Definitions and Tradeoffs: Cost-Effectiveness of Utility DSM Programs

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More and more U.S. utilities are running more and larger demand-side management (DSM) programs. Assessing the cost-effectiveness of these programs raises difficult questions for utilities and their regulators. In particular, should these programs aim to minimize the total cost of providing electric-energy services or should they minimize the price of electricity?

Most of the debates about the appropriate economic tests to use in assessing utility programs are philosophical and do not address the magnitude of the impacts. As a result, questions remain about the relationships among utility DSM programs and acquisition of supply resources and the effects of these choices on electricity prices, bills, and costs. This study offers quantitative estimates on the tradeoffs between total costs and electricity prices. This study uses a dynamic model to assess the effects of energy-efficiency programs on utility revenues, total resource costs, electricity prices, and electricity consumption for the period 1990 to 2010. These DSM programs are assessed under alternative scenarios for three utilities: a "base" that is typical of U.S. utilities; a "surplus" utility that has excess capacity, few planned retirements, and slow growth in fossil-fuel prices and incomes; and a "deficit" utility that has little excess capacity, many planned retirements, and rapid growth in fossil-fuel prices and incomes.

Introduction

During the past several years, more and more electric utilities and their regulatory commissions have recognized the benefits of improving efficiency of electricity use (Faruqui et al. 1990; Hirst 1991a). However, considerable controversy remains over the appropriate economic test(s) to use in assessing utility programs that increase customer energy efficiency and therefore reduce electricity use and utility revenues. People concerned about minimizing the total cost of electric-energy services favor the total-resource-cost test (TRC), while those concerned about minimizing electricity prices favor the rate-impact measure (RIM); see Table 1.

Most of the debates about the economic tests to use in assessing utility programs are philosophical and do not address the magnitude of the impacts (Cavanagh 1986; Electricity Consumers Resource Council 1990; Lovins 1989; Ruff 1988). As a consequence, questions remain about the relationships among utility DSM programs and acquisition of supply resources and the effects of these choices on electricity prices and costs. If aggressive DSM programs are implemented, by how much will electricity prices rise, and over what time? If the RIM test is used, how much of a resource that would be cost effective under the TRC will be foregone? Most of the quantitative estimates that have been made of the tradeoffs between the RIM and TRC tests are based on the static equations developed by the California Public Utilities Commission and California Energy Commission (1987) or are for a particular utility under its baseline assumptions.

During the past few years, several public utility commissions (PUCs) (including those in Connecticut; Idaho; Illinois; Massachusetts; Montana; Nevada; Vermont; Washington, DC; and Wisconsin) have issued orders on the cost-effectiveness tests for DSM programs. These PUCs rejected use of the RIM test to screen DSM programs, relegated the RIM test to a secondary role, or mandated use of the TRC as the primary determinant of the cost effectiveness of utility DSM programs. The Maine PUC (1987) determined that a utility DSM program that:

> is reasonably likely to satisfy the All Ratepayers Test [the TRC] is cost effective. ... Any program that is reasonably likely to satisfy the All Ratepayers Test and to fail the Rate Impact Test, but only to the extent that the utility's present value of revenue requirements per kWh do not increase by more than 1% over the duration of the program, may be continued or implemented without prior program specific Commission approval.

Others (Electricity Consumers Resource Council 1990) argue that utilities should aim to minimize electricity prices. Any other strategy would needlessly raise prices,

Table 1. Elements of the Key Economics Tests Used to Assess the Benefits and Costs of Utility Demand-Side Management Programs

Perspective	Benefits	Costs
Rate-Impact Measure	Avoided supply costs (production, transmission, and distribution) based on energy and load reductions	Utility program costs, including incentives to participants, plus net lost revenue caused by reduced sales
Total-Resource Costs[a]	Avoided supply costs (same as above)	Total program costs to the utility and participants (i.e., measure costs plus utility administrative costs)

(a) The total resource cost is the same as utility revenue requirements and customer bills in the present analyses because the utility pays 100% of the costs of the DSM programs.

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

encouraging electricity consumers to shift their energy needs to other fuels.

