Chapter 3
Demand-Side Resources

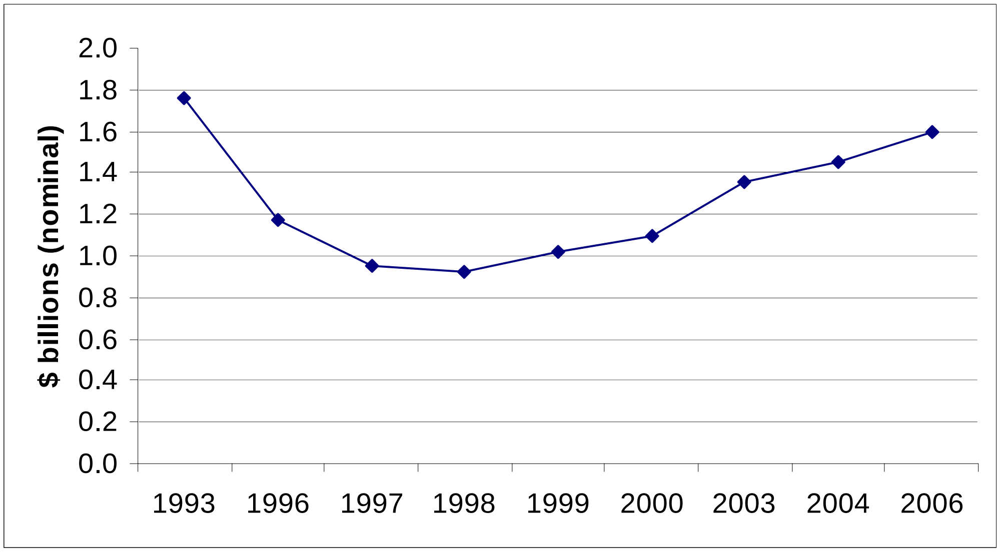
Current Situation

Utilities in many states have been implementing energy efficiency and load management programs (collectively called *demand-side resources*), some for more than two decades. According to one source, U.S. electric utilities spent $14.7 billion on DSM programs between 1989 and 1999, an average of $1.3 billion per year.[1] Interest in these programs gradually grew in the 1980s and early 1990s, then went through a "hiccup" in the mid-1990s as many states and utilities cut back on their demand-side efforts in order to prepare for electric industry restructuring. Growth resumed in the late 1990s when many states decided not to restructure. Also, even many restructured states decided that demand-side programs were important and created mechanisms to fund and provide such programs, most notably "public benefits" programs, which in many cases are administered and implemented by non-utility organizations.

Since the turn-of-the-century, investments in demand-side resources have steadily increased. In 2006 spending on electric energy efficiency programs (both utility and non-utility programs) totaled $1.6 billion (see Figure 3-1).[2] In 2007 and 2008, spending is continuing to grow. For example, the Consortium for Energy Efficiency, in a 2007 report, estimated that 2007 spending on electric demand-side programs increased 14% relative to 2006.[3] Furthermore, quite a few states decided in 2007 and 2008 to substantially expand their programs, which should lead to budget growth in future years.[4]

[1] Loughran, David S. and Kulick, Jonathan, "Demand-side Management and Energy Efficiency in the United State," The Energy Journal, January 2004.
[2] Eldridge et al., 2008, *State Energy Efficiency Scorecard.* ACEEE Report E086. Washington, DC: American Council for an Energy-Efficient Economy. This number is lower than estimates for 2006 spending previously published by the Consortium for Energy Efficiency (CEE 2007) since CEE collected data on estimated spending and the ACEEE data was collected on actual spending. Such spending in some key states, particularly California, was significantly lower than budgeted (estimated).
[3] Consortium for Energy Efficiency 2006: *U.S. Energy Efficiency Programs: A 2.6 Billion Industry;* and 2007, *Energy Efficiency Programs: A $3.1 Billion U.S. and Canadian Industry.* Note: CEE's total estimates include natural gas, low-income and load-management programs---3 types of programs not included in ACEEE's national estimates (electric energy efficiency programs only).
[4] For example, in response to legislation enacted in Colorado, Connecticut, Delaware, Florida, Illinois, Maryland, Massachusetts, Minnesota, New Jersey, New Mexico, North Carolina, Ohio, Oregon, Rhode Island, Texas and Washington. Michigan and Pennsylvania enacted new laws in October 2008.

Figure 3-1. Annual Utility Sector Spending on Energy Efficiency Programs, 1993-2006.



Source: ACEEE data.

As spending on demand-side programs has grown, so have savings. Cumulative annual savings from electric energy efficiency programs were nearly 90 TWh in 2006, which is 2.4% of total electricity sales to end-users in 2006. Some states are achieving 7-8% or more by this measure, constituting a significant utility resource.[5] Electric energy efficiency, load management and demand response programs also have achieved significant levels of demand savings. For example, EIA estimates that in 2006, these programs collectively reduced peak demand in the U.S, by 27,240 MW, of which 59% came from energy efficiency programs and 41% from load management and demand response programs.[6]

To put these current figures in perspective, nationwide, in 2006, the $1.6 billion in spending was about 0.5% of total utility revenues. Individual states varied enormously in spending, ranging from Virginia, Wyoming and Oklahoma who spent virtually nothing to Vermont, Washington and Oregon who spent 2% or more of revenues. Likewise, on the savings side, the ~8 TWh that were saved in 2006 are 0.2% of total 2006 retail electric sales, with figures for individual states ranging from zero to over 1%. These percentages are for savings in 2006 from programs operated in 2006.[7]

Similarly, load management and demand response programs vary from region to region, with demand response capability in 2008 ranging from a low of about 1.7% of peak demand in ERCOT (Texas) and SPP (primarily Oklahoma and Nebraska) to a high of

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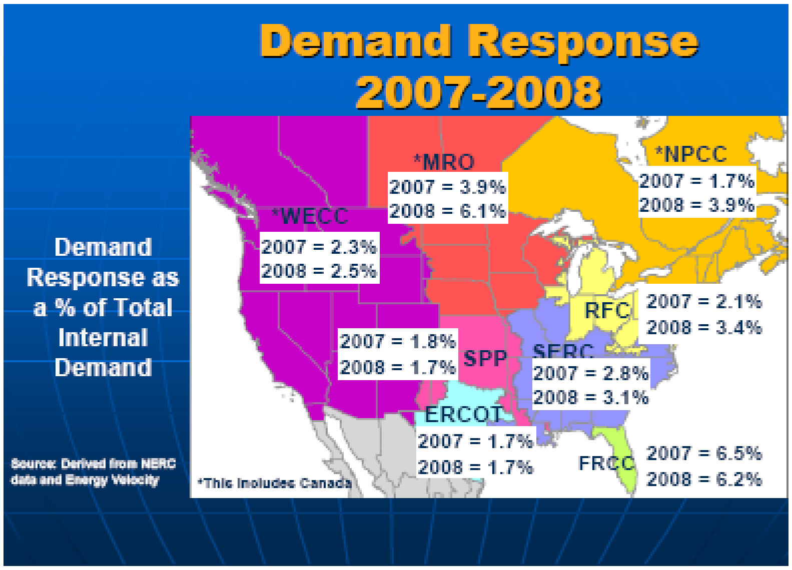
[5] Forthcoming ACEEE 4th National Scorecard on Utility and Public Benefits Energy Efficiency Programs – exact title not yet available.

[6] http://www.eia.doe.gov/cneaf/electricity/epa/epat9p1.html

[7] Eldridge, et al., 2008, *State Energy Efficiency Scorecard.* ACEEE Report E086. Washington, DC: American Council for an Energy-Efficient Economy. See also, forthcoming ACEEE 4th National Scorecard on Utility and Public Benefits Energy Efficiency Programs – exact title not yet available.

more than 6% in FRCC (Florida) and MRO (upper plains states). These trends are illustrated in Figure 3-2.

Figure 3-2. Demand Response Resource in 2007-2008 as a Percent of Total Internal Demand.



Source: FERC. 2008 Summer Market and Reliability Assessment.

