost measures to qualify for implementation in the high-cost areas, this targeted approach to DSM should encourage more comprehensive programs. It should also discourage the 'cream-skimming' observed in some programs where only the the most attractive measures are implemented, making the remaining marginally cost-effective DSM opportunities more difficult to expolit in future programs. Such comprehensive DSM programs can also stimulate innovation in end-use products, systems and services that have not previously been attractive. This effect is illustrated by the NEES lighting retrofit program, described above, and its influence on the ability of the contractors to apply energy-efficient technology (Miller et al 1992).

The effect of comprehensive DSM programs can also be seen in equipment markets. For example, the majority of electronic lighting ballasts and about half of the integral compact fluorescent lamps (CFLs) have been bought with utility incentives (Geller and Nadel 1994). Recently, US utility DSM programs have begun to focus on capturing long-term energy-efficiency improvements by influencing equipment manufacturers and building designers to offer more efficient products by encouraging equipment distributors to stock, advertise and sell efficient products, even to customers who do not participate in the programs.

7. THE ROLE OF TARGETED DSM IN INTEGRATED RESOURCE PLANNING

Different types of DSM measures have important differences with regard to the flexibility in planning utility DSM programs. One aspect of program flexibility is the dispatchability of the measures used. Some load management measures, such as DLC, can be put into service when needed to meet peak demands, while most CEE measures influence peak demands indirectly, through their effect on customer load profiles, without active utility control.

The targeted DSM strategy is based on the variations in MDCC, which is strictly a capacity cost. The MDCC is derived from the peak area-specific demands during relatively few hours of the year and has no energy-cost component. Although the MEC increases the avoided cost and thus the value of a targeted DSM program, the net effect of applying ATSMC analysis to targeted DSM, relative to conventional DSM, is to encourage programs with high avoided MDCC values, regardless of their MEC values and regardless of their energy savings.

A targeted DSM strategy based on ATSMC analysis therefore tends to favor dispatchable DSM resources (DLC, TES, etc.), which can directly reduce MDCCs. If this becomes the emphasis, are we still talking about energy efficiency? Recovery of DSM costs and lost revenue is the key issue. As long as a utility can recover DSM costs, they can saturate their high-cost areas with CEE measures as well as dispatchable load management, and ignore their low-cost areas until the MDCCs increase. Without cost recovery, they would be discouraged from capuring energy savings and only focus on the dispatchable resources.

The ATSMC approach is applicable to integrated resource planning regardless of whether DSM cost recovery is in place to encourage CEE investments. Utilities still need to know their avoided costs, and they can benefit from ATSMC information to target DSM programs, whether such programs emphasize energy efficiency or dispatchable load management. Either way, the benefits of DSM are defined by the avoided costs, and these costs can be more precise and useful if they account for ATSMCs. The difference, from the IRP perspective, is whether or not lost revenues are counted as a DSM cost. The different standard measures of the economic costs and benefits of DSM measures, based on the different perspectives of IRP, are summarized in table 3. It is often convenient to compare avoided costs (per kWh) to the DSM measures' cost of saved energy (CSE), which is simply the annualized capital and administrative cost of the efficiency measure, plus any increase in operating costs, divided by the reduction in annual energy consumption (Meier et al 1983).

Table 3. Cost-Effectiveness Criteria for Energy-Efficiency Measures

Perspective	Benefits	Costs
Utility	Avoided Supply Costs	Utility Cost of DSM Measures and Marketing
Ratepayer (Rate Impact Measure)	Avoided Supply Costs	Utility Cost of DSM Measures and Marketing Plus Lost Revenues
Society (Total Resource Cost)	Avoided Supply Costs	Utility Cost of DSM Measures and Marketing Plus Net Customer Costs
Society (Total Social Cost)	Avoided Supply Costs Plus External Costs	Utility Cost of DSM Measures and Marketing Plus Net Customer Costs
Participant	Lost Revenues (Bill Savings)	Net Customer Costs

Source: CEC, 1987.

The problem with DSM cost recovery is that it puts upward pressure on electricity rates, by adding a cost element and reducing sales. Even though the economic benefits to society and especially to participating customers may be positive, non-participating customers will be penalized by higher rates. To the extent that utility deregulation encourages price competition between retail suppliers, utilities will tend to adopt a rate-minimizing behavior that discourages DSM investments in energy efficiency (York 1993; Swisher 1994a).

Table 3 shows that any IRP perspective requires information about avoided costs of DSM, including ATSMCs. Under the rate impact measure (RIM) test, lost revenues are a cost of DSM and any measure that would increase rates is not cost-effective. If avoided costs per kWh are greater than the sum of the rates and the CSE, then CEE measures can be cost effective. However, this is a very strict requirement that is unlikely to be met under the present trend of declining MECs and MCCs, a trend that may accelerate in the short-term as supply-side competition is introduced.