Some proponents of the RIM test (Ruff 1988) argue that it is economically inefficient for the utility to pay customers "twice" for energy-efficiency improvements. Utilities pay once through the direct cost of their programs (marketing and financial incentives to install energy-efficient devices); they pay a second time through the customer's reduction in his/her electricity bill. Others (Hirst 1989; Lovins 1989) argue that consumers in all sectors of the economy face many market barriers to improving energy efficiency. Thus, energy markets do not operate properly and require utility involvement. Utilities can help overcome these barriers and do so at low cost.

The reduction in customer electricity bills stimulated by utility DSM programs, often called lost revenues, is at the heart of the debate over the appropriate role of utilities in promoting energy efficiency. Some believe that the RIM test ensures that (1) markets are not tampered with needlessly and (2) nonparticipating ratepayers do not suffer because of utility DSM programs. Others believe that strict adherence to the RIM test ensures "no losers, but few winners" (Cavanagh 1986) and will increase the overall cost of electric-energy services.

While this study does not resolve the philosophical debate over the proper role of electric utilities on the "customer side of the meter," it does offer quantitative estimates on the tradeoffs between total resource costs and electricity prices. This study uses a dynamic model of an electric utility [Decision Impact Assessment Model (DIAMOND), described in Gettings, Hirst, and Yourstone 1991] to assess the effects of utility DSM programs on utility revenues, total resource costs, electricity prices, and electricity consumption (Hirst 1991b).

The Utilities Analyzed

DIAMOND is used to assess DSM programs under alternative scenarios that vary fossil-fuel prices, load growth, the amount of excess capacity the utility has in 1990, planned retirements of existing power plants, the financial treatment of DSM programs, and the costs of energy-efficiency programs. These analyses are conducted for the 1990--2010 period for three utilities:

- a "typical" U.S. utility, based on data and estimates from the Energy Information Administration (presented in Hirst 1991b);
- "surplus" utility that has excess capacity, few planned retirements, and slow growth in fossil-fuel prices and income; and
- a "deficit" utility that has little excess capacity, many old plants that will be retired, and rapid growth in fossil-fuel prices and income.

For the year 1990, the base utility had 2275 MW of generating capability, of which 48% was coal, 24% nuclear, 19% gas, and 9% hydro. Peak demand that year was 2000 MW (including customer demand, 10% demand loss, and short-term on-peak sales), yielding a reserve margin of 14%.

In 1990, the base utility generated 11,600 GWh (including customer electricity use, 5% energy loss, and short-term off-peak sales). The system's load factor that year was 63%. Coal provided 63% of the generation, nuclear 27%, hydro 7%, and natural gas 3%. The utility's power plants produced electricity with a wide range in variable costs, from 0.3 to 4.5¢/kWh. All costs and prices in this paper are in constant 1990 dollars.

Customer demand for electricity grows at an average rate of 2.0%/year between 1990 and 2010. The utility will need new resources because of this projected load growth and because it will retire 600 MW of existing generating units during the 2000s. The utility expects to become deficit in 1995, and this deficit is projected to grow to almost 700 MW in the year 2000 and to 1400 MW by 2010 (Table 2).

The surplus utility differs from the base utility in several ways (Table 2). It has an additional 200 MW of capacity in 1990, fewer customers and therefore lower demand, leading to a 27% reserve margin (instead of a 14% reserve margin). Because only 200 MW of existing plants are scheduled for retirement and because its load growth is only 1.5%/year, it needs only 400 MW of new capacity during the two-decade period (compared with 1400 MW for the base utility). Finally, both fossil-fuel prices and retail electricity prices are lower in 1990 and are expected to increase more slowly than for the base utility.

The deficit utility, on the other hand, has greater retirement of existing plants, higher load growth, and higher fossil-fuel and electricity prices, as shown in the last column of Table 2.

For simplicity in the present analysis, utility-built power plants are limited to only a few choices: 500-MW coal, 200-MW coal, 100-MW combustion turbine, and 100-MW combined-cycle combustion turbine. The construction and operating costs for these plants are based on estimates from the Electric Power Research Institute and the Michigan Department of Commerce; see Hirst (1991b) for specifics.

The utility can also choose to run DSM programs. Because the utility has only one customer class, only two types of DSM are practical, one aimed at new customers and one at existing customers. Conservation-program performance depends on two factors: participation in the program and the net energy savings of the program. The utility's cost has three components: (1) a fixed charge ($/year) that reflects the overall planning, design, and administration of the program; (2) a marketing charge ($/participant) that reflects the utility's cost to get customers to participate in the program; and (3) an acquisition charge (¢/kWh) that reflects the financial incentive paid by the utility for the materials and installation needed to acquire the conservation resource.

