Report by the Public Utilities Commission to the Utilities and Energy Committee Regarding LD 1851, "An Act to Establish the Regional Greenhouse Gas Initiative"

March 11, 2008

I. BACKGROUND

During its First Regular Session, the 123rd Legislature enacted a new law relating to the Regional Greenhouse Gas Initiative (RGGI) (PL 2007, Chapter 317). By letter dated June, 20, 2007, the Chairs of the Utilities and Energy Committee (Committee) requested the Public Utilities Commission (Commission) to provide RGGI-related information to the Committee by January 15, 2007.[1]

The June 20th letter requested information relating to the following five topics:

- Cost-effectiveness criteria;
- An outline of the Commission's energy efficiency programs;
- An outline of program budgets needed to achieve energy-use reduction benchmarks;
- An outline of peak demand reduction strategies; and
- A summary of estimated economic impacts of potential RGGI-driven price increases.

Each of these topics is addressed separately below.

II. COST-EFFECTIVENESS CRITERIA

The June 20th letter requests the Commission to provide "[t]he cost-effectiveness criteria as established in the Commission's rules and used by the Commission to achieve cost-effective energy efficiency, pursuant to Title 35-A, Section 3211-A, including a description of the process, evaluation and measurement system used."

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[1] The June 20th letter was also sent to the Department of Environmental Protection (DEP) and requested specified RGGI-related information from the DEP. In addition to requesting information from the Commission by January 15, 2008, the June 20th letter requested additional information from the Commission and the trustees of the Energy and Carbon Savings Trust by August 15, 2008 and from the Commission and the DEP on an annual basis.

Section 3211-A governs the state's conservation programs and establishes the Commission's responsibilities regarding those programs. In 2002, the Commission adopted Chapter 380 titled "Electric Energy Conservation Programs." Section 4 of Chapter 380 establishes the cost-effectiveness criteria for the Commission's energy efficiency programs. Section 4 is reproduced below. *Attachment 1* to this report is an excerpt from the Commission's Order Adopting Chapter 380. The attached excerpt provides the Commission's rationale for adopting the Rule's cost-effectiveness criteria.

§ 4 COST EFFECTIVENESS TESTS

The following tests will be used to determine whether a program is cost effective.

A. **Modified Societal Test**. Programs that are reasonably likely to satisfy the Modified Societal Test are cost effective. The Modified Societal Test is satisfied when the program benefits exceed the program costs. Costs and benefits shall be considered in the Modified Societal Test regardless of whether they are paid or experienced by the participant, the Conservation Program Fund, or any other individual, business, or government agency.

1. **Program benefits**. Program benefits will include the following:

a) Avoided electric generation costs including energy and capacity costs, using estimates of market prices and adjusting for line losses. These estimates may be differentiated by time periods that influence market prices, including but not limited to peak and off-peak periods and summer and winter periods;

b) Avoided transmission and distribution costs, using estimates of transmission and distribution utility marginal transmission and distribution costs. These estimates may be differentiated by time periods that influence costs;

c) Avoided fossil fuel costs, using estimated savings in oil, gas or other fossil fuel use, at estimated fossil fuel prices;

d) Other resource benefits, such as reduced water and sewer costs;

e) Non-resource benefits, including customer benefits such as reduced operation and maintenance costs, deferred replacement costs, productivity improvements, economic development benefits and environmental benefits, to the extent such benefits can be reasonably quantified and valued.

2. **Program costs**. Program costs will include the following:

a) Direct program costs, including program design, administration, implementation, marketing, evaluation and other reasonably identifiable costs directly associated with the program.

b) Measure costs. For new construction or replacement programs, measure costs are the incremental costs of the energy efficiency measure, including installation, over an equivalent baseline measure. For retrofit programs, measure costs are the full cost of the energy efficiency measure, including installation, less any salvage for the replaced measure.

c) Ongoing customer costs, including costs such as increased operation and maintenance costs, reduced productivity, and lost economic development opportunities, to the extent such costs can be reasonably quantified and valued.

3. **Discount rate assumption**. The discount rate used for present value calculations shall be the current yield of long-term (10 years or longer) U.S. Treasury securities, adjusted for inflation. The Commission may consider an alternative discount rate when characteristics of a program are inconsistent with use of long-term U.S. Treasury securities.

4. **Net present value**. Cost effectiveness of an energy efficiency measure will be calculated based on the net present value of the costs and benefits over the expected life of the measure.

5. **Post-program effects**. For those programs that are expected to influence the development of self-sustaining markets, program cost effectiveness will be calculated for a reasonable additional period after the program is terminated in order to capture post-program market effects.

6. **Incentive Level Limitation**. When developing a program that satisfies the Modified Societal Test, the Commission shall, when setting incentive levels, consider the value of the program savings associated with electrical production and delivery.

B. **Non-Quantifiable Cost Effectiveness Test**. The Commission may implement a program without satisfying the Modified Societal Test if:

1. Program benefits are known to exist but cannot be quantified with sufficient accuracy to conclude that the program benefits exceed the program costs;

2. The program satisfies some other statutory criterion or a goal or objective established by the Commission in implementing the Conservation Act; and

3. The entire portfolio of conservation programs produces quantifiable benefits that substantially exceed total portfolio program costs.

III. ENERGY EFFICIENCY PROGRAMS UNDER SECTION 3211-A

The June 20th letter requests the following:

> A detailed outline of the energy efficiency programs the Commission is likely to pursue to implement the requirements of Title 35-A, section 3211-A, as amended by Public Law 2007, chapter 317. It is our intention that this outline may be based on information contained in the Commission's March 9, 2007 report on its Inquiry into new conservation programs and developing a plan for using increases in the conservation fund (Docket No. 2006-446); the outline should include any subsequent changes to the conclusions presented in that report, as appropriate.

The Commission's March 9, 2007 report on its Inquiry into new conservation programs and development of a plan to use increases in the conservation fund provides a detailed outline of the Commission's plans for energy efficiency programs. A copy of the March 9th report is included as *Attachment 2* to this report. There have been no changes to the conclusions contained in the report since it was issued on March 9th.

IV. PROGRAM BUDGETS NECESSARY TO ACHIEVE ADDED ELECTRICITY SAVINGS

The June 20th letter requests the following:

> An outline of program budgets for energy efficiency programs needed to achieve reductions in electricity consumption in the State by 2%, 4%, 6%, 8%, and 10%, and the suggested order and priority for program implementation. It is our intention that this outline may be based on a simple straight line projection using the results of program achievement to date and may be completed without a formal study requiring the Commission to hire consultants.

Straight-line projections demonstrate that the 2% and 4% reductions can be achieved by 2010 under current budget and program plans. Greater savings would require additional investments of between \$8.4 million and \$26.5 million, as detailed below.

To develop those figures, Commission staff performed a straight-line analysis for projections through 2010. Total state electricity consumption was projected using historical data from the federal Energy Information Administration and Central Maine Power Company. The Commission's data on the Efficiency

Maine program provided benchmarks for considering investments needed to achieve the specific efficiency levels requested in the June 20th letter.

A noteworthy fact is that Efficiency Maine programs have steadily become more cost-effective since the program was established in 2003. As Table 1 shows, the cost per KWh saved has dropped significantly as program planning, development and ramp up costs become fully integrated. That trend is expected to continue, and further improvements in cost-effectiveness are built into this analysis.

Table 1 - Costs to Achieve MWh Savings

Year	EM Forecast of MWhs Saved	EM Total Budget	MWh/Millions$s	$ Per MWh
2003	5,827*	$2,921,800*	1,994*	$501.42*
2004	22,481*	$6,753,152*	3,329*	$300.39*
2005	50,924*	$9,080,226*	5,608*	$178.31*
2006	123,901*	$9,567,113*	12,951*	$77.22*
2007	204,713	$13,187,199	15,524	$64.42
2008	295,543	$14,627,563	20,205	$49.49
2009	390,755	$15,550,442	25,128	$39.80
2010	491,982	$16,391,004	30,015	$33.32

* *Data provided are actual figures*

Efficiency Maine's projected program budgets and cumulative program MWh savings under *status quo* programs for the coming years can be seen below in Table 2.

Table 2 - Efficiency Maine Cumulative MWh Savings

	FY'07	FY'08	FY'09	FY'10
New Schools	1,342	1,631	2,805	2,805
LI Appliances	18,631	26,744	36,801	47,435
Building Operator Certification	20,792	25,726	26,736	26,736
Residential Products	85,108	131,706	182,724	239,223
Residential New Construction		0	158	554
Business Program	78,840	107,699	136,188	166,482
Business New Construction		2,037	5,343	8,747
TOTALS (MWhs)	*204,713*	*295,543*	*390,755*	*491,982*
Percentage of Electricity Consumption	1.81%	2.51%	3.22%	4.08%
Budget	$13,187,199	$14,627,563	$15,550,442	$16,391,004

In 2007, Efficiency Maine's budget of $13,187,199 achieves projected electricity savings of 204,713 MWh, including the cumulative effect of three years of program operation. This represents approximately 1.81% of the total state load.

If current trends continue and projected data and budgets remain the same, then a 4% reduction in electricity consumption would occur by 2010. The savings continue to grow as Efficiency Maine leaves its startup period and becomes more cost effective.