Drivers

The growing investments in demand-side resources appear to be driven by several factors including environmental, economic and reliability concerns.

Environmental concerns include global climate change, emissions of currently regulated criteria pollutants, and energy-facility siting issues. With an increasing scientific consensus that the earth is warming, many states are using energy efficiency programs as a key strategy for reducing greenhouse gas emissions. Some states, such as Texas, are also using these programs as a key part of efforts to reduce NOx emissions and try to come into compliance with the Clean Air Act. And in individual states, opponents to specific power plants and transmission lines are often touting demand-side resource alternatives (e.g. Virginia and Vermont).

Economic issues are also increasingly coming into play. A 2004 study examining the results of program evaluations in six states, found that the average energy efficiency program was costing about 3 cents per kWh saved over its lifetime (levelized cost).[8] By comparison, conventional electricity supplies are becoming more expensive, driven by rising construction and fuel costs. For example, the Energy Information Administration's 2008 Annual Energy Outlook notes that construction costs have risen by "50% or more in

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[8] Kushler, M., D. York, and P. Witte. 2004. *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*. ACEEE Report U042. Washington, D.C.: American Council for an Energy-Efficient Economy.

recent years" and projects that power from new power plants will cost more than 6 cents per kWh.[9] Other analysts are projecting higher costs, for example, Lazard Associates in a presentation to the National Association of Regulatory Utility Commissioners found that new conventional base-load production sources generate electricity at a rate between $0.073 and $0.135 per kilowatt-hour.[10] For peak electric supply, the comparison is also dramatic. When power demand peaks, many power pools are finding that marginal supplies can cost 40 cents per kWh or more, with spikes as high as $4 per kWh being reported.[11] By comparison, load management and demand response strategies can range in cost, depending on the program, from just a few cents to perhaps as much as 25 cents per kWh.[12] However, while many efficiency, load management and demand response programs are cost-effective, not all programs are cost-effective, and there is some debate about how cost-effective specific programs are. Cost-effectiveness is discussed further in the Issues section of this chapter. Also, this discussion is from the ratepayer perspective; the utility and shareholder perspective can be different, as discussed below under Barriers.

Reliability concerns have been used to justify both demand-side and supply-side resources. In some power systems, NERC projects that new resources will be needed in over the 2009-2011 period in California, New England, Texas, the Southwest and the Rocky Mountain states, and over the 2012-2013 period in the Midwest (see Figure 3-3). Large power plants can take 8-10 years to build, so where resource needs are more imminent, either gas-fired power plants (which can be built as quickly as 3 years) or demand-side resources will be needed (in an emergency, substantial savings in one year[13], otherwise savings steadily ramp-up over several years[14]).

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[9] *Annual Energy Outlook 2008.* Washington, D.C.: U.S. Department of Energy, Energy Information Administration.

[10] Lazard. June 2008. *Levelized Cost of Energy Analysis – Version 2.0*: 2. Available at http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf

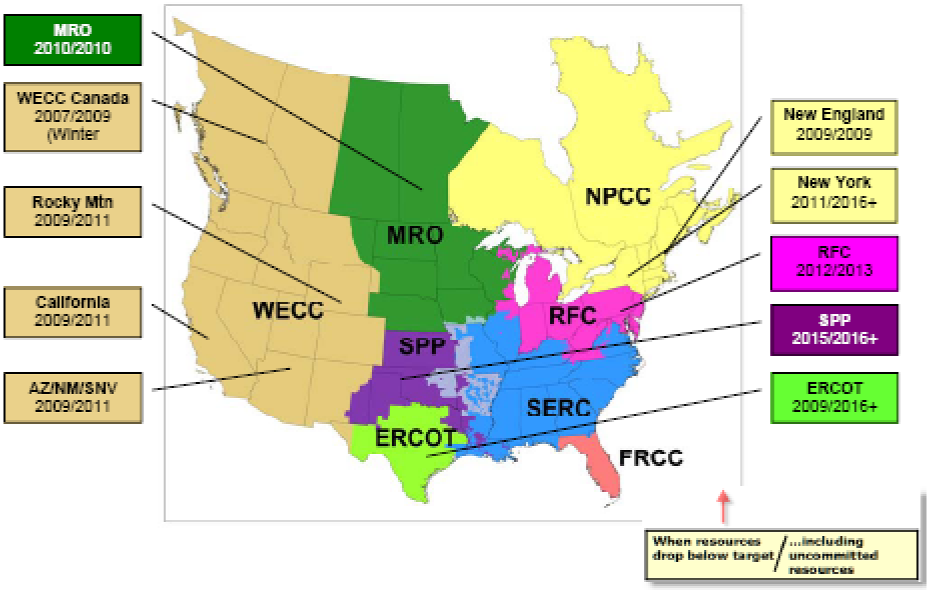
[11] Smith, R. 2008. "Deregulation Jolts Texas Electric Bills". *Wall Street Journal.* July 17, p. A1.

[12] The high end of this range can apply to standby generation programs in which owners of standby generators are paid approximately $0.20/kWh for taking load off the grid during critical peak periods and serving these loads with backup (standby) generators.

[13] For example, during the 2001 electricity crisis, California demand-side efforts reduced peak demand by 10% and electricity sales by 6.7% (Kushler and Vine 2003).

[14] For example, Vermont has ramped up programs beginning in 2000, and by 2007, had reduced sales approximately 7% relative to what sales would have been without these programs. *Efficiency Vermont 2007 Highlights.* Burlington, VT: Efficiency Vermont. http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf.

Figure 3-3. Year When New Power Resources are Needed.



Source: NERC, *2007 Long-Term Reliability Assessment.*

How Much More Might Be Available?

Given these drivers, a key question is how large is the potential demand-side resource. Fortunately, more than a dozen studies have been undertaken in recent years to attempt to answer this question. Most are at the state or utility level. Table 1 below summarizes the results of these studies.

Table 1. Meta-Analysis of Electricity Energy Efficiency Potential Study Results

	Total Efficiency Potential over Study Time Period (%)			Study Time Period	Average Annual Efficiency Potential (%)		
Region of Study	Technical	Economic	Achievable	(years)	Technical	Economic	Achievable
U.S. (Interlaboratory Workng Group 2000)	NA	NA	24%	20	NA	NA	1.2%
Mass. (RLW 2001)	NA	24%	NA	5	NA	4.8%	NA
California (Xenergy/EF 2002)	18%	13%	10%	10	1.8%	1.3%	1.0%
Southwest (SWEEP 2002)	NA	NA	33%	17	NA	NA	1.9%
New York (NYSERDA/OE 2003)	36%	27%	NA	20	1.8%	1.4%	NA
Oregon (Ecotope 2003)	31%	NA	NA	10	3.1%	NA	NA
Puget (2003)	35%	19%	11%	20	1.8%	1.0%	0.6%

Vermont (Optimal 2003)	NA	NA	31%	10	NA	NA	3.1%
Quebec (Optimal 2004)	NA	NA	32%	8	NA	NA	4.0%
New Jersey (Kema 2004)	23%	17%	11%	16	1.4%	1.1%	0.7%
Connecticut (GDS 2004)	24%	13%	NA	10	2.4%	1.3%	NA
New England (Optimal 2005)	NA	NA	23%	10	NA	NA	2.3%
Northwest (NW Council 2005)	25%	17%	13%	20	1.3%	0.9%	0.6%
Georgia (ICF 2005)	29%	20%	9%	10	2.9%	2.0%	0.9%
Wisconsin (ECW 2005)	NA	NA	4%	5	NA	NA	0.7%
Calififornia (Itron 2006)	21%	17%	8%	13	1.6%	1.3%	0.6%
North Carolina (GDS 2006)	33%	20%	14%	10	3.3%	2.0%	1.4%
Florida (ACEEE 2007)	NA	25%	20%	15	NA	1.7%	1.3%
Texas (ACEEE 2007)	NA	30%	18%	15	NA	2.0%	1.2%
Utah (SWEEP 2007)	NA	NA	26%	15	NA	NA	1.7%
Vermont (GDS 2007)	35%	22%	19%	10	3.5%	2.2%	1.9%
Average	NA	NA	NA	12.8	2.3%	1.8%	1.5%
Median	29%	20%	18%				

Note: Technical potential are measures that are technically possible to implement, but without regard to cost-effectiveness. Economic potential is a subset of technical potential and is limited to measures that are cost-effective (although the definition of "cost effective" varies from study to study. Achievable potential is a what can actually be achieved as a result of specific programs, policies and implementation rates.