Participation in the utility's conservation program follows an S-shaped logistic curve over time. The slope of these curves is a function of the utility's marketing expenses and of its financial incentive, the second and third components of the utility's cost noted above.

Energy savings are based on supply curves, which show the potential electricity savings per participant as a function of the marginal levelized cost of conserved electricity (CCE, in ¢/kWh). The electricity savings per participant increases as the utility increases its maximum CCE. These programs are assumed to have the same load factor as that of the utility system (63%), reflecting a mix

Table 2. Comparison of Situations Facing the Three Utilities

	Base	Surplus	Deficit
Installed capacity in 1990 (MW)	2275	2475	2275
1990 reserve margin (%)	14	27	14
Planned retirements of power plants (MW)	600	200	1100
Total resources added from 1990 to 2010 (MW)	1400	400	1900
Load growth (%/year)	2.0	1.5	2.4
Prices (1990 value in $/MBtu, %/yr growth, 1990-2010)			
Natural gas	3.12 3.4%	2.50 1.3%	4.26 3.8%
Coal	1.61 2.0%	1.24 1.1%	1.96 2.0%

of load-management programs with low load factors and energy-efficiency programs with high load factors.

To simplify comparisons across cases, the utility pays 100% of the DSM-measure costs in all programs (i.e., there is no customer contribution to these costs). This represents a worst-case scenario in terms of the RIM test. To the extent that customers share the cost of purchasing and installing DSM measures, the adverse price impacts of DSM programs are reduced, although participation and electricity savings will also be reduced in such cases.

All the utility's capital costs, both supply and demand, are included in the rate base. The costs of DSM programs are depreciated over 15 years, investments in transmission and distribution over 20 years, other investments (e.g., computers and office buildings) over 7 years, and power plants over the lifetime of the plant (ranging from 30 years for combustion turbines to 40 years for coal plants). The utility's cost of capital is 10.4%, which is the discount rate used to compute the net present value (NPV) of revenue requirements. Inflation averages 4%/year throughout the 20-year analysis period.

For these analyses, the utility maintains a balancing account to ensure that any variations between actual and forecast sales do not affect the utility's rate of return. This system is similar to the Electric Revenue Adjustment Mechanism used in California plus a fuel-adjustment clause. This mechanism ensures that utility shareholders are not penalized because DSM programs reduce electricity use.

Base-case Utility

Supply-Only Plan

I begin the analysis of the base utility by developing a supply-only plan. This plan is then used as the reference against which to compare plans that include DSM programs. Growth between 1990 and 2010 in income and prices to the utility for gas, coal, and nuclear fuels are the same for all the cases discussed in this section (Table 2).

This supply-only plan is the one, among many alternatives tested, that yields the lowest NPV of revenue requirements for the 1990--2010 period. The alternatives tested include construction of different types and numbers of power plants, started at various dates between 1990 and 2000. This plan includes a combination of coal- and gas-fired power plants, with additions that total 1400 MW between 1994 and 2008. Figure 1 shows the load/resource balance for this supply-only plan, and Table 3 presents summary statistics for this plan.

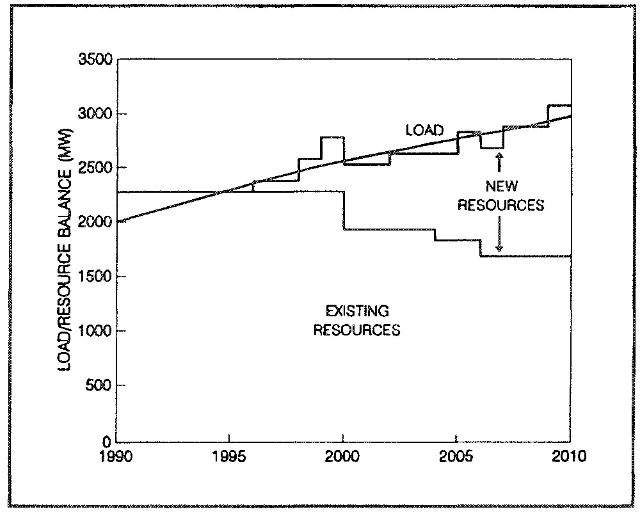

Figure 1. Load/Resource Balance Showing Peak Load, Existing Resources, and New Power Plants in the Optimal Supply-Only Case for the Base Utility

Electricity consumption increases at an average rate of 2.0%/year. Real electricity prices increase slowly at 0.6%/year. Over the 20-year period, the utility spends $1,880 million on new construction, of which 67% is for new power plants. The remainder is for transmission and distribution and other investments.

