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ENERGY DIVISION

ELECTRIC-UTILITY DSM PROGRAMS: 1990 DATA AND FORECASTS TO 2000

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SUMMARY

In April 1992, the Energy Information Administration (EIA) released data on 1989 and 1990 electric-utility demand-side management (DSM) programs. These data represent a census of U.S. utility DSM programs, with reports of utility expenditures, energy savings, and load reductions caused by these programs. In addition, EIA published utility estimates of the costs and effects of these programs from 1991 through 2000.

These data provide the first comprehensive picture of what utilities are spending and accomplishing by utility, state, and region. This report presents, summarizes, and interprets the 1990 data and the utility forecasts of their DSM-program expenditures and impacts to the year 2000. Only utilities with annual sales greater than 120 GWh were required to report data on their DSM programs to EIA. Of the 1,194 such utilities, 363 reported having a DSM program that year.

These 363 electric utilities spent $1.2 billion on their DSM programs in 1990, up from $0.9 billion in 1989. Estimates of energy savings (17,100 GWh in 1990 and 14,800 GWh in 1989) and potential reductions in peak demand (24,400 MW in 1990 and about 19,400 MW in 1989) also showed substantial increases. Overall, utility DSM expenditures accounted for 0.7% of total U.S. electric revenues, while the reductions in energy and demand accounted for 0.6% and 4.9% of their respective 1990 national totals (Fig. S-1).

The investor-owned utilities accounted for 70 to 90% of the totals for DSM costs, energy savings, and demand reductions. The public utilities (which include federal, state, municipal, and cooperative utilities) reported larger percentage reductions in peak demand and energy but smaller percentage DSM expenditures than the investor-owned utilities.

These averages hide tremendous variations across utilities. Almost 30% of these 363 utilities, for example, reported spending less than 0.1% of their revenues on DSM programs in 1990; 22% reported spending more than 1% of their revenues on DSM programs. DSM expenditures exceeded 2% of utility revenues in Maine, Massachusetts, Rhode Island, and Wisconsin.

Utility forecasts of DSM expenditures and effects show substantial growth in both absolute and relative terms. Real expenditures are forecast to grow at 5%/year, from $1.2 billion in 1990 to $2.0 billion in 2000 (in 1990 dollars). And DSM expenditures are expected to increase from 0.7% to 1.5% of revenues during this decade.

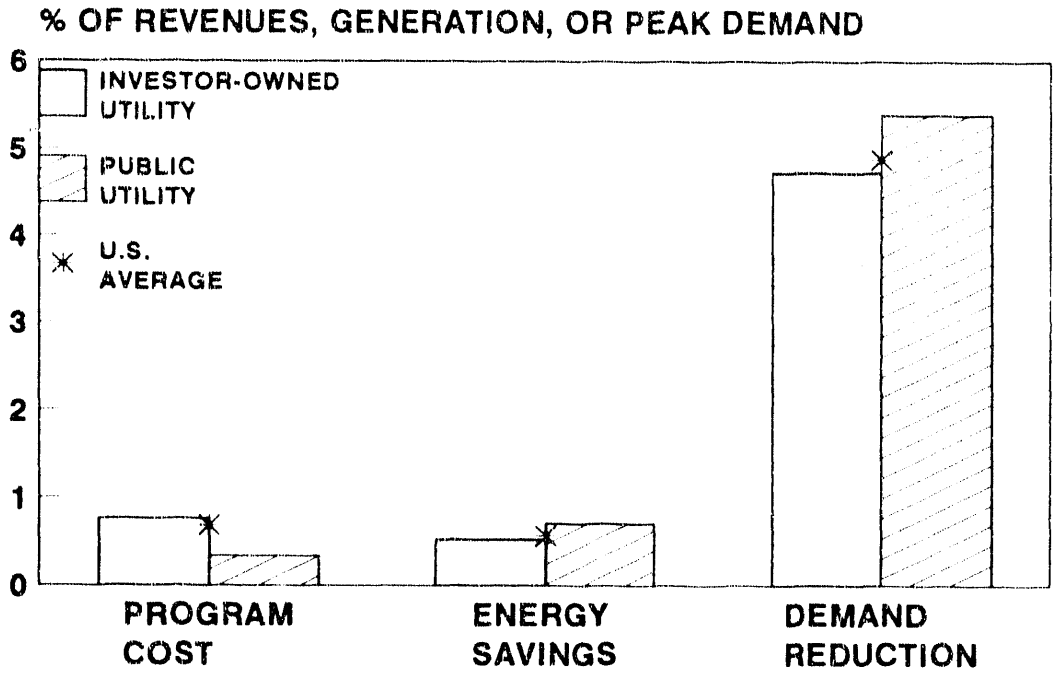

Fig. S-1. The 1990 costs and effects (in terms of energy savings and potential peak-demand reductions) of electric-utility DSM programs.

CHAPTER 1

INTRODUCTION

BACKGROUND

Almost every issue of *The Electricity Journal*, *Public Utilities Fortnightly*, and other publications dealing with electric utilities now contains articles on utility demand-side management (DSM) programs. Almost every resource plan prepared by utilities examines the energy savings and peak-demand reductions likely to occur because of the utility's DSM programs. And almost every proceeding before state regulatory commissions includes some discussion of the costs and benefits of utility DSM programs.

Although DSM is an increasingly important topic for utilities, their regulators, and others, little is known about the national scope, performance, and costs of such programs. The information we have on DSM programs is based primarily on anecdotes, samples of a few utilities, or estimates based on many assumptions. Faruqui et al. (1990) estimated that DSM programs cut annual electricity consumption by 1.3% and summer peak demand by 3.7% in 1990. Schweitzer, Hirst, and Hill (1991) conducted a survey of 24 utilities, representing about a third of total U.S. generating capacity; these utilities reported 1990 reductions of 0.8% for energy and 1.7% for peak demand. Moline (1992) mailed a survey to 2039 public-power utilities, of which 407 (about half of the respondents) reported operating DSM programs; these 407 utilities spent an average of 2.1% of their revenues on DSM programs. And Moskovitz, Nadel, and Geller (1991) obtained estimates of future DSM-program-induced demand and energy reductions from several utilities. But none of these studies was able to provide consistent and comprehensive coverage of the country as a whole.

Fortunately, the picture improved dramatically when the Energy Information Administration (EIA) published data from all U.S. electric utilities collected in its Form 861. EIA-861 is an annual census that collects basic information on utilities. EIA added Schedule V to its 1989 form to ask about the peak-demand reductions (MW), energy reductions (GWh), and costs of utility DSM programs. In April 1992, EIA published summary statistics based on the utility responses to Schedule V for 1989 and 1990 (Prete, Gordon, and Bromley 1992).