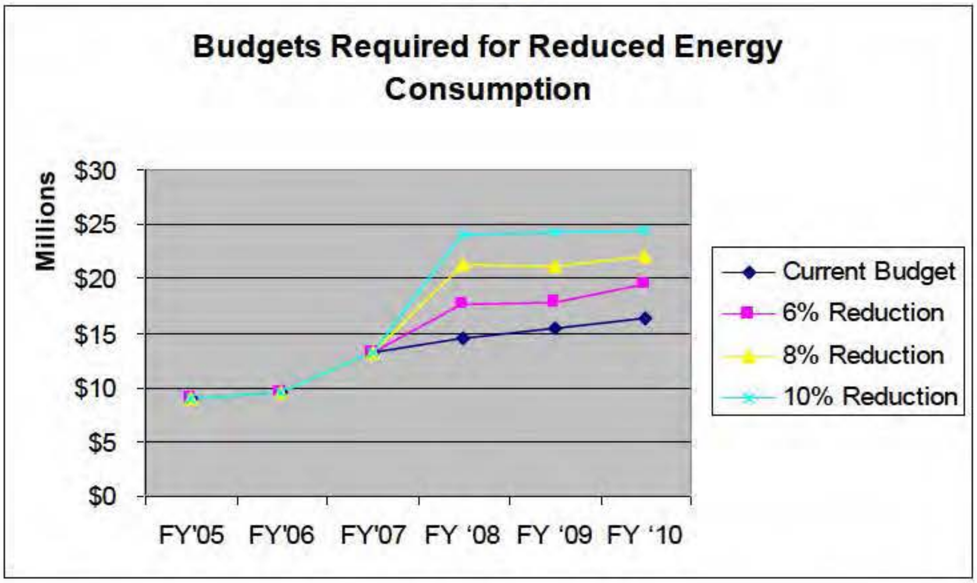
In order to reach reductions of 6%, 8%, and 10%, additional funds would be required, as shown below in Table 3. The budget numbers are based on a calculation that includes projections of total energy consumption each year, incremental energy savings needed each year to achieve the target reduction by 2010, and projections of total cost per MWh saved in each year as detailed in Table 1.

Table 3 - Estimated Efficiency Maine Budgets Needed to Achieve MWh Reductions

	FY '08	FY '09	FY '10
Current Budget (2-4% Reduction)	$14,627,563	$15,550,442	$16,391,004
6% Reduction	$17,632,091	$17,834,380	$19,516,028
8% Reduction	$21,329,143	$21,102,477	$22,115,484
10% Reduction	$24,173,044	$24,370,535	$24,562,685

The numbers in Table 3 above are displayed graphically in Chart 1 below.

Chart 1



To achieve a 6% reduction in projected electricity consumption, budgets would need to increase from authorized levels by $3,004,528 in 2008, $2,283,938 in 2009, and $3,125,024 in 2010.

To achieve an 8% reduction in projected electricity consumption, budgets would rise $6,701,580 in 2008, $5,552,035 in 2009, and $5,724,480 in 2010.

To achieve a 10% reduction in projected electricity consumption, budgets would rise $9,545,481 in 2008, $8,820,093 in 2009, and $8,171,681 in 2010.

These budget increases are summarized in Table 4 below.

Table 4 - Estimated Incremental Budget Increases Needed to Achieve Reductions

	FY '08	FY '09	FY '10
6% Reduction	$3,004,528	$2,283,938	$3,125,024
8% Reduction	$6,701,580	$5,552,035	$5,724,480
10% Reduction	$9,545,481	$8,820,093	$8,171,681

V. PEAK DEMAND REDUCTION STRATEGIES

The June 20th letter requests the Commission to provide "[a[n outline of peak demand reduction strategies, including an identification of peak demand periods and options available to reduce demand and lower electricity prices during those periods."

In our Inquiry into efficiency programs in Docket 2006-446, the Commission has engaged Synapse Energy Economics Inc. to analyze various components of Maine's demand response (DR) programs. The report developed by Synapse, titled "Increasing Demand Response in Maine," was completed in January 2008. The study concludes:

> *Maine is achieving high levels of DR under current policies and programs. When measured relative to its peak demand, Maine currently has the highest level of participation of any New England state in ISO New England's existing DR programs. Maine is expected to maintain that lead position under the ISO New England forward capacity market (FCM), scheduled to begin June 2010. The quantity of DR in Maine in year one of the FCM is expected to represent approximately 17.8% of the ISO NE forecast of peak demand for Maine in 2010. At that level, Maine would have one of the highest, if not the highest, levels of DR in the country. The vast majority of the DR that Maine is achieving is in the industrial, commercial and institutional sectors.*
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> *There may be a small potential for incremental DR in Maine, in the order of 1 to 2 % of total peak demand. This incremental potential appears to be achievable via energy efficiency programs and/or increases in appliance efficiency standards in all sectors, including residential and small commercial.*
>
> *Energy efficiency and appliance standards appear to [be] two of the most cost-effective sources for achieving incremental DR in Maine, because they require little or no incremental investment in enabling technologies such as communicating price signals, recording and reporting usage, and processing of usage data. The potential for capturing substantial incremental DR from other types of programs, such as direct load control and time-differentiated rates, appears to be limited by their implementation costs that may exceed their estimated benefits. The economics and potential of those programs requires further detailed analysis on a sector by sector basis.*
>
> *DR has the potential to provide societal benefits in the form of lower market prices for capacity and lower electric energy prices in Real-Time and Day-Ahead markets. Of those two, the benefit of lower market prices for capacity*

appears to be the larger and the one most likely to have most impact on retail customers[2].

The Synapse report, included as *Attachment 3* to this report, also details areas in both the residential and commercial sectors where further savings may be achieved.

VI. ECONOMIC EFFECTS OF ELECTRICITY PRICE INCREASES

The June 20th letter requests the following:

> A summary of estimated impacts of electricity price increases, ranging from $0.001 to $0.005 per kilowatt hour, based on existing analyses that predict the economic impact of price increases. It is our intention that this summary will be prepared in consultation with the Office of the Public Advocate, the State Planning Office, and other relevant state agencies and entities.

The State Planning Office (SPO) undertook such an analysis and provided the Commission with a copy in October 2007. The Commission and the Office of the Public Advocate reviewed the SPO's analysis which found that total economic impacts would range from $12.4 million to $61.8 million. It should be noted, however, that the calculations do not include any savings from reduction in demand. The SPO's analysis is summarized in Tables 5 and 6 below.

Table 5 - Total Electricity Costs by Class per $.001 KWh Price Increase (in millions)

	No increase	$0.001/kwh	$0.002/kwh	$0.003/kwh	$0.004/kwh	$0.005/kwh
Residential	$526.57	$ 530.90	$535.23	$ 539.56	$543.89	$548.22
Commercial	$427.67	$432.00	$436.32	$ 440.65	$444.97	$449.30
Industrial	$243.60	$247.31	$251.02	$ 254.73	$258.44	$262.15
Total	$1,197.84	$1,210.20	$1,222.57	$1,234.94	$1,247.31	$1,259.67
% Above No Increase		1.0%	2.1%	3.1%	4.1%	5.2%

Table 6 - Incremental Increases in Costs by Class per $.001 KWh Price Increase (in millions)

	No increase	$0.001/kwh	$0.002/kwh	$0.003/kwh	$0.004/kwh	$0.005/k
Residential	----	$4.3	$8.7	$13.0	$17.3	$21.7
Commercial	----	$4.3	$8.7	$13.0	$17.3	$21.6
Industrial	----	$3.7	$7.4	$11.1	$14.8	$18.6
Total	----	$12.4	$24.7	$37.1	$49.5	$61.8

[2] "Increasing Demand Response in Maine" Synapse Energy Economics January 3, 2007

Attachment 1

Section 4: Cost Effectiveness Criteria

1. Background. In Docket No. 2002-161, we discussed the background of, and offered options for, determining the cost effectiveness of interim programs.[1[9]] In that proceeding, we decided to rely on the framework established in the current version of Chapter 380 (Ch. 380-O) to determine the cost effectiveness of individual interim programs and of the portfolio of programs. Under that framework, we rely on the All Ratepayers Test to screen for cost effectiveness, but we also consider whether a program or group of programs is likely to have a significant impact on T&D utility rates.

Cost effectiveness testing for conservation programs has a long history before this Commission. Twenty-five years ago, the Electric Rate Reform Act authorized the Commission to order electric utilities to submit programs for implementing energy conservation techniques.[2[10]] Throughout this time period, we have periodically considered how to test whether proposed conservation measures are likely to minimize electricity costs. The debate typically is framed in terms of which of various cost effectiveness tests should be applied. That debate is generally reducible to a debate over our goals in adopting conservation programs.

Historically, the Commission has considered three cost effectiveness tests. The primary test has been the All Ratepayers Test (ART), which measures whether a conservation program provides the same level of end use amenity (e.g. lighting or hot water) at a lower overall net cost to utilities and ratepayers taken together. The ART generally measured savings in terms of avoided generation and delivery costs. The second test has been the Rate Impact Test, which measures the impact of a program on the average electric utility rate. Finally, the Societal Test is an expansion of the ART, in that it includes environmental and other social benefits external to the transaction between the utilities and their customers.

The Commission's use of these tests was prescribed in earlier versions of Chapter 380. Chapter 380 was developed in the 1980's and remained substantially unchanged until 1999, when legislation associated with electric restructuring shifted the responsibilities for conservation programs within the State. During the 1980's and 1990's, the purpose of Chapter 380 was to provide a set of rules under which utilities could implement conservation measures without seeking Commission approval. However, Chapter 380 allowed utilities to seek approval for programs that did not meet the three tests.[3[11]] Thus, the tests were not absolute limiters. The Commission could exercise its judgment in approving additional programs if it determined that such programs exhibited benefits not captured in the three cost effectiveness tests.

The current Conservation Act is broad in scope and includes goals that extend well beyond savings associated with generation and delivery costs. Increased consumer awareness, sustainable economic development, reduced environmental impact, the creation of more favorable market conditions for efficient products, a 20% funding target for low-income and small business consumers, and geographic and income diversity are all statutory goals that are likely to be difficult to accomplish under a strict cost effectiveness test. At the public hearing, the Public Advocate urged the Commission to be flexible in its use of cost effectiveness tests. In the Public Advocate's view, the Legislature has encouraged the Commission to "come to its own conclusions about a fair distribution of benefits." He comments that "there's no way to avoid the exercise of judgment in the design of cost effectiveness screens." We agree that our decisions regarding cost effectiveness criteria must include the flexibility to balance all the goals in the Conservation Act – whether strictly quantifiable and related to electrical generation and delivery, or less quantifiable and related to broader goals in the Act. At a minimum, we must retain the flexibility the Commission had under earlier provisions of Chapter 380. To comply with the Act, we must have as much flexibility as possible while retaining a consistent, economically rational approach to program design.