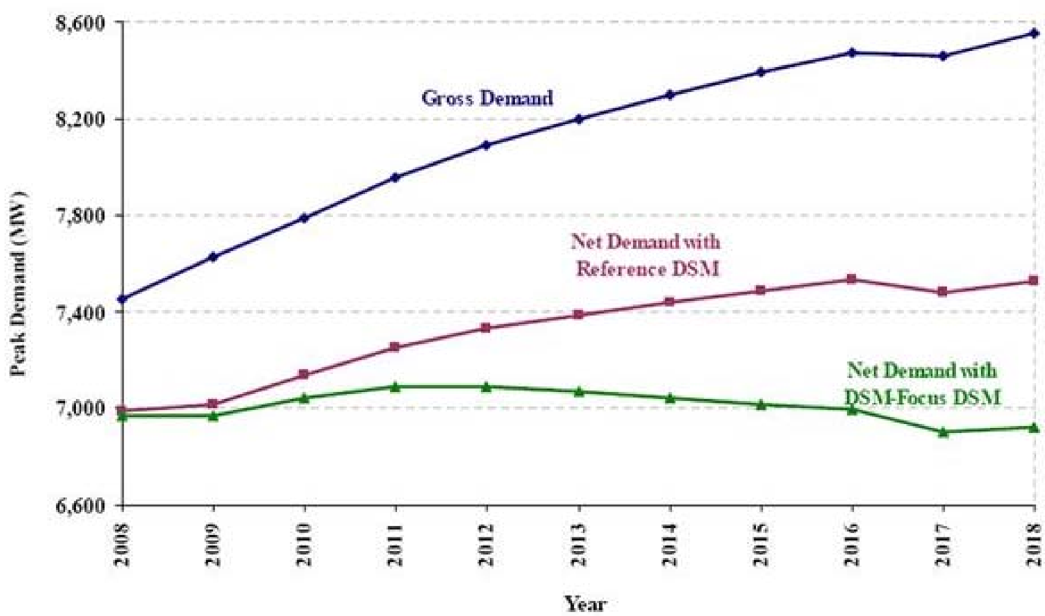
Source: Eldridge et al., 2008.

Overall, the median achievable efficiency potential from these studies is 18%, over about a 13 year period (achievable potential means cost-effective and able to be achieved as a result of policies and programs).[15] Efficiency potential tends to vary strongly as a

[15] Some stakeholder groups believe that estimating the market potential for energy efficiency is not a useful exercise because the estimates are often taken out of context and politicized. See Robert N. Stavins, Judson Jaffe and Todd Schatzki, "Too Good to be True? An Examination of Three Economic Assessments of California Climate Change Policy" JFK School of Government, Harvard University, Regulatory Policy Program, RPP-2007-01, 2007. On the other hand, some observers believe these results are much too

function of the number of years in the analysis, as over long time periods, most existing equipment is replaced and opportunities for cost-effective savings are greater (many efficiency measures are cost-effective when equipment is replaced, since the cost of efficiency is only the increment between average efficiency and high efficiency equipment). The average achievable potential per year of program implementation from these studies is about 1.5%, in line with the most aggressive programs discussed above and much greater than the approximately 0.2% per year savings that are being achieved on average nationwide. In other words, current efficiency programs are barely scratching the surface on what is achievable. Interestingly, average load growth in the U.S. is approximately 1.1%,[16] implying that in many areas, aggressive demand-side resource procurement could offset load growth. Vermont is already doing this and Connecticut is planning to do so shortly (see Figures 3-4 and 3-5).[17]

Figure 3-4. Connecticut Peak Demand (MW) Forecast under Different DSM Scenarios.



Source: Environment Northeast

There has not been as thorough a compilation of potential savings from load management and demand response programs, but analyses conducted by ACEEE for Florida, Texas,

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conservative. See Goldstein, D. 2008. *Extreme Efficiency: How Far Can We Go If We Really Need To?* Proceedings of ACEEE Summer Study on Energy Efficiency in Buildings. Washington, D.C.: American Council for an Energy-Efficient Economy.

[16] This is both the projected load growth from 2008-2030 (EIA, Annual Energy Outlook 2008) and the average growth rate over the 2000-2006 period. (http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html).

[17] Galbraith, K. 2008. "Energy Efficiency the Green Mountain Way." *New York Times*. October 8; Connecticut Light & Power, United Illuminating Company, and the Brattle Group for the Connecticut Energy Advisory Board. 2008. Integrated Resource Plan for Connecticut. http://www.ctsavesenergy.org/files/IRP_CLP_UI1.pdf

Maryland and Virginia estimate potential peak demand savings of 7-22%, varying primarily as a function of load duration curve and avoided costs for critical-peak, peak, and near-peak hours.[18] Preliminary results from a study by EPRI and EEI estimate a "realistic achievable" peak demand savings of 5.8% in 2020 and 6.3% in 2030 and a "maximum achievable" peak demand savings of 7.6% and 9.8% in 2020 and 2030 respectively.[19]

Key Players

Many players are involved in development and implementation of demand-side resources including utilities, regulators, government agencies, energy service companies and other contractors, non-profit organizations, and end-use consumers (including residences and businesses).

In states with demand-side management programs, utilities are typically the sole or primary operator of these programs, but several states have opted for some form of third-party administrator or implementer of efficiency programs.[20] In the case of investor-owned utilities, program oversight is provided by state utility commissions. Commissions generally establish the framework under which programs are planned, operated, and evaluated; review and approve plans; and review evaluation results. For municipal and coop utilities, oversight is provided by municipal and coop boards, with such oversight ranging from substantial to virtually non-existent. In a minority of states, state officials have moved primary implementing authority to another entity, such as a state agency (e.g. New York, previously in Wisconsin) or a statewide non-profit organization (e.g. Oregon, and Vermont and Wisconsin to a large extent). In a few states, the utility commission oversees implementation, hiring contractors to implement programs on the ground (e.g. Maine and New Jersey; this is also the route Vermont and Wisconsin used to hire their non-profit contractors). Regardless of who implements programs, extensive use is generally made of private contractors to help plan and market programs, and often to deliver services on the ground. Frequently these contractors work directly for the program implementer, but in some states (e.g. California), provision is made for a portion of programs to be directly run by third parties selected through a bidding process. Energy service companies can work as contractors, third-party implementers, or as participants in programs run by utilities and other implementers.

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[18] R. Neal Elliot, et al., 2007. *Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demand***.** ACEEE Report E072. Washington, D.C.: American Council for an Energy-Efficient Economy; Neal Elliot, et al. 2007. *Texas Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs***.** ACEEE Report E073. Washington, D.C.: American Council for an Energy-Efficient Economy; Eldridge, et al. 2008. *Maryland Energy Efficiency: The First Fuel for a Clean Energy Future*. ACEEE Report E082. Washington, D.C.: American Council for an Energy-Efficient Economy; Eldridge, et al. 2008. *Energizing Virginia: Efficiency First*. ACEEE Report E085. Washington, D.C.: American Council for an Energy-Efficient Economy.

[19] Rohmund, et al. 2008 "Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030)." *Proceedings 2008 ACEEE Summer Study on Energy-Efficiency in Buildings* (Washington, DC: American Council for an Energy-Efficient Economy).

[20] For example, the New York State Energy Research and Development Authority (NYSERDA), Efficiency Vermont, Efficiency Maine, Northwest Energy Efficiency Alliance, Wisconsin Focus on Energy, and the Energy Trust of Oregon.

