DEMAND-SIDE MANAGEMENT: DETERMINING APPROPRIATE SPENDING LEVELS AND COST-EFFECTIVENESS TESTING

Prepared for:

Canadian Association of Members of Public Utility Tribunals
(CAMPUT)

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EXECUTIVE SUMMARY

The Canadian Association of Members of Public Utility Tribunals (CAMPUT) RFP listed seven items that would provide insights and information to lead to a reasoned approach for addressing the overall engagement objective: *"What is the appropriate level of spending on DSM and what are the best mechanisms to ensure the testing of costs/benefits with a view to adopting guidelines for use by utilities and regulators?"*

1. The present level of interest in DSM in Canada and the US and how this may vary between areas in which deregulation has occurred and those areas which are still served by vertically integrated utilities.

2. Is the interest in DSM mainly driven by government, utilities, regulators, or others?

3. For areas that are promoting DSM, what types of programs are being promoted, e.g., load shifting, conservation, interruptible load, etc.?

4. What types of tests are used to determine the costs and benefits of DSM programs?

5. What is the level of spending by both utilities and customers, expressed in common units such as % of revenue, cents/kWh, etc.?

6. What criteria have various areas and entities used to determine the optimum level of spending?

7. Who determines what the optimum level of spending is?

Summit Blue Consulting and the Regulatory Assistance Project joined to determine the current state of energy efficiency and demand response in key states and provinces that could offer insights to CAMPUT. Our goal was to look for common threads, indicators of success. We also gathered data to support choices to engage in energy efficiency, illuminating things to watch out for. We identified jurisdictions with experiences useful for CAMPUT and interviewed knowledgeable people and applied what we learned and already knew from previous and current work. It is clear there is no single best way to implement energy efficiency and demand response, and electric energy efficiency is distinct from natural gas energy efficiency. Yet there are questions that regularly emerge, and sets of internally consistent choices regulators make that lead to a coherent, satisfying program. From this experience, we gleaned some insights for CAMPUT.

Overall spending levels have, in most cases, not been at a level sufficient to realize most of the cost-effective DSM in any jurisdiction. This is due to several factors: 1) concerns about the immediate rate impact of energy efficiency costs; 2) the inherent caution present in most legislative or regulatory proceedings; 3) changes in energy prices, particularly natural gas prices, between the time the enabling legislation or regulations were enacted and the present; and 4) rate structures that penalize utilities for conducting DSM programs. The research revealed seven key approaches to setting DSM funding levels.

1. DSM Spending Based on Cost-Effective DSM Potential Estimates

2. DSM Spending Based on Percentages of Utility Revenues

3. DSM Spending Based on Mills/kWh of Utility Electric Sales

4. DSM Spending Levels Set through Resource Planning Processes

5. DSM Expenditures Set through the Restructuring Process

6. Levels of DSM Tied to Projected Load Growth

7. Case-by-Case Approach

The scan of DSM issues across jurisdictions provides insights into lessons learned concerning natural gas and electric energy efficiency programs. There are a lot of factors associated with a successful DSM effort – that is the reality in the jurisdictions we examined, and illustrates why regulatory orders in energy efficiency dockets tend to be quite lengthy. The following are recommendations for various issues of interest to CAMPUT members.

It is extremely important that these recommendations not be taken out of context. There are a lot of variables that impact these recommendations that cannot easily be summarized. It is critical to read Section 4 of this report to understand the implications and nuances related to these recommendations.

Setting Appropriate Targets for the Amount of DSM

Determining the appropriate level of DSM is a challenging task for any utility, jurisdictional, or regional organization. There is no single or predominant approach but in many cases results are similar in terms of rough size of targeted savings and dollars allocated, sometimes as a percent of total revenues. Overall recommendations based on the scan of jurisdictions implementing DSM for several years are:

- *A minimum expenditure of 1.5% of annual electric revenues might be appropriate with a ramping up to a level near 3%.* These figures are irrespective of whether a jurisdiction has adopted retail electric competition or imposed generation divestiture, though regulatory oversight details may be quite different in either case.

- *Higher percentages may be warranted if there is expected to be rapid growth in electric demand or an increasing gap between demand and supply due to such things as plant retirements or siting limitations.* Even those states with 3% of annual revenues as an expenditure target have found that there have typically been more cost-effective DSM opportunities than could be met by the 3% funding.

- *For gas utilities, the expenditure levels have been found to be lower in virtually every jurisdiction examined.* No good reason was found for this other than that gas has not received as much attention as electricity in analytic studies. Gas space heating and water heating, as well as industrial uses, can benefit from DSM efforts. Given the history observed through the interviews, recommending a range of 1% to 2% for gas DSM is consistent with industry practice.

- *These DSM targets should be reviewed periodically.* California calls for a review every three years, Texas requests annual DSM forecast and filings to ensure the 10% of growth is being obtained by the DSM programs offered, and Idaho and British Columbia conduct an IRP update every two years. It is important to update avoided costs used as the benchmark for determining cost-effective DSM, and to incorporate any unforecasted events (e.g., the recent rise in the price of natural gas) that might change the economics of DSM versus other resources. The review should take into account the importance of maintaining a critical mass of basic capacity within markets for implementing energy efficiency programs, such as contractors, craftsmen, and trade ally relationships.

Cost Recovery of DSM Expenditures

Cost recovery of expenditures is important for organizations spending monies and implementing DSM programs. Most utilities and regulators prefer to expense efficiency costs; in the long run, this is less expensive than capitalizing – deferring and amortizing – them. The only exception is where programs are being started from scratch, and decision-makers are worried about rate impacts. Expensing DSM program costs, possibly through a balancing account, seems to be an acceptable approach but there are probably several acceptable approaches. If near term rate impacts are a concern, capitalizing a portion of the costs may be appropriate. In general, jurisdictions address issues of cost recovery once a DSM target is set.

Of greater interest is how potential disincentives (e.g., lost revenues) are treated. Jurisdictions that allocate an automatic or formulaic budget to energy efficiency create a disconnect between DSM funding and other resource decisions made by utilities and regulators. A regulatory process that compares the values of all resources is more likely to settle on the least cost mix of resources, factoring in the long run and known risks. Updating DSM plans is important either when using a resource planning process or a benefit-cost analysis based on updated avoided costs. Failure to periodically analyze such a budget poses planning risks and decreases the flexibility to address unexpected events through DSM programs. A key component of the value of DSM investments is portfolio diversification and risk mitigation.

Addressing Incentives and Disincentives for DSM

Organizations that traditionally earn profits from selling a product now work with customers to help them use less of their product which lowers overall revenues and potentially lowers profits. This disincentive is real and should be addressed either through an adjustment clause that tracks and makes the utility whole (or mostly whole) for lost margins due to lower revenues, or through a decoupling option to eliminate this disincentive.

The overall recommendations are:

- *Lost margins due to lower sales of electricity and/or gas should be addressed such that it is not a disincentive to utility investment in DSM.*

- *Where additional incentives to meet or exceed DSM targets have been used, the impact on the utility and its rate-payers appears to be positive.*

Benefit-Cost Tests and Avoided Costs

Assessing and evaluating DSM accomplishments are important on a prospective basis to develop a cost-effective mix of DSM programs, and on a retrospective basis to discern whether the expected benefits were actually obtained. These retrospective studies also can be used to develop a more cost-effective mix of DSM activities and provide suggestions on how to make a specific program more effective. The use of benefit-cost tests reflects the importance that regulators in a jurisdiction place on different factors. This is one reason why there are five tests incorporated into the methodology in common use today—the California Standard Practice Manual tests. There is no single answer to the question about which test to use and how to construct it, but this effort provides the following recommendations for use of benefit-cost tests:

- *The primary test that should be used is the Total Resource Cost Test applied to a portfolio of programs, with program specific tests used to address appropriate program design and the mix of programs in the portfolio.* For retrospective analyses, it is important to understand that delivering a DSM program is like introducing a new product into a market. Some programs will likely work better than expected, while others will encounter problems that need to be rectified. As a result, it may be unreasonable to expect all programs to pass the TRC test, but the portfolio as a whole should pass the TRC test.

- *The Participant Test should be part of implementation to ensure that customers that participate in the program do benefit, but it should not have a significant role in setting overall DSM expenditure levels.* Rather, it is useful in the design of specific programs to ensure that the customer perspective in represented.

- *The other tests commonly calculated can be used to provide different perspectives.* If there is a large discrepancy between a ranking of DSM activities based on the TRC Test and one based on the RIM or Societal Test, then the planning process should be flexible enough to make adjustments. Also, if one program drops substantially in its ranking relative to other programs, it may pose some equity problems across customers that could be corrected by making adjustments in the program. It is recommended that the TRC Test generally be the guide, with other tests used to check for extreme differences suggesting some flexibility in the design of a DSM program or the mix of DSM activities.

- *The benefit-cost tests need accurate estimates of avoided costs.* This means that this should include not only avoided costs of generation (i.e., the commodity cost), but also avoided transmission and distribution (T&D) costs. Progress is being made on determining avoided T&D costs in various states that have started to focus on this issue. It is recommended that the best estimates of avoided generation and T&D costs both be used in the application of these tests.

DSM Program Assessment, Monitoring, and Evaluation

Any investment of ratepayer funds should be the subject of ongoing assessment and verification to provide assurances anticipated benefits are being attained, and feedback on the programs and their implementation such that they may be improved over time. There is extensive literature in this area from many jurisdictions. California is adopting evaluation protocols and BC Hydro has developed a state-of-the-industry evaluation approach; other regions have a long history of evaluating energy efficiency programs. The New York State Research and Development Authority has conducted three years of evaluation of their SBC funded Energy $mart℠ programs. And many New England states have helped pioneer evaluation literature as their evaluations have had to meet scrutiny required by payment of incentives.

Specific recommendations are:

- *At program design and initiation, key success factors in terms of number of participants, measures installed, monies spent, trade allies signed up or participating, customer satisfaction, and a timeline for meeting these success goals need to be developed.*

- *Also at program design, the data collection to be used to assess energy savings will need to be incorporated into a program tracking system with customer IDs such that sites can be sampled as part of a monitoring and verification process.* These data will also be used to estimate overall program impacts, net of what would have happened without the program. The key is to have an evaluation plan completed at program initiation so all data needed for evaluation will be in program records when it is time for evaluation.

- *An approach used by BC Hydro is representative of current state-of-the-practice evaluation efforts.* This consists of:
    - A complete evaluation plan prepared at DSM program initiation.
    - Actual evaluations conducted at major milestones or at program completion.
    - Process, market, and impact evaluations are conducted, and are overseen by a cross-functional DSM Evaluation Oversight Team.
    - For programs including larger individual projects, technical and financial reviews are conducted before an incentive is offered to provide assurance the technology is feasible, estimated electricity savings are reasonable, and the cost-effectiveness is acceptable.

Interest in DSM, Leadership, Pricing, and Other Factors

There are many facets to launching and overseeing quality energy efficiency and demand response programs. Success does nothing to diminish the appropriate level of oversight and vision needed to be effective. Some essential threads:

- *Leadership is needed to push through the challenges that invariably arise and to keep the longer term in mind – a DSM program may not be immediately cost-effective and it will take time for the value of DSM to be realized.* Good leadership can set appropriate expectations and timelines, as well as ensure that the effort is sustained and is one component of a multi-year plan.

- *A stakeholder process encompassing trade allies, customers, and other stakeholders can be valuable to gain new perspectives and support for programs.*

- *Demand response needs to be integrated with energy efficiency since there are complementary aspects in delivery and economies that can be gained through technologies that both save energy and provide the customer with the ability to manage their energy use such that they can participate in a DR program.*

- *Pricing of electricity and gas is important for the economics of energy efficiency and demand response.* Time differentiated rates that recognize the varying value of the resource across hours and also better reflect the full societal cost of new resources will make DSM look more favorable to planners and customers.

1. INTRODUCTION

Like many government agencies interested in energy policy in 2006, the principals of the Canadian Association of Members of Public Utility Tribunals (CAMPUT) are taking a closer look at energy efficiency. Rising and volatile natural gas prices represent one reason for this increased interest, but these add to long-standing reasons for promoting demand-side management (DSM) – a track record of saving energy at a low cost, the expense and difficulty of adding new generation and transmission capacity, increased attention to climate change in addition to pollution control, energy security, and local economic development. Energy efficiency funded by utility consumer payments has merit because the measures produce benefits to all consumers and to society as a whole, not just benefits to program participants, and because without these programs, most of these investments would not occur.

In the U.S., the National Petroleum Council, an advisory group to the Secretary of Energy made up of oil and gas companies, recommended in 2003 that in response to rising natural gas prices, energy efficiency for the electric and gas sectors is their number one recommendation among others that would enhance energy supplies. Efficiency is cited not just for its effectiveness, but because it is a resource that North Americans can control generally independent of global politics or environmental permitting. Fossil fuel markets have remained volatile and gotten even more expensive since then.

For jurisdictions reassessing or beginning an energy efficiency program, significant experience in the United States and Canada offers the opportunity to apply to new efforts the lessons of success and failure, coincidence and mistake, wisdom and shortsightedness. DSM programs have been underway for nearly 30 years. In each state and province, there are distinct features and also patterns consistent among many jurisdictions. The amount of money committed to energy efficiency is a critical element, but there is a long list of important factors that determine the quality of energy efficiency programs. This report will lay out these factors so regulators can get a picture of the whole task before them. Energy efficiency for natural gas utilities is generally organized similarly to electricity utility programs, but there are important distinctions between gas and electric DSM.

States and provinces have discovered that influencing electric customer behavior can be particularly valuable at peak times. While many jurisdictions have used interruptible contracts for decades, increasingly competitive wholesale markets are introducing demand response programs with a regional scope. These are being enhanced with pilots investigating more “dynamic” pricing, improving the match between the cost to produce electricity and the price to consume it.

In this assignment, Summit Blue Consulting[1] and the Regulatory Assistance Project are joining to find out the current state of energy efficiency and demand response in some key states and provinces, ones that can offer insights to CAMPUT. We are looking for common threads, for indicators of success. We are also accumulating data that will support choices to engage in energy efficiency, while illuminating things to watch out for. We will apply what we learn in our interviews, as well as what we already know from work that we do in the U.S. and Canada. It is clear that there is no single best way to implement energy efficiency and demand response, and that electric energy efficiency is distinct from natural gas energy efficiency. Yet there are questions that regularly emerge, and sets of internally consistent choices that regulators make that lead to a coherent, satisfying program. From these kernels of experience, we will provide insights on how Canadian provinces can cultivate a new commitment to efficiency.

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[1] Summit Blue Consulting is located in Boulder, Colorado, and this assignment was performed jointly with its partner company Summit Blue Canada in Ontario.

The balance of this report is organized as follows: Section 2 discusses the objectives of this assignment and the research approach; Section 3 presents a general discussion of the information developed from the research approach; and Section 4 builds on the information from Section 3 to examine important choices facing regulators in relation to DSM.

2. Objectives of Assignment and Research Approach

CAMPUT's RFP listed seven items that would provide insights and information to lead to a reasoned approach for addressing the overall engagement objective stated on page 1 of the RFP – "*What is the appropriate level of spending on DSM and what are the best mechanisms to ensure the testing of costs/benefits with a view to adopting guidelines for use by utilities and regulators?*"

The seven specified research items on page 2 of the RFP are:

8. The present level of interest in DSM in Canada and the US and how this may vary between areas in which deregulation has occurred and those areas which are still served by vertically integrated utilities.

9. Is the interest in DSM mainly driven by government, utilities, regulators, or others?

10. For areas that are promoting DSM, what types of programs are being promoted, e.g., load shifting, conservation, interruptible load, etc.?

11. What types of tests are used to determine the costs and benefits of DSM programs?

12. What is the level of spending by both utilities and customers, expressed in common units such as % of revenue, cents/kWh, etc.?