Of the roughly 3250 U.S. utilities that completed EIA-861, 872 reported operation of a DSM program. Of the 1,194 utilities with sales greater than 120 GWh, 363 reported running DSM programs in 1990, 30% of the total. These 363 utilities reported spending $1.2 billion on their DSM programs in 1990, up from $0.9 billion in 1989 (Table 1). Estimates of energy savings and reduction in peak demand also showed substantial increases. Overall, utility DSM expenditures accounted for 0.7% of total revenues, while the reductions in energy and demand accounted for 0.6% and 4.9% of their respective 1990 totals.

Table 1. Effects and costs of electric-utility DSM programs, 1989 and 1990

	Potential peak demand reduction (MW and %[a])		Energy savings (GWh/year and %[a])		Program cost (million $ and %[a])	
1989	--		14,800		890	
1990						
Totals[b]	24,400	4.9	17,100	0.6	1,210	0.7
Investor-owned	18,200	4.7	12,100	0.6	1,090	0.8
Public utilities	6,200	5.4	5,000	0.7	120	0.3

[a]These percentages reflect, respectively, total U.S. peak demand, electricity generation, and electric revenues for 1990.

[b]These totals are based on the 363 utilities with annual sales greater than 120 GWh that reported running a DSM program in 1990. Of these 363 utilities, 127 are investor-owned, and the remaining 236 are public.

Source: Prete, Gordon, and Bromley (1992).

The investor-owned utilities (IOUs) accounted for 70 to 90% of these DSM totals, consistent with their national shares of total generating capacity, electricity sales, and revenues. The public utilities (sometimes called customer-owned utilities, which include federal, state, municipal, and cooperative utilities) reported larger percentage reductions in peak demand and energy, but smaller DSM expenditures as a percentage of revenues.

This report presents and interprets the 1990 data and the utility forecasts of their DSM program expenditures and energy and load impacts to the year 2000, building on the analysis conducted by Prete et al. It also provides additional detail by analyzing the data in terms of utility ownership and state. Chapter 2 presents DSM-program expenditures for 1990. Chapters 3 and 4 discuss energy savings and potential peak-demand reductions, respectively. Chapter 5 discusses utility forecasts through the year 2000. And the final chapter presents caveats and conclusions derived from the EIA-861 data. But first, the remainder of this chapter describes the form itself, especially Schedule V.

EIA-861

All electric utilities are required by federal law to complete EIA-861. Schedule I collects basic information on the utility's name and address. Schedule II collects information on utility ownership, summer and winter peak loads, and sources and disposition of energy. Schedule III collects data on electric revenues. Schedule IV collects data on revenues, sales, and number of customers by sector and state in which the utility sells electricity. Schedule V collects data on the effects and costs of the utility's DSM programs for the prior year and estimates for the next ten years (Fig. 1). Only utilities with annual sales greater than 120

GWh are required to complete Schedule V. Finally, Schedule VI collects data on nonutility power production.

EIA defines DSM as "a utility-administered program that is designed to reduce demand and/or electricity use. ... [L]oad building, load retention, and fuel substitution activities designed to increase demand and/or electricity use are excluded from the Demand-Side Management Program" (EIA 1990).

DSM expenditures are those "incurred by the utility to achieve the capacity and energy savings from the Demand-Side Management program. Expenditures incurred by consumers or third parties are to be excluded. The expenditures are to be reported in nominal dollars in the year in which they are incurred, regardless of when the savings occur."

Two types of estimates of reductions in peak load are requested. The first refers to the actual reduction in peak load caused by the utility's DSM program, specifically including the effects of direct load control, interruptible load, and conservation and other DSM. The second refers to the potential reduction in peak load, based on "the capability of reducing system demand ... , whether or not any reduction actually occurred ... ." This report examines potential, rather than actual, demand reductions. The demand and energy reductions are intended to reflect cumulative effects, which include the effects caused by all program participants from the program's inception through the present year, not just the participants in the current year.

Although it is tempting to compare utility costs with benefits, the results obtained would be misleading. As noted above, the DSM-program expenditures exclude costs borne by program participants and other nonutility parties. More important, the costs reflect utility expenditures in a particular year, whereas the reported energy savings and load reductions reflect the benefits of past as well as current program activities. Thus there is an unavoidable temporal mismatch between the data on costs and benefits. The Tennessee Valley Authority provides an interesting example of this phenomenon. TVA canceled its DSM programs in 1989, which accounts for its report to EIA of zero DSM-program expenditures in 1990. However, the program that TVA operated between the late 1970s and 1989 produced substantial energy savings and load reductions, as shown in Chapters 3 and 4.

U.S. Department of Energy
Energy Information Administration
Form EIA-861 (1990)

Annual Electric Utility Report for the Reporting Period 1990

Utility Code:
Utility Name:

Schedule V
Demand-Side Management Information (Actual and 10-Year Forecast)

1. Do you have a utility-administered Demand-Side Management (DSM) program designed to reduce demand and/or electricity use ? a _____Yes b. _____No
   If "YES", and your sales to ultimate consumers reported on Schedule II, Question 8K or sales for resale reported on Schedule II, Question 8L are greater than 120,000 megawatthours, complete questions 2 through 6.
2. Enter for the reporting year (1990) the percent of peak load reduction attributable to each consumer class that participates in your DSM program.
   Note: a + b + c + d = 100%. a. _____ Residential b. _____ Commercial c. _____ Industrial d. _____ Other

For Questions 3 through 6, the DSM information should: (1) account for annual cumulative load reduction, cumulative energy savings, and expenditures; (2) reflect actual or expected realized amounts, not contract amounts; (3) conform with existing and planned activities that are expected to be in effect during the forecast period; and (4) account for retirements, equipment degradation, equipment turnover, and the regular cycling of energy efficiency units. Note: Power supply cooperatives, Federal Power Marketing Administrations, and the Tennessee Valley Authority are encouraged to coordinate the reporting of DSM information with their power purchasing utilities to avoid double counting.

3. Enter for the reporting year (1990) the actual reduction in annual peak load attributable to each of the following categories. Note: a = b + c + d.
   a. the total DSM program; including Direct Load Control, Interruptible Load, Conservation and Other DSM categories. _____ (MW)
   b. only the Direct Load Control activities that are included as part of the total DSM Program reported in (a). _____ (MW)
   c. only the Interruptible Load activities that are included as part of the total DSM Program reported in (a). _____ (MW)
   d. only the Conservation and Other DSM peak load reduction activities that are included as part of the total DSM Program reported in (a). _____ (MW)
4. Enter for the reporting year (1990) and for each of the next 10 years, in megawatts, the estimated annual peak load reduction achievable through full implementation of existing activities, and existing and planned activities, respectively, for each of the following DSM categories.