DSM Cases

Starting with the supply plan discussed above, several cases were developed that incorporated DSM programs of different intensities. Intensity refers to the utility's incentive payment for energy-efficiency investments (expressed as the maximum CCE) and its marketing budget per participant. As intensity increases, the electricity savings and average cost of conserved energy also increase, and the program's cost effectiveness from the TRC perspective declines. In all cases, DSM programs were started in 1990 and were run unchanged for the full 20 years of the simulation. The utility always paid 100% of the costs associated with DSM measures.

Programs were tested with maximum (not average) costs of conserved electricity of 6, 5, 4.5, 4, and 3 ¢/kWh. No effort was made to optimize the DSM programs by testing different combinations of marketing budgets and financial incentives for DSM measures. In all these DSM cases, some of the power plants that were constructed in the supply-only case are deferred or displaced by the energy and capacity resources provided by the DSM programs. The analysis proceeded as follows. The DSM program, begun in 1990, was added to the full set of power plants constructed in the supply-only case. Then, several

Table 3. Summary of Results for Supply-Only Plan and Combined Supply/Demand Plan with DSM Resources Purchased up to 4.5¢/kWh for the Base Utility[a]

	Average growth rate, 1990-2010 (%/year)	
	DSM	Supply-Only
Total electricity use (GWh/year)	1.2	2.0
Electricity price (¢/kWh)	0.9	0.6
Average electric bill ($/customer)	1.3	1.9
Utility revenues (million-$)	2.1	2.7
Summary statistics, 1990-2010:		
Net present value of revenues (million-$)	9,450	10,000
Average electricity price (¢/kWh)	6.94	6.89
Average electric bill ($/customer)	1,100	1,190

(a) Similar tables for the surplus and deficit utilities are in Hirst (1991b).

additional cases were run in which some of these power plants were deferred or eliminated. These iterations stopped when revenue requirements could be reduced no further, subject to the constraint that the reserve margin was roughly what it was in the supply-only case.

Results for the case with a maximum CCE of 4.5¢/kWh are shown in Table 3 and Figures 2 and 3. Over the 20-year period, construction costs (including DSM) total $1,770 million, 6% less than in the supply-only case. Whereas 1400 MW of new power plants were constructed in the supply-only case, only 800 MW of new power plants were constructed in the DSM case. Thus, these DSM programs displace the need for almost half the power plants that would otherwise have been built.

Electricity use in this case grows more slowly than in the supply-only case (1.2 vs 2.0%/year) and in the year 2010 is 15% lower (Figure 2). Correspondingly, utility revenues, assets, and customer bills are lower with the DSM programs. According to the TRC test, these DSM programs have a benefit/cost ratio of 2.7. The average CCE for these DSM programs (including the cost of the measures plus the utility's cost of program administration and marketing) is about 3.5¢/kWh at the customer meter, roughly two-thirds the cost of a small coal plant. Accounting for transmission and distribution losses (5% for energy and 10% for peak) plus transmission and distribution construction makes the DSM programs even more cost effective.

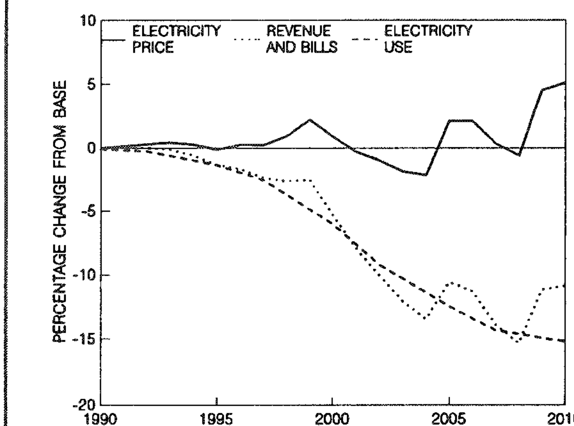

Figure 2. Effects of a Utility DSM Program (CCE = 4.5¢/kWh) on Electricity Use, Revenues (and Average Electric Bill), and Electricity Price. Model results for the last few years of the simulation are confounded by the fact that no new power plants are under construction to meet post-2010 electricity needs.

