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ENERGY DIVISION

**COSTS AND EFFECTS OF ELECTRIC-UTILITY
DSM PROGRAMS: 1989 THROUGH 1997**

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SUMMARY

All U.S. electric utilities are required to report to the Energy Information Administration data on their demand-side management (DSM) programs. These data provide a comprehensive view of utility DSM-program costs and effects (energy savings and load reductions) for 1989, 1990, 1991, and 1992 as well as projections for 1993 and 1997.

For 1992, 905 utilities (of about 3250 utilities in the United States) ran DSM programs. Altogether, these programs cost almost \$2.4 billion, saved 31,800 GWh, and cut potential peak demand by 32,900 MW. Normalized by retail revenues, sales, and peak demand, utilities spent 1.3% of their revenues to achieve energy and demand reductions of 1.2 and 6.0%, respectively.

These 1992 numbers continue the growth trends from 1989. Compared to their 1989 counterparts, utility DSM expenditures nearly tripled, energy savings doubled, and demand reductions increased 50%. And utility projections show continued growth in DSM-program costs and effects. DSM expenditures are expected to increase from 1.3% of revenues in 1992 to 1.8% in 1997. Energy savings are projected to grow from 1.2% of sales in 1992 to 2.5% in 1997 and demand reductions are expected to increase from 6.0% to 8.4% of peak demand (Fig. S-1). The more rapid increases in energy savings and load reductions than in program costs suggest that utility DSM programs are becoming more cost effective.

These national averages hide considerable variation across program types, customer classes, utilities, states, and regions. In 1992, energy-efficiency programs dominated utility DSM activity, accounting for 65% of utility DSM expenditures and 81% of energy savings but only 24% of peak-demand reductions. However, interruptible programs, which provided only 6% of the energy savings, accounted for almost half of the 1992 annual peak-demand reductions. The residential sector was especially important in terms of annual energy savings, while the industrial sector dominated demand reductions.

Utility DSM activity is concentrated in a few parts of the country, especially the east coast, the west coast, and the broad northern tier (Fig. S-2). This concentration, however, is less pronounced than it was in earlier years, suggesting that DSM activity is diffusing throughout the United States.

% OF PEAK DEMAND, SALES, AND RETAIL REVENUES

Fig. S-1. Utility data for 1989 and 1992 and projections for 1997 on DSM-program expenditures, energy savings, and potential peak-demand reductions.

% OF RETAIL REVENUE SPENT ON DSM

Fig. S-2. The percentage of retail revenues spent on DSM programs by state.

INTRODUCTION

In the current debates about retail wheeling, utility restructuring, and the possible demise of utility demand-side management (DSM) programs, it is too easy to forget all that those programs have accomplished. During the past several years, more and more U.S. electric utilities have relied increasingly on energy-efficiency and load-management programs to provide energy and capacity resources as alternatives to the construction and operation of new power plants. In addition, these programs provide valuable customer services, including ways to meet customer energy-service needs at lower environmental costs.

Beginning in 1989, the Energy Information Administration (EIA), through its form EIA-861, required all U.S. electric utilities to report annually on their DSM programs. For the years 1989, 1990, and 1991, Schedule V of EIA-861 required all utilities that ran DSM programs and had sales greater than 120 GWh/year to provide information on the costs, energy savings, and load reductions of their DSM programs. Beginning with the 1992 form, EIA expanded the scope of DSM information collected to include disaggregations by program type and customer class.

This report presents data reported to EIA for 1992 as well as utility projections of DSM activities for 1993 and 1997. Following roughly the same format used in reviews of the 1990 and 1991 data (Hirst 1992 and 1993), I present results for the "leading" DSM utilities, states, nine Census divisions, and the U.S. as a whole. In essence, this report provides additional detail beyond that published by EIA (EIA 1994b; Prete 1994). Subsequent chapters discuss 1992 DSM-program costs, energy savings, and load reductions and projections for 1993 and 1997.

FORM EIA-861

Of the roughly 3250 U.S. electric utilities, 905 reported to EIA that they operated a DSM program in 1992. Of these 905 utilities, 504 had annual sales greater than 120 GWh and were required to complete all of Schedule V of EIA-861. The remaining 401 utilities had to complete only parts of Schedule V. These 905 utilities accounted for 86% of the electricity sold to U.S. retail customers in 1992 and for 89% of the revenues collected from these customers that year [Edison Electric Institute (EEI) 1993]. Thus, the vast majority of electricity customers are served by utilities that offer DSM programs. Of the 905 DSM utilities, 142 are investor-owned utilities (IOUs), accounting for just over half the 260 such utilities. The remaining 763 DSM utilities are consumer-owned utilities (COUs), including municipal, cooperative, federal, and state utilities. These COUs, which are typically much smaller than the IOUs, account for about one-fourth of all such utilities in the United States.

Schedule V for the years 1989 through 1991 asked several questions about the costs and effects of utility DSM programs at an aggregate level. The 1992 EIA form required much greater detail. Specifically, the 1992 form asked for information on *incremental* and *annual* electricity savings and demand reductions (Table 1). These energy and load effects were disaggregated by customer class (i.e., residential, commercial, industrial, and other) and by program type (i.e., energy efficiency, direct load control, interruptible load, other load management, other DSM, and load building). Cost data were split into direct and indirect utility costs. Direct costs were disaggregated by program type, and indirect costs were split into administrative, marketing, monitoring and evaluation, utility-earned incentive, and other costs. In addition to requesting data on utility costs, EIA-861 requested data on nonutility (e.g., customer) costs of DSM programs. EIA requested these data for 1992 with projections for 1993 and 1997.

In this report, I exclude the costs and effects of utility load-building programs, primarily because they account for very small shares of the totals. (Utilities reported spending only \$32 million on these programs in 1992 in exchange for increased sales of 1,800 GWh and higher peak demands of almost 400 MW.) I discuss potential, rather than actual, peak-demand reduction because it provides a view of DSM more consistent with utility treatment of supply resources. For example, when reporting capability, utilities provide information on all generating units that were available to meet demand at the time of system peak, regardless of whether those units actually operated or not. To be consistent, the DSM resource should identify all the demand reductions available to the utility, even if some of the direct-load-control or interruptible options were not exercised. Although the utilities with sales of less than 120 GWh were not required to report annual figures, I do not treat the small and large utilities separately because these small utilities accounted for less than 1% of most DSM totals.

The DSM data collected through EIA-861 provide a valuable source of information on U.S. utility DSM efforts and accomplishments, especially given the additional detail obtained for 1992. However, as with any large data set for which information is provided by a diversity of organizations, there are bound to be data-quality problems. As discussed in Hirst and Sabo (1991), Eto et al. (1994), and the earlier versions of this report (Hirst 1992 and 1993), readers should view the numbers reported here with some skepticism. As examples, consider the following "data" reported to EIA. One utility reported a 29% cut in electricity sales and a 40% reduction in peak demand for 1992, benefits inconsistent with the utility's reported DSM expenditures. Four utilities reported spending more than 6% of revenues on DSM but all four reported zero energy and demand reductions. Twelve utilities reported incremental energy savings greater than annual savings, and another five utilities reported incremental demand reductions larger than annual reductions. The numbers reported by 15 utilities suggest that they cut electricity use at less than 0.1¢/kWh, while the numbers from another 37 utilities suggest that they spent more than 10¢/kWh to improve energy efficiency. (Although I am skeptical of some of the utility reports, I made no changes to the numbers reported on EIA-861.)