	Existing	Annual Cumulative Forecast									
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
a. Direct Load Control (MW)											
b. Interruptible Load (MW)											
c. Conservation and Other (MW)											

5. Enter for the reporting year (1990) and for each of the next 10 years, in megawatthours, the actual savings from existing activities and the estimated annual energy savings achievable through full implementation of existing and planned activities, respectively, for the total DSM Program.

	Actual	Annual Cumulative Forecast									
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DSM Energy Savings (MWh)											

6. Enter for the reporting year (1990) and for each of the next 10 years, in thousands of dollars, your total actual expenditures and estimated annual expenditures to achieve the capacity and energy savings from the existing activities, and the existing and planned activities, respectively, for the total DSM program.

	Actual	Annual Forecast									
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DSM Expenditures ($1000)											

Fig. 1. Schedule V from EIA-861.

DSM-PROGRAM EXPENDITURES

I begin with expenditure data because it is probably more reliable than the data on demand and energy reductions. Estimates of energy savings and load reductions are confounded by definitions concerning net vs total effects, cumulative vs annual savings, the treatment of transmission and distribution losses, and the data and analytical methods used to estimate these effects (Hirst and Sabo 1991); see Chapters 3 and 6.

Although DSM-program expenditures totaled $1.2 billion in 1990 (0.7% of U.S. electric revenues), the distribution across the 363 utilities is highly skewed (Fig. 2). Only 31 utilities (less than 9% of the 363) accounted for three-fourths of the DSM-program costs that year. Almost 30% of these 363 utilities reported expenditures less than 0.1% of electric operating revenues; on the other hand, only 8% reported spending 2% or more on DSM programs (Fig. 3).

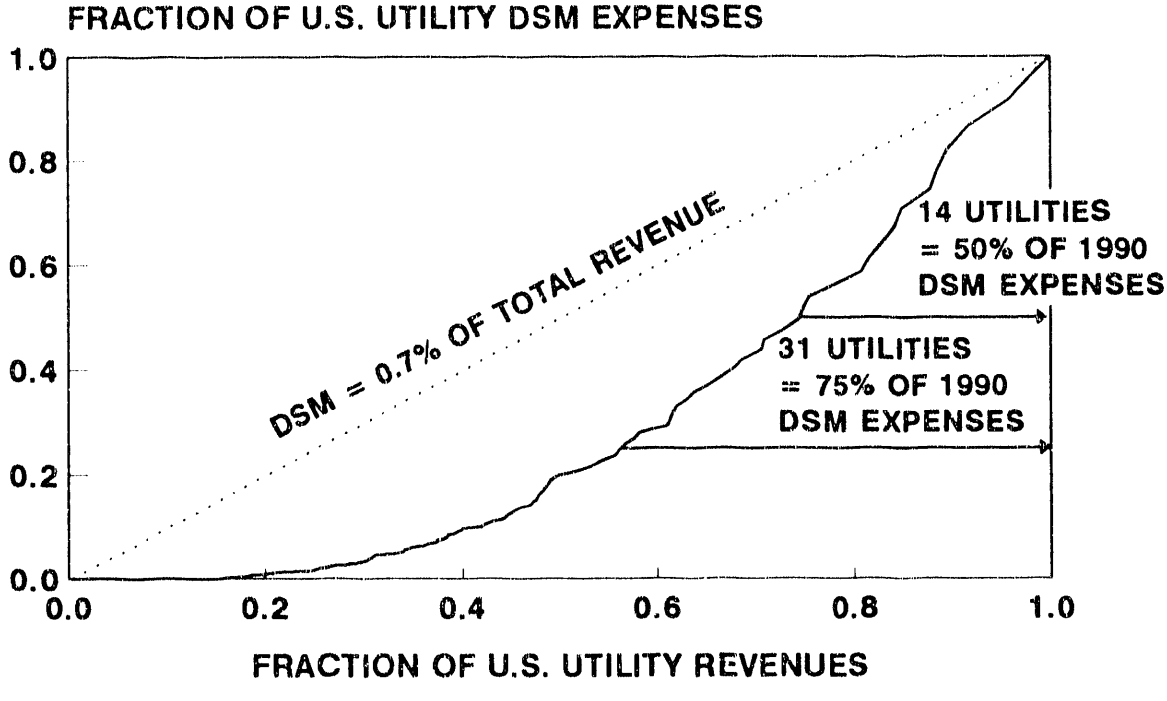

Fig. 2. 1990 DSM-program expenditures for the 363 electric utilities with DSM programs as a function of total revenues. The utilities are ordered in terms of increasing DSM expenditures.

A statistical analysis of the fraction of revenues spent on DSM showed no correlation with annual revenues, a weak correlation with utility ownership ($p = 0.20$), and a stronger correlation with electricity price ($p = 0.10$). Investor-owned utilities spent 0.1 percentage points more on DSM than public utilities. And each 1¢/kWh-increase in electricity price led to a 0.05 percentage point increase in DSM expenditures.

The data suggest that utilities on the east and west coasts plus a few in the midwest dominate in terms of DSM-program expenditures (Fig. 4). These results are only suggestive because many utilities sell electricity in more than one state. As examples, Duke Power and Carolina Power & Light dominate in North *and* South Carolina; PacifiCorp sells electricity in seven states in the northwest. Because of the difficulties in assigning DSM-program costs to individual states for utilities that serve in more than one, I combined results for a few states [i.e., North and South Carolina, the District of Columbia (DC) and Maryland, and Oregon and Washington]. DSM expenditures exceeded 1% of revenues in Maine, Massachusetts, Vermont, Connecticut, Rhode Island, DC and Maryland, North and South Carolina, Florida, Wisconsin, Washington and Oregon, and California.

Mitchell (1992) conducted a survey in 1991 to assess the status of integrated resource planning in each state. She defined "advanced" resource planning as one in which "significant DSM implementation is underway or has already occurred." All four of the states with DSM expenditures greater than 2% of revenues (Maine, Massachusetts, Rhode Island, and Wisconsin) were rated advanced by Mitchell. Ten of the twelve states rated advanced spent more than 1% of revenues on DSM; only Minnesota and Nevada spent less (between 0.7 and 1.0%). Thus, the utility reports to EIA and Mitchell's ratings are consistent with each other.

As shown in Fig. 2, a few utilities account for the vast majority of DSM expenditures. The top 25 utilities are listed in Table 2. One (Sacramento Municipal Utility District) is a public utility; the other 24 are investor-owned. These 25 utilities account for 68% of the national total DSM expenditure and for 37% of total U.S. electric revenues for 1990. Although the majority of these utilities are multibillion dollar companies, four (Puget Power, Central Maine Power, Commonwealth Electric, and Sacramento) are not.