13. What criteria have various areas and entities used to determine the optimum level of spending?

14. Who determines what the optimum level of spending is?

The consultants used two significant approaches to this research. We identified 15 states and provinces we felt would have experiences useful from the point of view of CAMPUT members. These jurisdictions were not randomly chosen. A judgmental process[2] was used where states and provinces were selected which, based on the experience of the authors, have been or are becoming active in DSM. As a result, this indicated a relatively high level of interest in DSM. In addition, we chose several states that bordered on Canada.[3] We interviewed knowledgeable people in these jurisdictions. We spoke with staff from the regulatory agency, the utility, and the energy efficiency administrator where such exists. We crafted these interviews into summaries, and these are provided in Appendix A.

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[2] There certainly could be different groupings of jurisdictions that fit the selection criteria, but it was judged that this mix of states would illustrate the DSM issues meant to be addressed by this report.

[3] There was a request in the comments on the draft report that an attempt should be made to rank all states and provinces with respect to their interest in DSM. After internal discussions, it was decided that such a judgmental ranking would not be very useful. For example, one stakeholder may be extremely interested in DSM but another entity may be working to delay DSM activities. Within a state, there are so many stakeholders with different views, that it is hard to make a judgment that others would tend to agree with. Also, there may have been recent changes at the regulatory level that are in the process of causing an increase in interest in a state. There is no central source for these data and, since we didn't interview all States, this would be difficult to ascertain. Determining what is going on across all jurisdictions is a difficult and time consuming task that is beyond the scope of this effort. The approach in which those states/provinces that the authors knew were actively addressing DSM issues would be surveyed was believed to be the best compromise.

Deregulated	***Traditional***
California[4]	British Columbia
Connecticut	Iowa
Illinois	Minnesota
Massachusetts	Vermont
New Jersey	Washington
New York	Wisconsin
Ontario	
Oregon	
Texas	

The interview questions addressed the level of interest in energy efficiency in the jurisdiction, from whom, and how that has changed lately. The consulting team collected information on what types of DSM programs are underway in each jurisdiction, and some important facts about them, as well as governance and responsibilities. Naturally, there are several money issues: how much is allocated and why; how the cost of DSM is compared with other resources, if it is; and how costs are recovered from utility consumers. The results of these interviews are reported in Section 3.

Secondly, we applied our significant experience in energy efficiency and demand response, both from inside government and as consultants to government and industry, to distill this information and augment it with other knowledge. This has become Section 4 of this report. Here we lead the reader through the many decisions that successful jurisdictions have already navigated to achieve high performing energy efficiency and demand response programs.

[4] Partially restructured.

3. RESEARCH FINDINGS

This section presents the research findings on the seven questions posed by CAMPUT, discussed in Section 1. These findings are primarily based on the interviews conducted on 15 jurisdictions covering 13 U.S. States and two Canadian provinces, but also incorporate previous research conducted by members of the project team.

3.1 Approaches to Setting DSM Spending Levels

This section presents the research findings regarding current levels of utility or "public benefits" DSM spending, how jurisdictions optimize DSM spending, and the ultimate decision maker regarding the optimal level of DSM spending in each jurisdiction.

3.1.1 Discussion of Approaches

Every jurisdiction faces a combination of political, economic, and societal goals that plays some role in determining the level of DSM spending. As a result, setting spending levels on DSM may include a number of different elements, e.g., a resource planning approach as well as a set of societal objectives. The diverse approaches for setting spending levels may make it seem like these approaches are more arbitrary than is actually the case. In the debates that lead to most DSM spending recommendations, there are several recurring themes: 1) the costs of building supply-side options (generation and delivery) that may be avoided due to DSM programs; 2) the size of the specific target markets for DSM programs; and 3) a discussion of the magnitude and types of DSM programs that make the most sense for that jurisdiction given energy prices and past investments in DSM.

Discussions before a province/state regulatory body or state legislature typically involve a variety of stakeholders with diverse opinions relying on different methods to support their cases. The final decision may involve a compromise between various positions and supporting methods. The California Public Utilities decision setting DSM targets, discussed in the first approach (below), illustrates this expansive approach. DSM targets and funding in California illustrate the types of positions[5] and compromises that are common in the target setting process. In some jurisdictions, these discussions were held a number of years ago but, with interest in DSM increasing in almost all jurisdictions with higher energy costs, many of these issues are currently being revisited.

For the purposes of this discussion, seven approaches to setting DSM spending levels are identified, with each discussed below. Several jurisdictions use more than one approach to setting DSM spending levels, often based on compromises stemming from the decision making process, so the categorization below is approximate, and is based on the primary factors used in each jurisdiction.

Approaches to Setting DSM Spending Levels

1. Based on Cost-Effective DSM Potential Estimates
2. Based on Percentages of Utility Revenues
3. Based on Mills/kWh of Utility Electric Sales
4. Levels Set Through Resource Planning Process
5. Expenditures Set Through the Restructuring Process
6. Tied to Projected Load Growth
7. Case-by-Case Approach

[5] See INTERIM OPINION: ENERGY SAVINGS GOALS FOR PROGRAM YEAR 2006 AND BEYOND; California Public Utilities Commission Decision 04-09-060 September 23, 2004.

Approach 1: DSM Spending Based on Cost-Effective DSM Potential Estimates

California bases DSM spending levels on the amount of cost-effective potential DSM in their jurisdiction. The California Public Utility Commission (CPUC) requires the four major Investor-Owned Utilities (IOUs) to procure all cost-effective DSM before pursuing supply-side options. The IOUs must meet annual MWh/therm savings goals, which are based on capturing 90% of all feasible efficiency. Funding is based on the cost of meeting the targets and requirements obtained from studies assessing the cost-effective potential of DSM in different target markets. Budgets are established for meeting these targets with the funds coming from a public goods charge, procurement budgets, and rates. An important element of the CPUC decision on spending levels was that the energy savings goals should be updated on a regular basis. The CPUC stated in Decision D0409060 that it is "our objective to capture all cost-effective energy efficiency that we establish numerical targets for electricity and natural gas savings today, and create a process for updating them on a regular basis in the future."

It is also important to note that the CPUC DSM targets are not a simple one-time target, but reflect a trajectory of increasing DSM over a period of 10 years, with updates scheduled every three years. This reflects the design, implementation, and penetration cycles that exist in DSM programs.

Approach 2: DSM Spending Based on Percentages of Utility Revenues

Four states, Minnesota, Oregon, Vermont, and Wisconsin have specified DSM spending levels as percentages of utilities' revenues. This percentage was generally arrived at through political processes at state legislatures.

- Minnesota – The State Legislature has determined statutory minimums that utilities must spend on DSM. [6] This is currently set at 0.5% for gas utilities and 1.5% to 2.0% for electric utilities, depending on whether or not a utility owns nuclear power plants. The Minnesota Public Utilities Commission can require electric utilities to exceed their statutory minimum DSM spending requirements through integrated resource plan (IRP) proceedings.
- Oregon – The two largest electric IOUs must spend 3% of their revenues on DSM and renewable energy efforts[7], and the largest gas utility must spend 1.5% of its revenues on DSM. Oregon's electric DSM spending requirements are set by statute, and are essentially fixed without legislative revisions to the governing statute, although current regulatory proceedings on least cost planning may provide some flexibility for DSM funding in the future. The gas utility's spending was determined in a regulatory proceeding.
- Vermont – The utilities are required by statute to capture all cost-effective efficiency, an obligation that is met through a statewide energy efficiency utility (EEU). In practice, however, DSM programs have historically been funded by a 3% surcharge on utility bills, which effectively caps DSM spending and may prevent all cost-effective potential from being captured. In 2005, the Legislature lifted the cap, and it is expected that the EEU's budget will increase, allowing it to capture a greater percentage of potential efficiency. How this will play out is currently uncertain. [8]
- Wisconsin – This state uses a 3% surcharge on IOU customers' electric bills as the largest funding component for its "public benefits" DSM programs, which transitioned from utility managed DSM programs starting in 2000. Wisconsin also uses other funding mechanisms for its DSM programs, including continuing pre-2000 gas DSM program funding, separately funded

[6] Minnesota statute 21B.241 covers the Conservation Improvement Program requirements.

[7] Over 80% of Oregon's electric public purpose charge is used for efficiency efforts; 17.1% for renewable energy.

[8] VSA 30, section 209c.

utility-managed load management and demand response programs, requiring utilities to conduct their own DSM programs as a condition for receiving approval to build new generating plants, and federal low-income weatherization funds.[9] Wisconsin's legislature has diverted about 40% of the funds intended for its Focus on Energy public benefits DSM programs to help balance the state's budgets in the last several years.

APPROACH 3: DSM Spending Based on Mills/kWh of Utility Electric Sales

Two states, Connecticut and Massachusetts, have specified electric DSM spending levels of 3.0 and 2.5 mills/kWh of utilities' total electric sales, respectively. These funding levels were specified by statutes as these states restructured the electric utility industry in the late 1990s, and can only be changed through legislative action. A securitization mechanism adopted by Connecticut's legislature to help balance the state budget will divert approximately 1 mill/kWh of DSM funds for about seven years.

APPROACH 4: DSM Spending Levels Set through Resource Planning Processes

Several jurisdictions contacted were found to require or allow utilities to implement the DSM programs that are found to be most cost-effective over time through an IRP process, or similar proceedings that involve viewing DSM as a resource on par with supply-side resources. Jurisdictions contacted that use this approach as their primary methods for setting DSM spending requirements are British Columbia, Idaho, Iowa, and Washington. Vermont is considering adopting such a process to overlay the current approach (see Approach 2).

These jurisdictions do not use any type of formulaic DSM spending guidelines or requirements. As an example, in Idaho, the largest electric utility (Idaho Power Company) has to file a formal resource plan before the State Commission every two years. This plan must include both DSM and renewables. The overall plan selected is the one that is deemed to be most cost-effective for meeting future electric needs taking into account supply-side, DSM, and renewable resources. A formal modeling approach and a structured stakeholder process are used in Idaho. By performing this planning exercise every two years, risks of changes in the market conditions are mitigated since the plan is revised on a regular basis.

Iowa does not use a formal IRP process, but compares costs of DSM to avoidable costs of new supply to determine the amount of DSM that is cost-effective. Other jurisdictions where a resource planning approach is used include:

1) The smaller gas and electric utilities in Oregon also invest in DSM as a result of IRP proceedings.

2) Gas utilities in Connecticut implement DSM programs approved in the context of supply/demand regulatory proceedings.

3) Gas utilities in Massachusetts present five-year DSM plans proposed by gas utilities in regulatory proceedings.

APPROACH 5: DSM Expenditures Set Through the Restructuring Process

A number of jurisdictions that have gone through restructuring and an unbundling of energy services have set spending amounts for DSM using a variety of governmental processes. Three such jurisdictions that have restructured their electricity markets are New Jersey, New York, and Ontario. In general, these

[9] Wisconsin's "Reliability 2000" legislation was contained in 1999's Wisconsin Act 9 (the 1999-2000 Biennial Budget Act).

levels were set as one component of the political process that resulted in the restructuring orders or legislation.

- New York – Annual electric DSM spending for SBC programs was set by the Public Service Commission as part of the re-authorization of the state's energy "public benefits" programs, [10] and recently extended for 2006 through 2011 at $175 million per year. [11]

- New Jersey – The Board of Public Utilities (BPU) recently assumed responsibility for managing the states' DSM programs from the utilities. New Jersey DSM funding is set at $140 million in 2005, and is projected to increase to $235 million in 2008. Funds for DSM programs in New Jersey and New York are raised by a "systems benefits charge" on IOU utility bills.

- Ontario – The Ontario Energy Board has approved $163 million of total funding for electric distribution company DSM programs for 2005 to 2007, and $25 million for gas DSM programs for 2005 to be recovered in utility rates.

APPROACH 6: Levels of DSM Tied to Projected Load Growth

Several states, Texas, Connecticut, and Illinois, require their electric investor-owned utilities to meet set percentages of their load growth through DSM. These states have restructured their electricity markets.

- Texas – The electric IOUs must meet 10% of their projected load growth through DSM.

- Connecticut – Recently enacted legislation in Connecticut is a variation on this approach, requiring an increasing percent of the state's electric supply to be met with distributed resources, reaching 4% by 2010. Certain DSM savings will count towards this distributed resource portfolio standard.

- Illinois – The Illinois Commerce Commission (ICC) has initiated a proceeding to implement the Governor's proposed Sustainable Energy Plan. [12] The Governor's proposal would require each of the state's electric IOUs to meet 10% of their load growth through DSM starting in 2006 or 2007, increasing over time to a maximum of 25% in 2015.

APPROACH 7: Case-by-Case Approach

Many jurisdictions do not actively regulate DSM spending or do so on an ad hoc basis, such as through rate case settlements. Jurisdictions have varying reasons for not directly trying to develop spending levels tied to some approach to achieving cost-effective DSM spending. Some jurisdictions have experienced utility and/or large industrial customer opposition to DSM.

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[10] Large customers were able to opt out of this public benefits charge arguing that they already have incentives to pursue all cost-effective energy efficiency. Large customer opposition to DSM spending, where some spending shows up in their rates, has been common. As a note, large customers are leading the way in energy efficiency expenditures in Idaho using an innovative approach creating a pool of money that any large customer can draw from for a cost-effective energy efficiency project. Since money is paid into the pool by the utilities, it is a use-it or lose-it proposition for these customers; Idaho has seen them aggressively compete for these energy efficiency dollars.

[11] Order Continuing the System Benefits Charge (SBC) and The SBC-Funded Public Benefit Programs (issued December 21, 2005). http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/5375707FAF2225B2852570D600700767/$File/05m0090_12_21_05.pdf?OpenElement

[12] See ICC web site: www.icc.illinois.gov, "Sustainable Energy Plan".

The information presented previously is summarized in Table 3-1 below.

Table 3-1. Summary of DSM Targets and Spending Amounts

State/Province	DSM Targets and Authorized Amount (Electric)	DSM Targets and Authorized Amount (Natural Gas)
British Columbia	All DSM that is cheaper than supply (This as resulted in expenditures that are about 3.3% of electric revenues)	Utility determined
California	Authorized budgets are based on funding levels necessary for utilities to meet CPUC savings targets by procuring cost-effective efficiency.	
Connecticut	3 mills/kWh (due to diversion by legislature, only 2/3 available for several years)	Varies within context of statutorily required supply and demand plans. Expected to increase due to new law.
Idaho	Approved as part of the Integrated Resource Plan (currently there is a 1.5% adder on to rates to pay for DSM approved by the State Commission. DSM is a relatively new initiative for Idaho)	
Illinois	Utilities must meet set percentage points of load growth through DSM	NA
Iowa	The regulator approves prudent, cost-effective efficiency in utilities' 5-year plans	
Massachusetts	2.5 mills/kWh	Varies with results of individual gas utility DSM plan regulatory proceedings.
Minnesota	Minimum spending: 2% of electric revenues for Xcel Energy; 1.5% for non-nuclear utilities. Integrated Resource Plan may result in increase.	Minimum spending: 0.5% of gas revenues
New Jersey	Balance cost-effective DSM with impact on rates; $1/MWh for economic DR	
New York	$175 million/year for SBC funded energy efficiency.	
Ontario	$163 million for 2005-2007	$25 million for 2005
Oregon	Public purpose charge of 3% of revenues of two major electric utilities; 57% administered by ETO for efficiency; 17% for renewables; remainder administered by others for low-income and school efficiency. Other utilities vary with Least Cost Plan.	1.5% of revenues of major gas utility; with 1.25% administered by ETO; 0.25% administered by utility for Low Income; other utilities vary with Least Cost Plan but less than 0.5% of revenues. Expected to increase.
Texas	Utilities must meet 10% of forecasted growth in demand through efficiency or approved load management.	NA
Vermont	Historically wires charge was capped at about 3% of electric revenues; in 2005 legislature removed cap.	Spending for one gas utility set in Integrated Resource Plan proceedings.
Washington	Based on Least Cost Plan	
Wisconsin	Up to 3% of electric revenues	Based on spending by utilities before the public benefits charge (1999).