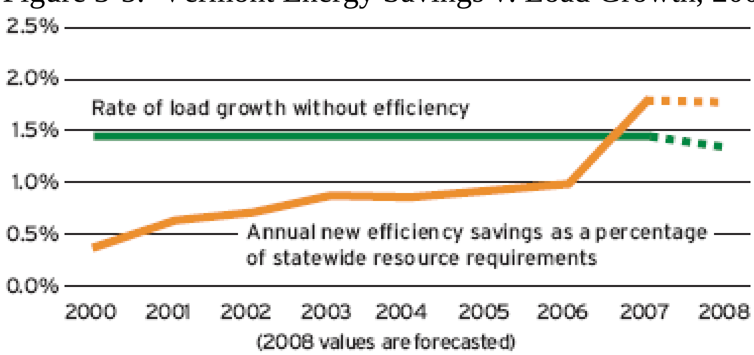
End-use consumers also develop and implement demand-side resources to reduce costs or, for some large sophisticated customers, to sell or bid in ancillary services markets. For example, an ACEEE study estimated that in 2004, energy efficiency investments in the U.S. totaled approximately $43 billion, which is more than an order of magnitude larger than utility investments. This figure is for the incremental cost of efficient goods and services relative to conventional goods and services.[21] Large commercial and industrial customers are also capable of selling demand response services to local utilities (under state PUC approved agreements) or in wholesale markets administered by ISOs or RTOs.

What Is Working

A multi-billion dollar demand-side industry has been created. With program operators spending more than $2 billion per year, when investments by businesses and homeowners are added, total investments that are several times higher. Substantial savings (many TWh and GW) are being achieved with these investments, saving money and reducing emissions.

Leading states are showing how much can be saved with cost-effective investments. For example, Vermont over the 2000-2007 period has reduced electricity sales by about 7%; in 2007 demand-side savings completely offset load growth (see Figure 3-5).[22] In California, programs have operated for more than 20 years, leveling load per capita. State law requires energy efficiency and demand response to be pursued before new supply resources can be built and efficiency resources (including utility-operated programs as well as building codes and equipment efficiency standards) are a key element in the state's climate plan (see Figure 3-6). In Minnesota, programs have also been operating for close to two decades and saving more than 0.5% per year annually. In 2007, a new law was enacted directing electric and gas utilities to ramp-up savings to 1.5% per year.

Figure 3-5. Vermont Energy Savings v. Load Growth, 2000-2008.



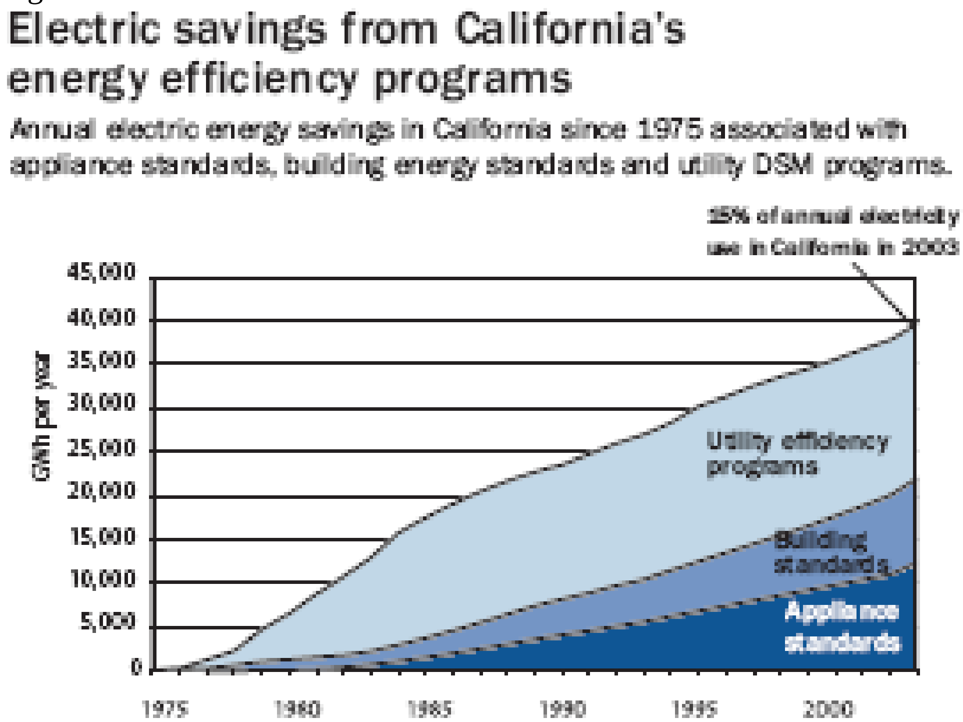
Source: Efficiency Vermont 2007 Highlights

[21] Ehrhardt-Martinez, K. and J. Laitner. 2008. *The Size of the U.S. Energy Efficiency Market: Generating a More Complete Picture*. ACEEE Report E083. Washington, D.C.: American Council for an Energy-Efficient Economy.

[22] *Efficiency Vermont 2007 Highlights.* Burlington, VT: Efficiency Vermont. http://www.efficiencyvermont.com/stella/filelib/2007%20Highlights%20Piece%20FINAL_09_08.pdf.

These states are leaders due to a long-history of supporting demand-side programs, driven in part by above-average electricity rates (in California and Vermont, not Minnesota), concern for the environment, and a willingness to try new ideas.

Figure 3-6.



Source: American Physics Association, Sept. 2008.

In some states, utilities are active supporters or even leaders in these efforts. Examples include utilities in California, Connecticut, Massachusetts, Minnesota and Oregon. These tend to be states in which regulators have paid attention to, utility finances, and have adopted schemes to make demand-side investments at least neutral, if not profitable, to utility shareholders.

Legislators and regulators are sometimes setting much more ambitious goals for the future. Minnesota has established 1.5% per year savings targets and seventeen other states have adopted mandatory targets.[23] As a result, these states are all embarking on major expansions of their programs. However, these are goals that for the most part have not yet been achieved on the ground.

[23] American Council for an Energy-Efficient Economy. 2007. "Energy Efficiency Resource Standards Around the U.S. and the World." http://www.aceee.org/energy/state/6pgEERS.pdf. Washington, D.C.: American Council for an Energy-Efficient Economy. In addition, Michigan has subsequently adopted such goals. See also "Michigan Commits to an Energy-Efficient Electric Future." October 7, 2008. http://www.aceee.org/press/0810michigan.htm

What is Not Working

Demand-side efforts are working well in some states, but not in others. In 2006, the top-fourteen states in terms of spending as a percent of revenue accounted for 76% of total U.S. spending.[24] These states only accounted for 35.7% of the U.S. population.[25] In 2007, two states (California and Vermont) reduced electricity sales through their programs by nearly 2%, and another 13 states were saving 0.5% or more as of 2006 (Connecticut, Hawaii, Idaho, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Hampshire, New York, Oregon, Rhode Island, and Washington). Much more needs to be done to get the rest of the states up to at least the 0.5% savings per year level, and to get leading states to 1-1.5% per year or more.

There are no nationally recognized standard protocols for impact evaluation of EE programs. Nor is there agreement on when and how to use measurement and verification (M&V) approaches or, alternatively, when and how to use deemed savings approaches. Impact evaluation is necessary to determine credible estimates of net savings in both energy (kWh) and capacity (kW) and when those savings occur. For example there are no commonly accepted standards for baseline calculations, the estimation of net to gross ratios, estimating free-ridership and spillover effects, and persistence analysis. The transparency of protocols that are used also varies from state to state. When every state does it a different way it is difficult to ascertain who is doing it right.

In addition, reliable efforts to integrate of energy efficiency programs results with resource planning and operation are still relatively nascent. Energy efficiency program impacts are not yet defined in terms of discrete, measurable time-based products (energy, capacity and ancillary services) that can be understood and used by system operators and system planners, and which warrant recognition by NERC.

Demand response programs are spreading, but more slowly, hampered by the high-cost of advanced metering equipment and debates about whether and how to pay these costs. In approximately half the country, demand response is also hampered by the jurisdictional split between the Federal Energy Regulatory Commission (FERC) and the states. FERC has jurisdiction over wholesale power markets that are administered by FERC-approved ISOs and RTOs. States are reluctant to allow retail jurisdictional customers to participate in wholesale markets for fear that they lose control of those customers and rate impacts.