Because public utilities are, on average, much smaller than investor-owned utilities, examination of the percentage of revenues spent on DSM programs (Table 3) reveals a different picture than that shown for absolute expenditures in Table 2. In terms of percentage expenditures on DSM, public-power dominates, with 14 of the top 25 utilities. On average, these 25 utilities spent 3.6% of revenues on their DSM programs, five times more than the national average of 0.7%.

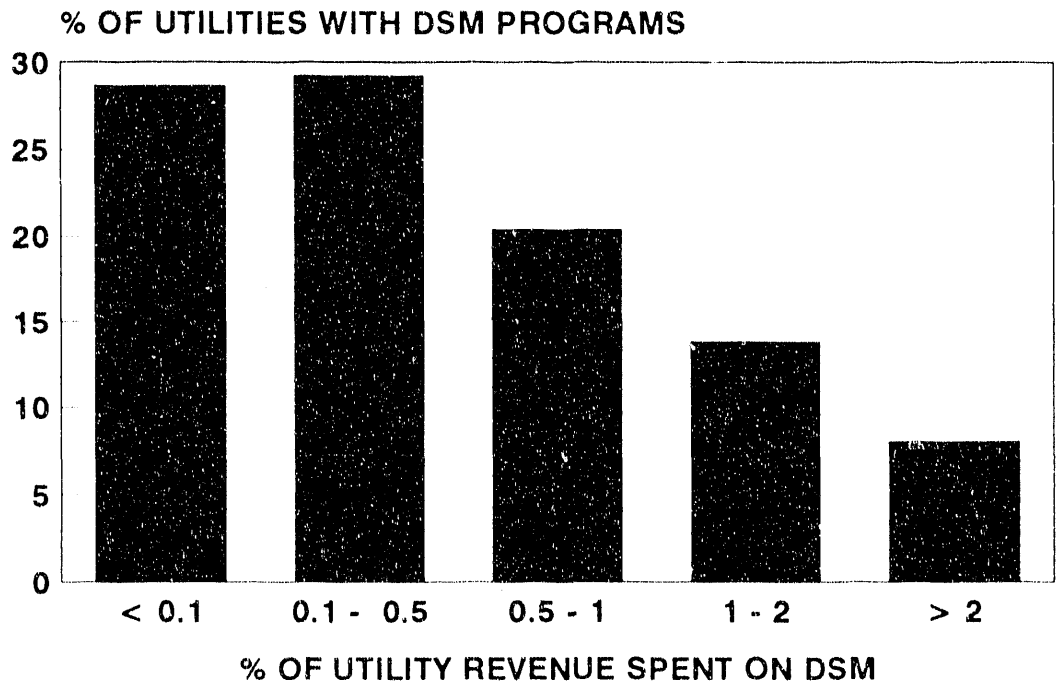

Fig. 3. Distribution of the 363 utilities with DSM programs by percentage of 1990 electric revenues spent on these programs. Both the mean value and the ratio of total expenditures to total revenues are 0.7%.

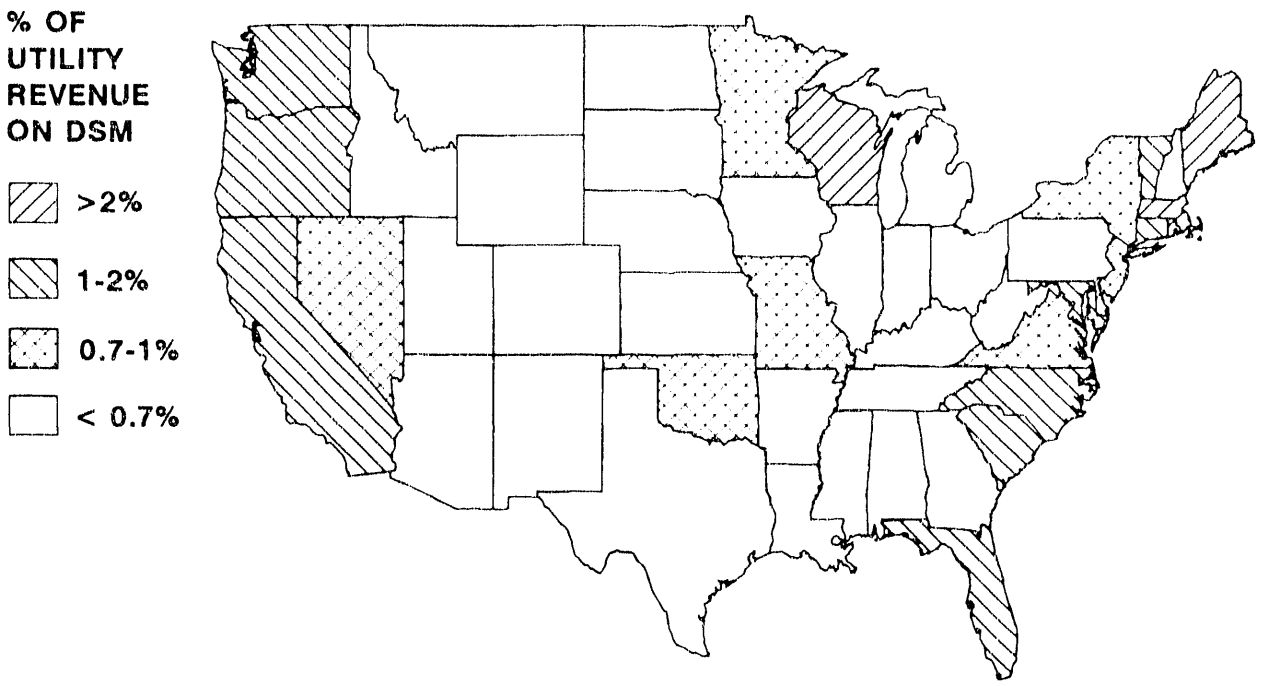

Fig. 4. The percentage of electric revenues spent on utility DSM programs by state.