The summary of approaches presented above is focused on electric energy efficiency spending. Jurisdictions vary considerably in how they treat natural gas energy efficiency spending and how they treat spending on load management or demand response programs.

Gas DSM Spending

It is almost universally the case that gas energy efficiency spending requirements are considerably less demanding than the corresponding electric DSM spending requirements. This situation is due to several factors: historically gas was a less expensive energy source than electricity, gas competes with unregulated heating oil in some locales, and new gas supply facilities generally raise less public opposition than corresponding electric plants and transmission lines. However, many jurisdictions have rebate programs targeted at major natural gas end-uses (i.e., space heating and water heating).

Several examples comparing gas to electric DSM spending requirements are shown below:

- In Illinois and Texas, gas IOUs are not covered by DSM spending requirements; electric IOUs are.

- In Minnesota, gas utilities must spend at least 0.5% of their revenues on DSM, compared to electric utilities that must spend 1.5% to 2.0 % of their revenues on DSM. The situation is similar in Oregon, where the largest gas utility must spend 1.5% of their revenues on DSM, compared to the largest electric utilities that must spend close to 3.0% of their revenues on DSM.

- In Vermont, total annual electric DSM spending is approximately $15 million, compared to Vermont Gas System's approximate $1 million annual budget for gas DSM.

Load Management and Demand Response Spending

Most of the focus on spending levels for DSM has been on energy efficiency. However, interest in load management and demand response has been increasing in recent years both because of rising end-use prices and because restructuring has exposed more end-use customers to the volatility of electricity prices in wholesale markets. Approaches to load management and demand response also vary considerably across jurisdictions.

Five types of approaches to load management and demand response were found in this review:

1. British Columbia, Illinois, Iowa, Minnesota, New York and Ontario treat load management or demand response similarly to how they treat electric energy efficiency programs. Load management or demand response program spending and/or impacts count towards overall DSM requirements.

2. California and Wisconsin encourage utilities to conduct load management and demand response programs, but regulate these programs in separate proceedings from energy efficiency programs. California takes this a step further by dividing demand response into two categories:

   A. <u>Price Responsive Load</u> – These are demand response programs that use price triggers and includes pricing programs such as Critical Peak Pricing (CPP) and Day-Ahead Pricing (DAP). These programs are event-based, i.e., the California utilities have to call for a CPP or DAP event;

then, customers are exposed to a high prices on those days and they have the choice as to whether they want to respond or simply absorb the high price.[13]

B. Curtailable Load Programs – These are the conventional load management programs where the utility has interruptible customers and can call on them for a load reduction. This includes such programs as simple large customer capacity call programs and direct load programs common to mass markets (e.g., direct load control of air conditioning or water heating).

California has been focusing on both sets of programs but with a recent emphasis on pricing to achieve load reductions. A 2003 California Public Utilities Decision[14] directed the utilities to achieve the capability to reduce their peak demand by 5 percent using price-responsive load programs in five years. The Commission continues to study the cost-effectiveness of this requirement with a recent set of filings by the utilities (August 2005) and, despite some utility pushback, a 5 percent reduction from price-responsive load programs is still the goal in California.

3. There has been an increased emphasis on demand response in Texas and Connecticut lately, resulting in more funds that were previously focused on efficiency being available for certain demand response or reduction strategies.

4. Massachusetts, New Jersey, Oregon, Vermont, and Washington either have very limited or no local load management or demand response programs available to customers. Utility spending on load management and demand response programs does not count towards DSM spending requirements. Rather, these costs are part of the overall resource procurement for utilities. There is some expectation that this area will become more robust in the near future in several of these states.

5. The Federal Energy Regulatory Commission, which governs interstate electric transactions, has been aggressive in working with the transmission and reliability organizations that perform dispatch and monitor the transmission grid to offer demand response programs. Generally, these organizations have been the Independent System Operators (ISOs).[15] The ISOs that offer reasonably aggressive demand response programs include the ISO New England, the New York ISO, the PJM ISO, and the ERCOT ISO in Texas. The states in these regions vary with respect to how they interact with the ISO programs. As a few examples:

   – New York ISO – The New York State Research and Development Authority (NYSERDA) directly uses monies collected from the Societal Benefits Charge levied by all the utilities to fund energy efficiency programs, but it also has programs that are designed to encourage customer participation in the New York ISO programs through both information and enabling technologies.

   – New England ISO States –ISO-New England encourages electric distribution companies to aggregate customers and participate in their programs by allowing the distribution company to retain a portion of the payments to customers that participate in the demand response programs.

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[13] These price-responsive load programs expose customers to price volatility in return for lower prices on non-event days in off-peak periods.

[14] The most recent CPUC ruling re-affirming these demand response targets is in: California Public Utilities Commission, OPINION APPROVING 2005 DEMAND ESPONSE GOALS, PROGRAMS AND BUDGETS, Rulemaking 02-06-001, Decision 05-01-056 January 27, 2005.

[15] For the purpose of this report, the distinction between ISO and RTO, Regional Transmission Organization, is not material. We will use the term ISO for simplicity.

– PJM ISO States – Pennsylvania, New Jersey, and Maryland have had a long tradition of demand response programs, primarily through rules that allow load providers to count demand response toward meeting their operating reserve requirements. With restructuring and creation of PJM as an ISO and the creation of active wholesale markets, PJM has developed its own reliability and economic demand response programs. Many of the individual state-level programs predate the development of demand response programs at PJM. The PJM ISO programs have been developed to co-exist with and augment the existing state and utility programs. The long term commitment to energy efficiency and DR among the original PJM states (i.e., the Mid-Atlantic States) has resulted in some large demand response programs (e.g., Baltimore Gas & Electric has over 300,000 customers in its demand response programs).

3.1.2 Summary of Research on DSM Spending Levels

The recent American experience with simple DSM spending requirements (e.g., mills/kWh, percent of revenue, or a specific dollar figure) reveals that spending levels have, in most cases, not been at a level sufficient to realize most of the cost-effective DSM in any jurisdiction. This is due to several factors:

- *The inherent caution present in most legislative or regulatory proceedings.* Few legislators or regulators want to become known as someone who authored requirements that could not practically be achieved.

- *Changes in energy prices, particularly natural gas prices, between the time the enabling legislation or regulations were enacted and the present.* For example, Minnesota's DSM spending statutes were last significantly updated in 1994. At that time the wholesale price of natural gas was approximately $2 per million BTUs, compared to the current natural gas wholesales prices of over $10 per million BTUs. More DSM will be cost-effective at today's high natural gas prices than was cost-effective when natural gas costs were much lower. This is true for both electric and gas DSM, as marginal new electric generating units are often fueled with natural gas.

- *Rate structures that penalize utilities for conducting DSM programs.* Decreasing sales through DSM programs also can reduce utility profits unless rate mechanisms that "decouple" utility profits from revenues are in place. Such decoupling mechanisms include allowing utilities to recover the lost profits from the revenues reduced through DSM programs, or tying utility profits to a secondary indicator such as the number of customers served instead of revenues.

- *Concerns about the immediate rate impact of energy efficiency costs.* This is a concern even when there is appreciation for long term cost savings to the utility system. As supply alternatives get more expensive, their rate impacts will become more onerous in comparison with efficiency. In addition, it is possible to ramp up DSM programs and expenditures over a two to three year period which can serve to mitigate price impacts even if these programs are funded by a rider on existing electric tariffs.

A process such as an IRP proceeding or DSM potential study is needed to set DSM targets, and additional procedures are needed to determine the most cost-effective portfolio of DSM programs to attain that target.[16] This will allow for the development of DSM plans that propose levels of program development

[16] The CPUC used overall DSM potential as the basis for setting reasonable targets and left the determination of the most cost-effective portfolio for attaining these targets to another proceeding. "The forum and process for considering what program offerings are cost-effective and reasonable will be dictated in large part by the administrative structure we adopt in a separate

and expenditures such that most cost-effective DSM will be implemented over a period of time. This is the case whether the simple DSM spending requirements are expressed in terms of spending a certain percentage of revenues on DSM, or a certain number of mills per kWh on DSM. The common element of processes that seek to optimize DSM spending is that DSM expenditure levels are part of an analysis designed to estimate the potential for cost-effective DSM, combined with a view that DSM is an alternative to developing supply-side resources. Potential studies are based on an increasing body of experience over time and jurisdictions. Generally, spending is not allowed up to levels that would fully test the estimated energy efficiency potential from these studies. On the other hand, one can learn a lot about a market without being overly precise in determining technical potential –regulators just need to know there is enough potential to at least justify the efficiency program and spending plan, which often can be done without an overly detailed study. However, there are other benefits that a DSM potential study can provide. Information from a DSM potential study is often used as the first step in the design of programs since potential studies can document current practices and establish energy use baselines. This information can be used to design the appropriate program for a region and help establish initial customer/trade ally incentives, if incentives are to be used. In addition, if the program is a market transformation one, a baseline is needed to develop market indicators to be tracked over time, providing information on how the market is changing and how much of this change can be attributed to the program. From this perspective, market potential studies can have three goals:

1. To provide an initial estimate of the potential savings that can be achieved from DSM programs to determine overall levels of expenditures on DSM.
2. To provide a baseline set of energy use practices that can help in the design of cost-effective programs.
3. To serve as the first step in the evaluation of programs since all estimates of program impacts and market transformation must be made in reference to a baseline.

Given these possible benefits of DSM potential studies, many jurisdictions spend more money on a potential study than is merely needed to justify a threshold level of expenditures on energy efficiency programs. They also use the results of the study proactively in program design and as the first step in program evaluation. This has caused the “price tag” of some DSM potential studies to be higher than others, depending on the depth of market analysis contained in the study.

The preceding discussion on the use of IRP processes and DSM potential studies is not intended to imply that simple DSM spending requirements are without merit. The clarity and simplicity of such requirements are naturally attractive to policy makers, utilities, and other stakeholders. Such funding requirements can ensure continuity and stability in DSM funding, and help ensure that such funding will not decline dramatically with short-term decreases in energy prices.

Benchmarks are available from other jurisdictions (See Section.4, Issue 1) and ramping up DSM expenditures over time (often a relatively short period of time, i.e., two years) allows programs that are almost certainly cost-effective to be implemented, and it also allows for information to be collected on end-use customer baseline practices as part of program implementation. This provides insight into the DSM potential of programs simply through implementation and good data tracking; a more focused potential study can be implemented after an initial set of DSM activities have been undertaken.

phase of this proceeding.” See: “Energy Savings Goals For Program Year 2006 And Beyond;” California Public Utilities Commission Decision 04-09-060 September 23, 2004.

3.2 DSM Benefit-Cost Analysis

There is an extremely large set of options for DSM programs. Depending upon the talent, creativity, and process with which a DSM program is designed and implemented, DSM programs which on paper appear similar can have quite different benefits and costs when actually implemented. In addition, some programs will simply be more cost-effective than others. As a result, regulators have generally mandated some form of benefit-cost analyses of DSM programs to both ensure that the utilities are being efficient in their implementation of programs, and establish that a cost-effective mix of programs are being offered.

In response to these concerns, utilities conduct DSM benefit-cost analyses that fall into two categories:

1. Dynamic analyses that identify the amount of DSM that is most cost-effective relative to other resources, primarily new energy supplies. This is most commonly done through IRP proceedings.

2. Static analyses that evaluate DSM's cost-effectiveness relative to a fixed set of avoidable supply-side resources and avoided costs.

Of the 15 jurisdictions researched for this project, seven used IRP[17] processes to assess DSM, even if the spending level was not directly tied to the outcome of that process. For example, with a fixed spending target, a resource planning process can identify which DSM programs are the most cost-effective within that spending target. Eight jurisdictions were not judged to use formal IRP processes in DSM assessment. The seven jurisdictions that had IRP elements in DSM planning were British Columbia, California, Minnesota, Ontario, Oregon, Vermont, and Washington. [18] Interestingly, almost half of these jurisdictions (California, Ontario, and Oregon) have either partially or fully restructured their electric utilities. For the eight jurisdictions that do not use IRP processes, all but two (Iowa and Wisconsin) are restructured.

Utilities or power planning organizations use IRP processes to select the lowest cost energy system expansion plan from among many possible options. As part of this process, the planning organization develops at least several scenarios for each type of supply or demand reduction resource. IRP planning periods are generally at least 20 years long (some as short as 10 years with others being as long as 30 years). DSM scenarios can be developed by adding or subtracting different types of DSM programs or technologies between scenarios, adding or subtracting customer groups covered by DSM programs, or varying DSM incentives such as customer rebates between scenarios. There are many models that can be used in an IRP context.[19] Typically, they calculate the long-term costs of various combinations of supply and demand reduction scenarios over the forecast period. Monte Carlo analyses can be used as part of the

[17] The use of the term Integrated Resource Planning (IRP) is meant to generally apply to an analytic process that is comprehensive in its analysis of resources, i.e., both supply-side and DSM (and often renewables) are all analyzed with reasonable characterizations of each resource option to assess the tradeoffs between resources and develop a going-forward action plan for meeting load growth. In some regions, the term IRP has become associated with a narrowly defined process that involved specific modeling activities that were viewed as counter-productive by some utilities and planning organizations. It is hoped that this more general view of IRP will avoid the debate that arises in some regions about the use of an IRP approach.

[18] About half of these jurisdictions (California, Minnesota, Oregon, Vermont) use another type of DSM spending requirement as the primary DSM regulatory approach. IRP proceedings are use to fine-tune DSM spending requirements that are (most commonly) defined by statutory requirements for utilities to spend certain minimum percentages of their revenues on DSM.

[19] Many models are used as tools in performing IRP-type studies. Some of the more models used in the jurisdictions surveyed include ProSym or RiskSym offered by Henwood Associates, PROMOD IV and Strategist offered by New Energy Associates, and the Aurora Model offered by EPIS, Inc. However, there are easily a dozen other models in use by utilities and regional planners and those mentioned. The models cited above are some of the models being used in states that were contacted in this research.

IRP analysis, and are particularly useful to quantify the risks of low probability but high consequence events between scenarios.

IRP analyses can be useful to determine the amount or type of DSM that is most cost-effective over the long term. However, IRP analyses are generally not conducted by utilities that have divested their generation assets, as they are no longer "integrated" utilities. This has resulted in a gap in information analyses as full retail competition has not emerged in most markets. Now, some regulators even in restructured markets are beginning to see the advantages of some integrated planning as are other entities such as state energy offices (e.g., the California Energy Commission) and regional groups (e.g., the Northwest Power and Conservation Council). IRP analyses can require a substantial amount of work for the responsible utilities or planning organizations, and the results can be contentious. As a result, some utilities and regional organizations try to manage the number of such analyses. However, other jurisdictions have found these IRP processes to be very successful and have used IRP processes for over a decade. The standard tools and techniques used in IRPs are generally well understood, although they are evolving over time.

It is hard to characterize the attributes of a successful versus an unsuccessful IRP process for assessing the level and types of DSM that should be targeted. Where it has been judged as being unsuccessful, it was generally seen as too burdensome, with some stakeholders essentially requesting every possible demand-side option be analyzed. Where it has been judged successful, there generally have been good stakeholder processes and accepted screening criteria to reduce the number of DSM options to categories and portfolios that receive detailed consideration down to a manageable level.