Many utilities lose money when efficiency programs expand, due to lost sales, particularly the base revenue portion of those sales. Also, all utilities earn a return on supply-side investments, but only a few earn a return or profits on demand-side investments. This results from rate designs that are inconsistent with a utility business model that includes both supply-side and demand-side resources, and also to differences and inconsistent treatment between demand-side and supply-side resources. The options

[24] Eldridge, et al., 2008, *State Energy Efficiency Scorecard.* ACEEE Report E086. Washington, DC: American Council for an Energy-Efficient Economy.
[25] U.S. Census Bureau. "State and County Quick Facts." http://quickfacts.census.gov. Washington, DC: U.S. Census Bureau.

are to re-design rates to make them compatible with a mixed business model, to introduce revenue mechanisms such as decoupling or lost revenue recovery, and/or to provide shareholders with some type of incentive for reaching energy and financial savings goals. While some states have addressed these issues, most have not. We discuss these various approaches further in the "Issues" section of this chapter.

Increasingly, due to utility mergers, more utilities have service areas in more than one state. Each state has it's own policies, often making planning and implementing common programs across state boundaries difficult. Differences between states also make it more difficult for program contractors, trade allies and businesses operating in multiple states to participate in programs.

While many demand-side programs have been very successful, some have not. In some states there is a confusing array of programs, particularly where different utilities operate different programs in the same state. There is always room to improve programs, learning from best practice programs around the country.

Interest in demand-side programs has ebbed and flowed over time, making it difficult to develop and sustain long-term efforts. Programs work best when they are treated as a long-term resource and this resource is gradually procured over time. When run as a series of short-time efforts, it is harder to retain staff and customer interest. Recently, with programs in many states ramping up, there is a shortage of skilled staff to plan, implement and evaluate programs.

Metrics for Effective Demand-Side Investments

Several metrics can be useful for assessing demand-side management investments, many of which have been used in the sections above. Key metrics relate to program cost effectiveness, energy savings and peak demand savings. These can be expressed in absolute terms such as benefit-cost ratio, "xxx" kWh of savings, or "yy" MW of peak demand reductions. Such absolute metrics can be useful for use in specific states or utility service territories, but are difficult to compare across states and utility territories due to differences in consumption, load profiles and avoided cost parameters. Therefore, it is common to express these metrics in some normalized fashion that can be compared from state to state or utility to utility. Some key normalized metrics are provided in the table below.

Variable	Metric	Notes
Cost-effectiveness	Levelized cost per kWh saved and per kW-year of peak demand reduction	Not as precise as benefit-cost ratio but easier to compare across states/territories.
Energy savings	Incremental annual kWh savings as percent of total electricity sales	Can range from ~0-2%
Peak demand savings	Coincident peak energy efficiency savings as % of peak demand Load management capability as % of peak demand	Two metrics, one for EE programs, one for load management programs.

Barriers

Electricity demand has surged over the last several decades as we increasingly rely on air conditioners, computers, microwaves, high-definition televisions and other electronic gadgets and gizmos in our wired residential, industrial and commercial sectors. As we examine the feasibility of introducing another device, the electric plug-in hybrid, to our ever growing list of electricity consuming systems, we need to consider what barriers exist so we can reduce the electricity we use from all these devices.

Various state, regional and federal instutions as well as quasi-public and private organizations have different roles within the complicated regulatory patchwork we have across the country to monitor, manage and potentially reduce this electric demand. The barriers to reducing electric usage fall within these regulatory and market sectors.

Ideally electricity would follow a perfect market with a large number of knowledgeable suppliers and consumers interacting in an open and transparent process to determine electricity's price. But electricty is a unique commodity - supply can't readily be stored and the demand for electricity may dramatically vary hour by hour. Most residential, commercial or even industrial consumers do not even face real-time wholesale prices, as their electric rates are based on average annual costs or some other regulatory derived construct.

Historically the utility industry designed its electric infrastructure to handle the peak period (usually per hour) usage patterns of its customers. Peak demand happens just a few times a year (typically less than 1% of the year), so the transmission, distribution and generation assets are operating below their design capacity for a significant portion of the year. While deregulation has changed some ownership of these infrastructure assets, the infrastructure must still be designed to meet these peak demands.

Planning and building this generation and transmission infrastructure takes years, so inherently this process requires the addition of new electric generation and transmission in large increments. The line from the movie *The Field of Dreams* "build it and they will come" seems apt as Independent System Operators (ISOs) and utilities focus on building just a handful of large facilities to meet system imbalances created by projected future loads. The market and the regulatory structure provides greater financial incentives, through its rate of returns and other cost recovery mechanisms, to build these few facilities rather than rely on more disparate demand resources – like the large scale deployment of load management systems.

Traditionally the process has been financially and structurally biased towards supply-side solutions, so that demand-side solutions are often overlooked. The market and the regulatory structure have provided greater financial returns to build generation, transmission and distribution infrastructure, but now a recent dramatic increase in capital costs, issues about siting these facilities and uncertainties associated with carbon emisssions and other issues creates an uncertain investment climate within the electric supply-side infrastructure. Recognizing these planning problems, FERC Order 890 even attempts to include demand-side approaches into the ISO planning processes.

Another critical issue is the potential conflict between state and federal regulation of price-responsive demand programs. Although FERC regulates wholesale markets and the ISOs that operate these markets, it has no jurisdiction over retail activities. Meanwhile the state utility commissions have authority over sales and service to retail customers but no direct control over wholesale markets. Utilities may be required by FERC to implement demand response programs that increase their costs and reduce their revenue; however, these costs can only be recovered if approved by state utility commissions who had no say in the demand response program's implementation.

Some additional regulatory barriers are:

- Traditional rate structures for utilities reward increased energy throughput with increased profits, while increasing energy efficiency reduces throughput and utility revenue; and
- Restructuring of the electricity industry into unique component parts across various state and ISO boundaries makes it difficult to develop an integrated, least-cost planning process to assess alternatives to supply options.

Demand-side resources are typically smaller, more diverse, and geographically dispersed compared to supply side assets. Understanding and organizing effective market oriented approaches through these demand-side resources poses numerous challenges. A market typically favors larger, more knowledgeable participants so the electric marketplace has been dominated by the electricity suppliers leaving residential consumers, commercial businesses and even most large energy users on the fringes of this over $300 billion dollar market. With a very large and diverse group of constituents demand-side resources face significant market barriers in establishing a unifying agenda and even in getting involved in the often obtuse infrastructure planning process.

Truly quantifying the potential load reduction available from demand-side resources and then actually implementing these reductions within planning timelines needed for daily dispatching of generating facilities or even including demand reductions within the longer infrastructure planning process have been viewed as market barriers for demand resources. Critics of demand-side resources contend that load reductions can not be assured and the electric grid's reliability would be impacted. The high capital costs of implementing an advanced metering system and the measuring system that some deem essential for proper demand resource utilization serve as a market and regulatory barrier as companies and state utility commissions investigate the cost-effectiveness of installing these systems.

Advanced metering systems can readily be incorporated into a Smart Grid system; a sophisticated two-way communication process that manages and oversees the entire grid. Smart Grids bring the power of internet technologies into our electricity network by improving their operations and ultimately reducing costs to consumers. Smart Grids could reduce peak demand by charging all customers the real cost of delivering power during peak times and even automatically enabling the grid to control specific loads during these critical hours. The Smart Grid's allure is this technological prowess - it would upgrade an aging and increasingly overextended infrastructure that still uses some 19th century relay technology into an adaptable responsive system that relies on the 21st century technology of microprocessors and our latest communications innovations.

While the Smart Grid may not be the panacea many envision, it does provide demand-side resources additional flexibility. There has been almost a natural market predilection towards using supply-side resources to balance energy supply and demand needs. Interacting with a relatively small number of existing supply-side participants seems easier than creating new strategies to include these emerging demand-side resources.