Currently, most other states – and particularly Northeast states -- use variations of the ART, variously called Total Resource Cost Test, Modified Total Resource Cost Test, Societal Test, or Modified Societal Test. These tests are distinguished by the fact that they include costs or benefits associated with "non-electric" resources (e.g., increased use of gas or water), customer O&M expenses (e.g., reduced maintenance), and improved ability to pay electric bills. They may include "spillover effects" (e.g., adoption of additional efficiency measures by customers outside of the efficiency program). Societal Tests may include costs and benefits accruing outside of Maine, such as environmental effects. Some states attempt to include economic development and job creation benefits. On the other hand, some states consider cost effectiveness from the participant's perspective or from the utility's perspective.

Quantification of some of these costs and benefits is difficult. Some states solve this problem by creating a percentage adder to represent environmental or other non-quantifiable costs. In general, these adders are not meant to represent a measured level of benefit, but are meant to acknowledge that some benefit exists and should be recognized.

Appendix A contains a summary of the most common costs and benefits included in commonly considered cost effectiveness tests.

Appendix B contains a summary of our understanding of other states' cost effectiveness tests.

2. Subsection A – Modified Societal Test. In subsection A of the proposed rule, we defined a Modified Societal Test (MST) as the cost effectiveness test that will be used for ongoing (as opposed to interim) conservation programs. The proposed rule defined the MST as the ratio between benefits and costs.

OPA supports the MST, but suggests that it be expressed as the difference (rather than a ratio) between benefits and costs. OPA comments that the magnitude of this difference (using a net present value calculation) is the "true economic value provided by the conservation measure or program" and that the MST should at least consider the net difference. In earlier comments and at the public hearing, OPA emphasized that, regardless of whether a ratio or a "net benefits" approach is used, the test should not be so rigid as to eliminate the Commission's ability to use judgment in balancing goals.

In our view, the choice of using a ratio approach (as in the proposed rule) or a net benefits approach (as suggested by OPA) will have very little influence on our choice of programs, if any at all. For a fixed budget, each approach would yield the identical decision. Absent a fixed budget, implementing programs with the greatest net benefit might focus funding on a small segment of the population, thereby conflicting with our efforts to offer programs to a wide variety of consumers. In either event, we agree with OPA's opinion that we should not choose programs rigidly based on the level of a ratio or net benefits. Notwithstanding these comments, we conclude that expressing the MST in terms of absolute dollars might make a program's effect more intuitively understandable without changing the intent or the impact of the proposed rule. Thus, we have revised subsection 4(A) and subsection 4(B)(1) of the final rule to express the MST as a net benefit measurement. We expect that we will express the results of the MST in terms of both dollars and a ratio, to retain the advantage of each.

The proposed rule included in the MST all costs and benefits that are reasonably quantifiable, regardless of who pays or experiences the cost or benefit. This approach is generally consistent with the All Ratepayer Test approach taken in years past, but expands the approach to include all impacts that clearly result from the programs. We recognize that some factors will continue to be difficult to quantify. We do not establish a percentage adder to represent those factors. Rather, we intend to quantify when possible and simply report program effects when quantification is not possible.

Subsection 4(A)(1) lists benefits to be included in the cost effectiveness calculation. Avoided electric generation costs will be estimated using regional prices. The proposed rule states that an average generation cost is adequate, but that more precise estimates based on time differentiation may be used when appropriate. Avoided T&D costs will rely on T&D utilities' marginal cost estimates, which also may be averages or time differentiated estimates. In the inquiry, utilities commented that their marginal cost estimates are imprecise. However, they are the most appropriate quantities available. Avoided fuel savings will include reduced use of oil, gas, or any other fuels saved. The rule does not specify a method for calculating fuel savings – we will use the best estimate available. Similarly, avoided costs of water, sewer, or any other resource will be estimated as accurately as is possible and reasonable. Finally, subsection (e) establishes that any other benefit that we can reasonably quantify will be included in the cost effectiveness test. We conclude that these benefits are important outcomes of conservation programs – sometimes by design and sometimes by good fortune – and they should be acknowledged whenever possible.

Subsection 4(A)(2) lists costs to be included in the cost effectiveness calculation. Direct program costs listed in subsection (a) and capital costs associated with the purchase and installation of appliances or equipment, listed in subsection (b), are traditional costs included in cost effectiveness tests. Subsection (c) lists other costs such as increased customer operation and maintenance costs. Considering such costs is consistent with considering all benefits that can be recognized as resulting from a program.

In its comments in the rulemaking, BHE suggests that we consider lost utility profits as a program cost, noting that lost utility revenue is a societal cost and will ultimately result in higher rates. We reject BHE's suggestion. To the extent that a utility's rates exceed its marginal delivery costs, a utility will lose revenue if a conservation program lowers total kWh use. That loss is a transfer-payment from the utility's stockholders (in the short term) to program participants. The utility's monetary loss is offset by participants' economic gains (whether through lower costs for similar productivity or through increased productivity at a lower price than would have occurred absent the program). At the heart of the economic tests used in most states and in Maine has been the policy decision that lowering society's overall expense of using electricity without lowering productivity level is a desirable goal. Historically, a transfer of funds has occurred under Total Resource Cost Tests, All-Ratepayer Tests, and Societal Tests, and has been mitigated by offering a wide range of programs to all ratepayers. Currently, very few programs that reduce kWh use would pass a test that included lost utility profits as a cost. It is unlikely that the Legislature intended us to establish a cost effectiveness test that excluded virtually all programs that reduce kWhs. Thus, our final rule treats lost utility profits in the manner they have been treated historically in cost effectiveness tests.

We note, moreover, that conservation programs will not always lower kWh use. The Act includes many goals, including the goals that programs "create more favorable market conditions for the increased use of efficient products and services" and "promote sustainable economic development." We have incorporated those goals into our goals, objectives, and strategies, and have also stated that programs shall "improve the efficiency of electric energy use by Maine residential consumers, businesses and other organizations."[4[12]] In our Order Approving Goals, Objectives, and Strategies, we assert that programs will not reduce kWhs per se, but will improve electric efficiency. Programs that meet these goals may *increase* utility sales, thereby improving, not harming, a utility's profits.

CMP suggests that we include the Rate Impact Test in a manner similar to its use in Chapter 380-O. According to CMP, under this approach the Commission would consider a program's impact on rates, rejecting the program if the impact exceeded a pre-defined level. CMP suggests that the 1% specified in Chapter 380-O would be reasonable.

We agree that we should consider the impact on rates from the portfolio of programs, and would do so as a matter of our normal approach to utility matters. However, we reject setting a specific rate impact that would automatically require program rejection. As discussed earlier in the order, the 1% level in Chapter 380-O only prohibited the utility from implementing a program without Commission approval. The Commission still retained the flexibility to use its judgment in balancing the rate impact with the program benefits. The breadth of the Act requires us to consider even more goals than we did under Chapter 380-O, and we intend to retain that flexibility to do so. Thus, in subsection 3(C) of the final rule we have added the provision that we must consider the likely impact of the full portfolio of conservation programs on a utility's rates, but we do not specify a level that would trigger program rejection and we do not state any action that must be taken based on our consideration. Under the final rule, we will weigh the program benefits with the harm to utilities and their ratepayers given the conditions at the time.

BHE and CMP comment that "non-electric benefits"[5[13]] should not be included in the MST. CMP advocates using the methods used in the All Ratepayers Test, which CMP asserts did not include such benefits as increased amenities and decreased operating expenditures not related to electricity use. CMP contends that quantifiable externalities may be considered as program benefits, but only if an All Ratepayers Test is first satisfied. BHE advocates capping non-electric participant benefits to participant costs, and capping non-electric benefits at some portion of total benefits. CMP notes that the All Ratepayers Test emphasized avoided cost benefits, while the MST is overly expansive. CMP quotes Commissioner Diamond in his separate concurring statement to the June 13 Order in Docket No. 2002-161 as asserting that it is difficult if not impossible to measure non-electric benefits such as environmental benefits. Both utilities comment that the programs are funded by electric ratepayer money and should be targeted to electric savings. On the other hand, OPA supports inclusion of non-electric benefits in the MST. OPA states that the Legislature has given the Commission a new mandate to "consider, without limitation" programs that promote sustainable economic development and reduce environmental damage. The OPA believes that a strict All Ratepayers Test is "neither necessary nor feasible" under the new mandate, and that it is appropriate to consider both quantifiable externalities and non-ratepayer specific benefits that result from a conservation program.

We agree that programs should be targeted to savings associated with how a customer uses and obtains electricity. However, we disagree that savings such as reduced operating expenses and alternative fuel savings should be excluded from the cost effectiveness test. As long as such savings result from the electric efficiency measure, they are a savings of the program and should be considered in a cost effectiveness test. We disagree with an implication that Commissioner Diamond asserted that *all* non-electric benefits are difficult to quantify; indeed many will be easily quantified. The Act allocates ratepayer funds to implement programs that are beneficial for reasons that extend far beyond avoided generation and T&D utility costs. The Act targets economic development and environmental benefits in particular. The Act directs the Commission to make an investment decision on behalf of the citizens of Maine. When making an investment decision, one considers all savings associated with the investment. While we agree that a program must focus primarily on electric use, we see no reason to ignore a subset of savings that result when the electricity measure is undertaken. Thus, the final rule retains the "non-electric" benefits contained in the proposed rule.