In the U.S., the most common types of static DSM program benefit-cost test analyses are done using the California Standard Practice Manual (SPM) approach.[20] These benefit-cost tests are a form of integrated planning, but they generally do not have the dynamic element common to the IRP approach discussed above. The link between the DSM program and supply-side options is made through the use of an "avoided supply cost." This is an estimate, often taken from the results of resource planning model, of the supply-side resource that is on the margin, i.e., is the next option to be built. An adequate amount of DSM could avoid the costs of this marginal unit. As a result, one of the key benefits as defined in these benefit-cost tests is the avoided costs of a supply-side resource. This makes the frequency of updates to the avoided cost number important for good DSM planning.

In general, the California SPM benefit-cost approach uses five "stakeholder" tests to assess the benefits and costs of DSM programs from different perspectives:

- <u>Participant (customer) test</u>. DSM benefits to participants are reduced energy costs from the DSM measures they installed, plus any productivity benefits they may receive from the DSM measures. DSM costs to participants are the net (after rebate) incremental costs of the DSM measures.

- <u>The utility test</u>. The primary benefits of DSM to utilities are the avoided costs they realize from not having to build new energy supply facilities. The DSM costs to utilities are the total costs of the DSM programs.

- <u>The rate impact test (formerly called the non-participant customer test)</u>. The benefits for this test are the avoided costs from not having to build new energy supply facilities. The costs for this test are the total program costs plus the "lost revenues" from the DSM measures. This test is similar

[20] California Energy Commission, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" (California Energy Commission, Sacramento, CA, October 2001).

to the Pareto efficiency test in economics: a policy or project that makes everyone better off without making anyone worse off.

- The total resource cost (TRC) test, essentially the perspective of all utility customers combined. The benefits for this test are the avoided costs from not having to install new energy supply facilities. The costs for this test are the DSM program administrative costs plus the net (after rebate) incremental costs of the DSM measures. This test is similar to the Kaldor-Hicks compensation test in economics: the winners from a policy or project could compensate the losers enough so that they would at least break even.

- The societal test. The societal test is very similar to the TRC test, except that it includes avoided environmental damages due to DSM programs.

The analyses are to be done using the net present value of DSM program benefits and costs over the lifetime of the DSM measures covered by the DSM programs. The DSM benefits should be based on "net" program impacts, that is, program impacts adjusted for free-ridership and spillover.[21]

Table 3-2 is a summary of results for each of these five tests for Xcel Energy's Minnesota Commercial and Industrial Lighting Efficiency Program for 2005. These results are common for many energy efficiency programs: benefit-cost ratios are somewhat greater than one for the participant test (otherwise why would the customer participate?), the TRC test, and the societal test, and much greater than one for the utility test. This program is cost-effective from all these perspectives. It is interesting to note that the environmental externality benefits only account for seven percent of the total societal program benefits, so the societal test results are very similar to the TRC test results. The benefit-cost ratio for the rate impact test is slightly less than one. This means that this DSM program will cause long-term electric rates to be slightly higher than they would be without the program.

[21] DSM program free riders are those program participants who would have installed the DSM measures even without the DSM program. DSM program spillover effects include savings from program participants and non-participants who installed DSM measures due to a DSM program, perhaps due to the program's informational effects, but did not receive any funding from the DSM program.

Table 3-2. Commercial and Industrial Segment Lighting Efficiency 2005 Cost Benefit Summary

	Participant Test $/kW	Utility Test $/kW	Rate Impact Test $/kW	Total Resource Test $/kW	Societal Test $/kW
Avoided Revenue Requirements					
Generation	N/A	$721	$721	$721	$721
T & D	N/A	440	440	440	440
Marginal Energy	N/A	1,604	1,604	1,604	1,604
Externality Willingness	N/A	N/A	N/A	N/A	220
Subtotal	N/A	$2,765	$2,765	$2,765	$2,985
Xcel Energy's Project Costs	N/A	$329	$329	$329	$329
Subtotal	N/A	$329	$329	$329	$329
Revenue Reduction	$2,589	N/A	$2,589	$0	$0
Subtotal	$2,589	N/A	$2,589	$0	$0
Participants' Net Costs					
Incremental Capital	$1,264	N/A	N/A	$1,264	$1,264
Incremental O&M	527	N/A	N/A	527	527
Rebates	(268)	N/A	N/A	(268)	(268)
Subtotal	$1,523	N/A	N/A	$1,523	$1,523
Net Present Benefit (Cost)	$1,066	$2,435	($154)	$913	$1,133
Net Benefit (Cost) per kWh Lifetime	$0.013	$0.029	($0.002)	$0.011	$0.013
Net Present Benefit (Cost) per Generator	$1,212	$2,768	($175)	$1,037	$1,288
Cost Benefit Ratio	1.70	8.39	0.95	1.49	1.61

For the 15 jurisdictions investigated for this project, the most important benefit-cost analysis tests are TRC and societal tests. Six jurisdictions each use these two tests as their primary DSM benefit-cost analysis test. Since these two tests often produce similar results, the jurisdictions researched for this project are quite similar in their conclusions regarding the most important DSM benefit-cost analysis test.

Three jurisdictions primarily use the utility cost test as their primary benefit-cost analysis test. Only one jurisdiction (British Columbia) uses the rate impact test as one of its primary benefit-cost analysis tests. The totals discussed above include some double counting, as a few jurisdictions use one test as the primary test for one type of DSM program, and use a second test as the primary test for other types of DSM programs. One jurisdiction (Illinois) was uncertain about which test would be their primary benefit-cost analysis test. Jurisdictions also vary considerably in how many of the California stakeholder tests they use as part of their DSM benefit-cost analysis. Only Iowa and Minnesota use all five California tests. Five jurisdictions (Massachusetts, New York, Ontario, Texas, and Vermont) only use one test, and three of those jurisdictions use the TRC test. Wisconsin uses the societal test, and developed a new DSM test that models the economic impacts of DSM on the Wisconsin economy.

3.3 Cost Recovery and Incentives

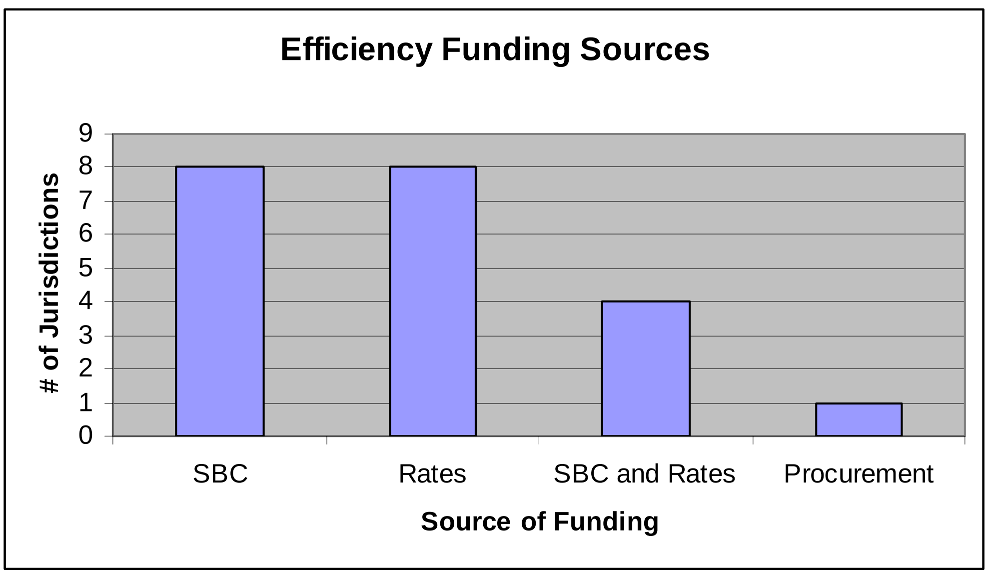
Among the jurisdictions interviewed, a number of different approaches to DSM funding are used. In most areas, load management and demand response programs are recovered directly through rates. Efficiency programs are generally funded by customers either through general rate recovery or through a system benefits charge (SBC). Some areas take a hybrid approach to efficiency funding, using both SBCs and rate recovery, and one state, California, funds efficiency through both an SBC and through utility procurement budgets. ***Regardless of the specific approach taken, DSM efforts are ultimately funded by ratepayers in each jurisdiction.***

When efficiency is funded through rates, the charges are determined by regulators during rate cases and may appear as a per-unit surcharge on wires or supply. This approach may be used by restructured jurisdictions (Illinois, Ontario, and Texas) as well as vertically integrated jurisdictions (British Columbia, Iowa, Minnesota, and Washington).

SBCs are known by a variety of names (a public goods charge in California; a public purpose charge in Oregon). In most cases, SBCs were instituted by statute during a state's restructuring process, with legislatively established funding levels. Some SBCs may have certain restrictions placed on them. In Oregon, for example, specific percentages of SBC funding must be spent on categories like schools and low-income customers, and in California, the SBC also funds renewable energy programs. The establishment of a SBC generally reflects legislative intent to preserve continuity of efficiency programs, which might otherwise have been dropped under the new regulatory scheme. One exception is Vermont, where the SBC was developed during restructuring discussions. In that case, the state chose to adopt the SBC funding mechanism while remaining vertically integrated.

A number of jurisdictions use dual approaches to efficiency funding. In California, meeting the state's efficiency goals requires funding over and above the SBC, and the regulator has authorized funding of efficiency through utilities' procurement budgets. Wisconsin maintains an SBC, and recovers some expenses through rates as well. Connecticut and Massachusetts have an SBC that funds electric efficiency, while gas costs recovery occurs in rates. Oregon and Vermont use SBC funds for programs through statewide efficiency implementers (Energy Trust of Oregon and Efficiency Vermont), and use rate recovery for DSM implemented by utilities.

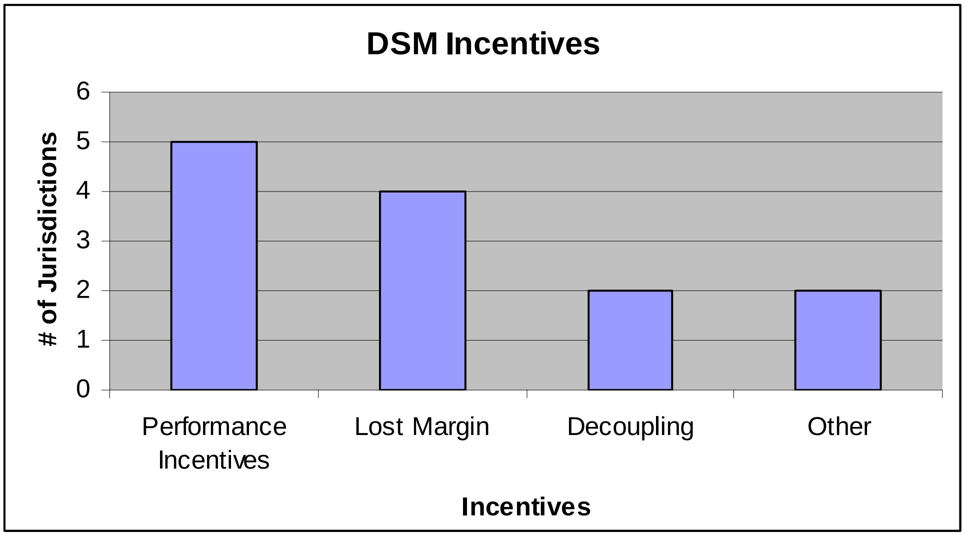
Figure 1. Efficiency Funding Sources



Among the interviewed jurisdictions, most states expense their efficiency costs. British Columbia is the only jurisdiction that capitalizes all expenses, although some states capitalize a portion of DSM expenses, such as demand response programs (New Jersey) or some amount of gas DSM (Vermont, Oregon). Utilities generally collect funds earmarked for efficiency and hold them in deferral accounts, from which expenses are drawn as needed. Accounts are balanced periodically. In states where efficiency is implemented by a statewide entity (New York, Oregon, Vermont), funds are submitted to the efficiency implementer or held in ESCROW until needed.

A variety of performance incentives and other mechanisms are used to encourage DSM in 10 jurisdictions. Connecticut, Massachusetts, Minnesota, Ontario, and Vermont offer performance incentives for efficiency. Four jurisdictions allow some sort of lost revenue recovery, either for all electric DSM (Connecticut), for gas DSM (Ontario, Massachusetts), or for a portion of electric DSM (Vermont). One state, California, has removed utilities' disincentives to delivering efficiency by decoupling profits from sales for both gas and electric sectors. Oregon has decoupled profits from sales for one gas utility. One jurisdiction interviewed (BC) reports the use of performance-based regulation, and one jurisdiction (Washington) imposes fines on one utility for failing to meet savings targets.

Figure 2. DSM Incentives



Only four of the jurisdictions interviewed for this study were offering incentives to utilities to implement DSM programs—Connecticut, Massachusetts, Minnesota, and Ontario. Vermont only provides incentives to the central agency. Both Connecticut and Massachusetts offer incentives for a range of achievement of goals, between 70 and 130% for Connecticut and between 75 and 110% for Massachusetts. Minnesota will provide incentives once 91% of the goal has been achieved, whereas Ontario provides a simple incentive of 5 per cent of net TRC benefits. In Massachusetts shareholders may earn up to 5% after tax return on the annual expenditures, subject to the level of performance achieved by the programs, which has become a fairly complex calculation to ensure that various goals are met.

The specifics of DSM incentives vary significantly across jurisdictions. A 1995 report stated that "current practice in DSM incentives varies widely"[22] and that remains true today. Appendix B to this report contains language from several regulatory decisions that were identified during the course of this project that can illustrate how these specific DSM incentives have been designed..

3.4 Factors Driving Interest in DSM

This section discusses the level of interest in DSM in Canada and the US and how this may vary between areas in which deregulation has occurred and those areas which are still served by vertically integrated utilities. As mentioned previously, the study team conducted interviews in jurisdictions judged to have a

[22] This report, while authored a number of years ago, still contains a good discussion of DSM incentive issues. See: Stoft, S., J. Eto, and S. Kito, "DSM Shareholder Incentives: Current Designs and Economic Theory". Energy & Environment Division, Lawrence Berkeley Laboratory, LBL-36580, January 1995

relatively high interest in DSM based on recent activity. Due in part to this selection of jurisdictions, Only two jurisdictions, Illinois and Texas, were self-described as having a modest or steady interest, respectively, in DSM. The interviews covered a wide variety of jurisdictions, including both traditional and deregulated energy sector structures. However, there were no indications that a jurisdiction's restructured status determined the level of interest in DSM. Nor were there any significant differences found in terms of DSM drivers, types of programs, and approaches.

Deregulated		***Traditional***
California[23]	New York	British Columbia
Connecticut	Ontario	Iowa
Illinois	Oregon	Minnesota
Massachusetts	Texas	Vermont
New Jersey		Washington
		Wisconsin

Several areas have had a long-term interest in DSM: California, Washington, and Oregon in the West, New York, New Jersey, and the New England states in the East, and Iowa, Minnesota, and Wisconsin in the Midwest. Interest in electricity DSM is generally much higher than in natural gas, although increasing gas prices recently have been reflected in an increasing interest in gas DSM (mentioned in about half the jurisdictions). And interest in electricity DSM has also increased recently, again in about half the areas studied, mainly due to high energy prices, environmental concerns, or supply and transmission issues. Most persons interviewed noted several drivers for interest in DSM, generally a combination of factors shown in the table opposite.

Drivers for Interest in DSM

High Energy Prices: DSM is a more cost-effective resource, lowers bills, and provides a hedge against risk and market volatility.

Environmental Concerns: greenhouse gases, other air pollutants, non-attainment issues and the desire for 'greener' solutions..

Supply and Transmission Issues: potential shortages this winter, growing peak demand, transmission constraints, congestion-related charges, reliability issues, generator retirements, reserve margin concerns.