Electricity prices are slightly higher with DSM programs. Prices are initially almost unchanged because of the DSM programs and then increase from 2005 to 2010 (Figure 2). At the end of the analysis period, electricity prices are higher with DSM programs than without because no new power plants are started at the end of the period. In the supply-only case, construction costs for new power plants

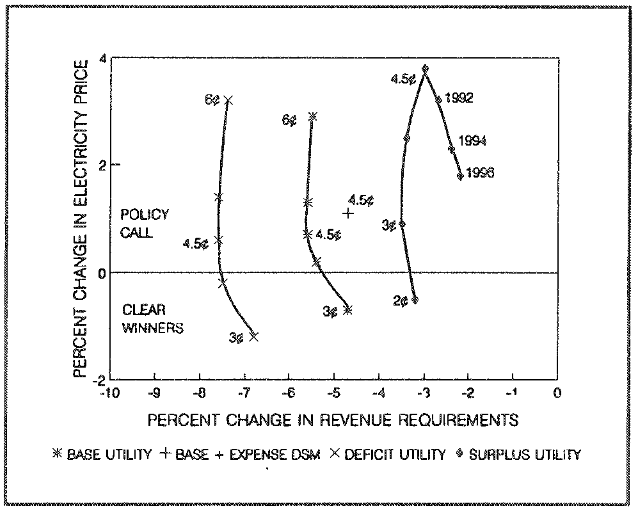

Figure 3. The Effects of Utility DSM Programs on NPV of Utility Revenues and Average Electricity Price (1990 through 2010) for the Base, Surplus, and Deficit Utilities. The prices shown refer to the maximum CCE (in ¢/kWh) paid by the utility in its DSM programs. The DSM programs all begin in 1990, except for the three noted with their starting years for the surplus utility. The zero points for revenue requirements and electricity prices are the values for the appropriate supply-only resource plan.

are zero in 2009 and 2010. However, in the DSM case, the DSM programs continue through the year 2010, leading to higher construction costs from 2008 to 2010.

Overall, electricity *prices* are 0.7% higher, but electric *bills* are 8% lower, and utility revenue requirements are almost 6% lower. Bills and utility revenues are consistently lower throughout the 20-year period with DSM programs (Figure 2).

Other cases with different DSM programs were run, and the comparisons between each of these cases and the supply-only case are shown in Figure 3. At values of maximum CCE above 5¢/kWh, conservation programs increase both electricity bills and prices relative to cases with moderate conservation programs. These results also show that it is possible to reduce both revenue requirements and electricity prices with modest DSM programs. For example, the case with maximum CCE of 3¢/kWh yields reduction in average electricity price of 0.7% relative to the supply-only case. Even this "modest" program cuts electricity use in the year 2010 by 11%, cuts revenue requirements by 4.7%, and cuts electricity bills by 6.2% (compared with the 15% cut in 2010 electricity use, the 5.6% cut in revenue requirements, and the 7.1% cut in bills achieved with the 4.5¢/kWh program).

Expensing vs Rate-Basing DSM

In the cases discussed above, the utility's costs of its DSM programs were capitalized and depreciated over 15 years at the utility's cost of capital (10.4%/year). This financial treatment of DSM is consistent with the treatment of other investments (e.g., in power plants and transmission and distribution systems) and ensures that the costs and benefits of DSM are roughly contemporaneous.

However, utilities often treat DSM-program costs as an expense, which means that they recover these costs the year they occur; these costs appear immediately in electricity prices. I compared the effects of expensing vs rate-basing with a 15-year depreciation on the tradeoff between total costs and electricity prices (Figure 3).