Having stated our decision regarding the cost effectiveness test that is required before we will fund a program, we turn to a different decision – namely, the amount of funds we will commit to customer incentives within a program. We acknowledge that non-electric savings such as reduced maintenance and non-fuel costs benefit only the participant, while avoided generation and T&D costs generally benefit all electric users. This becomes relevant because we desire that the program portfolio benefit as many consumers as possible. With this concern in mind, we are initially inclined to limit the incentive we award participants to the level of savings attained through avoided generation and T&D delivery costs. This approach would address many of BHE's and CMP's concerns. We decline to adopt a rigid provision that requires imposing this limitation. Rather, we will judge each situation on its merits. Thus, in Section 4(A)(6) of the final rule, we have added the sentence that the Commission consider the value of the program savings associated with electrical production and delivery when setting incentive values.

In addition, we observe that environmental benefit in the form of reduced emissions has, for many years, been considered by some to be an important benefit of conservation programs. The current law is no exception. The Act contains a goal of attaining environment benefits, yet program proposals made to us have contained no estimates – either quantified or not -- of environmental impact. While it is difficult to determine precise quantification of this benefit, it is not impossible to produce estimations. We ask persons who view environmental improvement to be important to submit program suggestions that explicitly target environmental improvement. For example, a program that reduces energy use or demand at a time when the marginal generating units produce high emissions would help us fulfill the Act's environmental goal. We also ask all persons submitting program proposals to provide, if possible, information on the environmental impact of the program. Finally, we intend to issue a solicitation, separate from this order, that requests proposals for conservation programs that explicitly target environmental improvement as a primary goal. These actions will allow us to include programs in our portfolio that may reasonably be considered to meet the environmental goal of the Act.

Finally, BHE and CMP recommend that the Commission reject non-quantifiable benefits in the MST. CMP comments that the All Ratepayers Test was a "simple, objective, mathematical test" while the MST is imprecise and encourages disputes and second-guessing. In our view, the Act clearly rejects a "simple, objective, mathematical" view of cost effectiveness by including a variety of broad and difficult-to-quantify goals. As pointed out by the Public Advocate in his comments, the Act requires that the Commission exercise judgment when determining cost effectiveness and when balancing goals. The fear of less than perfect precision should not cause us to ignore important benefits that are consistent with the intent of the Act. The proposed rule used terms such as "reasonably identifiable costs" (subsection 4(2)(a)) and "to the extent such costs can be reasonably quantified and valued" (subsection 4(2)(c)). We consider these phrases to be adequate protection against disputes or abuse and have not changed them in the final rule.

In the proposed rule, subsection 4(A)(3) established guidelines for the discount rate to be used in cost effectiveness calculations. We commented that the cost effectiveness of a program is calculated from the perspective of Maine consumers as a whole (as opposed to only the participant). Thus, the discount rate should be a societal discount rate. Long-term treasury securities yields are reasonable for this purpose.

In its comments in the rulemaking, BHE suggests that, for each program, the Commission choose a discount rate that reflects the risk profile of the program. BHE points out that some measures are short-lived and that some costs and benefits cannot be predicted with certainty. In our view, establishing a discount rate to use when evaluating most programs establishes consistency and predictability and creates a result that is reasonably accurate. However, consistent with comments made earlier in this order, this rule should not limit our ability to exercise judgment. We acknowledge that variability in certainty and measure life exists. Thus, while we decline to state a prescribed method for linking risk to the discount rate, in subsection 4(A)(3) of the final rule we have introduced the flexibility to consider alternative discount rates when conditions warrant doing so.

Subsection 4(A)(4) establishes that costs and benefits will all be measured on a comparable, net present value, basis. This is a traditional, established calculation method. No person suggested changing this subsection.

Consistent with our intent to consider all costs and benefits that can be recognized, subsection 4(A)(5) establishes that costs and benefits will be estimated for as many years in the future as seems reasonable.

3. Subsection B – Non-Quantifiable Cost Effectiveness Test. Subsection B of section 4 accommodates programs that satisfy statutory or Commission-established goals but whose benefits cannot be quantified. While we will measure costs and benefits whenever possible, we conclude that there are programs that will benefit consumers in Maine, or that meet statutory criteria, but whose benefits cannot be reliably estimated. Indeed, there may be requirements of the Act that cannot be met if all programs must pass the Modified Societal Test. In particular, it may be impossible to spend 20% of total funds on low-income or small business programs and it may be impossible to conduct energy education as the Act contemplates, unless programs with non-quantifiable benefits are considered. The subsection includes three criteria, all of which must be met, before a program can be implemented without passing the Modified Societal cost effectiveness test. Subsection 4(B)(1) allows a program with non-quantifiable benefits to be implemented, while subsection 4(B)(2) establishes that the program must meet statutory or Commission-established goals and subsection 4(B)(3) establishes that the entire portfolio must be substantially cost effective.

This subsection creates the possibility that a program whose benefit-to-cost ratio *is* quantifiable but is less than one, and that meets particular goals, cannot be implemented. However, a program whose benefit-to-cost ratio *is not* quantifiable, and meets the same goals, may be implemented.

In its comments in the rulemaking, MCAA supports the inclusion of a non-quantifiable cost effectiveness criteria, calling the provision "forward-looking." MCAA comments that this provision will allow the Commission to implement "cutting edge" ideas to determine whether they are successful. BHE expresses the concern that subsection 4(B) could result in abuse and reiterates the suggestion that non-quantifiable benefits be limited to a portion of total benefits. While we decline to specify such a percentage, as a practical matter we expect to limit our funding of programs with non-quantifiable benefits.

In the inquiry, we invited interested persons to express their views on whether there should be a quantitative standard for the distribution of benefits. To elaborate, the MST looks at benefits and costs in the aggregate. We wondered whether the Commission also should be required to find that benefits will exceed costs for some minimum percentage of Maine consumers. For example, if it were determined that for a particular portfolio of programs the benefits will exceed the costs in the aggregate (i.e., the portfolio passes the Modified Societal Test) but that only 20% of consumers will actually receive more in benefits than they pay in costs, should that portfolio be deemed cost effective?

The OPA does not support this approach, commenting that, given limited resources, it would foreclose many programs, particularly those in smaller service territories. BHE comments that resources should not be diverted from high benefit programs in favor of high penetration programs. We did not introduce such a provision in the final rule.

In the inquiry, we also welcomed comments on whether the existence of statutory requirements that certain percentages of the spending be directed at specified groups and that all groups be given the opportunity to participate warrants the conclusion that the Legislature did not expect the Commission to deal further with distributional equity issues. Even if one answers this question in the negative, we asked whether it is realistic to expect the Commission to be able to determine the percentage of ratepayers who will have a benefit-to-cost ratio in excess of 1 (or a net benefit greater than 0) for a particular program or portfolio of programs. Finally, given the Commission's conclusion that the Rate Impact Test is not feasible in a restructured environment, which means that some and perhaps many ratepayers may have costs in excess of benefits from these programs, we inquired whether the Commission should suggest to the Legislature that it may want to reexamine the statute.[6][14]

The OPA suggests that, in the Act, the Legislature has already determined the distributional equity it considers to be appropriate. The Commission should not delve further into the issue. BHE suggests that the Act should be re-evaluated. We made no change in the final rule based on these comments.

Inquiry into New Conservation Programs and Developing a Plan
for Using Increases in the Conservation Fund:
Results from Docket 2006-446

Prepared for:

Utilities and Energy Committee
123rd Maine Legislature

Prepared by:

Maine Public Utilities Commission
242 State Street
Augusta, ME 04333-0018

ADAMS, Chairman and REISHUS, VAFIADES, Commissioners

March 9, 2007

I. EXECUTIVE SUMMARY

In response to legislation passed by the 122nd Maine Legislature, the Maine Public Utilities Commission opened an inquiry into its energy programs to seek stakeholder input entitled "Inquiry into New Conservation Programs and Developing a Plan for Using Increases in the Conservation Fund" (the "Inquiry"). The Inquiry addressed in broad terms the issues of how Efficiency Maine should approach load control, existing and proposed new efficiency programs, funding and staffing levels, the creation of an Efficiency Maine Advisory Council, and options for changing the method in which Efficiency Maine is funded.

The Maine Public Utilities Commission's Efficiency Maine program, has four broad goals established by statute:

(1) Increase consumer awareness of cost-effective options for conserving energy;

(2) Create more favorable market conditions for the increased use of efficient products and services;

(3) Promote sustainable economic development and reduced environmental damage; and

(4) Reduce the price of electricity over time for all consumers by achieving reductions in demand for electricity during peak use periods.

As a result of the Inquiry, and recent evaluations of the residential and business programs the Commission will:

1) Establish a load control mechanism to enable Maine consumers to participate as demand side resources in the Forward Capacity Market (FCM);

2) Undertake a detailed study of the value and the type of load response programs most suitable for Maine;

3) Open a rulemaking proceeding to double the cap on incentive amounts for participating businesses and school districts to $100,000 per year or $200,000 over two years;

4) Initiate a residential new construction program; and

5) Form an Efficiency Maine Advisory Council.

In response to language in the statute regarding the funding levels for PUC energy programs, the Commission has provided in this report three funding scenarios with accompanying program portfolios that are illustrative of the type of program expansion and new programs required to access additional cost-effective energy efficiency.

II. BACKGROUND

During its last session, the Legislature enacted an Act to Encourage Energy Independence for Maine (Act). P.L. 2005, ch. 569. Section 1 of the Act modified section 3211-A (2)(A) by adding a fourth consideration criterion for conservation programs and directing the Commission to consider programs that "[r]educe the price of electricity over time for all consumers by achieving reductions in demand for electricity during peak use periods." Section 7 of the Act directed the Commission to develop a plan for using revenues from any increase in the assessment on transmission and distribution utilities. The plan was to include a description of how increased funds would contribute to the goals of increasing energy efficiency for program participants and reducing electricity prices for all consumers. Section 7 also directed the Commission to consider whether increases to program funding levels should be used to increase the current business program incentive cap.