Other Economic Benefits: job creation and net economic benefits due to energy bill savings, new technologies, and increased energy service company activities

3.4.1 Role of Stakeholders in Driving Expanded DSM

The entities that drive expansion in DSM activities is truly diverse. Most prominent as a key supporter are environmental interveners; they almost always take a proactive stance with regard expanding DSM activities. In addition, there is a set of organizations such as the American Council for an Energy-efficient Environment (ACEEE) that actively supports DSM throughout North America. The ACEEE has spun off regional entities that continue to press regulators, utilities, and legislative bodies to consider DSM as a resource. Beyond these common supporters, the surveys showed the utilities could lead the issue. Regulatory bodies seeking least cost plans for meeting customer needs were often leaders. Province/State governments also were leaders in a number of jurisdictions examined with legislation used as the vehicle to expand DSM activities. The level of interest in DSM by a high-level champion (CEOs in BC Hydro,

[23] Partially restructured.

and governors in California, Iowa, and Illinois) can have a significant impact on DSM activities. The table below shows the number of jurisdictions noting specific groups who are driving DSM.

Who is driving the interest in DSM?	# Jurisdictions citing
Political (government, legislature)	13
Interest Groups (customers, vendors, etc.)	11
Regulators	8
Utilities	7

The regional energy situation can also lead to increased interest by these stakeholder groups. The price spikes that occurred in a number of areas in 1999 and 2000 increased interest, supply shortages drive the search for cost-effective solutions, and the overall increase in energy prices during the past two years is another factor.

3.4.2 Types of DSM Programs and Delivery

This section looks at how DSM programs are being delivered in different regions and the types of DSM programs that are being promoted.

Approach to Electric DSM – Delivery

In general, the utilities – with or without third party contractors – plan, design, implement, and evaluate DSM programs, with regulators providing review and approvals. Most program administrators receive significant input and guidance from stakeholders and technical experts. Examples include formal advisory board arrangements, formal or informal public processes, or technical advisory groups or consultants. The term “collaborative” is often used to described the on-going group of stakeholders, including the administrator, that provides input to the administrator and the regulator.

	Utilities	Independent Administrator	3rd Party	Regulator/ Government
Plan Generic Programs	All other jurisdictions + VT	NY[24], OR[25], VT[26]	NJ, WI	
Design Specific DSM Programs	All other jurisdictions	NY, OR, VT	NJ	TX
Approve Programs			NJ	All other jurisdictions
Implement Programs	BC, IL, IA, MN, ON, WA, CA	NY, VT	CT, IL, MA, MN, NJ, ON, OR, TX, WI	
Evaluate Programs	BC, CT, IL, IA, MN, ON, VT, WA		CT, MA, NJ, NY, ON, OR, WI, VT	CA, OR, TX, VT

[24] Through the New York State Energy Research and Development Agency (NYSERDA)

[25] The Energy Trust of Oregon

[26] Efficiency Vermont, the Energy Efficiency Utility

Several states have implemented a centralized approach to DSM. For example, New York's electricity and natural gas programs are provided through NYSERDA. In Vermont, in 2000, an "energy efficiency utility" known as Efficiency Vermont was established to deliver efficiency in the state. It is run by the Vermont Energy Efficiency Investment Corporation, a non-profit firm selected competitively for a six year contract; load management is provided by the utilities. Recently, VEIC was awarded a new six year contract beginning in 2006. In Oregon a non-profit organization, the Energy Trust of Oregon, was created in 1999 to administer electricity conservation and market transformation programs and promote new renewable energy. Natural gas efficiency responsibilities were added recently.

Some states are completely changing their approach to DSM. Efficiency Vermont's approach continues to evolve (see inset). And New Jersey, which used to deliver natural gas and electricity DSM through the utilities, has established an RFP process to hire third party contractors to provide DSM and renewable energy.

Efficiency Vermont Approaches

Initial	Program based (e.g. Residential Low Income)
2002	Service-oriented (targeted market segments)
2006	Market-based (remove market barriers)

An influential organization for the delivery of DSM programs known as market transformation programs has developed in the Pacific Northwest. The Northwest Energy Efficiency Alliance (NW Alliance) spans Oregon, Washington, Idaho, and Montana. This is a unique organization in that it was set up to implement programs that were viewed as regional in nature. Some programs naturally cut across utility service territory boundaries and it may be inefficient for individual utilities to each set up the infrastructure to implement similar programs. The Northwest Energy Efficiency Alliance is a non-profit corporation supported by electric utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. The NW Alliance tends to implement market-wide and market transformation programs while the individual utilities continue to implement what have been termed resource acquisition programs that are more easily targeted at their customer base and service territory.[27]

A few states, such as Massachusetts and Wisconsin, try to make "market transformation" a key component of many or most energy efficiency programs, both for natural gas and for electricity. Other states, such as California and Washington, are facing supply constraints and have taken a "resource acquisition" approach to programs, in which efficiency is treated as a supply-side resource. These states emphasize programs whose main purpose is to get concrete energy and demand savings impacts, for example, by replacing inefficient equipment through use of rebates and incentives. In California and Vermont, resource acquisition is increasingly done by market-based approaches, in which utilities identify and eliminate barriers to efficiency that exist in the marketplace. Methods used in this approach may include offering rebates to customers, ensuring that efficient products are readily available for sale, and educating contractors and salespeople.

Approach to Electric DSM – Types of Programs

Utilities or DSM program administrators in most jurisdictions offer a combination of electric energy efficiency programs, load management, and demand response programs. However, the number of programs offered and the range of DSM measures covered by the programs varies considerably between jurisdictions. Several jurisdictions such as Massachusetts and Washington offer few or no load

[27] These diverse entities support the NW Alliance and work together to make affordable, energy-efficient products and services available in the marketplace. More information on the NW Alliance can be found at www.nwalliance.org.

management or demand response programs through the utilities or distribution companies. Massachusetts is in the New England ISO which does offer a number of ISO programs, but the utilities in New England (now restructured in to distribution companies) do not generally play a large role in the ISO DR programs.

Approach to Gas DSM – Delivery and Types of Programs

Natural gas DSM, if done, is generally done on a much smaller scale than electricity, usually focusing on weatherization and heating applications. In Ontario, however, the two large natural gas utilities have large customer programs and are quite different than most other U.S. utilities. Illinois is only beginning to look at natural gas DSM; the Governor's proposed Sustainable Energy Plan issued earlier this year had no provisions directly concerning natural gas. Six states treat electricity and natural gas in a similar fashion: California, Iowa, New Jersey, New York, Oregon, and Washington. In Iowa and Washington several of the utilities provide both natural gas and electricity. In the other eight jurisdictions studied they are treated differently, particularly in terms of type and level of funding. For example, in Minnesota electric utilities spend 1.5 to 2% of revenues on DSM and gas utilities spend only 0.5%, and in Connecticut gas DSM programs focus on low income consumers. Massachusetts relies heavily on natural gas for both electricity generation (30%) and space/water heating (60%) but funding for gas efficiency programs continues to be determined by regulators on a case-by-case basis. Electricity is funded by the SBC ($120 million/year) and emergency legislation was passed in Nov 2005 to extend funding to thru 2012. Natural gas DSM spending is between $20 and $25 million/year. However, both gas and electric programs focus on market transformation.

In Ontario, natural gas DSM funding and evaluations have been done through rate cases, a process which has been both time consuming and costly. For the new electricity DSM programs, the regulator is trying to avoid these issues by using guidelines and pre-specified variables for measures, including free riders, persistence, incremental costs, etc. In Oregon the regulator and the gas utilities are beginning to discuss distribution system optimization and DSM. For example, Cascade has constraints in Washington State, due primarily to transporter customers.

Approach to Demand Response Programs

Demand response (DR) programs range from Time of Use (TOU) and Real-Time Pricing (RTP) pricing (Illinois, British Columbia, Washington), and demand bidding (Minnesota, Oregon, Wisconsin) through to a complex offering of programs like in California (DBB, CPP, etc.). Demand response is a strategy that is growing in prominence in California. In response to the energy crisis in 2001, the IOUs began to implement a wider array of offerings, such as critical peak pricing and a "Flex Your Power" marketing campaign, still in use, that encourages all customers statewide to use less energy during peak periods, either by switching usage to off-peak hours or by reducing usage entirely. During the last few years, the IOUs have piloted and implemented programs ranging from TOU to advanced metering initiatives. At times the number of potential programs has been confusing to customers. Currently the IOUs and the CPUC are examining the results of these programs and looking to simplify offerings, make them more customer friendly, and ramp up the most promising programs.

In jurisdictions where there is an independent system operator such as PJM (New Jersey), NYISO (New York), NE-ISO (Massachusetts, Connecticut, Vermont), IESO (Ontario), or ERCOT (Texas), utilities often help customers to participate in those programs. Sometimes utilities also provide DR programs as in Connecticut and Ontario. In New York, DR is delivered both through NYSERDA and the NYISO. The Governor's

In Vermont, IOUs can establish contracts with customers who want to participate in ISO demand response programs, but there have been concerns about the programs and participation has been limited.

Coordinated Demand Response Working Group includes the New York Power Authority, Long Island Power & Light, the New York State Dept. Public Service, and NYSERDA.

Approach to Determining Spending Levels

In all the jurisdictions surveyed, the appropriate level of spending is set either by statute or by the regulatory body. In British Columbia, however, BC Hydro determines what electricity DSM programs are cost-effective and the appropriate level of spending.

Who	States/Provinces
Legislature	Connecticut, Massachusetts (electric), Minnesota, New Jersey, New York (electric), Oregon (electric), Texas, Vermont (electric), Wisconsin
Regulators	BC (gas), Illinois, Iowa, Massachusetts (gas), New York (gas) Ontario, Oregon (gas & electric), Vermont (gas), Washington
Utility	BC (electric)

4. REGULATORY CHOICES

The scan of DSM issues across jurisdictions, which included the interviews for this project, information shared with us by government and utility DSM officials, and our own experience with energy efficiency and demand response, provides insights into lessons learned concerning natural gas and electric energy efficiency programs. There are a lot of factors associated with a successful DSM effort – that is the reality in the jurisdictions we examined, and illustrates why regulatory orders in energy efficiency dockets tend to be quite lengthy.

This section builds on the more general discussion contained in Section 3 to examine choices that face regulators when working to develop or expand the role of DSM to help meet the energy needs of a region. These are posed as issues that need to be addressed by regulators followed by a discussion and recommendations.

ISSUE 1: SETTING APPROPRIATE TARGETS FOR THE AMOUNT OF DSM

Determining the appropriate level of DSM is one of the most challenging tasks facing any utility, jurisdictional, or regional organization. The interviews indicated that there was no single approach taken, but in many cases the results are similar in terms of the rough size of the energy savings targeted and the dollars allocated, sometimes as a percent of total revenues.

Issue 1: Discussion – Appropriate DSM Targets

The interviews indicated that this issue draws the opinions of a large number of stakeholders, each with a different reference point for making recommendations. In most jurisdictions, the ultimate decision represented a political compromise in the context of multi-variable negotiations involving environmental issues, customers' electric and gas rates, revenue for renewables, needs of different customer classes, and funding required for a target level of energy efficiency and load management. Jurisdictions that do consider the issue substantively seem to have a set of common themes:

Factors Influencing DSM Targets and Expenditures:

- Estimation of the total available resource for EE is generally developed through a technical potential study. Given changing market conditions, a number of states have updated technical potential studies[28] which were completed many years ago[29] and are using them to adjust the target DSM levels. These studies take into account a region's building stock, baseline levels of efficiency that already exist, a forecast of how baselines might change over time, electric and gas prices (higher prices will support a larger amount of DSM), and cost of other resources that could also meet energy needs (e.g., supply-side options and renewables)

[28] British Columbia is beginning the process of updating the technical potential study for that region, and Oregon is undergoing such a study right now. California, Iowa, Minnesota, New Jersey, New York, and Vermont are other states that have conducted technical potential studies in the past few years.

[29] The debates through the 1990s over whether to restructure a region's electric industry and how it should be restructured diverted the focus on DSM. Generally, rates were stable during this period and many believed the competitive retail market would provide DSM on its own to customers as part of bundling commodity and services. A number of states were not fully convinced of this argument and set Societal Benefits Charges (SBCs) which were mills per kWh fees paid into an account used to advance different DSM initiatives.

- The future need for additional resources. Some jurisdictions set DSM targets to meet a given percent of future load growth.

- The existing infrastructure to deliver programs and what changes might be required to deliver the target level of the DSM resource. Building up required infrastructure, training trade allies in EE design, maintaining a reliable supply of certified contractors, and working with suppliers to develop the availability of EE materials has been one of the most important aspects of sustaining a long-term commitment to DSM.

- A DSM plan that ramps up programs in different sectors over a period of time beginning with programs that represent "lost opportunities." These are generally new construction programs since it is much cheaper to build in energy efficiency during construction than it is to retrofit.

- The need for processes to assess DSM accomplishments and to perform analyses that help ensure that DSM is delivered in the most cost-effective manner possible.

Even jurisdictions that have undertaken these substantive analyses can arrive at different conclusions. For example, the DSM target for Texas is to meet 10% of new load growth each year (with annual reports required), while Illinois has a Sustainable Energy Plan that calls for increasing percentages each year starting in 2007. The Illinois Commission will also tolerate a maximum percentage rate increase per year of 0.5% to obtain the load reductions. The time table for the Illinois Sustainable Energy Plan calls for:

- 10% of Projected Annual Load Growth to be met in 2007/2008;
- 15% of Projected Annual Load Growth to be met in 2009-2011;
- 20% of Projected Annual Load Growth to be met in 2012-2014; and
- 25% of Projected Annual Load Growth to met in 2015-2017.

Other approaches for setting targets, as discussed in Section 3.1, use an expenditure amount tied to a percentage of total electric revenues. These include:

- Minnesota where the largest utility (Xcel Energy) must spend a minimum of 2% of revenues on DSM;
- Oregon with a Public Purpose Charge of 3% for the two major electric utilities;
- TXU, an IOU in Texas which has to meet 10% of load growth each year by DSM. TXU spent about 2% of annual revenues, though that is not how the target was determined;
- Vermont has set spending caps[30] that changed each year, but the end result is that they spent about 3% of electric revenues for DSM. 3% was not the target but about how much was actually spent;
- Wisconsin targets 3% of electric revenues; and,
- Utility representatives for PG&E in California estimate that spending on electric efficiency in 2004 and 2005 has been between 2.5% and 3% of electric revenues.

While the process and rationale for setting these targets varied substantially in each jurisdiction (see Section 3.1 and Appendix A), DSM expenditures for a number of major utilities and jurisdictions vary

[30] This 3% cap on spending in Vermont has been lifted in 2005 and new funding levels have not been established.

between 2% to slightly above 3%.[31] In several cases, even spending 3% of revenues on DSM was not enough to capture the identified cost-effective DSM in the offered programs. For example, Vermont found there were additional energy efficiency projects and customers in the pipeline that could not be captured under the 3% funding cap.

Issue 1: Recommendations – Appropriate Targets for DSM

There are several considerations viewed as important in setting targets. First, targets should cover a period of time that allows for ramp-up of DSM programs and development of the appropriate infrastructure for resource acquisition and market transformation programs. Second, a minimum level of expenditure can be established such that the amount dedicated to energy efficiency is sufficient to build and maintain a critical mass of infrastructure within markets program capacity; and, over time, the amount should never go so low that critical capacity (i.e., qualified contractors, trained employees) is eliminated. In Vermont, when Efficiency Vermont was created, this minimum amount was thought to be roughly a 1.5% surcharge on rates. Program budgets were ramped up from there after the first year (2000) to the current level of roughly 3.0% of rates in 2005.