These results show that expensing DSM-program costs reduces the benefits of these programs. This finding is true for both the TRC and the RIM tests. Revenue requirements are cut by 4.7% with expensing vs 5.6% with ratebasing and prices increase by 1.1% with expensing vs 0.7% with ratebasing (compared to the supply only case). Expensing increases utility costs relative to the supply-only case each year from 1990 through 1997; it is only in the later years that revenues are lower with expensing. When DSM-program costs are rate-based, revenue requirements are lower every year with DSM programs than without.

Prices are higher with DSM programs than without until 2003 if DSM-program costs are expensed. As discussed above, if these costs are depreciated over 15 years, DSM programs have little effect on electricity prices until the early 2000s, after which prices are usually higher with DSM programs than without.

This comparison of ratebasing vs expensing of DSM programs is confounded by end effects. That is, the costs of new power plants and DSM programs are captured fully in the revenue requirements from 1990 through 2010. But some of the benefits of these new resources, with lifetimes that extend well beyond the year 2010, are not. Because the discount rate used in the NPV calculations and the utility's cost of capital are the same, the financial treatment of DSM programs would have no effect on results if a longer time period was analyzed. However, the financial treatment of DSM matters if customers have a different discount rate than does the utility. In particular, if customers have a higher discount rate, ratebasing DSM costs is preferable. Also, ratebasing DSM program costs is consistent with the treatment of power plants and ensures that the costs and benefits of these programs occur at roughly the same time.

Surplus Utility

Here I present cases similar to those developed in the Introduction but with different assumptions concerning installed capacity in 1990, 1990 reserve margin, load growth, and fossil-fuel prices (Table 2). These assumptions simulate the situation in which a utility has substantial excess capacity and slow load growth, leading to only a modest need for additional capacity between 1990 and 2010. The purpose of these cases is to show whether DSM programs offer benefits to a utility with excess capacity.

The supply-only case includes the addition of 200 MW of coal plants and 200 MW of combustion turbines. Again, several cases with DSM programs were simulated. The case with a CCE of 4.5¢/kWh increased electricity price almost 4% and decreased revenue requirements 3% and bills 5% (compared with an increase in electricity price of 0.7% and decreases in revenue requirements and bills of 6% and 7% for the base utility; see Figure 3). Thus, for the surplus utility, the benefits of DSM programs are much less than for the base utility from a TRC perspective and even worse from a RIM perspective.

At first glance, these reductions in revenue requirements seem startling: How can DSM programs reduce costs for a utility that has substantial excess capacity and needs no additional capacity until 2004? Because the DSM-program costs are depreciated over 15 years, revenue requirements with the DSM program are lower in all years except 1990 and 1991. In other words, the cost of the DSM programs is less than the reduction in operating costs plus the reduction in transmission and distribution construction costs. If the DSM-program costs were expensed instead of rate-based, the revenue requirements with DSM would be greater each year from 1990 through 2002 than in the supply-only case. Again, these results show the substantial effect of financial treatment on DSM-program economics.

The case with a CCE of 3¢/kWh led to the greatest reduction in the NPV of revenue requirements (Figure 3). The DSM programs displaced the need for 75% of the power plants that were constructed in the supply-only case (i.e, 200 MW of coal plants and 100 MW of combustion turbines). With such reductions, the NPV of revenue requirements is cut by 3.5%, bills are cut by 4.7%, and electricity price is higher by 0.9%.

Deficit Utility

This section discusses cases for a utility that faces rapid load growth, has a small reserve margin in 1990, plans to retire much of its existing generating units by 2010, and faces higher fossil-fuel prices (Table 2). In essence, these cases are the opposite of those discussed in the Utilities Analyzed section.

The supply-only plan for this deficit utility involves construction of 1600 MW of coal plants plus 300 MW of combustion turbines. As shown in Figure 3, the reductions in revenue requirements caused by DSM programs are much greater for the deficit utility than for either the base or surplus utility. However, even for the deficit utility, most of the DSM programs increase average electricity prices. Only when the maximum CCE is at or below 4¢/kWh do both revenues and prices decline compared to the supply-only case.

The case with a CCE of 4.5¢/kWh, which led to the largest reduction in revenue requirements (almost 8%), increased the average electricity price by 0.6% and cut bills by almost 9%. These DSM programs cut load growth from 2.4 to 1.5%/year and displaced the construction of 500 MW of power plants.