The electricity market has historically supported supply-side resources by socializing transmission costs as FERC ruled that the costs for those limited number of backbone 500 KV lines and greater should be shared among all ratepayers. While new forward capacity markets are being developed in New England ISO, PJM and other ISOs, considerable sway has historically been given to supply-side resources. For instance PJM's Reliability Pricing Model (RPM) supports payments of billions of dollars to generators.

While fledgling demand-side resources seek this support, until recently there's been no comparable treatment of demand-side resources in these larger electricity markets. Some Smart Grid proponents believe its deployment may delay or even offset supply-side remedies like new transmission lines or generating facilities. Smart Grid advocates contend a more dynamic, self-healing, integrated grid system enables more customer choices and improves the entire grid's capabilities more than the infusion of new transmission and generation facilities. Some of these advocates argue that the billions of dollars for new transmission and generating facilities, money mainly spent to meet those limited number of peak hours per year, might have been better spent into deploying a

Smart Grid.[26] Regardless a more inclusive market approach, one including both supply-side and demand-side resources, would better serve the electric system.

In the current electricity market there has been minimal incentives for most customers to reduce their energy usage. Most end-users pay regulated retail rates based on monthly consumption and not actual wholesale prices based on generating power over hourly increments. End-users could be considered free-riders, not being charged a fair share for their energy use. This “free” access and the seemingly unrestricted demand for electricity lead, in some observer’s eyes, to electricity’s over-use. *Many customers view price volatility and potential increase in electric costs as an undesirable risk.*

Until recently relatively low and stable energy costs have enabled end-users and others to use existing, inefficient end-use energy systems without significant price consequences. There had been minimal economic incentive to upgrade these older systems to newer, more efficient systems. Even with the impact of higher energy prices, customers may have the behavioral inclination to leave the existing systems in place or not to recommend newer, more appropriate systems. This *inertia for change* leads *customers* into using *existing products.*

End users, contractors, builders, developers and others buying, installing or even recommending energy systems might not be sufficiently aware of or *lack comprehensive information about efficiency technologies and costs*. While technology constantly changes there’s a reluctance to try newer systems that have a limited performance record. Besides apprehension about installing a “newer and better” system, there might not even be the realization that other newer alternative(s) even exists by designers, builders and end-users. Even if there’s an awareness alternatives exist, they may not be readily available in that region because of local code issues or because the better replacement equipment is not readily stocked.

Financing energy efficiency projects is another market barrier for demand–side resources. The large capital costs required to retrofit facilities or even install more efficient equipment in new buildings are *first-cost problems. Customers m*ight have *limited capital resources* or are unable to obtain traditional financing for these energy efficiency improvements. There are a limited number of financial institutions providing assistance for energy efficiency projects as evidenced by the lack of energy efficient mortgages being processed.

Companies operating in several states bemoan the often cumbersome process of trying to implement nationwide programs through varying local, state and federal jurisdictions. The *high transaction costs for delivering and installing many small efficiency improvements* across numerous facilities may thwart corporate efforts. Companies with their internal rate of return thresholds fund other more potentially profitable endeavors.

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[26] Pacific Northwest National Laboratories. 2007. “Department of Energy putting power in the hands of consumers through technology.” http://www.pnl.gov/topstory.asp?id=285. Richland, Wash.: Pacific Northwest National Laboratories.

Many energy efficiency projects are not undertaken because of this investment uncertainty and the allocation of their benefits. The combination of large initial capital costs and *uncertainty about* how many years the upgraded facility will be used (the payback period) prevents energy efficiency systems from being installed by homeowners, landlords, and businesses. This problem is further compounded when the developer or owner of the facility is not the occupant or user of the installed equipment. Developers and owners lack a strong incentive to specify, purchase or install energy-efficient equipment since they are not responsible for operating expenses. This *split-incentive* exists between *builders and buyer as well as between landlords and tenant*s. Split-incentives even hamper governmental and corporate decision making as different departments might be responsible for capital and operating budgets.

Some other market barriers include:

- *understanding what loads can customers easily shift or even eliminate from hour to hour, day to day, or across even longer spans*; and
- *difficulty of interacting with a large number of diverse customers rather than collaborating with a limited number of utilities.*

Issues

Questions often raised about the application of demand-side resources in utility resource plans are how much to use, how much demand response and energy efficiency is cost effective, how to integrate demand, response, efficiency and supply-side resources in resource planning exercises, and how and who should pay for the resources. These issues are explored below.

How Much Efficiency? How Much Demand Response?

As illustrated in Table 1 earlier in this chapter, many studies have been done to estimate the potential for cost-effective energy efficiency investments. Across 20 studies, the median achievable potential from efficiency investments is estimated to be 18% savings relative to a business-as-usual baseline, with the savings achieved over about a 13-year period. Some studies have significantly lower and higher estimates (e.g. low of 4% over 4 years to a high of 32% over 10 years). For demand response, less estimates are available, but available studies, as summarized earlier in this chapter, generally estimate peak demand savings of 4-22%. Energy savings from demand response are not very well determined. Findings thus far from pilot programs are that sometimes energy use increases a little, sometimes it decreases a little, but on average there is little effect on energy sales.[27]

These are substantial savings, and rather than arguing over the exact size of the efficiency and demand response resource, we agree that efforts need to be stepped-up to tap this

[27] Cite a forthcoming EPRI study if it is ready in time.

resource. The experience gained in these efforts will provide additional information on the ultimate size of these demand-side resources.

How to Best Integrate Efficiency, Demand Response, and Supply-Side Resources?

Both demand response resources and energy efficiency strategies can be used as part of a concerted effort to meet portions of our electric demand while also realizing other advantages like reducing greenhouse gas emissions and reducing the carbon footprint.

If the impacts of demand response (DR) and energy efficiency (EE) programs are recognized as resources (in kW and kWh) comparable to traditional generation supply—and subject to appropriate impact evaluation protocols—then DR and EE should be treated on a non-discriminatory basis in a utility's resource plan. There exist today four general approaches to resource planning by regulated electric utilities:

(1) Demand-side planning ("first fuel" approach): Adoption of target such as 15-by-15 or 20-by-20, meaning 15 or 20% load reduction by 2015 or 2020, respectively. Such targets are generally set based on studies on the cost-effective demand-side resource available. This resource is factored into load forecasts. Demand-side programs should be evaluated, for actual savings achieved, and forecasts adjusted as needed. If demand growth is low, demand-side resources can fully offset load growth. If demand growth is higher, demand-side resources will reduce but not eliminate the need for new power supplies, as well as replacement power sources when aging power plants are retired. The advantage of the demand-side planning approach is it quickly leads to development of demand-side resources, resources that have not received a lot of attention in many states. The disadvantage is that if targets are set without regard to the size of the cost-effective resource, or if programs are ineffective and not evaluated and improved, then suboptimal investment levels will result.

(2) Regulation and Integrated Resource Planning (IRP): Demand-side and supply-side resources are simultaneously evaluated in context of long-term planning and operational needs of the utility. Such evaluations have planning horizons of varying periods, but typically extend for 10-20 years. The advantage of this approach is that all resources can be evaluated on a common basis and the optimal amount of each resource selected. The disadvantage of this approach is that it can be time-consuming, particularly since IRP plans are often controversial, and many details are frequently adjudicated.

(3) Market-based methods such as competitive bidding: Utility's short- and long-term planning and operational needs are acquired through competitive solicitations or auctions. This approach is common in FERC-jurisdictional wholesale markets and in ERCOT. There is growing acceptance of demand-side resources in these markets but when demand-side resources are bid in, the emphasis is on demand response, and improvements to very large facilities. Hard-to-reach markets such as small commercial and residential customers (particularly multifamily housing and low-income households) are rarely bid in. The advantage of this approach is that all interested market players can participate, and prices are set by the market. The disadvantages are that many cost-

effective demand-side resources are frequently left on the table and costs can be high, as bidders are generally sophisticated enough to estimate the market clearing price, and come in with bids just below this value.[28]

(4) Supply-side planning: Utility plans its next generator based on long-term load forecasts that may or may not internalize demand-side effects. This type of plan may have to be done after "demand-side planning," or as a stand-alone process. The advantage of this process is that if cost-effective demand side resources are first maximized, supply-side decisions are frequently less controversial. The disadvantage of this approach is that demand-side resources can be ignored in some cases.