A. Commission Inquiry

On August 9, 2006 the Commission initiated MPUC Docket No. 2006-446, "Inquiry into New Conservation Programs and Developing a Plan for Using Increases in the Conservation Fund." The purposes of the Inquiry were to: (1) seek input from interested persons on how to interpret and implement the requirements of Section 1 of the Act; (2) invite interested persons to propose new conservation programs that are consistent with the Act; and (3) invite comments regarding the plan required by Section 7 of the Act. A list of the 13 parties providing comments in the Docket is attached as Appendix A.

This report presents the overall highlights and summary of our Docket proceeding. A summary of specific comments provided by Docket participants and additional docket related details are included in the following appendices:

Appendix A: Docket Participants
Appendix B: Demand and Price Reductions
Appendix C: Caps
Appendix D: Efficiency Maine Budget, New Conservation Programs, and Staffing Levels
Appendix E: Prior Recommendations
Appendix F: Other Questions

B. Existing Budget and Programs

In 2002, Maine's Legislature directed the Commission to assume responsibility for planning and implementing energy conservation programs. In response, the Commission conducted a series of hearings and rulemakings to develop a funding level and to plan programs responsive to the Legislature's direction. These programs are now beginning their fourth year of operations. Efficiency Maine currently offers five programs designed to provide every Maine electric customer an opportunity to participate. Low income residential consumers are provided energy efficient appliances and lighting through partnerships with Maine Housing and with local housing authorities. Non-low income residential customers can take advantage of the Efficiency Maine Residential Lighting Program. Large and small businesses, towns, schools, and agricultural businesses can participate in the Efficiency Maine Business Program. New schools can be designed and built more energy efficiently through the Efficiency Maine High Performance Schools program. Educational programs targeting diverse customer segments from school children to building operators and facility managers to architects and engineers, provide information, tools, and advice on becoming more energy efficient.

The Commission recently completed independent third party evaluations of the Efficiency Maine business and residential programs[1]. The evaluations provide valuable information on how the programs can be improved, but also conclude that the programs are cost effective and achieving substantial savings. The evaluations along with information from MPUC Docket 2005-446 indicate that the Efficiency Maine program is achieving greater energy savings at lower costs than was projected at the time of program development.

The productivity of the program implementation has helped the Commission achieve greater savings than expected with its existing budgets. Annual program revenues started at $2.6 million in fiscal year 2003, and have grown to $9.2 million in fiscal year 2006. Current projections show that at current levels of assessment, the funds available for conservation programs will be $17 million in fiscal year 2010[2]. Based on these budget projections, the Commission has determined current funding is adequate to maintain the current programs it offers. It will also develop a limited expansion to the residential lighting program to include other products as budgets allow. It will add a commercial new construction program and a limited residential new construction program.

[1] http://www.efficiencymaine.com/documents.htm

[2] These increases are the result of three factors. The most significant is CMP's retirement of payments to expiring Power Partners contracts and represents no increase in costs to consumers. The second most significant effect is the ramp up of assessment on utilities other than CMP to the 1.5 mil statutory cap. CMP's customers are already at the 1.5 mil statutory cap. The least significant increase is due to projected annual increases in sales.

III. Demand Reduction

Section 1 of P.L. 2005, ch. 569. ammends the Conservation Act by adding a fourth consideration criterion for conservation programs, by requiring the Commission to consider programs that "[r]educe the price of electricity over time for all consumers by achieving reductions in demand for electricity during peak use periods." (MRSA 35-A§3211-A (2)(A)4).

Demand reduction programs can reduce prices because of the way in which power plants are dispatched. The lowest cost plants run first, with higher cost plants being dispatched to serve increases in system demand. Thus, at the periods of highest use, the most expensive plants are in operation. Thus, demand reduction programs can reduce energy prices. Demand reduction programs may be broadly divided into three types; peak clipping, peak shifting, or peak shaving. Peak clipping programs eliminate use at the time of the power system's period of highest use (peak). Programs that interrupt load by cycling air conditioners or water heaters on or off or by dimming office lights are examples of peak clipping. Peak shifting programs move customer use from the system peak to periods in which there is less demand on the system. Examples of peak shifting programs are payments to customers to change their pattern of consumption or smart metering programs that convey time-of-use price signals. Peak shaving programs are conservation programs similar to some of those currently being implemented in the Efficiency Maine program.

Based on comments received in this Inquiry (Appendix B) the Commission will initiate a study before beginning the implementation of any demand reduction programs. The study will allow us to determine which hours of the system peak are most valuable, the type of load (e.g. air conditioners, water heaters, industrial process) available for interruption at those hours, and the potential magnitude of load reduction available during those periods. This part of the study will determine the potential value available through demand reduction programs and will involve modeling of the bulk power system and require cooperation of the ISO and electric utilities. A second part of the study will investigate the costs of recruiting the reductions[3]. Together, the answers to these questions will allow the Commission to determine whether there are net benefits and cost effective price reductions available to all consumers through the implementation of such programs.

IV. Increases to Business Program Incentive Cap

Section 7 of an "Act to Encourage Energy Independence for Maine (Act). P.L. 2005, ch. 569" directs the Commission to consider whether increases to program funding levels should be used to increase the current business program incentive cap.

During the development of its business program, the Commission instituted a $50,000 per year incentive cap for any single business customer. The cap was

[3] e.g. What price is required to encourage large and/or small customers to change their patterns of consumption?

instituted to ensure the greatest number of customers are able to participate in the program. According to information received from some larger customers, the cap was not large enough for them to initiate large scale efficiency projects at their facilities. In addition, some complained that the amount of incentive available to them was less than the amount of money that they contributed to the fund. To help address the first issue, the Commission allowed customers to apply two years' worth of incentive to large projects in a single year ($50,000 in any single year or up to $100,000 over two years).

Since the imposition of the incentive cap program budgets have grown, and experience has shown that there are relatively few projects that trigger the cap[4]. Based on its experience and comments received in its investigation (see Appendix C), the Commission has concluded that it can double the existing incentive caps within its current. A more ambitious large customer efficiency funding approach that would allow for very large projects depends on increased funding and is discussed in section V below.

V. Increased Budget and Expenditure Plans

Section 7 of the Act directed the Commission to develop a plan for using revenues from any increase in the assessment on transmission and distribution utilities. The plan was to include a description of how increased funds would contribute to the goals of increasing energy efficiency for program participants and reducing electricity prices for all consumers.

Since initially being directed by the legislature to plan and implement energy efficiency programs, the Commission has examined the potential for achievable cost-effective energy efficiency (MPUC Docket No. 2002-162); it has reviewed and received public comment on its programs to help refine current offerings and solicit input for additional programs (MPUC Docket No. 2005-446), it has conducted formal reviews of its two largest efficiency programs; and it has conducted this Inquiry to help respond to Section 7 of the Act. Our conclusions from these multiple Inquiries are that:

- Current Efficiency Maine program offerings are cost effective and meeting all statutory directives;
- Programs are producing greater savings and at lower costs than was expected during the planning stages;
- The existing Efficiency Maine programs continue to receive broad support from stakeholders;
- Existing programs for efficient products provide a platform, which can be expanded to capture additional efficiency without adding new programs;
- New commercial and residential construction programs will provide opportunities for additional cost effective savings that cannot be achieved through the existing programs; and

[4] Since program inception, the cap has been triggered only 17 times.

- Significant cost-effective energy efficiency opportunities remain [5]

The language of Section 7 directs the Commission to develop a plan for spending any additional revenues. As mentioned above, our existing programs along with our new commercial and residential new construction programs, will allow us to deliver some level of efficiency savings from all sectors. The growing demand for existing programs will itself absorb a major portion of increased funding[6]. Increased budgets would also allow the Commission to initiate a commercial/industrial bid for savings program modelled after CMP's earlier Power Partners program[7]. Finally, expanded funding could allow the Commission to coordinate with the Office of Energy Independence and Security to offer an expanded existing home performance program.

The Commission has accepted the recommendations of all parties for additional energy efficiency programs as we believe program expansion will result in the capture of additional cost-effective energy efficiency that cannot be achieved with the existing programs. Expanding energy efficiency investments will allow additional cost-effective energy efficiency to be secured.

To address the concerns of larger customers, the Commission will open a rulemaking proceeding to raise the cap on incentives for large projects as discussed in Appendix C.

Should budgets increase, the Commission could again raise the incentive cap or alternatively, if the budget is expanded to 2.5 mils, or about $25 million per year, we believe there would be enough funding available to implement a meaningful bid for savings program as recommended by IECG[8]. The scenarios below do not include any allocations directed to demand response initiatives, as recommended by CMP as we believe further analysis is necessary prior to making any recommendation.

In response to Section 7 of the Act, the Commission has examined program expansion and provided 3 funding scenarios for illustrative purposes[9]; at 2 mils, 2.5 mils, and 3 mils. A brief description of each funding scenario is provided below. More detail on funding for each of the programs and the responses of stakeholders to questions in the Commission Inquiry are provided in Appendix D.

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[5] OPA report in MPUC Docket No. 2002-162 indicated the maximum achievable levels of cost effective energy efficiency could be captured with average program budgets of $71 million per year, or about 4.4 times the level at which the Conservation fund is expected to reach by FY 2010.

[6] Annual energy savings from program measures in FY'06 increased by a factor of four over program measures installed in FY'04.

[7] Power Partners was the first bid for savings program of its kind. Rather than develop a program delivery structure, CMP requested $/kWh bids from its "Power Partners" to provide efficiency savings. Power Partners contracts included stringent measurement and verification clauses to ensure program performance.

[8] "Bid for Savings" refers to a type of energy efficiency program that invites competitive responses from businesses for proposed efficiency savings given a requested level of incentive payment.