For example, if the MDCC is low due to excess distribution capacity and rates are higher than the sum of MEC and MCC, as is now common, then CEE measures with a CSE of zero are not even cost effective. This means that many system-wide DSM costs are not cost effective under the RIM-test. If the MDCC is higher but avoided costs are only above rates during the local peak-demand period, the high MDCC values will indicate positive benefits from dispatchable DSM measure such as load control and interruptible rates, but offer little incentive for CEE unless the total ATSMC values are very high. If the shape of the local cost curve demonstrates that avoided costs are low and concentrated in a very few peak hours, then only DLC is likely to be very attractive.

Under the total resource cost (TRC) test, lost revenues can be recovered by the utility and are not considered a DSM cost. This means that DSM is cost effective whenever the avoided costs are greater than the CSE. In this case, ATSMC analysis will identify areas with particularly high avoided costs, enabling the targeted DSM "blitz" approach described above. Other areas may have some cost effective DSM retrofit options, but it may be better to avoid the possibility of "cream-skimming" and save those low-cost areas until their avoided costs are sufficient to justify a DSM "blitz."

8. POTENTIAL TO REDUCE EMISSIONS USING TARGETED DSM PROGRAMS

The IRP evaluation criteria (RIM vs. TRC) determines the extent to which CEE measures appear cost-effective as DSM options. ATSMC information can help target DSM programs, thus increasing the opportunities for applying cost-effective DSM options, including CEE measures, under both a regulated (TRC-based) and a deregulated (RIM-based) IRP structure.

However, deregulation by itself does not create incentives for CEE in DSM programs. A deregulated, segmented power market tends to encourage rate minimising, sales maximising behaviour as is observed in countries as diverse as England, Norway, Argentina and New Zealand (York 1993; Swisher 1994a). In this case, the dominant DSM benefits under an area-specific costing regime could well be load management by dispatchable DSM options.

If DSM for CEE does not easily become part of the competitive environment, can it still be justified? One of the principal reasons for pursuing energy-efficiency improvements is that energy consumption leads to pervasive externalities, ranging from local pollution and greenhouse gases to energy and nuclear security risks, that are not reflected in energy supply costs. As public concern and government mandates regarding environmental threats get stronger, there will be a greater need for clean energy solutions such as CEE.

This trend seems to run counter to the deregulation trend, in that the latter tends to discourage CEE in DSM programs. When these opposing trends collide, as is likely before long, the resolution will require new ways to stimulate CEE investments while preserving the economic efficiency of deregulation and competition. Given the difficulties of implementing the regulated (TRC-based) DSM model in an environment of increased competition, we need to consider what options targeted DSM offers for capturing the environmental benefits of utility CEE.

The costs of environmental emissions from electricity supply are part of the avoided cost of DSM and renewable supply sources. For a given generation-fuel source, emissions are essentially proportional to the amount of electric energy generated. Marginal environmental costs therefore tend to supplement the MEC, rather than the capacity costs, and including such costs would tend to favor DSM measures with significant energy savings (dkWh). A TRC-based (or social cost-based) analysis would encourage CEE through DSM, and a targeted approach would make it possible to increase the comprehensiveness and cost-effectiveness of such a program, as shown above. On the other hand, the results of a RIM-based analysis would depend on whether environmental cost savings are sufficient to compensate for DSM costs including lost revenues.

The environmental costs can either be emission charges actually paid by the utility, or they can be proxy values used to prioritize and select DSM and supply options in the IRP process. Experience in North America with such proxy values has been that they have little effect on DSM activity, even under a regulated (TRC-based) planning structure (Hashem et al 1994). Under a deregulated (RIM-based) structure, environmental costs would have to be actually paid by the utility in order to have any effect via higher rates. This effect would depend on the mechanism for cost recovery, which under RIM would continue to bias decisions against DSM for CEE. However, it is also possible that either regulatory or competitive pressure would make it difficult to recover 100% of the environmental costs, and utilities in such a situation would find CEE via DSM increasingly attractive.

To the extent that targeted DSM, including CEE, becomes profitable to the utility, then the utility's financial interests coincide with environmental concerns. In a deregulated (RIM-based) structure, the targeted approach based on ATSMCs would include emissions as system-level costs, which add to the MEC and can be offset by CEE investments, as well as some local emissions costs. It is still possible that emission costs would not be sufficient to overcome the effect of lost revenues system-wide, which would be necessary to make energy efficiency appear cost-effective system-wide under the RIM-test. However, the variation in MDCC could combine with the emission costs to make comprehensive DSM, including CEE, cost-effective in high-cost areas, and such areas would appear in additional places over time.