Table 2. The 25 utilities with the greatest 1990 expenditures on DSM

Utility	State	IOU (Yes, No)	DSM expenditure (million $)	Revenue (million $)	% revenue on DSM
Pacific Gas & Electric Company	CA	Yes	100.0	7044	1.4
Southern California Edison Co	CA	Yes	62.2	6977	0.9
Duke Power Company	NC	Yes	55.0	3681	1.5
Florida Power Corporation	FL	Yes	49.8	1709	2.9
Wisconsin Electric Power Co	WI	Yes	43.0	1208	3.6
Florida Power & Light Company	FL	Yes	42.7	4988	0.9
Massachusetts Electric Company	MA	Yes	42.2	1253	3.4
Connecticut Light & Power Co	CT	Yes	39.3	2170	1.8
Long Island Lighting Company	NY	Yes	34.4	2086	1.7
Boston Edison Company	MA	Yes	29.5	1256	2.3
Consolidated Edison Co-NY, Inc	NY	Yes	29.3	4756	0.6
Georgia Power Company	GA	Yes	28.3	4235	0.7
Puget Sound Power & Light Co	WA	Yes	26.6	935	2.8
Central Maine Power Company	ME	Yes	25.4	755	3.4
Carolina Power & Light Company	NC	Yes	24.8	2617	0.9
Virginia Electric & Power Co	VA	Yes	23.0	3462	0.7
Commonwealth Electric Company	MA	Yes	21.8	354	6.2
Public Service Electric & Gas Co	NJ	Yes	21.5	3332	0.6
Potomac Electric Power Company	DC	Yes	20.9	1412	1.5
Union Electric Company	MO	Yes	20.0	1939	1.0
PacifiCorp	OR	Yes	19.0	2184	0.9
Niagara Mohawk Power Corp	NY	Yes	17.0	2646	0.6
San Diego Gas & Electric Co	CA	Yes	16.7	1355	1.2
Baltimore Gas & Electric Co	MD	Yes	16.5	1684	1.0
Sacramento Municipal Utility Dist.	CA	No	16.0	702	2.3
Totals and average			824.9	64740	1.8

Table 3. The 25 utilities with the greatest 1990 percentage of expenditures on DSM

Utility	State	IOU (Yes, No)	DSM expenditure (million $)	Revenue (million $)	% revenue on DSM
Minnkota Power Coop, Inc	ND	No	6.5	93	7.0
Commonwealth Electric Company[a]	MA	Yes	21.8	354	6.2
City of Detroit Lakes	MN	No	0.2	5	4.8
Grant-Lafayette Electric Coop	WI	No	0.5	10	4.7
Northeast Oklahoma El Coop Inc	OK	No	1.0	22	4.4
City of Burlington	VT	No	1.5	37	4.2
City of Ashland	OR	No	0.2	7	3.6
Wisconsin Electric Power Co[a]	WI	Yes	43.0	1208	3.6
Narragansett Electric Company	RI	Yes	14.5	412	3.5
Polk-Burnett Electric Coop	WI	No	0.4	10	3.5
City of Eugene	OR	No	3.0	86	3.5
Massachusetts Electric Company[a]	MA	Yes	42.2	1253	3.4
Central Maine Power Company[a]	ME	Yes	25.4	755	3.4
Federated Rural Electric Assn	MN	No	0.2	6	3.3
Granite State Electric Company	NH	Yes	1.7	52	3.3
BARC Electric Cooperative, Inc	VA	No	0.3	9	3.2
Wisconsin Power & Light Co	WI	Yes	14.8	467	3.2
Cambridge Electric Light Co	MA	Yes	3.4	116	2.9
Florida Power Corporation[a]	FL	Yes	49.8	1709	2.9
Puget Sound Power & Light Co[a]	WA	Yes	26.6	935	2.8
Yellowstone Valley Elec Coop Inc	MT	No	0.2	8	2.6
Tri-County Electric Coop, Inc	IL	No	0.6	21	2.6
PUD No 1 of Snohomish County	WA	No	5.9	231	2.5
Lake Region Coop Elec Assn	MN	No	0.4	15	2.5
Western Massachusetts Elec Co	MA	Yes	9.5	375	2.5
Totals and average		11	273.5	8197	3.6

[a]These six utilities are in both Tables 2 and 3.

DSM-PROGRAM ENERGY SAVINGS

The results presented in this and the following chapter should be viewed cautiously for several reasons. First, utilities may use different definitions for DSM programs. For example, Carolina Power & Light and Florida Power Corporation include the energy provided by cogenerators in their DSM-program totals; most other utilities do not. Some utilities might have included the effects of their load-building programs even though the EIA instructions clearly stated that they should not.

Second, utilities use different methods to estimate the effects of their DSM programs; in general, engineering estimates are higher than estimates based on billing data or load-research data (Nadel and Keating 1991).

Third, utilities might report estimates at the customer meter or at the generator busbar; these estimates differ by roughly 5 to 15% because of losses in the transmission and distribution system.

Fourth, some utilities might report total savings rather than net savings. Net savings are the reductions in electricity use and demand that can be attributed directly to the program, whereas total savings are the reductions in electricity use and demand experienced by program participants (Hirst and Sabo 1991).

Finally, some utilities might have reported annual savings instead of the cumulative savings requested by EIA. Messenger (1992) notes that the California utilities reported annual savings; he suggests that the correct number for Southern California Edison is 4,100 GWh, not the 610 GWh reported by the company.

The distribution across utilities in energy savings (Fig. 5) is even more skewed than is the distribution of program expenditures. Here, only 13 utilities account for three-fourths of the national savings. Almost two-thirds of the 363 utilities reported energy savings less than 0.1% of 1990 generation. And only 7% of these utilities reported cutting energy use by 2% or more.

As shown in Fig. 5, a very few utilities account for most of the energy savings. The top 25 are listed in Table 4. Four of these utilities are publics, and the remaining 21 are IOUs. Two of the public-power utilities are federal agencies, the Tennessee Valley Authority and the Bonneville Power Administration, which sell electricity to almost 300 public-power utilities. Altogether, these 25 utilities accounted for 86% of the total DSM-program energy savings in 1990, compared with only 27% of total generation. On average, these utilities cut energy use by 2.1%, more than triple the national average of 0.6%.