[9] We are not ruling out the addition of programs beyond what is presented here, nor are we excluding the possibility of adding load response programs to the menu of Efficiency Maine services. Prior to implementation of any new programs, we will seek input from stakeholders as required by §3211-A.

A. Increase Funding by 33% to 2 mils ($0.002/kWh)

As discussed above, with the addition of a new residential construction program this summer, the Commission will be able to target efficiency savings in all major sectors. With funding set at the 2 mil level, the annual program revenues are estimated to be $20 million with energy savings 8% greater and lifetime economic benefits 19% greater than program performance in FY'06. A discussion of implications for increased funding for each sector follows.

1. Residential Programs: Efficiency Maine currently provides an efficient products program, a low income appliance replacement program, and will soon add a limited residential new construction program. The efficient products program has been targeted primarily at residential lighting. This summer, the program will begin providing limited incentives and offerings for other products such as efficient clothes washers and air conditioners as budgets allow. The Commission has decided to add a residential new construction program to its menu of programs. At current funding levels, adequate resources exist to conduct a baseline study of housing construction practices and to provide builder training programs. Funding at a 2.0 mil assessment level would increase the budget for the efficient products program by up to $1 million per year and allow more products to be promoted for periods of greater duration. This would also allow the Commission to budget approximately $1.5 million per year towards residential new construction, enabling more expansive training and program promotion. The increased funding would also allow the Commission to increase its grant to the Maine Home Performance program from $150,000 per year to $500,000[10]. Low income residential customers receive efficient appliances and lighting through a program cooperatively administered with Maine Housing. At current funding levels, the program can serve between 2,500 and 3,000 low income customers per year. An increase to 2.0 mils would yield an approximate 30% increase in the low income program budget[11]. The Commission is exploring ways to deliver program benefits to additional eligible low income customers which could absorb additional funding. One possibility would be for the Commission to revisit the income guidelines it has set for classification as low income, and by so doing expand the population eligible for services.

2. Business Programs: The Efficiency Maine business programs include a new commercial construction program and incentives and advice for improving the efficiency of existing facilities. At least 20% of all funding must be targeted towards small businesses. By increasing the assessment levels to 2 mils, the annual budget for the existing facilities and new commercial construction programs would be about $9.7 million per year. The expanded budget would allow for increased program promotion and allow the Commission to meet the increasing demand for the existing products

[10] Budgets for the residential products program are approximate and determined after mandated expenditure levels for small business and low income programs have been deducted from projected increases in revenues.

[11] Forecasts for the low income program budget are driven by statute which directs that the Commission must ensure that 20% of all program funds are targeted towards services to low income households.

program. It would allow the Commission to (if warranted) once again increase the per customer incentive cap, and would allow for provision of more comprehensive services in the new construction program.

3. Schools: The Efficiency Maine program provides services to schools through three avenues; the High Performance Schools program increases energy efficiency through improvements in the design and construction process of five to ten new schools built each year, the Building Operator Certification program provides training on energy efficient and preventative maintenance practices to approximately eighty school facility personnel each year, and the Efficiency Maine business program provides financial incentives and technical assistance to existing school buildings. We do not foresee making any changes to the budgets for these programs from revenues generated at the 2 mil assessment level. Demand for the High Performance School program is driven largely by the number of schools approved by the Maine Department of Education each year. Current program budgets are adequate to provide for the current rate of construction. Increases in the business program budget discussed above will allow us to package and market a more comprehensive set of measures for existing schools.

B. Increase Funding by 66% to 2.5 mils ($0.0025/kWh)

At this level, annual program revenues are estimated to be $25 million with energy savings 36% greater and lifetime economic benefits 50% greater than program performance in FY'06. Beyond incremental expansion to existing programs described above, the Commission would initiate a bid for savings program funded at $2.5 million per year.

C. Increase Funding by 100% to 3 mils ($0.003/kWh)

An assessment level of 3 mils would result in program revenues of approximately $30 million per year. We project that the energy savings from a program of this size would be nearly 70% greater and net lifetime economic benefit would be 80% greater than those yielded by the current programs in FY'06. As explained in B above, all programs would receive incremental increases to their budgets and funding for the bid for savings program would increase to an estimated $5 million per year.

VI. Summary and Conclusion

Based on information gathered in its Inquiry, the Commission will initiate a quantitative study of the value of load response programs. The study will examine the wholesale market system's economic dispatch to assess the periods in which demand reduction would yield the greatest economic benefit. The study will determine whether the cost of acquiring those reductions is less than the benefit yielded. Finally, the study will document any price reduction effects likely to occur from the demand reductions. Information gathered through this study will inform the Commission's efforts to develop an economic load response program.

The Commission will open a Chapter 380 rulemaking proceeding to change the current per customer annual incentive limitation of $50,000 per customer per year or $100,000 per customer every two years, to $100,000 per customer per year or $200,000 per customer every two years.

The Commission will form an Efficiency Maine Advisory Council composed of a representative group of stakeholders. The Council will serve as a way for the Commission to regularly inform this group on the progress of the Efficiency Maine programs and as a venue for the Council to provide regular input to the Commission.

Two new programs, commercial new construction and residential new construction will be initiated beginning in FY'08 and will operate within the current budgets expected from the current 1.5 mil assessment cap. Should the legislature elect to increase program funding levels by removing the current cap on the assessment, these programs would be expanded to absorb increased program budgets. At annual budgets of $25 and $30 million, the Commission would initiate a bid for savings program. In addition, should the legislature elect to increase efficiency program budgets and assessment levels, it should adopt a gradual ramp-up in the program revenues to allow for gradual program expansion.

APPENDIX A:
DOCKET PARTICIPANTS

A total of 13 parties provided written comments for this Docket proceeding and are grouped in the following categories presented below:

Utilities
- Central Maine Power (CMP)
- Bangor Hydro Electric (BHE)
- Maine Public Service (MPS)

Industry:
-Industrial Energy Consumer Group (IECG)
- Madison Paper Industries

Environmental Groups:
- Natural Resources Council of Maine (NRCM)
- Environment Maine
- Environment Northeast

Efficiency Organizations/Firms:
- Northeast Energy Efficiency Partnerships (NEEP)
- North Atlantic Energy Advisors (NAEA)

Other:
- Maine State Housing Authority (MSHA)
- Office of Public Advocate (OPA)
- Office of Energy Independence and Security (OEIS)

APPENDIX B:
DEMAND AND PRICE REDUCTIONS

In Section 1 of the Notice of Inquiry, the Commission sought input on questions related to programs to address demand and price reductions.

1.A. Peak demand reductions

Question 1.A.1 of the Docket asked how the "peak period" should be defined; whether it should be based on in-State system peak or on the New England system peak.

All but one respondent stated that "peak" be defined based on ISO-New England peak period definitions. Maine Public Service (MPS) stated that the "peak" should be defined based on the relevant wholesale electricity market, noting that northern Maine is winter peaking and southern Maine is summer peaking.

Question 1.A.2 asked if the Commission should consider all three types of programs (energy efficiency, load shifting, and load interruption) as peak reduction programs for the purpose of interpreting newly-enacted section 3211-A (2)(A)(4). *Energy efficiency* programs result in permanent reductions to peak demand by improving the efficiency of use. The demand reduction continues as long as the efficient equipment remains in place. *Load shifting programs*, may not improve efficiency but reduce peak demand by encouraging consumers to change their pattern of consumption. Examples of such programs are Time-of-Use rate structures or smart metering programs. *Load interruption programs* such as water heater cycling or voluntary interruptible programs reduce peak loads but do not increase energy efficiency.

Comments furnished by utilities Central Maine Power, Bangor Hydro-Electric, and Maine Public Service support shifting funds from the implementation of efficiency programs to load shifting and load interruption programs, hereafter referred to simply as "demand response" programs. According to CMP and MPS, if a sufficiently large demand response program is implemented it could reduce peak demand enough to reduce the spot clearing price for electricity, thereby providing benefit to all customers through lower prices for generation service. Others, such as Northeast Energy Efficiency Partnerships and Environment Maine discouraged the use of conservation funds for demand reduction programs stating that the long term benefits of efficiency are greater than demand response. While Natural Resources Council of Maine acknowledged the potential benefits of demand response programs, they noted that when considering the long term public benefits of avoided costs they prefer efficiency. Maine's Office of Public Advocate urged the Commission to apply the same set of cost effectiveness criteria to load shifting and load control programs as are currently applied to energy efficiency programs as a factor for deciding where to invest conservation funds. Additionally, OPA noted that demand response, unlike efficiency, only reduces peak demand, with little to no effect on energy consumption. As such, they note that utilities commonly favor demand response as it provides capacity savings while not impacting revenue to the same extent of investment in energy efficiency. Additionally, unlike efficiency investments which typically have at least a 10 year measure life, the measure life of a load control program is one year, thus resulting in limited capacity savings relative to its cost. OPA and Environment Northeast suggest that with the rise of the Forward Capacity Market (FCM), consideration should be given to using FCM funds for any demand response effort, thereby not displacing the existing system benefit charge funding stream for efficiency.

Question 1.A.3 asked whether it would it be necessary to involve electric distribution companies in load reduction/load shifting programs. There was unanimous agreement of stakeholders responding to this question that electric distribution companies would be required to participate in any load reduction program for it to be successful.

1.B. Price Reductions

Question 1.B.1 asks how the Commission should determine whether demand reduction "[r]educe the price of electricity over time for all consumers" as required under section 3211-A (2)(A)(4)? Should the Commission only consider demand reduction programs which have operated elsewhere and have empirically demonstrated price reductions for all consumers? Would a demonstration of price effects over time using hypothetical load reductions and a computer model suffice?

Stakeholder response to this question was divided. Utility respondents agreed that empirical evidence and evaluations of price reduction associated with demand reduction programs should be required prior to program implementation. Others, such as NEEP and OPA would be satisfied if such benefits could be demonstrated through a study modeling the effect of such a program.