There are a number of ways to set the final amount. It can be set administratively, as in many restructured states. This would typically be a rough round number approximating what policymakers felt consumers could afford, informed by how much was spent on energy efficiency in the past. This is simple, and in jurisdictions where energy efficiency stirred some of the more contentious regulatory disputes (owing to the throughput incentive), the relief from fighting is just as welcome as the secured commitment. But this approach has a long term problem—energy efficiency is disconnected from other resources that are serving customers. There is no assessment as to whether all cost-effective energy efficiency is being achieved. The program becomes like a government program, in which managers get a budget and do their best to manage within it, without necessarily considering fundamental questions about the size and purpose of the program.

In most states and provinces where energy efficiency programs exist, at one time or another a resource-driven process was used to set energy efficiency budgets. In some states, spending has not returned to the nominal levels of the early 1990s (i.e., not accounting for inflation) despite higher avoided costs today. To really know the appropriate spending level for energy efficiency, some regulatory process in which energy efficiency and other resources are evaluated together is necessary. For some, the term integrated resource planning (IRP) is loaded and connotes a burdensome process.[32] Good best examples today of an unconstrained process in which all cost-effective energy efficiency is available are the Northwest Power and Conservation Council and the California IOUs.

A key issue in each jurisdiction, not always explicit, is resolving the conflict between wanting to procure all cost-effective energy efficiency and concern about the resulting immediate effect on rates. In many jurisdictions, it is evident some compromise was struck, allowing for a significant yet limited rate impact

[31] While BC Hydro was quite explicit in stating that they did not use expenditure targets to determine the level of DSM, i.e., their goal is to implement all cost-effective DSM given practical considerations in terms of what could be rolled out. However, a calculation of what BC Hydro spends on DSM compared to revenues showed that approximately 3.3% of revenues was spent on DSM.

[32] Some participants in IRP processes of the early 1990s viewed them as overly burdensome simply due to the number of combinations of supply-side and demand-side alternatives that some stakeholders wanted examined. There is the curse of dimensionality in resource planning since there are a nearly infinite number of combinations of resources that can be used to meet future load growth. As a result, a resource planning process needs to have a good screening phase such that only those combinations of supply-side and demand-side resources that are likely to be components of a least-cost resource plan are actually evaluated in the modeling phase of the work.

to support a meaningful suite of programs. Budgets based solely on findings from an IRP, or from a benefit-cost assessment would come down squarely on the side of accepting whatever rate effects are necessary to secure a long term overall resource plan—energy efficiency might enable fewer kWh to meet the region's energy needs but at a somewhat higher price for each kWh.

For an overall recommendation, the scan of jurisdictions that have been implementing DSM for several years seems to indicate that:

1. *A minimum expenditure of 1.5% of annual electric revenues*[33] *might be appropriate with a ramping up to a level near 3%.* These figures are irrespective of whether a jurisdiction has adopted retail electric competition or imposed generation divestiture, though regulatory oversight details may be quite different in either case.

2. *Higher percentages may be warranted if there is expected to be rapid growth in electric demand or an increasing gap between demand and supply due to such things as plant retirements or siting limitations.* Even those states with 3% of annual revenues as an expenditure target have found that there have typically been more cost-effective DSM opportunities than could be met by the 3% funding.[34]

3. *For gas utilities, the expenditure levels have been found to be lower in virtually every jurisdiction examined.* No good reason was given for this in the surveys conducted other than that gas has not received as much attention as electricity in analytic studies. Still, gas space heating and water heating, as well as industrial uses, can benefit from DSM efforts. Given the history observed through the interviews, a recommendation of a range of 1% to 2% for gas DSM seems more consistent with industry practice than the minimum recommendations of 1.5% to 3% for electric DSM.

4. *These DSM targets should be reviewed periodically.* California calls for a review every three years, Texas requests annual DSM forecast and filings to ensure the 10% of growth is being obtained by the DSM programs offered, and Idaho and British Columbia conduct an IRP update every two years. This is important to update avoided costs used as the benchmark for determining cost-effective DSM, and to incorporate any unforecasted events (e.g., the recent rise in the price of natural gas) that might change the economics of DSM versus other resources. The review should take into account the importance of maintaining a critical mass of basic capacity within markets for implementing energy efficiency programs, such as contractors, craftsmen, and trade ally relationships.

[33] Electric revenues for an integrated utility would include commodity, transmission, and distribution since DSM can have avoided costs in all of these operating areas. For a restructured industry, the percent would be based on those elements of the bill that address commodity, transmission, and distribution.

[34] In some cases these expenditures have been tracked by rate class such that contributions by, for example, the large customer class are used to fund DSM programs for those customers. This potentially addresses some equity issues, but is clearly less efficient overall in that if there are more cost-effective DSM opportunities in the commercial sector then the least cost plan would distribute the funding such that kWh are saved at the lowest possible cost. In the long term, this should be the best plan for all customers as overall costs of electricity would be lower. However, some consideration towards equity in who pays for the DSM programs is appropriate. Some states provide an opportunity for certain customers to opt out of SBC payments for DSM programs. For example, New York allows larger customers to opt out of paying the SBC rider, but then they cannot participate in any of the offered DSM programs at any of their facilities. In general, the common belief is that there are adequate opportunities for energy efficiency across all segments and it is not recommended that some customers be given the choice to opt out.

ISSUE 2: COST RECOVERY OF DSM EXPENDITURES

Cost recovery of expenditures is an important factor for organizations that are spending monies and implementing DSM programs.

Issue 2: Discussion – Cost Recovery

Most utilities and regulators prefer the practice of expensing energy efficiency costs; in the long run, this approach costs less than capitalizing—deferring and amortizing—costs. The only exception is in cases where programs are being started from scratch, and decision-makers are worried about rate impacts. Capitalizing energy efficiency costs from a period of one year to the average lives of the program measures is done in some jurisdictions. This practice does reduce the immediate cost to implement programs, but there are problems. The carrying cost (at the utility average cost of capital, 7-9% these days) of the unamortized balances adds cost to consumers, quite a lot if the amortization period is long. Eventually, consumers are paying each year's amortized balances, which add up to the annual amount spent on efficiency, plus the carrying cost. Utilities are also concerned about increasing "regulatory asset" balances, assets on the utility books not backed by actual equipment. Once this practice starts, it is hard to convert to expensing, again due to rate impact concerns.

Issue 2: Recommendation – Cost Recovery

The practice of expensing the costs of DSM programs, possibly through a balancing account, seems to be an acceptable approach. However, there are probably a number of approaches that may be acceptable to parties. If near term rate impacts are a concern, capitalizing a portion of the costs may be appropriate. Also, if the DSM targets are based on a percent of electric revenues, the revenues that flow to the implementing organization may need to be levelized since they may be higher in winter or summer, yet implementation of DSM programs may be steady and even increasing in spring and fall in preparation for the cooling or heating season. In general, different jurisdictions have been able to address issues of cost recovery once a DSM target is set. Of greater interest is how potential disincentives (e.g., lost revenues) are treated.

Early energy efficiency programs were fully integrated into utility budgets and finances. In the transition to retail electric competition, many states decided to separate energy efficiency funds from the rest of the funds to run the utility. A system benefit fund, such as a Systems Benefit Charge (SBC), was set up with money collected as a surcharge from consumers for the purpose of paying for public purpose programs like energy efficiency.

In some states, these separate funds became targets for legislative appropriators in times of tough budgets who found ways to siphon these monies away from their intended purpose to support general government. While it is unwise to suggest that a state legislature cannot do something, these experiences suggest it is advisable either to avoid creating a system benefit fund, especially if utilities will continue to administer programs, or to create explicit legislative intent that states the purpose of the fund and prohibits funds from being used for other purposes. Vermont has such language, and has thus far avoided losing any funds to the appropriations process.

More fundamental to the question at hand is the fact that states with system benefit charges allocating an automatic or formulaic budget to energy efficiency create a disconnect between DSM funding and other resource decisions being made by utilities and regulators. This underscores a point already made, that a regulatory process that compares the values of all resources benefits consumers. Updating DSM plans is important either when using a resource planning process or a benefit-cost analysis based on updated avoided costs. Setting a SBC charge and not periodically analyzing this charge would pose planning risks and decrease the flexibility to address unexpected events through DSM programs, a key component of the value of DSM investments, i.e., the portfolio diversification and risk mitigation.

ISSUE 3: ADDRESSING INCENTIVES AND DISINCENTIVES FOR DSM

Organizations that traditionally earn profits from selling a product are now being asked to work with their customers to help them use less of their product which lowers the organization's overall revenues and potentially lowers its profits.

Issue 3: Discussion – Incentives and Disincentives

Most jurisdictions with successful energy efficiency efforts recognize the tension of the throughput incentive, the link between sales and net income (profits) that is an inevitable outcome of traditional regulation.[35] To illustrate its influence, a 5% decrease in sales for an integrated utility leads to a 25% reduction in net profit. For wires-only companies, the effect can be nearly double. Government or consumer-owned utilities have similar concerns. Even though they do not earn "profit," they must pay attention to debt coverage and are concerned (along with their bondholders and lenders) that revenue erosion from reduced sales can hinder debt repayment. The throughput incentive, where it exists, is identified universally as a barrier, and maybe the key barrier, to effective energy efficiency deployment. Yet, as the long-standing method of regulation that is well understood by participants, there can be overwhelming reluctance from utility and regulatory staff to change.

Some jurisdictions return lost margins to utilities, sometimes as a result of a regulatory proceeding that produces a precise accounting based on evaluation of program accomplishments in terms of saved kWh. Regulatory proceedings to calculate lost revenue adjustments can be time consuming and contentious, often due to debates over the accuracy of the evaluation of saved kWh, unless there is a clear process that is easily implemented.

Some states (e.g., Oregon, Maryland, and California) have changed the way some utilities make money, decoupling sales from profits, by keying utility revenues to something other than sales, such as number of customers. This approach is effective, and has the advantage of opening the utility to consider all cost-effective measures that might lead to reduced sales (efficiency, demand response, customer-owned generation) without concern for eroded profits. A revenue cap approach can also explicitly build in ways to share risks between consumers and utilities of unseasonably hot or cold weather, volatile commodity prices, or economic downturns. In this approach, there is no reason to change the customer rate design, at least not for the purpose of changing utility incentives (regulators may wish to change rate design to influence consumption patterns, which will be discussed later).

Some industry advocates suggest a different form of decoupling. The idea is that rate design is shifted such that more money is collected via the fixed portion of the rate, and less is collected in the variable portion. The rationale is that utilities will be more open to energy efficiency if they do not have so much revenue dependent on the commodity charge. As we have just seen, a better way to avoid commodity charge dependence is to connect revenues with numbers of customers, and this way also preserves the long run marginal cost pricing signal to customers that maintain the message to conserve.

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[35] A more detailed discussion of this issue of incentives and disincentives in the delivery of DSM can be found in the Regulatory Assistance Project Newsletter, "Regulatory Reform: Removing Disincentives to Utility Investment in Energy Efficiency," September, 2005. (Available at www.raponline.org).

Finally, there are a number of states that offer positive incentives for attaining the DSM goals in terms of sharing the benefits of DSM between customers and rate-payers. This was discussed in Section 3.3. Five jurisdictions (Connecticut, Massachusetts, Minnesota, Ontario, and Vermont) offer performance incentives for meeting or exceeding specified efficiency targets. Performance goals and incentives can be used independent of the throughput issue. Goals can be an organizing focus for energy efficiency staff, and linking achieving these goals with some financial reward allows a connection to employee bonuses and a shareholder benefit. In addition to the program incentives just mentioned, there are other financial ways regulators can signal to utilities that energy efficiency is a priority. Appendix B contains language from several regulatory decisions pertaining to DSM incentives.

One way is to assure that investments in energy efficiency appear on the utility books in a way equivalent to an investment in a power generator or a transmission line. A drawback to this approach is the difference in control that the utility has between the owned, tangible asset of a generator and a "regulatory asset" represented by the capital spent, but not by a hard asset. As long as the investment community is comforted that rates will be set to recover the costs of these investments, there should be no substantive difference, but utilities are likely to want to limit the amount of regulatory assets on their books.

A more simple way to reward a utility for a job well done on energy efficiency is to add basis points to the cost of capital used to set rates. Investor owned companies can allocate some of these funds directly to shareholders. In the case of a publicly owned utility or an IOU, this revenue from customers can be used for performance incentive pay for employees involved in the successful programs.

<u>Issue 3: Recommendations – Incentives and Disincentives</u>

The issue of lost revenues and potential disincentives to utility investment in DSM has been a contentious issue in a number of jurisdictions, even though it is undoubtedly true. If the utility or distribution company sees sales decline over what would have been the case, then they must not be earning the same level of revenues and profits. Nevertheless, this disincentive is real and should be addressed either through an adjustment clause that tracks and makes the utility whole (or mostly whole) for lost margins due to lower revenues, or through a decoupling option to eliminate this disincentive. The overall recommendations are:

1. *Lost margins due to lower sales of electricity and/or gas should be addressed such that it is not a disincentive to utility investment in DSM.* This can be accomplished through a reconciliation procedure[36] or a decoupling of revenues by tying them to the number of customers and weather adjusted sales.

2. *Where additional incentives for meeting or exceeding DSM targets have been used, the impact on the utility and its rate-payers appears to be positive.* The incentive now provided to Massachusetts distribution companies, for example, is not overly large, but it does capture the attention of management and helps create best efforts for cost-effective DSM (See Appendix B).

[36] It is important that lost revenues not be allowed to accumulate over a large number of years. When a rate case is held, all the balancing accounts are addressed and reset at zero. If there is a long period between rate cases, the lost revenues adjustment can grow to be as large as the total expenditures on DSM; this happened in Vermont and a similar situation occurred in Massachusetts. To address this, Massachusetts simply limited lost revenues to a rolling three year average such that this balancing account was zeroed out every three years and reset. Such a process should be implemented if a lost revenue adjustment mechanism is to be used.

ISSUE 4: BENEFIT-COST TESTS AND AVOIDED COSTS

Assessing and evaluating DSM accomplishments is important on a prospective basis to develop a cost-effective mix of DSM programs, and on a retrospective basis, benefit-cost analysis is needed to discern whether the expected benefits from the DSM programs were actually obtained. These retrospective studies also can be used to develop a more cost-effective mix of DSM activities and provide suggestions on how to make a specific program more effective (see Section 3.4).

<u>Issue 4: Discussion – Benefit-Cost Tests</u>

A jurisdiction reveals its view on the purpose of energy efficiency by the benefit – cost tests it uses to evaluate programs and measures. Use of the Ratepayer Impact Test (RIM) indicates a strong interest in the satisfaction of individual consumers, but ignores the resource and societal values that flow to all along with the obvious value to the program participant. Many widely used energy efficiency programs do not pass the RIM Test.

Use of the total resource cost (TRC) test instead of a societal test values the economics of energy efficiency compared with other sources, but values at zero other advantages to society that, though perhaps hard to quantify, are worth more than zero. These other advantages may flow from avoided air pollution, water use, or reduced risk from avoided capital construction of generation and transmission, for example. Use of the societal test to evaluate energy efficiency programs represents a view that all effects of energy efficiency programs are important. Precision in the societal test is elusive, and jurisdictions that use it sometimes apply a rough “adder” or “multiplier” to handicap other sources in comparison with efficiency.

Accurate valuation of energy efficiency requires reasonable assessments of system avoided costs. Such assessments must be updated from time to time, and provide a valuable benchmark for managing energy efficiency activities. A valuable element to this process comes from gaining knowledge about the shape of the utility’s hourly load curve. Programs that produce savings in particularly valuable hours have more value to consumers.

With increasingly regional electricity markets, stakeholders in New England and, separately, in California, are collaborating on an avoided cost analysis framework that many will share. As a practical matter, the avoided cost assessment matters most if energy efficiency budgets are actively managed and are set based on this assessment. If a set amount of dollars is allocated to efficiency, the challenge becomes how best to use those funds, so avoided cost still remains important for program evaluation.