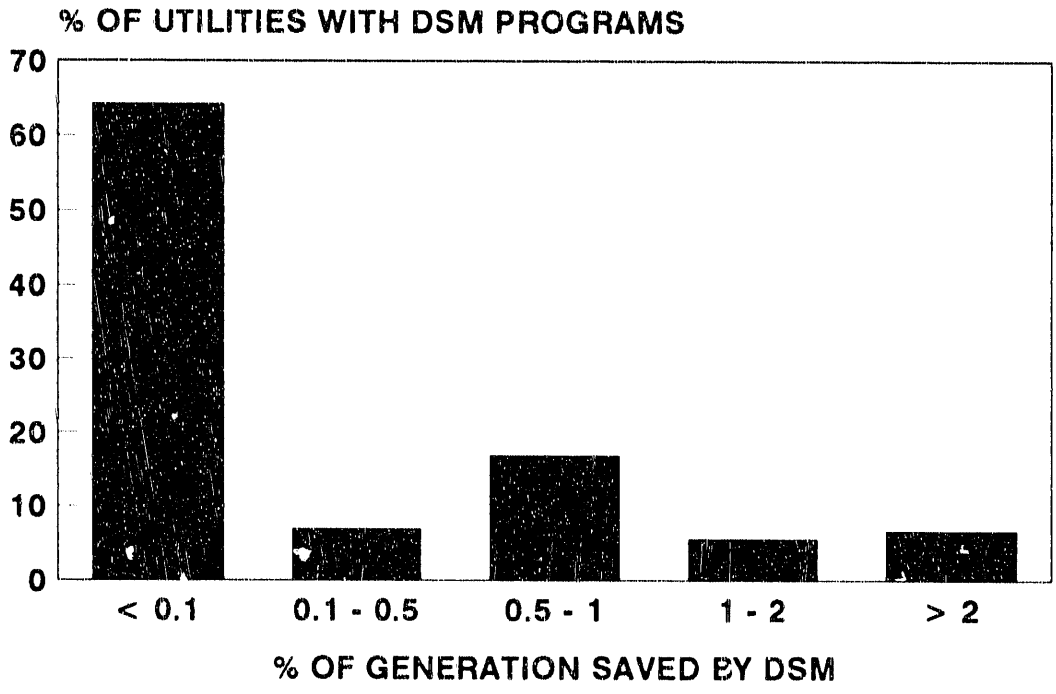

Fig. 5. Distribution of the 363 utilities with DSM programs by percentage of total 1990 generation saved by these programs. The mean value is 0.5% of generation saved, and the ratio of total energy savings to total generation is 0.6%.

Table 4. The 25 utilities with the largest 1990 energy savings

Utility	State	IOU (Yes, No)	GWh saved	Total GWh	% GWh saved
Carolina Power & Light Company	NC	Yes	3578	41437	8.6
Tennessee Valley Authority	TN	No	3066	118397	2.6
Philadelphia Electric Company	PA	Yes	877	36507	2.4
Bonneville Power Administration	OR	No	867	88600	1.0
Florida Power Corporation	FL	Yes	817	28523	2.9
Southern California Edison Co	CA	Yes	607	80368	0.8
Wisconsin Electric Power Co	WI	Yes	591	25020	2.4
Connecticut Light & Power Co	CT	Yes	580	26560	2.2
Public Service Electric & Gas Co	NJ	Yes	539	39418	1.4
Pacific Gas & Electric Company	CA	Yes	408	81200	0.5
Gulf Power Company	FL	Yes	405	10110	4.0
Northern States Power Company	MN	Yes	329	33192	1.0
Central Maine Power Company	ME	Yes	327	10032	3.3
Massachusetts Electric Company	MA	Yes	206	16649	1.2
Long Island Lighting Company	NY	Yes	204	17374	1.2
Sacramento Municipal Utility Dist.	CA	No	192	8811	2.2
PUD No 1 of Snohomish County	WA	No	183	5885	3.1
Hawaiian Electric Company, Inc	HI	Yes	152	6831	2.2
Tampa Electric Company	FL	Yes	133	14160	0.8
Boston Edison Company	MA	Yes	120	15260	0.8
Virginia Electric & Power Co	VA	Yes	118	58312	0.2
Potomac Electric Power Company	DC	Yes	103	24975	0.4
San Diego Gas & Electric Co	CA	Yes	103	16173	0.6
United Illuminating Company	CT	Yes	92	6335	1.5
Black Hills Corporation	SD	Yes	90	1548	5.8
Totals and average			14700	813677	2.1

DSM-PROGRAM PEAK DEMAND REDUCTIONS

The distribution across utilities in the potential demand reduction at the time of system peak is much less skewed than for either expenditures or energy savings (Fig. 6). This difference reflects the fact that, traditionally, utility DSM programs have emphasized reductions in peak demand rather than overall improvements in customer energy efficiency. Whereas only 13 utilities account for 75% of the 1990 energy reduction, 40 utilities account for 75% of the peak demand reduction. Whereas 64% of the 363 utilities reported energy savings less than 0.1% of generation, only 6% reported demand reductions less than 0.1% of peak demand. Almost 50% of the utilities reported potential reductions greater than 5% of peak demand.

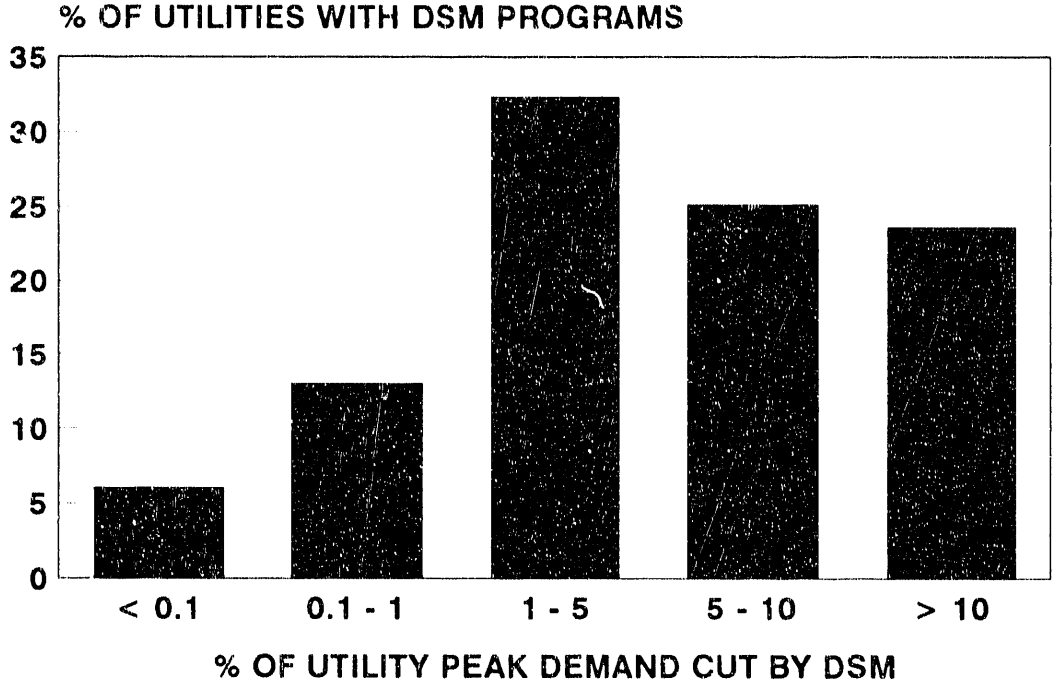

Fig. 6. Distribution of the 363 utilities with DSM programs by percentage of total 1990 peak-demand savings by these programs. The mean value is 7.9% of system peak, and the ratio of total potential demand reduction to total peak is 4.9%.

Table 5 lists the top 25 utilities in terms of potential demand reductions. Twenty of these utilities are investor-owned, and three of the five publics are federal utilities. Altogether, these 25 utilities account for 63% of the total demand reduction and 40% of the summer peak. On average, these 25 utilities cut peak demand by 10.1%, double the national average of 4.9%.