In general, the expenditure data are more reliable than are the energy and demand estimates. The cost figures are typically actual expenditures in various utility accounts, whereas the energy-saving and demand-reduction figures are estimates. As one aggregates from utilities

Table 1. Key elements of DSM data required by EIA-861 for 1992

Program Effects

Incremental — changes in 1992 energy use and peak load caused by new participants (i.e., those that began participation in 1992) in the utility's DSM programs; these estimates assume that all these customers participated on January 1, 1992

Annual — changes in 1992 energy use and peak load caused by all the participants in the utility's DSM programs, including those that participated in 1992 as well as those that participated earlier

Peak Reduction

Potential — the "installed" reduction in 1992 peak load that could have been achieved by customers participating in the utility's DSM programs, which is larger than the actual peak reduction because of direct-load-control or interruptible options not exercised by the utility in 1992^a

Actual — the actual reduction in 1992 peak load achieved by customers participating in the utility's DSM programs

Program Type

Energy efficiency — programs aimed at reducing electricity use, typically without reducing the services provided, generally without regard for the timing of program-induced savings

Direct load control — programs that can interrupt customer loads at critical times, under the direct control of the utility system operator

Interruptible load — programs with contractual arrangements that permit the utility system operator to request customer load reductions at critical times

Other load management — programs other than direct load control and interruptible load that limit or shift usage from onpeak to offpeak periods, such as energy storage and aggressive promotion of time-of-use pricing

Other DSM — a residual category to include programs that cannot be meaningfully included in any of the other categories, including fuel switching and self-generation

Load building — programs aimed at increasing electricity use

Program Costs

Direct — those costs that can be directly attributable to a particular DSM program

Indirect — those costs that cannot be meaningfully attributed to a particular program, including administrative, marketing, monitoring and evaluation, and utility incentive costs

^aEIA's aggregation of programs for potential peak reductions excludes the actual reductions caused by energy-efficiency programs.

Source: EIA instructions for Schedule V of EIA-861.

to states to regions to the nation, the accuracy of the data improves. The overall quality of utility DSM-program data is surely improving in response to various efforts to standardize the terms and reporting forms used to collect such information and as DSM evaluation practices mature.

The EIA-861 form and its instructions are a good example of this phenomenon. So too are the forms and definitions developed by Lawrence Berkeley Laboratory, Oak Ridge National Laboratory, and the Northeast Region Demand-Side Management Data Exchange (Association of Demand-Side Management Professionals 1992).

KEY RESULTS

In 1992, utilities spent almost \$2.4 billion on DSM programs, cut energy use by 31,800 GWh, and cut potential peak demand by 32,900 MW. Compared to national totals for the electric-utility industry, DSM accounted for 1.3% of retail revenues, 1.2% of sales, and 6.0% of peak demand (Table 2). (The national totals, from EEI, are \$186.7 billion retail revenue, 2,730 GWh retail sales, and 548,700 MW of summer peak demand.)

The 1992 figures show continued growth in DSM expenditures and effects from 1989 on (Table 2 and Fig. 1). For example, utility DSM expenditures increased from 0.5% of revenues in 1989 to 0.7% in 1990, 1.0% in 1991, and 1.3% in 1992.

As was true in prior years, IOUs devoted larger fractions of their revenues to DSM than did COUs. However, the COUs reported larger energy and demand reductions. These differences might be real. Or the IOUs might conduct more careful evaluations (leading to more conservative estimates of DSM-induced energy and demand reductions) than do COUs, perhaps because IOUs are, on average, much larger.

Energy-efficiency programs dominated DSM expenditures and energy savings (Fig. 2). Specifically, these programs accounted for 65% of total utility DSM costs and 81% of energy savings but only 24% of peak-demand reductions. Direct-load-control programs were second in terms of expenditures, accounting for 17% of utility DSM expenditures, 23% of demand reductions, and 1% of energy savings. And interruptible-rate programs contributed the most to demand reductions, accounting for almost half of this total.

Utility DSM expenditures are highly correlated with incremental energy savings ($r^2 = 0.70$) and potential demand reduction ($r^2 = 0.52$). Not surprisingly, the greater the expenditures, the greater the benefits.

Table 2. Annual effects and costs of electric-utility DSM programs, 1989 to 1992

	Program cost (million \$ and % ^a)		Energy savings (GWh/year and % ^a)		Potential peak- demand reduction ^b (MW and % ^a)	
1989	870	0.5	16,300	0.6	20,100	3.8
1990						
Totals ^c	1,180	0.7	18,700	0.7	23,300	4.3
Investor-owned utilities	1,060	0.8	13,200	0.7	17,500	4.3
Consumer-owned utilities	120	0.3	5,500	0.9	5,800	4.7
1991						
Totals ^d	1,750	1.0	23,300	0.9	26,700	4.8
Investor-owned utilities	1,510	1.0	17,600	0.8	19,500	4.5
Consumer-owned utilities	240	0.6	5,700	0.9	7,200	6.1
1992						
Totals ^e	2,360	1.3	31,800	1.2	32,900	6.0
Investor-owned utilities	2,020	1.4	24,000	1.1	24,200	5.3
Consumer-owned utilities	340	0.9	7,800	1.2	8,700	9.9

^aThese percentages reflect, respectively, total U.S. retail electric revenue, retail electricity sales, and summer peak demand for 1989, 1990, 1991, or 1992.

^bUtilities report to EIA estimates of actual and potential peak-demand reductions (17,700 MW vs 32,900 MW for 1992). The actual figures are the amount of load shed during system peaks. The potential figures represent the amount of load that the utility could have shed. The difference between the two numbers represents, as examples, interruptible contracts that were not exercised and load-control devices that were not activated. All the numbers presented in this report are potential estimates.

^cThese totals are based on the 363 utilities with annual sales greater than 120 GWh that reported running at least one DSM program in 1990. Of these 363 utilities, 127 are investor-owned, and the remaining 236 are consumer-owned.

^dThese totals are based on the 439 utilities with annual sales greater than 120 GWh that reported running at least one DSM program in 1991. Of these 439 utilities, 133 are investor-owned, and the remaining 306 are consumer-owned.

^eThese totals are based on the 504 utilities with annual sales greater than 120 GWh that reported running at least one DSM program in 1992. Of these 504 utilities, 140 are investor-owned, and the remaining 364 are consumer-owned.

Fig. 1. Costs and effects of electric-utility DSM programs, 1989 to 1992.

Fig. 2. Distributions of 1992 DSM-program expenditures and effects among program types.