9. IMPLICATIONS FOR THE STRUCTURE AND TIMING OF DSM PROGRAMS

In addition to dispatchability, another aspect of flexibility in DSM programs is the degree of control over when retrofit options are exploited, depending on the need for load reductions and the resources available (Hirst 1991). There is little such flexibility, however, for improving energy performance in new and replacement equipment, which presents one-time opportunities that are lost if they are not exploited when the equipment is first installed.

Thus, the timing of these options is not always compatible with the timing of targeted DSM, which depends on where and when area costs are high. However, the lowest-cost CEE measures are generally found in new and replacement equipment rather than retrofits of existing buildings and equipment (Hirst 1992; Swisher 1991, 1994b). Capturing this inexpensive "lost opportunity" energy-efficiency resource should therefore be a high priority for energy policy and program design.

The timing of area-specific DSM programs may allow these opportunities to be lost, unless the programs happen to be implemented where and when building and renovations are highly concentrated. If a supply-capacity investment can be defered several years by DSM, there may be sufficient time to capture a significant amount of CEE potential in new facilities, but generally the targeted "blitz" approach would require programs that can be done quickly and thus focus on retrofits. For example, targeted DSM introduces the possibility of using early retirement of old appliance models as a DSM option. If one can save 400 kWh by buying a new refrigerator one year earlier than normal in order to retire an old unit, the CSE is the carrying charge for one year (perhaps 10 percent) on the cost of the new unit (ECU 800), or (0.10) (800) / 400 = ECU 0.20/kWh. This may be cost-effective in a high-cost area, but it is many times the CSE of changing from an average new refrigerator to the best available unit.

The "lost opportunity" resource in new facilities represents CEE measures that should be captured where and whenever available, including in low-cost areas. Such one-time options are not "cream-skimming," because they will not be available until the area becomes a high-cost area. Such measures are appropriate for energy performance standards, particularly for end-uses such as household appliances and service-sector lighting. Even relatively modest standards can help capture many low-cost "lost opportunity" resources. This allows utility DSM planners to set thresholds for incentives that exceed the standards, requiring more comprehensive sets of measures where few free riders are likely (Swisher et al 1994). Such programs would fit well with the targeted DSM strategy based on ATSMC analysis.

Efficiency standards overcome information barriers in diffuse markets such as home appliances, and they address other barriers to energy efficiency (Johansson and Swisher 1993). For example, standards can reduce the risk to vendors of stocking and selling energy-efficient products. This kind of risk can also be addressed by other "technology-push" policy measures that stimulate manufacturers to produce efficient equipment. An innovative energy-policy intervention is public technology procurement (teknik upphandling), which has been developed in Sweden by NUTEK, the technology and industrial development ministry. This process combines government incentives with guaranteed orders from organised buying groups (such as apartment managers) in a competitive solicitation for improved energy-efficient products (Nilsson 1992).

An effect of "technology-push" programs such as technology procurement is to overcome the risks for producers to introduce a new energy-efficient product without knowing if customers will buy it. While the procurement process accelerates the introduction of more efficient equipment on the market, standards help remove less efficient models and increase the market penetration of their efficient replacements (Swisher 1994b). Together, these two complementary instruments signal producers that future markets will reward development of efficient new models with growing demand and sales, removing much of the associated risk.

These non-utility energy policy instruments are complementary to a targeted utility DSM strategy that emphasizes retrofits and dispatchable resources. Especially under a deregulated (RIM-based) structure, such instruments can help capture low-cost "lost opportunity" energy-efficiency resources in new buildings and equipment, which might not appear cost-effective in low-cost areas, because of the effect of lost revenues on rates and non-participants.

10. CONCLUSIONS

This paper has explained ATSMC methods and shown how they can provide an improved approach to the analysis of avoided utility costs in the context of IRP. The variations in ATSMC values across space and time, resulting from variations in the costs of distribution capacity expansion, suggest a new utility DSM strategy based on targeted programs. With ATSMC information available, a utility can target comprehensive DSM programs when and where avoided costs are high, rather than doing general programs that achieve small savings and low participation rates. In a regulated IRP environment, this approach should increase the cost-effectiveness of most DSM programs, especially those based on retrofit measures.

In a deregulated market, where there may be little incentive for DSM investments in CEE, the targeted approach will provide a market niche for dispatchable DSM measures. The differences bewteen the attractiveness of CEE via DSM, in the deregulated case compared to the regulated case, result from the different perspectives used for IRP, and whether the rate-increasing effect of lost revenues is acceptable when total costs are reduced. Even in the deregulated case, increasing environmental constraints may encourage utility investments in CEE, and the targeted approach based on ATSMC analysis will increase the opportunities for using DSM to reduce emissions and costs. Non-utility policy measures such as performance standards and technology procurement are complementary to targeted DSM, because they focus on improving energy efficiency at low cost in new buildings and equipment.

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