Table 5. The 25 utilities with the greatest 1990 peak-demand reductions

Utility	State	IOU (Yes, No)	MW saved	Peak demand		% MW saved
				MW-Winter	MW-Summer	
Southern California Edison Co	CA	Yes	1494	12405	17647	8.5
Texas Utilities Electric Co	TX	Yes	1363	15620	18007	7.6
Carolina Power & Light Company	NC	Yes	1248	7205	8134	15.3
Tennessee Valley Authority	TN	No	1182	18451	21749	5.4
Florida Power Corporation	FL	Yes	1079	5026	5946	18.1
Houston Lighting & Power Co	TX	Yes	1070	8302	11150	9.6
Florida Power & Light Company	FL	Yes	970	10047	13754	7.1
Bonneville Power Administration	OR	No	878	18034	16316	4.9
Duke Power Company	NC	Yes	742	11607	13514	5.5
Georgia Power Company	GA	Yes	629	8977	13196	4.8
Alabama Power Company	AL	Yes	444	6936	8878	5.0
Northern States Power Company	MN	Yes	444	5341	6733	6.6
Oklahoma Gas & Electric Co	OK	Yes	402	3480	4810	8.4
Western Area Power Administration	AZ	No	379	--	--	--
PacifiCorp	OR	Yes	353	7735	6713	4.6
Oglethorpe Power Corporation	GA	No	342	2038	3203	10.7
Philadelphia Electric Company	PA	Yes	319	--	--	--
Tampa Electric Company	FL	Yes	303	2052	2630	11.5
Minnkota Power Coop, Inc	ND	No	270	504	328	53.6
Public Service Electric & Gas Co	NJ	Yes	265	5817	8497	3.1
Potomac Electric Power Company	DC	Yes	245	3947	5442	4.5
Iowa Electric Light & Power Co	IA	Yes	238	747	1005	23.7
Pennsylvania Power & Light Co	PA	Yes	232	5661	4959	4.1
Connecticut Light & Power Co	CT	Yes	218	3765	4015	5.4
Arkansas Power & Light Company	AR	Yes	217	2492	3993	5.4
Totals and average			15326	166189	200619	10.1

UTILITY FORECASTS, 1991—2000

EIA requested estimates of future DSM-program expenditures and effects for the years 1991 through 2000 in Schedule V. I normalized these utility reports with EIA's projections of growth in electricity use and prices from 1990 through 2000 (EIA 1991). EIA expects electricity use to increase at an average annual rate of 1.9% during the 1990s and electricity price to remain unchanged in real terms.

Assuming an average inflation rate of 4.5%/year during the 1990s, these utility forecasts show growth in DSM expenditures from $1.2 billion in 1990 to $2.0 billion in 2000 (in 1990 dollars), an average growth of 5%/year. Compared to projected revenues, DSM budgets are expected to increase from 0.7% in 1990 to 1.5% in 2000 (Fig. 7).

Energy savings are expected to increase from 17,100 GWh in 1990 to 78,500 GWh in 2000, with a relative growth from 0.6% to 2.2% of total generation. Potential demand reductions are also expected to increase, from 24,400 MW in 1990 to 55,800 MW in 2000, with a relative growth from 4.9% to 9.3% of peak demand. As shown in Fig. 7, the increase in energy effects is much greater than for either expenditures or demand reductions.

I believe that these utility forecasts, made in early 1991, underestimate future DSM expenditures and effects. Utility resource plans often show increases in estimates of future DSM-program effects as the utility gains experience in running DSM programs. Consider the following examples. Georgia Power reported zero energy savings for each year, 1990 through 2000, in its EIA-861 submission (although it reported nonzero DSM-program expenditures and peak-demand reductions). However, its 1992 resource plan shows substantial energy savings expected from its DSM programs, reaching 580 GWh in 1995 and 1,680 GWh in 2000 (Georgia Power 1992). Duke Power's EIA-861 responses also showed zero energy savings throughout the 1990s. However, its 1992 resource plan showed rapidly increasing energy savings caused by its DSM programs: 14 GWh in 1992, 269 GWh in 1993, 664 GWh in 1994, and almost 2,000 GWh in 1997 (Duke Power 1992). The Los Angeles Department of Water and Power (the nation's largest municipal utility) reported having no DSM program on the 1990 EIA-861. Since then, however, the utility has begun a rapidly expanding DSM program (Association of Demand-Side Management Professionals 1992). The utility plans to spend $500 million on DSM programs during the next ten years. PacifiCorp (1992) provides a less dramatic example. Its 1992 resource plan shows an estimated energy savings of 239 GWh in 1993, 10% higher than the value reported to EIA.

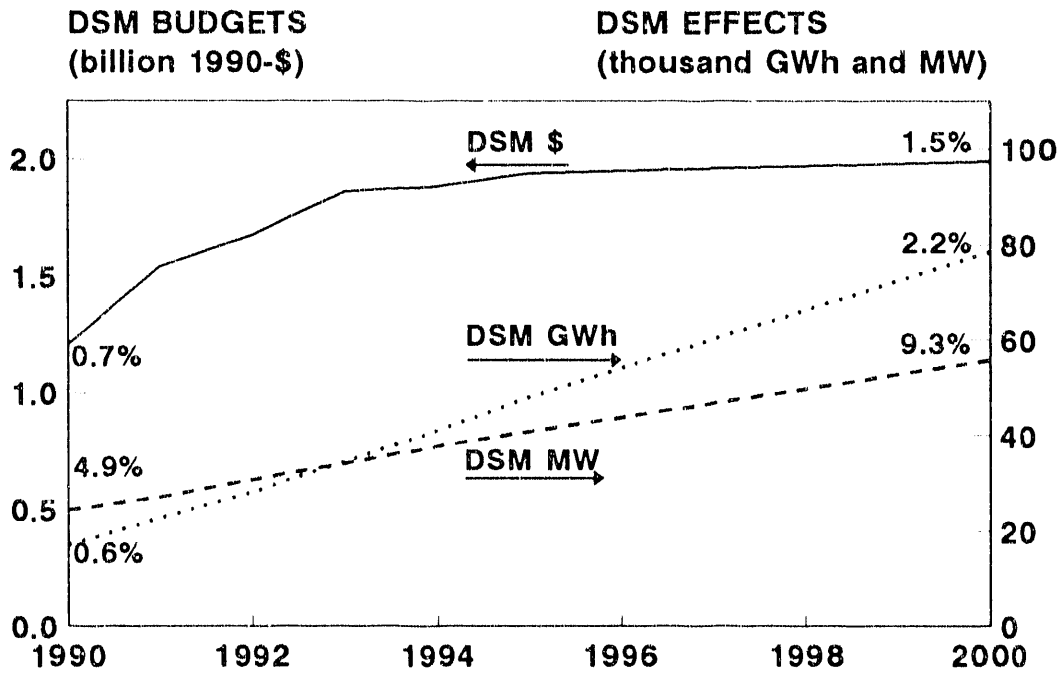

Fig. 7. Utility forecasts of DSM-program expenditures and effects from 1990 through 2000 in absolute and relative terms. The percentage figures are relative to the 1990 and 2000 national totals for annual electric-utility revenues, sales, and peak demands.