1992 DSM-PROGRAM EXPENDITURES

In 1992, utilities spent \$2.36 billion on their DSM programs. Almost 80% (\$1.85 billion) was for direct program costs, with the remaining 20% (\$0.51 billion) for indirect costs. Almost two-thirds of these costs were devoted to energy-efficiency programs. In addition to these utility costs, customers and other participants in DSM programs spent \$0.48 billion, bringing the grand total to \$2.84 billion. (Only about 70 of the 504 utilities reported such nonutility expenditures.)

As was true in prior years, the distribution among utilities in DSM expenditures is skewed. The two top utilities, Pacific Gas & Electric and Consolidated Edison, alone accounted for almost 15% of the national total (Table 3).

Eighteen of the top 25 utilities were also among the top 25 for 1991 (Hirst 1993). The seven additions for 1992 include the Tennessee Valley Authority, San Diego Gas & Electric, Consumers Power, Wisconsin Public Service, Ohio Edison, Northern States Power, and Baltimore Gas & Electric. These 25 utilities, of which 23 are IOUs, accounted for two-thirds of the U.S. electric-utility expenditures on DSM in 1992; the top five utilities accounted for a full 25% of the industry's DSM expenditures. These 25 utilities spent 2.3% of their revenues on DSM, about double the national average. They also achieved 64% of the annual energy savings and 44% of the annual demand reduction for that year.

Because COUs, are, on average, much smaller than IOUs, a display of the percentage of revenues spent on DSM shows a different picture than that presented by absolute expenditures (compare Tables 3 and 4). COUs account for 13 of the top 25 utilities in percentage of revenue spent on DSM in 1992. These 25 utilities spent almost 5% of their revenues on DSM, more than three times the national average.

About one-fourth of the utilities spent less than 0.1% of revenues on DSM (Fig. 3). At the other end of the spectrum, 28% of the utilities spent more than 1% on such programs. Compared to the 1991 distribution, utilities tended to shift from the 0.1-to-0.5% category to the 1.0-to-2.0% category.

Table 3. The 25 utilities with the largest 1992 DSM expenditures

Utility	State	IOU	Peak (MW)	Output (GWh)	Revenue (M\$)	Total DSM without load building				Cost (M\$)	1992 DSM as % of				Cost
						ΔSales (GWh)		ΔPeak (MW)			ΔSales		ΔPeak		
						Incr'l	Annual	Incr'l	Annual		Incr'l	Annual	Incr'l	Annual	
Pacific Gas & Electric	CA	Y	14345	82740	7756	621	1352	696	865	219	0.8	1.6	4.9	6.0	2.8
Consolidated Edison	NY	Y	8477	38518	4906	480	638	214	271	116	1.2	1.7	2.5	3.2	2.4
Florida Power & Light	FL	Y	14661	74691	5100	94	2559	189	1258	96	0.1	3.4	1.3	8.6	1.9
Southern California Edison	CA	Y	18413	82199	7713	0	636	240	2695	88	0.0	0.8	1.3	14.6	1.1
Florida Power	FL	Y	6982	29192	1774	51	922	346	1285	77	0.2	3.2	5.0	18.4	4.3
Niagara Mohawk Power	NY	Y	6159	39251	3123	313	475	62	108	76	0.8	1.2	1.0	1.7	2.4
Duke Power	NC	Y	14149	75631	3961	38	50	197	1382	75	0.0	0.1	1.4	9.8	1.9
Tennessee Valley Authority	AL		21980	120866	5075	11	3239	868	2120	66	0.0	2.7	4.0	9.6	1.3
New York State Electric & Gas	NY	Y	2524	20940	1452	137	139	25	55	66	0.7	0.7	1.0	2.2	4.5
Carolina Power & Light	NC	Y	8745	44602	2767	169	4634	169	1369	62	0.4	10.4	1.9	15.7	2.2
Boston Edison	MA	Y	2545	18061	1407	86	336	50	113	56	0.5	1.9	2.0	4.4	4.0
Massachusetts Electric	MA	Y	2791	16019	1413	114	345	34	102	56	0.7	2.2	1.2	3.7	3.9
San Diego Gas & Electric	CA	Y	3285	16857	1444	0	118	4	68	56	0.0	0.7	0.1	2.1	3.8
∞ Puget Sound Power & Light	WA	Y	3906	20710	1025	245	1230	0	13	54	1.2	5.9	0.0	0.3	5.3
Wisconsin Electric Power	WI	Y	4640	26201	1299	272	751	156	292	54	1.0	2.9	3.4	6.3	4.2
Connecticut Light & Power	CT	Y	4016	27367	2316	133	1035	27	265	45	0.5	3.8	0.7	6.6	2.0
Public Service Electric & Gas	NJ	Y	8445	41592	3408	29	58	91	181	44	0.1	0.1	1.1	2.1	1.3
Potomac Electric Power	DC	Y	5546	26552	1602	105	214	59	339	41	0.4	0.8	1.1	6.1	2.5
Sacramento Municipal Utility	CA		2119	9061	648	111	173	45	281	40	1.2	1.9	2.1	13.3	6.2
Long Island Lighting	NY	Y	3611	17030	2177	136	460	184	251	34	0.8	2.7	5.1	7.0	1.6
Consumers Power	MI	Y	5939	34211	1863	59	117	31	31	33	0.2	0.3	0.5	0.5	1.8
Wisconsin Public Service	WI	Y	1494	10373	478	139	210	54	84	33	1.3	2.0	3.6	5.6	6.8
Ohio Edison	OH	Y	4629	30104	2059	0	44	27	224	32	0.0	0.1	0.6	4.8	1.6
Northern States Power	MN	Y	6128	33880	1716	174	507	111	550	31	0.5	1.5	1.8	9.0	1.8
Baltimore Gas & Electric	MD	Y	5558	29949	1968	102	116	111	389	30	0.3	0.4	2.0	7.0	1.5
Totals top 25		23	181087	966597	68448	3619	20358	3988	14590	1576	0.4	2.1	2.2	8.1	2.3
Top 25 as % of national totals			31.6	29.4	34.9	62.5	64.1	51.9	44.3	66.8					

Table 4. The 25 utilities with the largest 1992 DSM expenditures as a percentage of retail revenue