The cases with a maximum CCE of 4 to 6¢/kWh led to almost the same reduction in revenue requirements. However, the effects of these programs on electricity prices and consumption are large. While the 6¢/kWh case reduced electricity use in the year 2005 by 17%, it increased the average price of electricity by more than 3%. On the other hand, the 4¢/kWh case reduced electricity use by 11% and led to a 0.2% decrease in electricity price. These results show that the decision on DSM-program intensity involves more than a tradeoff between costs and prices; it also involves electricity consumption and the displacement of supply sources.

Synthesis of Results

Is the increasing use of demand-side management programs good for the customers of electric utilities? The answer, of course, depends on the criteria used to judge "goodness." Those who argue over the appropriate economic test(s) to use in selecting DSM programs see customer benefits in different ways. Some focus on the *price* of electricity, while others focus on the *cost* of electric-energy *services*.

This paper focuses on the tradeoffs between price and cost and identifies how much of a price increase might be associated with how much of a cost reduction when a utility provides DSM programs for its customers. This tradeoff was explored with a new planning model developed at ORNL (DIAMOND). The model was used to examine the effects of DSM programs on revenue requirements (total resource costs), electricity bills, electricity prices, electricity consumption, and the need for additional power supplies under a variety of circumstances. Additional details on the results are in Table 15 of Hirst (1991b).

The base-case results (Introduction) show that the percentage reductions in customer bills and utility revenue requirements are much greater than the percentage increases in electricity prices. Thus, the appropriate question to ask in regulatory proceedings and utility boardrooms is: Is a 1% average increase in electricity price justified by a 5% decrease in electricity costs and bills over the next 20 years?

The analyses suggest that it is possible (although unlikely) to reduce both costs and prices. The circumstances under which this can occur include rapidly increasing fuel prices, the need for large amounts of new resources, and truly inexpensive DSM. Inexpensive DSM implies not just that the cost of the measures and their installation is cheap, but also that the cost to the utility to plan, design, implement, promote, and evaluate the program is low. For example, on an engineering-economic basis, low-flow showerheads are remarkably cost effective. However, utility programs that promote installation and use of such devices among their residential customers have administrative and marketing costs that exceed the cost of the showerhead itself (Flaim, Miedema, and Clayton 1989).

The primary findings from the analyses conducted here are:

- In general, DSM programs reduce electricity costs and raise electricity prices. Utilities and PUCs must make tradeoffs between the TRC and the RIM tests.
- Typically, the percentage reduction in electricity cost far exceeds the percentage increase in electricity price caused by DSM programs. Roughly speaking, the ratio of percentage changes is 2:1 for the surplus utility, 5:1 for the base utility, and 8:1 for the deficit utility.
- The financial treatment of DSM programs is important. Expensing the costs of DSM programs raises electricity prices in the short term, whereas capitalizing these costs over 15 years defers the price increase for several years.
- Even if DSM is very inexpensive or the utility faces very high avoided costs, the tradeoff between costs and prices remains. However, under either of these circumstances, the percentage reduction in costs will be far greater than the percentage increase in prices. In special cases where the cost per kWh of DSM programs is very low, both prices and costs can be reduced.
- From the perspective of the TRC test, DSM programs are cost effective even if the utility has excess capacity and slow load growth. This situation occurs because DSM programs offset not just the operating costs of existing power plants, but also reduce the other costs of operating the utility system, defer construction of new transmission and distribution facilities, and in the long term defer the construction and operation of new power plants.
- The tradeoff between the TRC and RIM tests can be reduced by having customers share in the costs of the DSM measures installed by the program, by reducing the maximum CCE paid by the utility, or by delaying implementation of the program. However, each of these approaches also reduces the amount of electricity savings achieved by the programs, increasing the need for additional power supplies.

Based on these simulations, I recommend that utilities and PUCs adopt a flexible approach to the assessment of DSM programs. Rather than adhering strictly to any single measure of cost effectiveness, the parties should modify program design and timing so that DSM programs provide major reductions in electric-energy-service costs (the TRC test) with only minor increases in electricity prices (the RIM test). Price impacts can be mitigated by adjusting the timing of the programs and their cost recovery, and by appropriate rate design (allocating the costs across customer classes and among the monthly, demand, and energy components of the pricing structure). In particular, I urge that the large reductions in total costs not be foregone because of small increases in electricity prices.

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