CAVEATS AND CONCLUSIONS

CAVEATS

Because Schedule V is a new form, some of the responses are likely to be ambiguous or incorrect. For example, although EIA asked utilities to report "cumulative" energy savings, the word cumulative was not defined. Cumulative effects are the changes in electricity use and demand caused by all of a program's participants from the program's inception through the current year (Hirst and Sabo 1991). Some utilities might have reported annual effects, which are the changes in electricity use and demand caused by a program's activities during a given year. This type of error would underestimate DSM-program effects.

On the other hand, possible double-counting would overestimate effects. EIA encouraged "power supply cooperatives, federal power marketing administrations, and the Tennessee Valley Authority ... to coordinate the reporting" of DSM program information, but there is no assurance that this occurred.

Estimates of program effects can differ substantially depending on the point in the system at which they are estimated, the data and analytical methods used to derive these estimates, and the definition of program effect that is used. Estimates of peak-demand reduction at the generation level are likely to be 10 to 15% higher than estimates at the customer meter; for energy savings, the difference is likely to be 5 to 10%. Reliance on measured electricity use (either monthly billing data or time-of-use data) coupled with sophisticated statistical methods is likely to yield estimates of energy savings that are lower (and more accurate) than those based on simple engineering calculations. And estimates that focus on the effects of the program in question and therefore exclude the effects of market forces, government efficiency standards, and nonutility programs are likely to be lower than estimates that take credit for these other influences on customer electricity use.

In some cases, utilities left blanks. For example, some utilities reported DSM-program expenditures for 1990 but not for future years, which has the effect of underestimating DSM-program costs. (I corrected for this in Chapter 5 by excluding those utilities from the analysis of growth in expenditures from 1990 through 2000.) Several utilities did not report estimates of program-induced energy savings, although subsequent resource plans from these companies show substantial commitments to energy efficiency.

Developing state totals is complicated by the fact that many utilities sell electricity in more than one state. For example, Potomac Electric Power Company serves customers in the District of Columbia and in Maryland. Assigning all its activities to DC leads to a 140% overestimate of the DC total utility revenue and a 21% underestimate for Maryland. When

DC and Maryland are combined, the EIA-861 results agree very closely with the state totals reported in the *Electric Power Monthly* (EIA 1992a).

CONCLUSIONS

As of 1990, the costs and effects of utility DSM programs were small. These programs cut peak demand by 4.9% and energy use by 0.6%; utilities spent 0.7% of total revenues that year on such programs. These averages, however, hide a tremendous amount of variation across utilities in both the absolute and relative effects of their DSM programs. Specifically, although 363 (of 1,194) utilities reported running DSM programs in 1990, the "top" 50 utilities account for three-fourths of these costs and effects (Fig. 8). Thus, the majority of U.S. utilities are running what could at best be considered modest DSM programs.

However, projected growth for the 1990s is very rapid. DSM budgets are expected to nearly triple, peak-demand reductions are expected to more than double, and energy savings are expected to increase more than four-fold (Fig. 7). Relative to the expected increases in electricity use and revenues, DSM effects and costs also increase, but at slower rates.

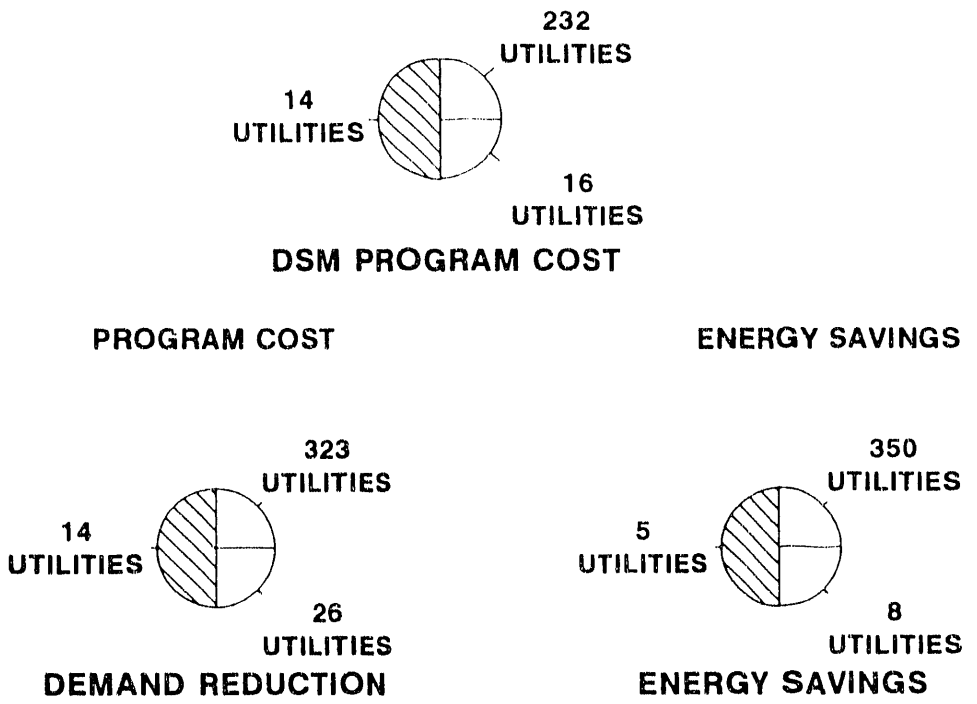

Fig. 8. Distributions across the 363 utilities with DSM programs in 1990 of totals for program costs, peak-demand reductions, and energy savings. For example, only 14 utilities account for 50% of the total demand reduction caused by DSM programs in 1990.

The differences in DSM budgets and effects across utilities is astonishing. To some extent this variation is a function of utility ownership and location, with investor-owned utilities and those in New England and the west coast more likely to spend a larger fraction of revenues on DSM programs than other utilities are.

There are limitations in the 1990 data reported on EIA's form 861, an unavoidable consequence of any new data-collection instrument. Nevertheless, these data provide a comprehensive and useful picture of 1990 activities and plans through the year 2000. EIA (1992b) is expanding the scope of Schedule V. The draft 1992 form includes questions on DSM-program effects by customer class and breakdowns by type of DSM program (energy efficiency, load management, interruptible load, load building, and other programs). These additional questions should yield a much more detailed picture of utility DSM programs and their effects.

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