Utility	State	IOU	Peak (MW)	Output (GWh)	Revenue (M\$)	Total DSM without load building				Cost (M\$)	1992 DSM as % of				Cost
						ΔSales (GWh)		ΔPeak (MW)			ΔSales		ΔPeak		
						Incr'l	Annual	Incr'l	Annual		Incr'l	Annual	Incr'l	Annual	
Wisconsin Public Service	WI	Y	1494	10373	478	139	210	54	84	33	1.3	2.0	3.6	5.6	6.8
Sacramento Municipal Utility	CA		2119	9061	648	111	173	45	281	40	1.2	1.9	2.1	13.3	6.2
Seattle, City of	WA		1727	9199	295	50	279	0	0	18	0.5	3.0	0.0	0.0	6.1
Mid-Carolina Electric Coop	SC		137	587	39	2	6	2	9	2	0.3	1.0	1.2	6.8	6.0
Eugene, City of	OR		526	2636	91	16	134	3	29	5	0.6	5.1	0.6	5.5	5.8
Osceola, City of	AR		28	181	9	0	0	0	3	1	0.0	0.0	1.1	10.8	5.6
Wabash Valley Power Assn	--		791	3716	157	0	0	4	44	9	0.0	0.0	0.5	5.6	5.6
Granite State Electric	NH	Y	119	680	61	7	21	2	6	3	1.0	3.1	2.0	5.4	5.4
Port Angeles, City of	WA		112	680	20	1	9	0	0	1	0.2	1.3	0.0	0.0	5.3
Puget Sound Power & Light	WA	Y	3906	20710	1025	245	1230	0	13	54	1.2	5.9	0.0	0.3	5.3
Tacoma, City of	WA		1016	6197	193	30	165	6	31	10	0.5	2.7	0.6	3.1	5.1
Madison Gas & Electric	WI	Y	483	2466	143	17	62	10	19	7	0.7	2.5	2.1	3.9	5.0
New York State Electric & Gas	NY	Y	2524	20940	1452	137	139	25	55	66	0.7	0.7	1.0	2.2	4.5
Florida Power	FL	Y	6982	29192	1774	51	922	346	1285	77	0.2	3.2	5.0	18.4	4.3
Runestone Electric Assn	MN		30	148	9	0	1	2	17	0	0.1	0.9	7.2	55.4	4.2
Wisconsin Electric Power	WI	Y	4640	26201	1299	272	751	156	292	54	1.0	2.9	3.4	6.3	4.2
Western Massachusetts Electric	MA	Y	699	4532	411	42	183	9	45	17	0.9	4.0	1.4	6.4	4.1
Boston Edison	MA	Y	2545	18061	1407	86	336	50	113	56	0.5	1.9	2.0	4.4	4.0
Morganton, City of	NC		54	274	16	0	7	4	7	1	0.0	2.7	6.6	12.5	4.0
Massachusetts Electric	MA	Y	2791	16019	1413	114	345	34	102	56	0.7	2.2	1.2	3.7	3.9
San Diego Gas & Electric	CA	Y	3285	16857	1444	0	118	4	68	56	0.0	0.7	0.1	2.1	3.8
Orange & Rockland Utilities	NY	Y	943	4764	403	55	123	15	76	15	1.2	2.6	1.6	8.0	3.8
Iowa Lakes Electric Coop	IA		42	241	17	5	32	1	7	1	2.1	13.2	1.2	16.5	3.8
PUD No 1 of Lewis County	WA		147	642	25	0	1	0	0	1	0.0	0.2	0.0	0.1	3.6
United Power Assn	--		615	5208	174	2	15	15	193	6	0.0	0.3	2.4	31.3	3.6
Totals top 25		12	37756	209567	13000	1383	5263	786	2777	588	0.7	2.5	2.1	7.4	4.5
Top 25 as % of national totals			6.6	6.4	6.6	23.9	16.6	10.2	8.4	24.9

Fig. 3. Distribution of the 504 utilities with DSM programs by percentage of 1992 revenues spent on these programs. On a national-average basis, utilities spent 1.3% of 1992 revenues on DSM. The figure also shows the comparable distribution for the 439 utilities reporting DSM data in 1991.

The utilities in seven states—California, Florida, Massachusetts, North Carolina, New York, Washington, and Wisconsin—spent more than \$100 million on their DSM programs in 1992.* On average, the utilities in California, Connecticut, the District of Columbia, Florida, Maine, Massachusetts, New York, Rhode Island, Vermont, Washington, and Wisconsin spent more than 2% of revenues on DSM in 1992 (Fig. 4). Of these 11 states, 6 (California, Connecticut, Massachusetts, Rhode Island, Washington, and Wisconsin) were on the comparable list for 1991.

*For several reasons, readers should be cautious about the state results presented here. First, for utilities that operate in more than one state, I assumed that the DSM costs and effects were allocated the same way that retail sales were. But for some utilities (e.g., PacifiCorp) that face very different regulators in their states, this allocation across states may not be correct. Second, the DSM utilities in Alaska, Louisiana, and Mississippi account for less than half the retail sales in those states. Although this probably means that there is little DSM activity in these states, I cannot be sure. Third, I could find no state-level data on peak demands. My assignment of state peaks is based on utility reports reconciled to the EEI report of national summer peak demand. My state numbers differ from those reported by Schweitzer and Young (1994) because they included only IOUs, whereas my numbers include all utilities.

Fig. 4. The percentage of retail revenues spent on DSM programs by state.

1992 DSM-PROGRAM ENERGY SAVINGS

In 1992, EIA-861 requested for the first time utility estimates of incremental and annual energy savings. Incremental savings is the annualized savings achieved by those customers that began participation in 1992, while annual energy savings is the savings in 1992 caused by all prior and current participants in the utility's DSM programs. Annual savings in 1992 amounted to 31,800 GWh, 1.2% of retail sales. Incremental savings totaled 5,800 GWh, 18% of annual savings.

Energy-efficiency programs accounted for the vast majority (92% of incremental and 81% of annual) of total energy savings. Dividing the levelized utility cost of these programs by the incremental savings caused by energy-efficiency programs yields an estimated 4.3¢/kWh cost of conserved electricity. Including the customer costs of DSM raises the total to 5.2¢/kWh. These estimates assume a 10-year lifetime of the efficiency measures and a discount rate of 8%. If the DSM measures last, on average, only five years, the utility cost of conserved energy is 7.2¢/kWh; if the measures last 15 years, the cost drops to 3.4¢/kWh. (Changes in the discount rate have much less effect on the cost of conserved electricity than does the estimated lifetime of the measures.) These calculations ignore the value of the demand reductions caused by energy-efficiency programs. Crediting the energy-efficiency programs for these demand reductions (discussed in the following chapter) lowers the utility cost of conserved electricity from 4.3 to 4.1¢/kWh.

Readers should view these cost figures cautiously. As Joskow and Marron (1992) pointed out, utilities often ignore various costs (e.g., those borne by participating customers) and overestimate benefits (e.g., by using engineering estimates of energy savings) in their calculations of DSM-program cost effectiveness. Eto et al. (1994) showed that careful and consistent accounting of costs and energy savings can reduce the variance in estimates of cost effectiveness across programs. Their analysis of 20 commercial/industrial lighting programs yielded an overall cost of 5.6¢/kWh. The fact that their estimated cost for lighting programs, generally thought to be the most cost-effective of DSM programs, is higher than the estimates derived above from the EIA-861 data suggests that the Joskow and Marron concerns are valid. In particular, it is likely that customer costs accounted for more than the 17% of total costs implied by the 1992 EIA-861 data.