These different approaches can be integrated. For example, Connecticut has a demand-side planning target set in law of 1% savings per year, but then conducts an IRP, and through this IRP has identified additional demand-side resources to procure. They also bid out a portion of their demand-side needs.

All of these approaches can work if properly done, and can be suboptimal, if done poorly. While some members of the Subcommittee prefer some options, and other members prefer others, we all agree that whatever method is chosen must be done well, with demand-side resources fully considered, and investments selected (both demand- and supply-side) that minimize long-term costs to ratepayers.

It should be noted that a key component to the use of distributed resources and energy efficiency is a well defined and standardized evaluation, measurement and verification process.

How to Pay for Demand-Side Resources

Despite the fact that DSM programs have been implemented for three decades, there remains considerable debate on how EE and DR resources should be compensated and costs allocated and recovered. Thus if generators sell capacity and energy under long-term contracts or purchased-power agreements at market-based rates, it is rarely the case that demand-side resources are eligible for the same form of compensation. Thus, DR and EE costs and the allocation and recovery of generation costs are typically done on an apples and oranges basis.

The industry is likely entering a sustained period in which demand-side resources become a natural part of the regulated utility's business model. How to expense or rate-base of funds committed to EE and DR programs needs to be resolved in the context of normal rate design and cost allocation procedures, or whether there is a continued need for

[28] See, for example, Kushler, M.D. and P. Witte. 2001. *Can We Just "Rely on the Market" to Provide Energy Efficiency? An Examination of the Role of Private Market Actors in an Era of Electric Utility Restructuring*. ACEEE Report U011. Washington, D.C.: American Council for an Energy-Efficient Economy.

separate ratemaking treatment such as with special riders or single-issue proceedings for the purpose of adjusting (increasing) rates in isolation of other costs of doing business.[29]

Historically, investments in supply-side resources were raised in capital markets and rate-based, allowing shareholders a reasonable opportunity to earn a recovery of and a rate of return on their investments at a level of profit commensurate to the investments' risk. DSM program costs are generally expensed and not rate based. Thus it is ratepayers who are providing the "capital" for demand-side resources. On the other hand, under this approach, ratepayers do not have to pay a rate of return on these investments, and utilities do not earn such a rate of return.

Many utilities and regulators have come to recognize that utilities can make profits by building supply-side resources, but they do not generally earn a profit from demand-side resources. This is in part due to the fact that returns are only earned on capitalized investments, but in part due to how utility kWh sales affect profits. One way many utilities earn profits is to increase sales beyond the level of sales assumed when rates were calculated. Rates are set to recover fixed and variable costs, at the predicted sales level. But if sales exceed the forecast, then the fixed cost portion of rates is added profit. And if sales are less than forecast, then fixed costs are not fully recovered and profits decline.

To address the first issue – return on investments, two approaches have been used:

1. Put demand-side investments in the rate-base and allow utilities to earn a return on these investments. This approach is now used in Nevada, and Florida is likely to use this approach.
2. Provide utilities with some small profit incentive for successfully reaching or exceeding demand-side goals. Such incentive could be in the form of specific payments for achieving specific goals (e.g. $x million to shareholders if kWh savings goals are met[30]), in the form of a set percentage incentive for achieving a specified percentage of the savings goal[31], or can be in the form of sharing the savings from the difference between demand-side and supply-side costs[32] (e.g. California utilities now can earn 9% of the net benefits from demand-side programs, once they approach their demand-side goals and 12% of net benefits if they exceed their goals[33]).

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[29] Almost all state regulatory commissions provide a rate case process to evaluate and measure the appropriate overall cost of service where a balanced review of jurisdictional expenses, rate base investment, the cost of capital, and revenues at present rates are investigated at a common point in time (i.e., the test period).

[30] This approach is now used Vermont.
[31] This approach is currently used in Massachusetts, Michigan, Nevada, Ohio, and Rhode Island.
[32] This approach, in various forms, is used in California, Connecticut, Colorado, Georgia, Hawaii, Minnesota, New Hampshire, New Jersey, and Texas.
[33] Public Utilities Commission of the State of California. Order Instituting Rulemaking to Examine the commission's Future Energy Efficieny Policies, Administration and Programs. Interim Opinion: Energy

To address the impact of sales on profits, there are several policy options:

1. Decouple revenues from sales[34]
2. Allow recovery of "lost revenues" in retail rates
3. Redesign retail rates with a Straight Fixed (SFV) rate design to remove fixed costs from tail blocks[35]
4. Do nothing because many electric utilities continue to experience positive growth in sales and customer numbers regardless of the level of EE programs.

In general, the Subcommittee supports utilities earning a reasonable return on their demand-side investments, proportionate with the risks. But these returns need to be reasonable, with a substantial majority of demand-side benefits going to ratepayers.

Recommendations for Improving Use of Demand-Side Resources

The United States has a long tradition of relying on the marketplace to drive results. Often, these results rely upon sound economic principles which attract market participants who endeavor to capitalize on market opportunities. It is with this in mind that we recommend various opportunities for improving the use of demand side resources.

Most notably, our recommendations rely upon the establishment of a National Policy to promote sustainable and economically viable energy efficiency programs. These programs should optimally be designed to maximize cost-effective energy savings, reduce environmental impact of electric infrastructure utilization including end use infrastrucure, reduce energy use during peak periods, coordinate with Smart Grid initiatives and enhance the overall reliability of the electric infrastructure.

Under this broad rubric, we make several specific recommendations to DOE:

1. Develop National Measurement and Verification Protocols/Standards that will better measure the savings that are being achieved, so that these savings can be more reliably counted upon to be a substitute for some new power plant construction, and to better ensure that demand-side investments are cost-effective.

2. Place priority on expanding existing DOE programs that capture energy efficiency savings (e.g. updating Federal Appliance/Equipment Standards and national model building codes) and that help develop new energy-saving technologies that can be used in future decades (i.e., DOE's research and development initiatives).

Savings Goals for Program Year 2006 and Beyond. Rulemaking 01-08-028. Decision 04-09-060. September 23, 2004.

[34] See National Action Plan for Energy Efficiency, "Aligning Utility Incentives with Energy Efficiency Investment," November 2007

[35] See National Regulatory Research Institute (NRRI), "A Rate Design to Encourage Energy Efficiency and Reduce Revenue Requirements," July 2008.

3. Promote at the federal and state levels policies that can encourage expanded energy efficiency and load management efforts including:
    a. utility business models and rate setting approaches that encourage and reward cost-effective energy-efficiency investments while providing a substantial majority of benefits to ratepayers;
    b. expanded federal technical assistance to states and utilities;
    c. allowing Demand Resources to participate in ISO Forward Capacity Markets; and
    d. enacting binding energy savings targets for utilities to meet that are based on sound analysis of cost-effective opportunities and that fairly treat each customer class.

These recommendations and subrecommendations are discussed in the sections below.

National Measurement and Verification Protocols

DOE should advocate the development of measurable and verifiable metrics for estimating reliable resource values (kW and kWh) of mass-market energy efficiency (EE) programs if the intent of such programs is to defer or avoid new utility infrastructure or obtain net reductions in GHG emissions. This will enable the impacts of such programs to be recognized on a comparable or source-neutral basis as traditional generation resources. In fulfilling this objective, DOE should advocate the development of national consensus measurement and verification (M&V) protocols, standards and business practices, with input from a broad range of interested parties. Such an effort should build upon existing protocols and standards developed by individual states, the Northwest Power and Conservation Council, and emerging efforts by the North American Energy Standards Board (NAESB), Northeast Energy Efficiency Partnerships (NEEP), and the National Action Plan for Energy Efficiency (NAPEE). DOE should also provide federal technical assistance to States to participate in this effort. DOE should also encourage the North American Electric Reliability Corporation (NERC) to continue its efforts to refine the reporting of demand-side resources in NERC's reliability assessment activities.