APPENDIX C:
CAPS

Question 4.C.1 of the Notice of Inquiry refers to Section 7 of the Act that directs the Commission to "consider using funds resulting from any increased assessments to increase the per-business incentive cap imposed on large businesses under the business program. . .." The initial reason for the incentive cap was to prevent depletion of the fund by a few very large projects. The Commission asked docket participants if a different maximum value should be adopted and, if so, how should it be determined?

NRCM supported a process of establishing caps based on a cash flow analysis of the project in question, up to a maximum of $200,000 per customer over a four year time period. OPA supports multi-year caps, with an increased cap level for lost opportunity projects such as new construction, versus, discretionary retrofit. Additionally, while OPA is a firm supporter of caps to ensure that no single customer reserves a significant percent of overall program funding in any cycle, they justify the need for flexibility, and a provision to allow the program to waive the cap when programs are undersubscribed or for very large lost opportunity projects.

BHE expresses support for caps consistent with the original intent to ensure availability of funds for all customers. CMP did not support caps, other than to cap incentives at the amount the customer is actually assessed. CMP states this could be accomplished by escrowing funds contributed by customers to the conservation fund for use at a later time or limiting the amount that business customers are required to contribute in the first place. MPS did not support an increase in the cap, noting that businesses in southern Maine are larger and would absorb most of the funding with an increased cap, thereby reducing available funds for northern businesses. IECG does not support the use off caps, rather, cost-effectiveness should be the criteria for determining an individual project incentive level.

Question 4.C.2 asked if the Commission should reserve a "large incentive" fund within its business program with a "first come first served" application process. BHE responded that they do not support this idea, as they want to ensure their smaller business customers have access to incentive resources. OPA and IECG also did not support this idea.

APPENDIX D:
EFFICIENCY MAINE BUDGET, NEW CONSERVATION PROGRAMS, AND STAFFING LEVELS

Section 4 of the Notice of Inquiry addressed questions in Section 7 of the Act directing the Commission to develop a plan for using revenues from any increase in the assessment on transmission and distribution utilities pursuant to section 3211-A (4).

The Commission received input on a variety of questions related to budget levels from Docket participants, conducted a comparative review of spending on efficiency in Maine compared to other New England states and nationally, and finally, for illustrative purposes only, presented three different funding scenarios and portfolio designs to provide an indication to the Legislature how the Commission might allocate additional efficiency funds if authorized by the Legislature.

<u>Assessment levels</u>

In Section 4.A of the Notice of Inquiry, the Commission asked Docket participants if the existing assessment level of 1.5 mills ($0.0015/kWh) is adequate, or should the Commission recommend an increase in the assessment?[12] The Commission noted the assessment level for efficiency activities is actually 1.45 mils as 0.05 mils are allocated to fund the Maine Solar Energy Rebate program. The Commission asked if the assessment amount available to support efficiency activities should be raised back to the full 1.5 mil rate level in the event the rebate program is allowed to sunset. Finally, the Commission asked if the recommendation is for an increase in the assessment level at what rate should the assessment escalate.

Comments on this question were divided. CMP, BHE and MPS stated the current assessment level is adequate and noted that the expiration of the Power Partners contracts and continued load growth will result in increased budgets over time.[13] As noted previously in this report, the Commission projects the Efficiency Maine budget to grow to $16.4 million by 2010. CMP notes that Maine electricity consumers, in addition to paying for the Efficiency Maine programs, are also paying for the ISO-New England Demand Response programs. CMP says Maine's assessment on T&D utilities is already high. At the same time, CMP notes that Maine already has high market shares for ENERGY STAR appliances and the recent Energy Policy Act of 2005 will result in increased standards and tax credits on efficient products, all of which will advance efficiency goals. IECG does not support an increase in the assessment, rather, they voice support for reallocation of the existing funds.

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[12] The Commission's investigation in Docket 2002-162 determined the current 1.5 mil assessment level captures only a fraction of the achievable economic potential for energy efficiency savings. *Order On Conservation Program Funding,* Docket 2002-162 (April 4, 2003).

[13] The projected budget for efficiency programs is $13.1 million for fiscal year 2007. At current assessment levels, the budget is projected to grow to $16.4 million by 2010 due to the payoff of Power Partners expenses, the graduated increase in assessment for consumers who are not yet paying the full 1.5 mil rate, and the expected increases in sales.

Regarding the issue of raising the mil rate back to the full 1.5 to account for the 0.05 deduction to fund the solar program, IECG and BHE did not support this idea. On the contrary, the environmental and efficiency groups and the OPA all supported raising the level back to the full 1.5 mil rate if the solar rebate program expires.

NRCM, Environment Northeast, Environment Maine, NEEP, and OPA all support an increase in the assessment level, noting that Maine's funding of energy efficiency is the lowest in New England.

Section 4.A.3 asked if the Commission recommends an increase to the assessment level, should the increase be introduced gradually to correspond with ramp up in activity for new programs? If so, at what rate should the assessment escalate?

Responses to this question, although varying in specific amounts and timelines, uniformly support a gradual phase in of increased assessments if the Legislature were to authorize an increase in the assessment level. Although BHE and MPS were not supportive of an increase in the assessment level overall, they both stated that any increase be phased in gradually, at a rate of approximately 0.2 mils per year or approximately $2 million per year as agreed to by the Commission previously in Docket 2002-162. NRCM supported a more accelerated increase in assessment levels, increasing to 1.75 mils to eventually 3.0 mils in two to three years.

4.B. <u>Targeted Spending</u>

Question 4.B.1 asked whether if the Commission recommends an increase in the assessment, should the existing spending allocations remain the same. As currently written, section 3211-A (2)(B) requires the Commission to target at least 20% of available funds to low income customers and at least 20% to small business customers.

Responses to the question were mixed, with the majority in support of maintaining the existing arrangement. BHE, CMP, and Maine State Housing Authority (MSHA) all supported a continuation of the current allocation requirements. OPA stated that the current allocation should be maintained and consideration given to an increase. OPA noted that on a per capita basis, the set-aside for low income customers in Maine is lower than required funding allocations for efficiency spending in Vermont or Massachusetts. IECG did not support a continuation of the automatic allocation.

Question 4.B.2 referred to Section 7 of the Act that directs the Commission to "consider using funds resulting from any increased assessments to increase the per-business incentive cap imposed on large businesses under the business program. . .." The Commission sought input on how to interpret this directive and whether this negates the mandated 20% allocation to low income and small business customers.

Response to this question was divided as well, with the majority (BHE, MSHA, and OPA) supporting the interpretation that if the assessment is increased, the 20% allocations should remain intact. On the contrary, IECG stated an opinion that if the assessment is increased, the 20% allocations should be capped at the 1.5 mil rate funding level, and additional funds used for increasing the business caps.

In question 4.B.3 the Commission explained how the current low income residential program effort is directed at customers who meet 150% of the federal poverty guidelines and qualify for LIHEAP. The Commission asked if it makes sense to continue an automatic allocation of 20% of the conservation fund to this class in light of the limited opportunities for electric savings in residential dwellings in Maine?

BHE, MSHA, and OPA all supported the continued 20% allocation. OPA stated that the Commission's guidelines for low-income eligibility do not need to correspond with the federal poverty guidelines, citing both Vermont and Long Island, NY as locations that have more generous income eligibility guidelines. Additionally, OPA expressed support for an expansion of the electrical end-uses targeted by the program.

IECG does not support a continuation of the automatic 20% allocation, rather, they state their preference for investment of efficiency funds that will maximize cost-effectiveness.

Table 1 below shows that Efficiency Maine's funding level of 1.5 mils is the lowest in New England, additionally, efficiency spending as a percent of electric sales revenue is also the lowest in New England at 2.02%.

Table 1: Comparison of 2006 New England Energy Efficiency Program Budgets

State	2006 Electric Efficiency Budget (Millions)	Mills per KWh	Efficiency Budget as Percent of Electric Sales Revenues
Connecticut	$56.8	3.0	3.30%
New Hampshire	$17.8	1.8	2.91%
Massachusetts	$122.5	2.5	2.81%
Vermont	$16.4	2.8	2.40%
Rhode Island	$21.0	2.0	2.21%
Maine	$11.9	1.5	2.02%
AVERAGE	**$41.1**	**2.3**	**2.60%**

Notes:

Budget estimates as reported by CEE 2006 research http://www.cee1.org/ee-pe/06_elec.pdf

Mills per kWh as reported by previous NEEP research. 2006. Source. Jim O'Reily, NEEP.