The residential sector accounted for 41% of the annual DSM-induced energy savings, much more than its 34% of retail sales (Fig. 5). The industrial sector, on the other hand, accounted for a smaller share of energy savings than of retail sales. Incremental savings, however, paint a different picture. Here the commercial sector dominates, with both the residential and industrial sectors accounting for smaller shares of savings than of sales. These

comparisons show that the historical focus of DSM programs on the residential sector has shifted strongly to the commercial sector. The industrial sector continues to get less attention in terms of energy savings.

As was true in past years, the distribution across utilities in DSM-induced annual energy savings is more skewed than the distribution of DSM-program costs (compare Figs. 3 and 6). Almost 60% of the utilities reported savings of less than 0.1% of total sales in 1992. At the other end of the spectrum, only 10% reported savings of 2% or more.

Table 5 lists the 25 utilities that reported the largest annual electricity savings caused by their DSM programs. Nineteen of these utilities were among the top 25 for 1991 also. The additions for 1992 include Puget Sound Power & Light, Alabama Power, City of Austin, City of Seattle, Metropolitan Edison, and PacifiCorp. These 25 utilities, 21 of which are IOUs, account for three-fourths of the total U.S. electric-utility annual savings. These utilities also account for almost half of the annual demand reduction and more than half of the utility DSM expenditures. Overall, these utilities cut annual electricity use by 2.5%, about double the U.S. average.

Of the top 25 utilities in terms of annual energy savings for 1992, 14 also made the top 25 for incremental savings. It is likely that reporting errors account for some of the differences. In particular, Bonneville and Southern California Edison report substantial annual savings and DSM expenditures, but both utilities report zero incremental energy savings. The 11 utilities that ranked among the top 25 in terms of incremental, but not annual, savings include Baltimore Gas & Electric, Consumers Power, Georgia Power, New York State Electric & Gas, Portland General Electric, Potomac Electric Power, Rochester Gas & Electric, Sacramento Municipal Utility District, City of San Antonio, Wisconsin Power & Light, and Wisconsin Public Service. These 11 utilities might be considered emerging because of the growth in their programs over time.

The utilities in Connecticut, Florida, Maine, Massachusetts, Montana, North Carolina, Rhode Island, South Carolina, Tennessee, Washington, and Wisconsin all saved more than 2% of their retail sales in 1992 (Fig. 7). Six of these eleven states (Connecticut, Maine, Massachusetts, Rhode Island, Tennessee, and Wisconsin) saved more than 2% in 1991 also. Nine other states saved between 1 and 2% of their retail sales in 1992. Comparison of the maps in Figs. 4 and 7 shows considerable similarity. Utilities along the east and west coast and the upper midwest dominate in both DSM expenditures and energy savings. Relative to the maps for 1991, DSM is diffusing into the interior regions of the country from the east, west, and north.

Aggregate annual electricity savings exceeded 2000 GWh in five states, California, Florida, North Carolina, New York, and Washington. Aggregate incremental savings exceeded 400 GWh in California, New York, Washington, and Wisconsin.

Fig. 5. Shares of 1992 incremental and annual energy savings and retail sales by customer class.

Fig. 6. Distribution of the 504 utilities with DSM programs by percentage of 1992 generation saved by those programs. On a national-average basis, utilities cut annual generation by 1.2% in 1992. The figure also shows the comparable distribution for the 439 utilities reporting DSM data in 1991.

Table 5. The 25 utilities with the largest 1992 annual energy savings caused by DSM

Utility	State	IOU	Peak (MW)	Output (GWh)	Revenue (M\$)	Total DSM without load building				Cost (M\$)	1992 DSM as % of				Cost
						ΔSales (GWh)		ΔPeak (MW)			ΔSales		ΔPeak		
						Incr'l	Annual	Incr'l	Annual		Incr'l	Annual	Incr'l	Annual	
Carolina Power & Light	NC	Y	8745	44602	2767	169	4634	169	1369	62	0.4	10.4	1.9	15.7	2.2
Tennessee Valley Authority	AL		21980	120866	5075	11	3239	868	2120	66	0.0	2.7	4.0	9.6	1.3
Florida Power & Light	FL	Y	14661	74691	5100	94	2559	189	1258	96	0.1	3.4	1.3	8.6	1.9
Bonneville Power Administration	MT		15201	76303	1749	0	1753	0	574	13	0.0	2.3	0.0	3.8	0.8
Pacific Gas & Electric	CA	Y	14345	82740	7756	621	1352	696	865	219	0.8	1.6	4.9	6.0	2.8
Puget Sound Power & Light	WA	Y	3906	20710	1025	245	1230	0	13	54	1.2	5.9	0.0	0.3	5.3
Connecticut Light & Power	CT	Y	4016	27367	2316	133	1035	27	265	45	0.5	3.8	0.7	6.6	2.0
Florida Power	FL	Y	6982	29192	1774	51	922	346	1285	77	0.2	3.2	5.0	18.4	4.3
Wisconsin Electric Power	WI	Y	4640	26201	1299	272	751	156	292	54	1.0	2.9	3.4	6.3	4.2
Consolidated Edison	NY	Y	8477	38518	4906	480	638	214	271	116	1.2	1.7	2.5	3.2	2.4
Southern California Edison	CA	Y	18413	82199	7713	0	636	240	2695	88	0.0	0.8	1.3	14.6	1.1
Northern States Power	MN	Y	6128	33880	1716	174	507	111	550	31	0.5	1.5	1.8	9.0	1.8
Niagara Mohawk Power	NY	Y	6159	39251	3123	313	475	62	108	76	0.8	1.2	1.0	1.7	2.4
Arizona Public Service	AZ	Y	3859	21831	1670	32	467	73	580	6	0.1	2.1	1.9	15.0	0.4
Long Island Lighting	NY	Y	3611	17030	2177	136	460	184	251	34	0.8	2.7	5.1	7.0	1.6
Alabama Power	AL	Y	8801	58276	2847	46	453	29	634	22	0.1	0.8	0.3	7.2	0.8
Austin, City of	TX		1498	7404	453	43	407	19	242	5	0.6	5.5	1.3	16.2	1.1
Gulf Power	FL	Y	1836	11206	571	14	401	4	135	3	0.1	3.6	0.2	7.4	0.4
Central Maine Power	ME	Y	1396	10062	872	63	352	12	85	17	0.6	3.5	0.9	6.1	2.0
Massachusetts Electric	MA	Y	2791	16019	1413	114	345	34	102	56	0.7	2.2	1.2	3.7	3.9
Boston Edison	MA	Y	2545	18061	1407	86	336	50	113	56	0.5	1.9	2.0	4.4	4.0
Potomac Edison	MD	Y	1987	17595	688	34	286	18	154	1	0.2	1.6	0.9	7.8	0.1
Seattle, City of	WA		1727	9199	295	50	279	0	0	18	0.5	3.0	0.0	0.0	6.1
Metropolitan Edison	PA	Y	1845	12985	822	20	277	29	375	5	0.2	2.1	1.5	20.3	0.6
PacifiCorp	OR	Y	7258	59638	2361	82	263	0	300	22	0.1	0.4	0.0	4.1	0.9
Totals top 25		21	172807	955827	61895	3282	24056	3530	14637	1241	0.3	2.5	2.0	8.5	2.0
Top 25 as % of national totals			30.2	29.0	31.6	56.7	75.7	46.0	44.5	52.6

Fig. 7. The percentage reduction in retail sales caused by utility DSM programs by state.