Further study of energy efficiency value is underway in several states. Utilities are considering the ability of EE (and other distributed resources) to avoid or delay load growth that would otherwise lead to investments in upgraded transmission and distribution, in addition to new generation already captured in most avoided cost calculations.

Another facet of benefit-cost is the prevalence of “potential studies.” A potential study provides useful intelligence, telling a decision-maker how much energy efficiency is available from among the regularly occurring “opportunities” and the accumulated “retrofits.” Recent studies in the Northeast U.S. indicate the potential of such quantities that annual energy use could be reduced year after year with a modest increase in spending from current levels. The only downside of a potential study is the expense – $250,000 to $500,000 or more for a comprehensive regional study. However, as discussed previously in Section 3.1, DSM potential studies can be designed to meet multiple objectives. Information from a DSM potential study is often used as the first step in design of programs since such studies can document current practice and establish energy use baselines. This information can also be used to design an appropriate program for a region and help establish initial customer/trade ally incentives and marketing messages.

Issue 4: Recommendations – Benefit-Cost Tests

The use of benefit-cost tests reflects the importance that regulators in a jurisdiction place on different factors. This is one reason why the tests in common use today, the California Standard Practice Manual tests, incorporate five tests. As a result, there is no exact answer to the question about which test to use and how to construct that test. However, this effort provides the following recommendations for use of benefit-cost test:

1. *The primary test that should be used is the Total Resource Cost test applied to a portfolio of programs, with program specific tests used to address appropriate program design and the mix of programs in the portfolio.* For retrospective analyses, it is important to understand that delivering a DSM program is like introducing a new product into a market: the customer needs to become aware of the offering (marketing), be brought to the point where they are willing to act (sales), and there must be the follow-through delivery of the program (fulfillment). Some programs will likely work better than expected, while other programs will encounter problems that need to be rectified. As a result, it may be unreasonable to expect all the programs to pass the TRC test, but the portfolio as a whole should pass the TRC test.

2. *The Participant Test should be part of implementation to ensure that customers that participate in the program do benefit, but should not have a significant role in setting overall DSM expenditure levels.* Rather, it is useful in the design of specific programs to ensure that the customer perspective in represented.

3. *The other tests commonly calculated can be used to provide different perspectives.* If there is a large discrepancy between a ranking of DSM activities based on the TRC test and one based on the RIM test or the Societal Test, then the planning process should be flexible enough to make adjustments. For example, a societal test may show that one program is much better from an environmental perspective (a cost commonly used in the Societal Test). Also, if one program drops substantially in its ranking (not in its benefit-cost ratio, but in its ranking relative to other programs); then, it may pose some equity problems across customers that could be corrected by making some adjustments in the program. In general, it is recommended that the TRC test be the guide, with the other tests used to see if there are extreme differences that might suggest some flexibility in the design of a DSM program or the mix of DSM activities.

4. *The benefit-cost tests need accurate estimates of avoided costs.* This means that this should include not only avoided costs of generation (i.e., the commodity cost), but also avoided transmission and distribution (T&D) costs. Progress is being made on determining avoided T&D costs in various states that have started to focus on this issue. It is recommended that the best estimates of avoided generation and T&D costs both be used in the application of these tests.

ISSUE 5: DSM PROGRAM ASSESSMENT, MONITORING, AND EVALUATION

Any investment of ratepayer funds should be the subject of ongoing assessment and verification to both provide assurances that anticipated benefits are being attained, and to provide feedback on the programs and their implementation such that they may be improved over time.

Issue 5: Discussion – Assessment, Monitoring, and Evaluation

Energy efficiency programs focus on barriers to consumers making these investments, and administrators should spend no more resources than needed to knock down these barriers. There are literally thousands of creative and good ideas to address these barriers that have been developed by program administrators and implementers in the U.S. and Canada. This section distills these into important messages.

Sometimes, all that is needed is information, and the customer will act. Sometimes, cash incentives are needed to defray the cost between what the customer would do anyway and the more efficient option. Sometimes, the supply chain does not put energy-efficient options in front of the customer, so programs that work with supply chains and trade allies are a critical element of a successful suite of programs. Sometimes, it takes creativity to identify “the customer” who makes the actual decision on energy matters in a business or in the construction of a new development. Deep familiarity with the energy market in the territory is very helpful to successfully answer these questions.

If customer incentives are needed, they should be set to get the desired savings at the desired price, and the incentives should be reduced as consumer acceptance grows; this pattern is evident in many states for retail discounts on compact fluorescent light bulbs. The concept of leveraging consumer funds and time is an important aspect to designing and managing programs.

Regulators expect program costs to be minimized. One way this happens is by focusing resources on the moment when consumers are about to make a purchase or a commitment. Attention to these opportunities means many different things for different programs and customer classes in practice, but is generally an organizing principle behind many successful programs.

Many successful programs are characterized by staff particularly trained for selling. This sort of staff member is not always found in numbers in the ranks of utilities, yet working with customers large and small, trade allies, and others on energy efficiency in the end requires the skills to satisfy the customer and close the deal. A compensation system linked to program performance goals is an extension of this connection to traditional sales.

To help sales, federal agencies are continuing to develop the Energy Star brand which is meant to identify the top quartile of energy performing products. Energy Star is also being applied to whole buildings, reinforcing the benefits of this perspective. Most states use Energy Star as a standard in at least some of their programs. Energy Star is popular, and some warn that administrators may be tempted to use Energy Star too liberally, diluting its value as a brand used exclusively for the top echelon of energy performing products.

Low income residential consumers face distinct barriers to energy efficiency investments, among many barriers. Knocking down these barriers has significant societal value as part of a safety net to assure some minimum level of affordable comfort. Programs addressing low income consumers are universally available, and in most cases much lower benefit-cost ratios are allowed.

On a different end of the economic spectrum, large business customers in many states have gained some flexibility regarding their obligation to support energy efficiency programs. These customers argue that they operate in a competitive world and are highly motivated to secure cost-effective energy efficiency savings. In some states, these customers are given the opportunity to opt out of some or all of the charge they pay for energy efficiency if they can show that they spent to achieve significant results independently. There may be opt-out programs with merit, but it is important to remember that the charge for energy efficiency that all consumers pay goes in part to pay for the societal or total resource benefits that all consumers share. For this reason, it is appropriate that the opt-out still leaves a requirement to pay a portion of the charge (in Vermont, the opt-out customer still pays 30% of the full energy efficiency charge). Interestingly, there are also experiences when such customers are helped by specialists in their industry provided by program administrators to find energy efficiency opportunities missed by plant personnel.

Some jurisdictions take a “portfolio” view of energy efficiency. This recognizes that different programs have different benefit-cost ratios, and that some programs with strong social values may have a benefit-cost ratio of one or lower. With this approach, the target benefit-cost (let’s say, 2) is based on all programs together, allowing programs with high ratios (3 or 4) to offset the results of programs with low ratios (1 or lower). This approach is useful if there is a strong linkage between energy efficiency programs and governmental priorities.

One program issue that has attracted significant attention over the years is fuel switching. This is an issue because there are many electric space heating and hot water heating customers, and it is sometimes cost-effective from a societal perspective to switch them to natural gas or another fossil fuel. The question for regulators is: should the regulator direct the electric utility as part of its energy efficiency effort to switch the equipment to natural gas (or other fossil fuel) and lose the end use in the process? A few states, including Vermont, tackled this issue in the early 1990s, but for the most part, this issue is dormant, and fuel switching is rarely a part of the current suite of efficiency programs.

The factors discussed above tend to focus on program implementation tactics and strategies and often are the subject of what has become known as process evaluations, i.e., are the existing programs being delivered efficiently and are they addressing the appropriate target market. In addition to these efforts, it is important to address how much energy is being saved by these DSM efforts.

States with successful programs appreciate that evaluation, measurement, and verification (EM&V) is vitally important. While it costs money that is not spent delivering programs and services, EM&V helps all stakeholders to maintain confidence that consumer funds for energy efficiency are appropriately managed and identifies possible improvements. Most EM&V activities are done by entities independent of the program administrator, either a contractor hired by the administrator or by the government.

There must be oversight by the regulator on the cost of EM&V to be sure it is not excessive. We can expect EM&V costs to be around 5%, at times up to 10%, at other times less of total EE program costs. How the EM&V is done affects the cost. Some states let the utility make the arrangements and others, such as California, forbid this utility approach to quality control. In Vermont, the state energy office and public advocate is responsible for EM&V. This approach has value since the public advocate is motivated by its overall mission to control costs, while, as the energy office, there is great expertise. Costs are also low in Vermont because there are few companies to review. For all, including the state approach, costs are covered by energy efficiency program costs, and are included in program benefit/cost assessments.

An important aspect of EM&V is the set of baselines used to evaluate success. Baselines refer to what would happen if the programs did not exist. Because equipment and appliances are getting more efficient, and because some consumers may be more likely than before to buy a more efficient model, it is important to regularly reassess and, if necessary, raise the baseline against which program savings are measured.

In each jurisdiction, the approach to measure savings is a little different. There is now an effort in the Northeast U.S. to resolve these into agreement, to the extent that is possible. National Grid, a company operating in four states, is hoping that this effort does not create a fifth protocol to worry about but is cooperating because consistency would simplify its administrative process. Canadian provinces may wish to encourage consistency in measuring savings.

One reason for valuing consistency is if there is any future plan to institute an energy efficiency portfolio standard among Canadian provinces. Such a standard would apply a requirement to produce annual energy efficiency savings of x % of load. Utilities subject to the requirement could meet it through its own programs, or purchase credits from others that over-comply and produce excess credits. Such a standard is under development in Connecticut and Pennsylvania. In each of these places, the challenge of creating a system to turn programs into credits such that a MWh from a lighting program is the same as a MWh from an industrial motors program is significant.

Consistency is also important if there is a chance that efficiency will create credits to address pollution or climate change requirements.

Issue 5: Recommendations – Assessment, Monitoring, and Evaluation

Delivering cost-effective DSM programs is more difficult than many realize. Marketing, sales, supply channel development, and fulfillment tasks each have to be addressed successfully. It is often the case that it can take more than a year for a DSM program to overcome these start-up issues and become cost-effective. This complexity in the delivery of these programs, along with the value of creative ideas in implementation, makes it important to assess these programs in terms of delivery processes on an annual basis. This can be done by using performance indicators initially, e.g., the number of participants, measures installed, and trade allies signed up. However. eventually an accounting of the actual energy savings attributable to the DSM programs will be needed to ensure that the expected benefits from DSM are actually being obtained.

California is in the process of adopting evaluation protocols[37] and, based on the interviews, BC Hydro has developed a state-of-the-industry evaluation approach. Other regions of the country have a long history related to the evaluation of energy efficiency programs. In New York, the New York State Research and Development Authority has conducted three years of evaluation of their SBC funded Energy $mart[SM] programs.[38] Many New England states, specifically Massachusetts, have helped pioneer the evaluation literature as their evaluations have had to meet the scrutiny required by the payment of incentives for the accomplishments of their program; many program specific evaluations have been filed with the Massachusetts Department of Telecommunications and Energy.[39] Given this extensive literature[40], the specific recommendations are:

1. *At program design and initiation, key success factors in terms of number of participants, measures installed, monies spent, trade allies signed up or participating (e.g., contractors for new construction), customer satisfaction, and a timeline for meeting these success goals need to*

[37] "The 2005 California Energy Efficiency Evaluation Protocols;" prepared for the California Public Utilities Commission, by TecMarket Works (and subcontractors), December 5, 2005. See: http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/rulemaking/evaluationreportingprotocol-2nddraftchangestracked.doc.

[38] "New York Energy $mart[SM] – Program Evaluation and Status Report;" Report to the System Benefits Charge Advisory Group; Final Report - May 2005. See: http://www.nyserda.org/Energy_Information/05sbcreport.asp.

[39] The development of guidelines for evaluation in Massachusetts began in the early 1990's. A landmark decision was issued in "Order Promulgating Final Guidelines to Evaluate and Approve Energy Efficiency Programs" D.T.E. 98-100, last modified on 27-Apr-2004. See: http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm.

[40] In the mid-1990s, the National Association of Regulatory Commissioners (NARUC) contracted for a report focused on regulatory issues in DSM evaluation. While somewhat dated, the unique focus of a regulator's perspective on evaluation still contains many insights that are relevant today and it was written when DSM activity was at its height in the United States. It is available from NARUC publications store at: http://www.naruc.org/storeindex.cfm?startrec=21 and the reference is: *Regulating DSM Program Evaluation: Policy and Administrative Issues for Public Utility Commissions.* NARUC, Washington, DC, NTIS Pubs. #ORNL/Sub/95X-SH985C, by Violette, D. and J. Raab; April 1994.

be developed. Many utilities or DSM implementers report some of these factors quarterly, while others may only be reported annually.

2. *Also at program design, the data collection to be used to assess energy savings will need to be incorporated into a program tracking system with customer IDs such that sites can be sampled as part of a monitoring and verification process.* These data will also be used to estimate overall program impacts, net of what would have happened without the program. These attribution assessments of energy savings may be performed annually for some programs, but only every two years with other programs. The key is to have an evaluation plan completed at program initiation so that all the data needed for evaluation will, in fact, be in the program records when it comes time to perform the evaluation.

3. *An approach used by BC Hydro approach is representative of current state-of-the-practice evaluation efforts*.[41] This consists of:

    - A complete evaluation plan is prepared at DSM program initiation.
    - The actual evaluations are conducted at major milestones or at program completion.
    - Process, market, and impact evaluations are conducted, and are overseen by a cross-functional DSM Evaluation Oversight Team.
    - In addition, for programs that include larger individual projects (i.e., > 0.3 GWh/year), technical and financial reviews are conducted before an incentive is offered to provide assurance that the technology is feasible, that the estimated electricity savings are reasonable, and that the cost-effectiveness is acceptable.

ISSUE 6: INTEREST IN DSM, LEADERSHIP, PRICING, AND OTHER FACTORS

This section ties together a number of other factors that are important and deserve to be addressed briefly.

Issue 6: Discussion – Other Factors Influencing DSM

Energy Efficiency Motivators

Apart from the policy and program details, it is evident that states and utilities are increasingly motivated to create and expand energy efficiency programs. This trend flows from the dilemmas and risks associated with supply resources, the experience of inexpensive energy efficiency in many jurisdictions from many program types, and environmental quality. Keeping consumer dollars circulating in local economies is also a factor in some places. These motivations have led decision-makers to engage in the initiatives, innovations, and upgrades to energy efficiency this report covers. Likewise, attention to meeting electric peak load and to creating electric wholesale markets is increasing interest in demand response programs.

Leadership

A common theme in jurisdictions active in energy efficiency is leadership. Leaders may be elected officials, appointed officials, or utility CEOs. Leadership is often challenged by advocates arguing for low

[41] An overview of this approach is in the Resource Planning Guidelines – http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf. More detail is available in BC Hydro filed evaluation plans and in "DSM Evaluation Summary and Plan; Appendix M" in BC Hydro, Revenue Requirement Application – 2004/05 and 2005/06 Volume 2, December 2003.

rates in the present while devaluing longer term benefits mentioned in the prior section. Statutes permit, and in some cases, drive leaders to push for significant and sometimes expanding energy efficiency budgets, emboldened by the belief in significant missed opportunities for cost-effective investments. This commitment has led to policies such as the "loading order" of California,[42] in which cost-effective energy efficiency is the priority resource among all resources, and to the energy efficiency performance standards in Connecticut.

Administration

In several jurisdictions, the regulator or the legislature has opted to delegate administration of energy efficiency programs to a central agency or private sector business. These jurisdictions include Oregon, Wisconsin, Ohio, New York, New Jersey, Washington DC, Vermont, and Maine. Connecticut created a body to review and approve the programs that are implemented by the utilities.