Expand existing DOE programs addressing federal appliance/equipment standards, national model building codes and research and development of new energy efficiency and demand response technologies and practices

The US Department of Energy (DOE) has “missed all 34 congressional deadlines for setting energy efficiency standards for the 20 product categories with statutory deadlines that have passed” according to a General Accounting Office (GAO) Report from January 2007 (GAO-07-42). The report stated that “Lawrence Berkeley National Laboratory estimates that delays in setting standards for the four consumer product categories that consume the most energy--refrigerators and freezers, central air conditioners and heat pumps, water heaters, and clothes washers--will cost at least $28 billion in forgone energy savings by 2030.” The new DOE Secretary should give top priority to this internal DOE effort.

In addition, national model building codes, developed by the International Code Council (ICC) and the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) are now undergoing revision. ASHRAE is targeting a 30% reduction in energy use relative to the 2004 standard. The ICC recently updated it's residential energy standard to reduce energy use by an average of about 17% [confirm number], and narrowly defeated a proposal to increase the energy savings to 30%.[36] This "30% solution" proposal is likely to be proposed again in 2009. DOE should actively support these efforts to reduce energy use in new buildings by at least 30%, including providing technical and analytic support for this efforts, and testifying/commenting on behalf of cost-effective approaches that achieve these savings levels. In the longer-term, DOE should provide similar support for making new buildings 50% more efficient than current codes, in line with the efficiency levels for new buildings now being promoted by federal tax incentives included in the Energy Policy Act of 2005.

DOE also has a major R&D program to develop new energy saving technologies and practices. In Fiscal Year 2008, energy efficiency expenditures totaled approximately $700 million [DOE should check and provide the correct number]. Many independent panels have recommended that resources devoted to energy efficiency R&D be substantially expanded, including the President's Committee of Advisors on Science and Technology (PCAST), the National Commission on Energy Policy, and the American Physical Society in order to help reduce energy use, costs and emissions in the long-term and to keep the U.S. at the cutting edge of new technology development.[37] As programs are expanded, we recommend that these efforts include increased joint R&D with utilities and states, demonstration projects, Golden Carrot programs, and other technology procurement efforts.

Promote at the federal and state levels policies that can encourage expanded energy efficiency and load management efforts

Research and encourage utility business models and rate setting approaches that encourage and reward cost-effective energy-efficiency investments while providing substantial majority of benefits to ratepayers

Individual state utility commissions regulate utility operations and have tried different approaches to encourage more demand-side resource deployment. State commissions have approved approaches that decouple utility profits from utility sales, created incentives that reward energy efficiency, allowed utilities to recoup lost sales through a lost revenue adjustment clause and other mechanisms. Despite the efforts of some individual states, in many states utility profits can suffer if they promote energy-efficiency and therefore these states do not maximize the potential contributions that

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[36] Forthcoming ICF analysis.

[37] The President's Committee of Advisors on Science and Technology, Report of the Energy Research and Development Panel. 1997. *Federal Energy Research and Development Challenges of the Twenty-First Century*. 3-26; The National Commission on Energy Policy. 2004. *Ending the Energy Stalemate*. 30; American Physical Society. 2008. *Energy Future: Think Efficiency*. Section 1:9.

distributed resources could contribute to the electric infrastructure. We recommend that state utility commissions seriously examine these issues and introduce regulatory reforms so that utility profits do not suffer when they make cost-effective investments in energy efficiency and demand response. DOE can assist in these efforts by providing a coordinated strategy and guidance to help state commissions and utilities analyze information and develop / execute strategies that will positively contribute to the overall utilization of distributed resources. DOE may be able to capitalize on the use of its National Labs and other resources to conduct analyses that will help determine the economic implications of regulatory options to address these issues. Further, DOE can advocate before the Federal Energy Regulatory Commission (FERC) and the appropriate state public utility commissions and other local regulatory bodies in favor of utility business models and ratemaking procedures that are resource neutral. DOE should advocate ratemaking procedures that allocate costs of demand-side and supply-side resources on a comparable basis such that investments in either form of resource affords the utility a reasonable opportunity to earn a return on the investment, provided that the resource mix is least-cost to ratepayers. Ultimately, decisions will remain at the state level but DOE can provide, perhaps working with other associations such as NARUC and EEI, significant guidance and resources to evaluate potential regulatory reforms.

Provide more federal technical assistance to states and utilities on energy-efficiency programs and policies

In the 1990's DOE had a substantial Integrated Resource Planning program that worked with NARUC and other organizations to conduct research and provide technical assistance on demand-side management issues. This effort has shrunk to a small proportion of its prior size. DOE and EPA also initiated The National Action Plan for Energy Efficiency (NAPEE), to foster the collaborative efforts of key energy market stakeholders including utilities, regulators, energy consumers and partnership organizations to establish and further a national commitment for energy efficiency. The results of this commitment were meant to generate investment in energy efficiency through sound economically viable business cases, identification and implementation of best practices and through education to various audiences. The program today provides assistance to state regulators in the form of focused education helping states to meet their desired energy needs, cleanly and efficiently. However, relative to the need for information and technical assistance, both the DOE and NAPEE efforts are small and should be expanded. We recommend a major focus on working with NARUC, provision of technical assistance to individual states, and coordination with technical assistance efforts by others, such as work now starting at EPRI and EEI's Energy Efficiency Institute. Such an effort can also compile and provide to U.S. organizations information on best practice programs and policies elsewhere in the world.

Encourage and assist with regional coordination on demand resources so utilities, businesses and trade allies can more easily work across state/utility territory lines in the same region

The electric infrastructure of the future seeks to maximize its utilization, increase reliability, minimize unproductive investment and minimize its adverse impact on the environment. Demand side resources can successfully contribute to these goals. However, in order to successfully contribute to attaining these goals it is necessary to establish and execute a coordinated demand resource strategy. This strategy must focus on optimizing the installation and utilization of these types of equipment. The desire to have a fully integrated electric grid which maximizes the use of its components necessitates that the potential solutions that demand resources offer be independent of the jurisdictional borders established by state/utility/municipal boundaries. Accordingly, coordination (and the acceptance of a coordinated resource strategy) among these bounded entities needs to be facilitated to ensure that demand resource opportunities are maximized. These efforts can be integrated with the increased technical assistance called for in the preceding recommendation. A good model for these efforts is the work of the Northwest Power and Conservation Council, that facilitates common approaches to demand-side issues in the northwest.

Response in Forward Capacity Markets

DOE should advocate before the Federal Energy Regulatory Commission (FERC) and the appropriate regional transmission organizations (RTOs) and state public utility commissions that any retail customer (including aggregators of retail customer loads) be authorized to participate in the forward capacity markets of ISOs and RTOs by reducing or curtailing its load (kW capacity) for specific time periods, subject to adequate evaluation of actual load reductions. This includes both energy efficiency and demand response actions. DOE should also advocate that ISOs and RTOs allow and encourage participation by retail customers (including aggregators of retail customer loads) in any forward capacity market administered by the ISO or RTO.

Establish energy-savings targets for utilities at the state and/or federal levels

As discussed earlier in this section, 18 states have now established energy efficiency resource standards – binding energy-saving and/or peak reduction targets that utilities must meet. Such targets start at low levels initially, and gradually ramp-up, allowing programs to start small and expand over time. Such targets are spurring a substantial increase in energy-efficiency investments and are focusing efforts on best ways to meet targets at minimal costs. Such targets should be based on studies and experience on the cost-effective savings that can be achieved, but with safety valves if savings are more expensive than supply options. Such programs can also be structured to allow large customers to meet targets on their own, without participating in utility programs (e.g., Ohio and Michigan have such provisions). DOE should encourage additional states to develop targets based on these principles and should also assist and support efforts by Congress to adopt appropriate targets at the national level.

In addition to these recommendations, the subcommittee discussed a several other recommendations. We recommend that these be studied further.

1. Develop and encourage greater financing tools like energy efficient mortgages and on-bill financing for energy-saving retrofits

2. Create energy performance ratings for existing buildings, as a tool to help potential property purchasers and renters to assess relative performance. Such a program can build on HERS ratings, the EPA Energy Star Commercial Buildings program, the Energy Performance Certificate in England, and programs now being developed in Kansas, Nevada and Texas.