1992 DSM-PROGRAM DEMAND REDUCTIONS

Utility DSM programs provided capacity equivalent to 32,900 MW in 1992. Interruptible-rate programs accounted for 45 % of this capacity, with energy-efficiency and direct-load-control programs each accounting for almost one-fourth. The incremental demand reductions from DSM in 1992 totaled 8,200 MW, roughly one-fourth of the annual total. Interruptible programs accounted for more than half the total incremental demand reduction. Some DSM programs, such as interruptible rates and direct load control, are dispatchable (i.e., the utility can call on that capacity much as it would turn on a combustion turbine). Other programs, such as energy efficiency, are not dispatchable (i.e., they provide capacity regardless of system need).

The much larger percentage reduction in peak demand than in energy savings is reflected in the utilities' conservation load factor. CLF is the ratio of DSM-program induced average demand reduction to peak reduction and is analogous to a utility's system load factor. The national average CLF for 1992 was 11 %, far lower than the U.S. system load factor of 49 %.

The industrial sector dominates DSM-induced demand reductions. Although national data on the contributions to peak demand by sector are not available, Fig. 8 suggests that the industrial sector's peak-demand reductions substantially exceed its contribution to peak demand (which is probably less than 30 % of the total). Recently, utilities have focused more DSM attention on demand reductions in the industrial sector, as shown by differences between incremental and annual demand reductions.

Calculating the cost of reduced demand is complicated because some of the costs (in particular, for interruptible-rate programs) are recurring and provide savings only for the year in question. Other costs (in particular for direct-load-control programs) are for capital investments (e.g., switches, controls, and communications equipment) that provide load reductions for several years. The cost of interruptible programs is \$53/kW-year, and the cost of direct-load-control programs (with the same 8 % discount rate and 10-year lifetime assumptions used for energy efficiency in the preceding chapter) is \$35/kW-year. Together, these programs account for three-fourths of the incremental demand reduction at an overall cost of \$48/kW-year.

The distribution of utilities by percentage reduction in peak demand is much broader than the distributions of DSM costs and energy savings (compare Figs. 3 and 6 with Fig. 9). Roughly equal percentages of the utilities reported potential demand reductions of less than 0.5 % or more than 10 % (about 25 % in each case). Fully 10 % of the utilities reported demand reductions greater than 20 %, which seems unlikely.

Fig. 8. Shares of 1992 incremental and annual peak-demand reductions by customer class.

Fig. 9. Distribution of the 504 utilities with DSM programs by percentage of 1992 potential peak demand saved by these programs. On a national-average basis, utilities cut annual peak demand by 6.0% in 1992.

Table 6 lists the 25 utilities that reported the largest annual potential peak demand reduction for 1992. Twenty one of these utilities were among the top 25 for 1991. The additions for 1992 include Arizona Public Service, Metropolitan Edison, Southwestern Public Service, and Consolidated Edison. These utilities, 21 of which are IOUs, accounted for 58% of the total U.S. annual demand reduction. These utilities also accounted for 62% of the annual energy savings and 49% of the utility DSM expenditures for 1992. Overall, these utilities cut peak demand by 8.8%, almost 50% more than the national average.

Fourteen of the top 25 utilities in terms of annual demand reductions for 1992 were also among the top 25 in terms of incremental demand reductions. Four utilities reported zero incremental demand reductions for 1992, which suggests that reporting error played a role, as it did in reporting incremental energy savings. The 11 utilities that ranked among the top 25 in terms of incremental, but not annual, demand reductions include Cleveland Electric Illuminating, Georgia Power, Gulf States Utilities, Jersey Central Power & Light, Long Island Lighting, Minnesota Power & Light, Northern Indiana Public Service, Pennsylvania Power & Light, Public Service Electric & Gas, Texas-New Mexico Power, and West Penn Power.

I was unable to find state-level data on peak demands. I estimated these peaks by summing the peak demands of the individual utilities in each state, which ignores the differences in timing of utility peaks. The national total so obtained was within 3% of the national total reported by EEI. Figure 10 shows the distribution of demand reductions by state. The utilities in six states—Delaware, Florida, Mississippi, North Carolina, North Dakota, and Vermont—reported demand reductions of 10% or more.* Comparing Figs. 7 and 10 shows major differences. While the utilities in the Pacific Northwest spend substantial fractions of their revenues on DSM, their programs focus on energy savings, not on demand reductions, surely a consequence of the large hydroelectric resource in that region. On the other hand, utilities in the middle of the country (roughly from North Dakota to Texas) focus much more on peak reductions than on energy savings.

Aggregate annual demand reductions exceeded 1000 MW in eight states, including Alabama, California, Florida, North Carolina, Pennsylvania, South Carolina, Tennessee, and Texas. Incremental load reductions exceeded 400 MW in six states—California, Florida, North Carolina, New York, Tennessee, and Texas.

*The North Dakota average of 34% demand reduction seems implausible, especially because utility expenditures on DSM amounted to only 1.4% of total retail revenue in the state. Three cooperatives in North Dakota reported peak demand reductions of more than 50%.

Table 6. The 25 utilities with the largest 1992 annual demand savings caused by DSM