Advantages of this approach are several.

- A primary motivation for this choice is to take the utilities out of the position of promoting reduced sales through energy efficiency, while at the same dealing with a financial structure that improves with every sale and declines with every lost sale.

- Other advantages include a coherent rationale and identity for energy efficiency programs throughout the jurisdiction. This helps to unify advertising of programs in the media, and also unifies media coverage (making success more important). Consumers learn to expect one consistent level of service quality, which is helpful for businesses with several locations throughout the jurisdiction in different utility service areas.

- Regulators have to focus on the performance of just one entity, reducing the number of dockets in which energy efficiency performance and corollary cost recovery are issues. Costs are also saved in administration and in evaluation, monitoring and verification.

There are disadvantages with the central administration, though all have solutions.

- The utility knows its customers and its service territory – keeping the customer contact with the utility promotes customer satisfaction with the utility and also makes it easier the utility to target efficiency to address system load growth and to integrate with resource planning. Further, in some jurisdictions, the central agency has been unable to obtain customer information valuable to deliver superior customer service. Regulators can address these coordination issues by making it clear that the central agency and the utility are equals in using and protecting customer information from inappropriate use. With full information in hand, the central agency and the utility can work as partners to serve customer and system needs.

- On the other hand, the central agency may become isolated from customers, especially if contractors are extensively used. The central agency can make it a priority to maintain a customer focus. An advisory committee can also serve to assure that real customers and their needs remain in clear focus for the central agency.

- Some utilities find that energy efficiency is consistent with core values and resent the lack of confidence represented by having the responsibility taken away, and their customers lose the

[42] This is discussed in more detail in Appendix A under California DSM Summary.

chance to be served by a truly committed utility. The jurisdiction can provide a process that allows such a utility to petition to provide service to its customers that is equal or superior to service from the central agency. This is allowed in Vermont; two utilities, Burlington Electric Department and Washington Electric Cooperative, deliver programs.

- Since government has a hand in centralizing the money collected for energy efficiency, appropriators have been tempted to siphon the money for general government purposes, essentially creating a hidden tax on electric consumers. Vermont's statute addresses this concern.[43]

- In cases where utilities in a jurisdiction have dramatically different avoided costs, there could be a concern about imposing a statewide cost benefit test to apply to extremely different circumstances. On the other hand, with wholesale market competition becoming increasingly settled in practice, and a consistent set of incremental supply options available, avoided costs, while at least as difficult to forecast as ever, are far more consistent across a group of proximate utilities than average costs based on legacy decisions are likely to be. Jurisdictions such as Vermont and California are pursuing a practice of a statewide minimum energy efficiency effort (California via utilities, Vermont via a third party statewide entity) overlaid with a utility-specific commitment to energy efficiency based on each utility's specific circumstances.

- Finally, the targeting and implementation of DSM programs and their evaluation may require data and information that have been collected by utilities over the years, e.g., consumption data. In some cases, the cooperation between the central DSM delivery agency and the utility has been less than satisfactory with claims of proprietary customer data inhibiting program implementation and evaluation.

The debate over the administration and evaluation of DSM efforts has been intense in a number of states.[44] Vermont was the first state to truly centralize DSM delivery. California has tried a number of approaches, with the current approach being the delivery of DSM by that state's utilities, but the impact evaluation of the programs is conducted by the CPUC (process evaluations can be conducted by the utilities). The debate over the appropriate administration of programs, particularly where there are a number of utilities in a jurisdiction, has been controversial – most utilities oppose the use of a central

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[43] The full text of Vermont statute, 30 VSA section 209 (d) (3) with the relevant part bolded: In addition to its existing authority, the board may establish by order or rule a volumetric charge to customers for the support of energy efficiency programs that meet the requirements of section 218c of this title. The charge shall be known as the energy efficiency charge, shall be shown separately on each customer's bill, and shall be paid to a fund administrator appointed by the board. When such a charge is shown, notice as to how to obtain information about energy efficiency programs approved under this section shall be provided in a manner directed by the board. This notice shall include, at a minimum, a toll free telephone number, and to the extent feasible shall be on the customer's bill and near the energy efficiency charge. **Balances in the fund shall be ratepayer funds, shall be used to support the activities authorized in this subdivision, and shall be carried forward and remain in the fund at the end of each fiscal year. These monies shall not be available to meet the general obligations of the state.** Interest earned shall remain in the fund. The board will annually provide the legislature with a report detailing the revenues collected and the expenditures made for energy efficiency programs under this section.

[44] The discussion relating to the creation of the Office of Clean Energy within the New Jersey Board of Public Utilities (BPU) addresses many of these issues. The history of the Office of Clean Energy can be found on the BPU website: http://www.bpu.state.nj.us/cleanEnergy/CEPHistory.shtml and in a report on administration of energy efficiency programs. The report, commissioned by the BPU to assess alternative central and utility administrative options, is called "Recommendation on the Administration of Energy Efficiency and Renewable Energy;" for New Jersey Board of Public Utilities; Docket No EX01070447; Davies Associates Incorporated; April 2002. This is located on the BPU website at: http://www.bpu.state.nj.us/reports/davies/davies.pdf.

government agency to interact with customers on items that might impact that utility's relationship with a customer. In general, utilities still deliver DSM programs in most states, but a few leading states have set up central entities to deliver SBC funded programs (e.g., New York, New Jersey, and Wisconsin). Even in these states, exceptions have been made for certain types of programs and customer segments.

Stakeholders

Successful energy efficiency program administrators generally have access to a stakeholder process that provides useful insights into what is working and what needs fixing. It is important that the program administrator takes the approach that program changes are likely, given changes in penetration, changes in the economy and political environment, opportunities that emerge with specific prominent customers, and changes in the technology and services that can be offered to customers. Sometimes, this process is a formal collaborative one with long-standing members, supervised by the regulator, which may or may not have standing to make formal proposals to change programs. Stakeholders could also be organized into an advisory board. Occasional customer forums go further to assure programs are meeting community needs.

Annual reports are useful to demonstrate, in a transparent way, recent activities, including success stories and measuring success against goals, as well as to reinforce principles for why these programs exist in the first place.

Demand Response – Another Flavor of Consumer Electric Resources

It is becoming a bromide that a wholesale electric market cannot be considered fully working unless there is a sufficiently active demand side. What does this mean? In places that are developing demand response programs, they focus in two essential functions: as a peaking resource that contributes to resource adequacy such that more generation is not needed; or, as a resource prepared to be injected into the market at any time, not necessarily in a reliability situation, to control volatile prices.

A fundamental issue regarding demand response that remains under development is how to package the offering to the customer so that it is profitable and convenient to participate. The customer may have to add some investment to control loads, and may also require a communications link to the utility or ISO that may lack convenience or reliability. In addition, there are more utilities (see the discussion of PG&E in Section 3.1 and Appendix A) that are integrating energy efficiency and demand response offerings. For example, a lighting project may not be cost-effective on its own, but when dimming capability is added it can now participate as a DR resource and gain benefits from that set of programs. Regardless, it is more expensive to make multiple trips to a customer and a customer likes to receive all its demand-side services without having to work through separate programs and delivery organizations (one-stop shopping).

Another issue revolves around how to recognize the many values of demand response. For example, demand response can provide service equivalent to reliability reserves – is there a way to compensate customers for this value? A demonstration effort to address this is underway at ISO-New England.

Despite these growing pains, participation in demand response in ISOs like PJM is rising, and it may be that mature customer familiarity with demand response programs will take some time along with some concerted effort to educate them.

One dilemma in a place with an ISO is who should manage the demand response programs: the utility or the ISO? As the ISO is usually the reliability coordinator for the area and also usually manages the regional wholesale electricity market, there is a significant advantage to having unified programs. Under this model, the utility would "retail" the ISO programs to ultimate customers. Helping to work out disputes arising from utilities happy with their own programs is one occupation of regulators.

Efficiency through Pricing

Earlier, the issue of baselines was discussed. Another way baselines can change is by introducing a new pricing regime or a new rate design. If consumers are either allowed or mandated to take service with prices that change over the year to be higher when production costs tend to be higher, and lower when production costs tend to be lower, then they may be motivated to spend more on their own to avoid high priced usage. Some suggest that this is a powerful tool that is under-utilized, while others note that some of these systems cost a lot to implement and many consumers are unwilling or incapable of managing usage during different time periods, and would lose. New Jersey and California, for example, are experimenting with pricing pilot programs to evaluate these possibilities.

Generally, the more that rates reflect the long term societal costs of new resources, the more favorably energy efficiency will look to regulators, planners, and customers.

Issue 6: Recommendations – Other Issues

There are many facets to launching and overseeing quality energy efficiency and demand response programs. Success does nothing to diminish the appropriate level of oversight and vision needed to be effective. Some essential threads:

- Leadership is needed to push through the challenges that invariably arise and to keep the longer term in mind – a DSM program may not be immediately cost-effective and it will take time for the value of DSM to be realized. Good leadership can set appropriate expectations and timelines, as well as ensure that the effort is sustained and is one component of a multi-year plan.

- A stakeholder process encompassing trade allies, customers and other stakeholders can be valuable to gain new perspectives and support for programs.

- Demand response needs to be integrated with energy efficiency since there are complementary aspects in delivery and economies that can be gained through technologies that both save energy and provide the customer with the ability to manage their energy use such that they can participate in a DR program.

- Pricing of electricity and gas is important for the economics of energy efficiency and demand response. Time differentiated rates that recognize the varying value of the resource across hours and also better reflect the full societal cost of new resources will make DSM look more favorable to planners and customers.

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California

There have been many studies done in CA, analyzing CA EE programs in any number of ways. Studies available at http://www.calmac.org/search.asp (California Measurement Advisory Council website). Especially useful:

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  http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/45783.htm#P75_2023
- **D0509043** – September 22, 2005
  http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm

Connecticut

- Annual reports to Connecticut's legislature re: energy efficiency and load management costs, savings, benefits.
  http://www.dpuc.state.ct.us/Electric.nsf/By%20ECMB%5C4.%20Reports?OpenView&Start=1&Count=30&Expand=1#1
- The Energy Independence Act (Public Act 05-1) http://www.cga.ct.gov/2005/ACT/PA/2005PA-00001-R00HB-07501SS1-PA.htm
- Public Act 98-28 (restructuring legislation that established the C&LM fund)
  http://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm

Relevant dockets:

Active and inactive docket documents can be accessed at: http://www.state.ct.us/dpuc/database.htm

- Docket 04-10-02: Gas utility conservation plans.
- Docket 04-11-01: Included a C&LM-funded pilot supplemental price response program to be implemented in 2005 for certain high price events (see pp 20-21).
- Docket 05-07-14: In Phase I, the DPUC will identify short-term strategies to mitigate capacity-related and congestion-related charges ("federally-mandated congestion charges" or FMCC), including load response, conservation, distributed resources and other measures. Phase 2 will examine intermediate-term approaches to mitigate FMCC. Both supply and demand approaches will be allowed to compete.
- Docket 05-07-19: Examines the use of conservation and other DSM strategies as Class III resources to meet certain supply goals.
- Docket 05-09-09: Examining possible decoupling strategies for both gas and electric. utilities. Rate design options to support energy policy goals may also be considered.
- Docket 05-10-02: The 2006 C&LM plans filed jointly by the two major electric utilities (CL&P and UI).

- The Energy Conservation Management Board (ECMB) reports on program results to the legislature every spring. The "Report of the ECMB: Year 2004 Programs and Operations" can be seen at http://www.dpuc.state.ct.us/Electric.nsf/cafda428495eb61485256e97005e054b/834bce27d18f256a85256ff80051f63d?OpenDocument

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- DTE Order 98-100 re: cost-effectiveness http://www.mass.gov/dte/electric/98-100/finalguidelinesorder.htm
- The 1997 Restructuring Act www.mass.gov/legis/laws/seslaw97/sl970164.htm.
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- Personal conversation with Bridget McLaughlin, Regulatory Analyst for Xcel Energy, October 2005.
- Xcel Energy, "2005/2006 Biennial Plan, Minnesota Natural Gas and Electric Conservation Improvement Program" p. xx (Xcel Energy, Minneapolis, MN, June 2004).
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  - Docket # EX03110946: Order - In the Matter of Appropriate Utility Funding Allocation for the 2004 Clean Energy Program http://www.bpu.state.nj.us/wwwroot/energy/EX03110946_20040428.pdf

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- Report of the OEB on EDR 2006 http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_EDR.htm
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Texas

Documents on this topic for all distribution utilities in Texas can be accessed using the PUCT Interchange page at

http://interchange.puc.state.tx.us/WebApp/Interchange/application/dbapps/login/pgLogin.asp.

- Click on "log in."
- Enter control #30739, then search, to access efficiency reports and plans.
- Enter control #26310, then search, to view reports to the TCEQ on emissions reductions due to efficiency programs.

Present program offerings for all Texas distribution utilities can be seen at

http://www.texasefficiency.com/

See also the PUCT's January 2005 "Report to the 79th Texas Legislature: Scope of Competition in Electric Markets in Texas" at: http://www.puc.state.tx.us/electric/reports/scope/index.cfm

Discussion of efficiency programs begins on page 67 of that report.

Rules can be viewed at the PUCT website

http://www.puc.state.tx.us/rules/subrules/electric/index.cfm

The most relevant rules are:

- Rule 25.181 covers most of the substance of the program approach, including goal-setting, planning, administration, cost-effectiveness, cost recovery, M&V guidelines, detailed reporting requirements, etc.

- Rule 25.183 outlines general reporting requirements, including PUCT report to TCEQ re: emissions.

- Rule 25.184 includes links to templates for all the approved SOP and MT approaches, as well as deemed savings values, and stipulated values.

Vermont

- Act 61 of the 2005 Legislature established the SPEED program. Text can be found at: http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT061.HTM
- 30 VSA 209 (d) and (e) http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00209
- Docket 6290, establishing the DUP process, can be found at http://www.state.vt.us/psb/orders/2003/files/6290irpextord.pdf
- ACEEE's Special Case Study of VGS' comprehensive programs can be found at: http://aceee.org/utility/ngbestprac/vgsprtflio.pdf
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- Efficiency Vermont: 2003 Annual Report. http://www.efficiencyvermont.com/Docs/2003ExecutiveSummary.pdf

Washington

- For more information on PSE's programs, refer to their website at: http://www.pse.com/yourhome/rebates/index.html and http://www.pse.com/yourbusiness/grants/grants.html
- 2004 DSM Reports for PSE, Pacificorp, and Avista
- PSE's 2005 Least Cost Plan, available for download online at https://www.pse.com/about/supply/resourceplanning.html
- Pacificorp's 2004 Least Cost Plan, available at http://www.pacificpower.net/Navigation/Navigation36807.html

Wisconsin

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- Wisconsin Department of Administration, Division of Energy, "Wisconsin Public Benefits Program: 2005 Annual Report", p. 3 (Wisconsin Department of Administration, Madison, WI, 2005).
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- Telephone seminar presentation by WECC's Kathy Kuntz on September 28, 2005.
- Telephone seminar presentation by WECC's Ed Carroll on September 28, 2005.
- Wisconsin Department of Administration, Division of Energy, "Focus on Energy Statewide Evaluation: Initial Benefit-Cost Analysis" (Wisconsin Department of Administration, Madison, WI, March 31, 2003).
- Information on the Wisconsin Focus on Energy Programs and reports is available at www.focusonenergy.com.
- The Wisconsin Legislative Council staff's report on the Reliability 2000 legislation is available on the internet at: www.legis.state.wi.us/lc/3_COMMITTEES/JLC/Prior%20Years/jlc99/pubs/im99_6.pdf
- Report from the Wisconsin Governor's Task Force on Energy Efficiency and Renewable is available at http://energytaskforce.wi.gov/.