Utility	State	IOU	Peak (MW)	Output (GWh)	Revenue (M\$)	Total DSM without load building				Cost (M\$)	1992 DSM as % of				Cost
						ΔSales (GWh)		ΔPeak (MW)			ΔSales		ΔPeak		
						Incr'l	Annual	Incr'l	Annual		Incr'l	Annual	Incr'l	Annual	
Southern California Edison	CA	Y	18413	82199	7713	0	636	240	2695	88	0.0	0.8	1.3	14.6	1.1
Tennessee Valley Authority	AL		21980	120866	5075	11	3239	868	2120	66	0.0	2.7	4.0	9.6	1.3
Duke Power	NC	Y	14149	75631	3961	38	50	197	1382	75	0.0	0.1	1.4	9.8	1.9
Carolina Power & Light	NC	Y	8745	44602	2767	169	4634	169	1369	62	0.4	10.4	1.9	15.7	2.2
Florida Power	FL	Y	6982	29192	1774	51	922	346	1285	77	0.2	3.2	5.0	18.4	4.3
Florida Power & Light	FL	Y	14661	74691	5100	94	2559	189	1258	96	0.1	3.4	1.3	8.6	1.9
Houston Lighting & Power	TX	Y	11638	62603	3827	36	71	190	897	18	0.1	0.1	1.6	7.7	0.5
Pacific Gas & Electric	CA	Y	14345	82740	7756	621	1352	696	865	219	0.8	1.6	4.9	6.0	2.8
Tampa Electric	FL	Y	2762	16977	1006	-1	183	112	696	15	0.0	1.1	4.1	25.2	1.5
Alabama Power	AL	Y	8801	58276	2847	46	453	29	634	22	0.1	0.8	0.3	7.2	0.8
Arizona Public Service	AZ	Y	3859	21831	1670	32	467	73	580	6	0.1	2.1	1.9	15.0	0.4
Bonneville Power Administration	MT		15201	75303	1749	0	1753	0	574	13	0.0	2.3	0.0	3.8	0.8
Northern States Power	MN	Y	6128	33880	1716	174	507	111	550	31	0.5	1.5	1.8	9.0	1.8
Texas Utilities Electric	TX	Y	17525	86070	5029	0	110	0	528	22	0.0	0.1	0.0	3.0	0.4
Oklahoma Gas & Electric	OK	Y	4550	24684	1194	8	116	13	425	18	0.0	0.5	0.3	9.4	1.5
Baltimore Gas & Electric	MD	Y	5558	29949	1968	102	116	111	389	30	0.3	0.4	2.0	7.0	1.5
Metropolitan Edison	PA	Y	1845	12985	822	20	277	29	375	5	0.2	2.1	1.5	20.3	0.6
Potomac Electric Power	DC	Y	5546	26552	1602	105	214	59	339	41	0.4	0.8	1.1	6.1	2.5
Philadelphia Electric	PA	Y	6617	41032	3568	10	52	20	309	10	0.0	0.1	0.3	4.7	0.3
PacifiCorp	OR	Y	7258	59638	2361	82	263	0	300	22	0.1	0.4	0.0	4.1	0.9
Wisconsin Electric Power	WI	Y	4640	26201	1299	272	751	156	292	54	1.0	2.9	3.4	6.3	4.2
Sacramento Municipal Utility	CA		2119	9061	648	111	173	45	281	40	1.2	1.9	2.1	13.3	6.2
Southwestern Public Service	TX	Y	3220	19900	757	0	23	0	279	2	0.0	0.1	0.0	8.7	0.3
Minnkota Power Coop	ND		512	4276	100	0	0	5	275	1	0.0	0.0	1.0	53.7	1.3
Consolidated Edison	NY	Y	8477	38518	4906	480	638	214	271	116	1.2	1.7	2.5	3.2	2.4
Totals top 25		21	215531	1158657	71215	2460	19557	3871	18970	1147	0.2	1.7	1.8	8.8	1.6
Top 25 as % of national totals			39.3	35.2	36.3	42.5	61.6	50.4	57.6	48.6

Fig. 10. The percentage reduction in potential peak demand caused by utility DSM programs by state.

UTILITY FORECASTS TO 1997

EIA asked utilities to estimate DSM-program costs and effects for 1993 and 1997. These estimates were developed in spring 1993.* I normalized these estimates with EIA's Reference Case Projection, prepared for the *Annual Energy Outlook 1994* (EIA 1994a). EIA developed projections for the United States as a whole and for each of the nine census divisions, which are listed in Table 7 (EIA 1994c). The EIA projections show average annual growth in electricity sales of 1.3% between 1992 and 1997, essentially zero change in real electricity price, and inflation that averages 2.6%/year. Because EIA does not prepare projections of electricity use and prices by state, I could not develop normalized state forecasts of DSM costs and activities.

NATIONAL FORECASTS

Utilities expect their expenditures on DSM programs to increase from 1.3% of revenues in 1992 to 1.5% in 1993 and 1.8% in 1997 (Fig. 11). Similarly, forecast reductions in annual energy use increase from 1.2% in 1992 to 2.5% in 1997, and potential demand reductions grow from 6.0% to 8.4%. Thus, while energy savings are expected to more than double over this five-year period, demand reductions and DSM costs are likely to grow by 50% and 70%, respectively. These projections for 1997 DSM expenditures and effects are more ambitious than the utility projections for 2001 made in 1991 (Hirst 1992). For example, the utilities' 1991 estimate of energy savings for the year 2001 totaled 2.7%, only slightly above the 1992 estimate of 2.5% for 1997, four years earlier. These projections imply that utility DSM programs will become more cost effective.

In absolute terms, utility DSM expenditures in 1997 are expected to reach \$4.0 billion (in 1993 dollars). Energy savings and potential peak demand reductions are expected to reach 72,800 GWh and 49,500 MW, respectively. The correlations (r^2) between 1992 and 1997 DSM costs and effects are quite high, ranging from 0.78 for DSM expenditures to 0.90 for demand reductions. Thus, the utilities likely to be DSM leaders in 1997 were, by and large, leaders in 1992.

*These projections are from the 504 utilities that reported running at least one DSM program in 1992. This necessary exclusion of other utilities, some of which may have begun DSM programs after 1992, underestimates utility-industry DSM projections as of spring 1992.

% OF PEAK DEMAND, SALES, AND RETAIL REVENUES

Fig. 11. Utility data on DSM-program costs, energy savings, and potential peak-demand reductions for 1989 through 1992 and forecasts for 1993 and 1997.

REGIONAL FORECASTS

Utility DSM expenditures are expected to increase from \$2.4 billion in 1992 to \$2.9 billion in 1993 and \$4.0 billion in 1997 (Table 8). The New England region spends the highest percentage of revenues on DSM, 2.5% in 1992 and 3.3% in 1997 (Fig. 12). The Pacific region is a close second at 2.2% in 1992 and 2.9% in 1997. The Mountain region shows the most dramatic growth, with DSM expenditures increasing from 0.6% in 1992 to 1.7% in 1997. At the other end of the spectrum, planned expenditures in the East and West South Central divisions are only 0.4% of retail revenues.

The DSM-induced reduction in annual electricity sales is again greatest in New England, expected to reach almost 6% in 1997 (Table 9 and Fig. 13). The Pacific region again is a close second at 4.7%. On the other hand, DSM programs are expected to cut electricity use by only 0.5% in the West South Central region.

Finally, Table 10 and Fig. 14 show the effects of DSM programs on reducing peak demands in each of the nine census divisions. On this measure, the West North Central and South Atlantic regions lead, with planned reductions of more than 10% for 1997. The East North Central region is the only one with a planned reduction in peak demand of less than 5%.

Table 7. States by census division

<u>1. New England</u>	<u>4. West North Central</u>	<u>7. West South Central</u>
Connecticut	Iowa	Arkansas
Maine	Kansas	Louisiana
Massachusetts	Minnesota	Oklahoma
New Hampshire	Missouri	Texas
Rhode Island	Nebraska	
Vermont	North Dakota	<u>8. Mountain</u>
	South Dakota	Arizona
<u>2. Middle Atlantic</u>	<u>5. South Atlantic</u>	Colorado
New Jersey	Delaware	Idaho
New York	District of Columbia	Montana
Pennsylvania	Florida	Nevada
<u>3. East North Central</u>	Georgia	New Mexico
Illinois	Maryland	Utah
Indiana	North Carolina	Wyoming
Michigan	South Carolina	<u>9. Pacific</u>
Ohio	Virginia	Alaska
Wisconsin	West Virginia	California
	<u>6. East South Central</u>	Hawaii
	Alabama	Oregon
	Kentucky	Washington
	Mississippi	
	Tennessee	

Table 8. Costs of electric-utility DSM programs by census division, 1992 through 1997

Region	1992 revenues (million \$)	DSM expenditures			DSM as % of revenues		
		1992	1993	1997	1992	1993	1997
1 New England	10099	255	309	395	2.5	3.0	3.3
2 Mid Atlantic	28512	446	477	679	1.6	1.6	2.1
3 East North Central	30094	234	337	481	0.8	1.1	1.3
4 West North Central	11348	89	113	173	0.8	1.0	1.3
5 South Atlantic	35503	507	692	946	1.4	1.9	2.2
6 East South Central	12162	97	46	58	0.8	0.4	0.4
7 West South Central	22372	86	99	116	0.4	0.4	0.4
8 Mountain	10062	60	112	204	0.6	1.1	1.7
9 Pacific	26556	590	750	963	2.2	2.7	2.9
Totals	186708	2363	2934	4014	1.3	1.5	1.8

Fig. 12. The percentage of retail revenues spent on utility DSM programs by census division in 1992 and projections for 1997.

Table 9. Effects of electric-utility DSM programs on electricity sales by census division, 1992 through 1997

Region	1992 sales (GWh)	DSM energy savings			DSM as % of sales		
		1992	1993	1997	1992	1993	1997
1 New England	103641	2879	3515	6324	2.8	3.4	5.9
2 Mid Atlantic	307766	2960	4147	10434	1.0	1.3	3.3
3 East North Central	460934	1732	2586	6539	0.4	0.6	1.3
4 West North Central	188395	770	1107	3124	0.4	0.6	1.6
5 South Atlantic	547536	10468	11542	17997	1.9	2.1	3.0
6 East South Central	234725	3769	3828	4135	1.6	1.6	1.6
7 West South Central	365831	1263	1442	1872	0.3	0.4	0.5
8 Mountain	166676	1327	1962	4552	0.8	1.2	2.5
9 Pacific	354108	6597	10689	17810	1.9	3.0	4.7
Totals	2729612	31766	40818	72787	1.2	1.5	2.5

Fig. 13. The percentage of annual retail electricity sales reduced by utility DSM programs by census division in 1992 and projections for 1997.

Table 10. Effects of electric-utility DSM programs on peak demands by census division, 1992 through 1997

Region	1992 peaks (MW)	DSM peak reductions			DSM as % of peak		
		1992	1993	1997	1992	1993	1997
1 New England	18582	1044	1112	1710	5.6	5.9	8.9
2 Mid Atlantic	60367	2413	2994	4888	4.0	4.9	7.9
3 East North Central	92108	2403	2760	4598	2.6	3.0	4.7
4 West North Central	36147	2569	2913	4148	7.1	8.0	10.8
5 South Atlantic	120174	10468	11672	15872	8.7	9.5	12.1
6 East South Central	42272	3072	2740	3055	7.3	6.4	6.7
7 West South Central	67964	3844	4286	4632	5.7	6.2	6.4
8 Mountain	30685	1888	2039	2767	6.2	6.5	8.4
9 Pacific	79835	5150	5819	7783	6.5	7.2	9.1
Totals	548133	32850	36335	49451	6.0	6.5	8.4

Fig. 14. The percentage of peak demand cut by utility DSM programs by census division in 1992 and projections for 1997.

CONCLUSIONS

With four years of data (1989 through 1992), EIA-861 provides a comprehensive time series, cross-sectional view of U.S. utility DSM activities. Although the utilities surely reported the costs and effects of their programs in different ways, the level of detail and near-100% coverage of the industry makes EIA-861 a rich source of information.

The 1989–1992 results and 1997 projections lead to several findings:

- The costs and effects of utility DSM programs grew steadily each year from 1989 through 1992. In 1992, utilities spent 1.3% of their revenues on DSM and cut electricity sales and peak demands by 1.2 and 6.0%, respectively.
- As was true in prior years, investor-owned utilities devoted larger fractions of their revenues to DSM than did consumer-owned utilities. However, the COUs reported larger energy and demand reductions.
- Energy-efficiency programs dominated DSM expenditures and energy savings, accounting for 65% of total utility DSM costs and 81% of energy savings but only 24% of peak-demand reductions. Interruptible-rate programs were the most important in cutting peak demands, accounting for almost half the 1992 annual demand reduction.
- The residential sector accounted for a disproportionate share of DSM-induced electricity savings, with the industrial sector getting much less attention. However, the industrial sector dominated demand reductions, accounting for almost half the total reduction. Utility attention is shifting from the residential and industrial sectors to the commercial sector for energy savings and from the residential sector to the industrial sector for demand reductions.
- Although DSM activity is concentrated among a few utilities, this concentration is less than it was in previous years. Whereas only 24% of the 439 DSM utilities in 1991 spent more than 1% of revenues on DSM, 28% of the 504 reporting utilities spent more than 1% in 1992. And 10% of the utilities reported energy savings of greater than 2% in 1992, compared with only 7% in 1991.
- Utility DSM activity is also concentrated among a few states. Here, too, the concentration is less than it was in 1991. To illustrate, the number of states in which utilities averaged more than 2% of revenues on DSM jumped from 6 in 1991 to 11 in 1992. However, DSM expenditures averaged less than 1% in 1992 in the East and West North Central, East and West South Central, and Mountain regions.

- On average, the utilities delivered energy savings at a cost of 4.3¢/kWh and demand reductions at a cost of \$35/kW-year. These utility costs are often lower than the costs of providing new baseload energy or peaking capacity, respectively.
- Utility projections show continued growth in DSM activity between 1992 and 1997. While annual utility DSM expenditures are expected to increase 70% during this period, energy savings are expected to jump 129% and potential demand reductions are expected to increase 50%. These projections show that energy efficiency is likely to become more important over time, relative to demand reductions. Also, DSM programs are expected to become more cost effective.

The utility reports on EIA-861 paint a positive picture of the past, present, and future for DSM programs. But much is happening within the electricity industry that could change its use of DSM programs. In particular, increasing competition at the wholesale and even retail levels could lead to a much greater focus on electricity *prices* than electricity *costs*. Such an emphasis on price would make it difficult for utilities to run DSM programs that provide broad societal benefits. State regulatory commissions have a substantial influence on the nature and extent of utility DSM programs (Schweitzer and Young 1994). If competition erodes the retail monopoly franchise, regulators will have less ability to impose DSM requirements on utilities.

Almost every issue of *Demand-Side Report* contains articles about utilities (especially in the Northeast and California) that are cutting back on their DSM programs. The same issues often contain articles about utilities that are beginning new DSM programs or are ramping up existing programs. Only time (and the 1993 utility reports on EIA-861) will show whether utility DSM programs are increasing or not.

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