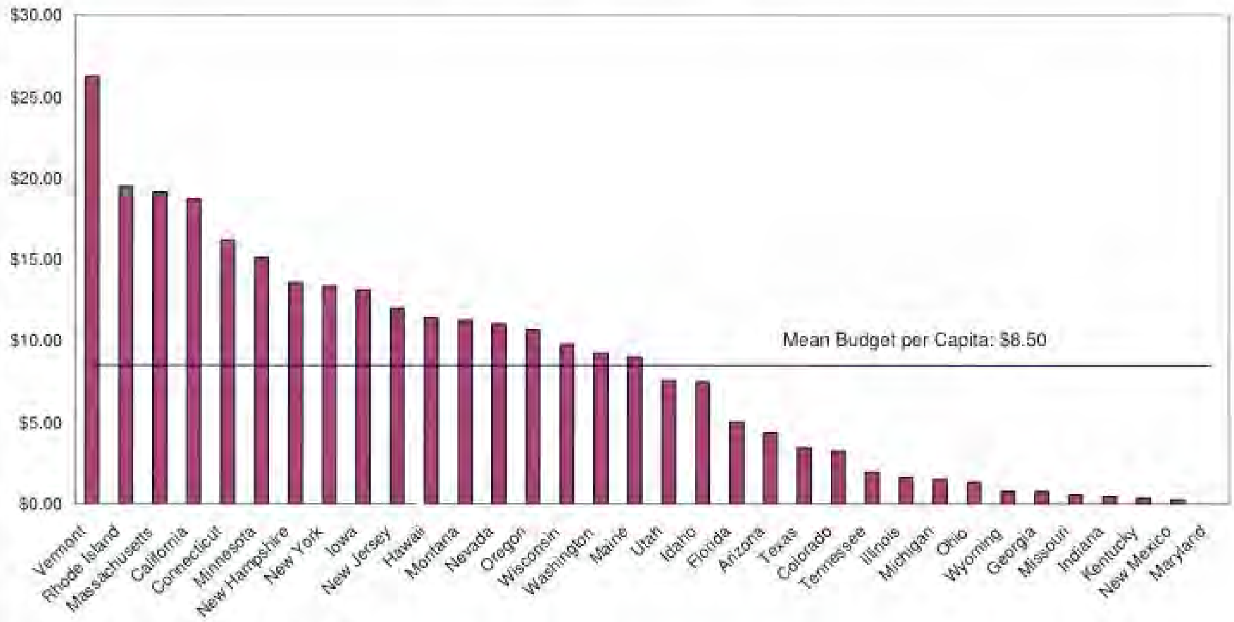
Percent of electric sales revenue based on ACEEE research, December, 2005.. http://aceee.org/briefs/mktabl.htm

As shown in figure 1 below, Maine ranks 17th nationally in levels of funding at approximately $8.25 annually per capita. This information was provided by in a recent review by the Consortium for Energy Efficiency (CEE).[14]

[14] Further information, on the comparative spending levels by states on energy efficiency is available in CEE's 2006 review of energy efficiency programs. http://www.cee1.org/ee-pe/cee_budget_report.pdf

Figure 1

Figure 1: Estimated Per Capita Budgets for Electric Energy-Efficiency Programs
for All 34 States with Energy-Efficiency Programs
(Excludes Load Management Programs)



For sources see Table 4: Estimated 2006 Energy-Efficiency Budgets for Gas Programs, by State and Sector. Table 1: Annual Estimates of the Population for the United States and States, and for Puerto Rico: April 1, 2000 to July 1, 2005 (NST-EST2005-01). Population Division, U.S. Census Bureau. December 22, 2005. http://www.census.gov/popest/states/NST-ann-est.html

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OPA states in their 2002 efficiency potential study, the remaining economically achievable potential for energy efficiency in Maine would support a tripling of the assessment level. They continue that Vermont regulators decided in 2006 to increase Efficiency Vermont's funding level by 75% to a total of $31 million/yr. OPA notes that even increasing Efficiency Maine's budget to $30 million/year represents capturing only approximately 33% of the economically achievable potential. NRCM supports a doubling of the assessment rate based on economic grounds of procuring the least cost electricity supply resource through efficiency, and propose a gradual increase in the assessment level from the existing 1.5 mils to 3.0 mils over a two-three year time period.

Environment Northeast commented that the state should set as a policy goal an objective to capture all cost-effective energy efficiency and demand reduction resources, and as such, budgets should be set according to this policy goal. Environment Northeast also notes that based on the results of the OPA potential study in 2002, to capture the maximum achievable economic potential funding should be more at the level of $70 million/yr over a ten year time period. They conclude by stating that the current 1.5 mil rate should be sufficient if the anticipated future funding streams from the FCM payments, proceeds from the auction of Regional Greenhouse Gas Initiative (RGGI) allowances, and any new rate-based investment ordered by the PUC is directed toward energy efficiency. However, if these future funding streams are not forthcoming in a timely manner and do not approach the levels required to obtain maximum achievable potential, then the SBC mil rate of 1.5 should be raised.

NEEP suggests raising the SBC rate to a minimum level of 2.5 mils and further integrated energy efficiency into the standard offer supply as part of a wider portfolio of programs managed by Efficiency Maine.

As detailed in Table 2, the findings from the OPA's 2002 study on the achievable potential for electrical energy efficiency in Maine found the potential economically achievable lifetime savings over a 10 year investment cycle to be over 74 million MWh representing a forecasted 36.7 million metric tons of avoided carbon dioxide (CO_2) emissions.[15] The OPA study projected that a total investment of $713 million over ten years (or approximately $71 million/yr on average in 2003 dollars) would result in a net economic benefit of approximately $549 million, with an overall benefit-cost ratio of 1.77.

[15] Source: The Achievable Potential for Electric Efficiency Savings in Maine. Prepared for the Maine Public Advocate by Optimal Energy Inc. & Vermont Energy Investment Corp. October 22, 2002

Table 2. Maine's Maximum Achievable Electrical Energy Efficiency Potential Over 10 Years (2003-2012)

Sector	Benefits	Costs	Net Benefits	Benefit-Cost Ratio	Lifetime MWh Savings	Lifetime Metric Tons Carbon Savings
Residential						
New Construction	$61,212,000	$42,023,000	$19,188,000	1.46	828,582	414,178
Efficient Products	$246,704,000	$160,647,000	$86,058,000	1.54	10,647,480	5,322,291
Low Income	$35,694,000	$29,046,000	$6,648,000	1.23	2,428,100	1,213,720
Subtotal Residential	**$343,610,000**	**$231,716,000**	**$111,894,000**	**1.48**	**13,904,162**	**6,950,189**
Commercial/Industrial						
New Construction	$120,177,000	$94,174,000	$26,030,000	1.28	8,175,585	4,086,680
Equipment Replacement	$127,894,000	$57,499,000	$70,395,000	2.22	7,592,020	3,794,977
Retrofit	$671,467,000	$330,470,000	$340,997,000	2.03	43,814,833	21,901,454
Subtotal C&I	**$919,538,000**	**$482,116,000**	**$437,422,000**	**1.91**	**59,582,439**	**29,783,111**
Total	**$1,263,147,000**	**$713,832,000**	**$549,316,000**	**1.77**	**73,486,601**	**36,733,300**

Lifetime MWhs and CO_2 savings based on an average 10 year measure life and 2004 ISO-NE Marginal Emission Estimates. Dollar values are based on societal present worth discounted to 2003 dollars.

Source: The Achievable Potential for Electric Efficiency Savings in Maine. Prepared for the Maine Public Advocate by Optimal Energy Inc. & Vermont Energy Investment Corp. October 22, 2002

To respond to the legislature's directive to provide a plan for how increased funds should be used, the Commission sought input regarding additional conservation programs it should consider implementing. It requested that proposals for any new programs reflect the goals, objectives, and strategies as revised by the January 18 Order in Docket No. 2005-446 and include demand reduction as well as conservation programs.

Central Maine Power Company recommended shifting funds from existing programs to load control and water heater wrapping. CMP also recommended that no new programs be added.

BHE commented that enhanced new residential construction needs are being met by Maine's Model Building Energy Code as such, a RNC program is not needed.

The Office of Public Advocate, Natural Resources Council of Maine, and the Northeast Energy Efficiency Partnerships recommended that the Commission add a Residential New Construction program to the menu of programs offered. NRCM recommends an expansion of incentives beyond efficient lighting to residential customers. OPA requests a small business direct install lighting program. OPA also suggests a significant re-orientation of Efficiency Maine's programs to focus on "lost opportunities", that being, positioning Efficiency Maine to influence the purchasing decision during new construction or equipment end of life replacement so that the efficient technologies are installed. OPA suggests with increased funding the efficiency potential present in the reservoir of retro-fit projects could be tapped. The Industrial Energy Consumers Group recommends implementation of a bid-for-savings program similar to CMP's former Power Partners program.

In Section 3, of the Notice of Inquiry, the Commission inquired whether there are particular products that increase consumer electrical efficiency or reduce their electrical demand not currently eligible for incentives which should be included under the program. Docket participants were requested to detail the type of product, incremental costs, energy and demand savings, product lifetime, and current market share of the efficient product. Additionally, the Commission was interested in learning about the market potential, anticipated natural market adoption rate, and current and projected future number of manufacturers. Finally, the Commission was interested in learning if any of the new proposed products would require a change in the current program management contractor oversight model.

CMP did not support the introduction of paying an incentive for any new products. OPA submitted a long and detailed list of numerous residential and commercial products that addressed specifically the questions asked by the Commission.

In terms of how increased levels of funding could be used, the Commission presented three different funding scenarios detailing in broad terms how the Commission might invest additional resources and the projected results if the Legislature decided to increase efficiency investments. Each table details the amount forecasted to be invested by program, projected budget share, annual and lifetime MWh savings, and projected economic benefits and metric tons of avoided CO_2 emissions.[16] The Commission has accepted the recommendations of all parties for additional programs, and with the exception of a bid for savings program, intends to implement each within currently projected budgets. Expanded budgets will allow additional products and services and more comprehensive program treatments. At its current budget level, the Commission will raise the cap on incentives for large projects as discussed in Appendix C. Should the budget increase further, the Commission would again raise the incentive cap. If the budget is expanded to 2.5 mils, or about $25 million per year, we believe there would be enough funding available to implement a

[16] In all three funding scenarios, estimates were derived from a straight line extrapolation of the results from Efficiency Maine's 2006 Annual Report and adjusted based on the proportional increase in funding by program areas. Savings for proposed new program areas such as business new construction and bid for savings programs are based on the results from the 2006 Efficiency Maine business program. Additionally, projected savings for residential new construction and home performance are based on Efficiency Vermont's 2004 Annual Report savings estimates, and scaled again proportionate to the varying levels of funding.

meaningful bid for savings program as recommended by IECG. The scenarios below do not include any allocations directed to demand response initiatives, as recommended by CMP as we believe further analysis is necessary prior to making any recommendation.

Table 3 below presents the actual funding levels and results from Efficiency Maine's 2006 Annual report. In 2006, at a funding level of 1.5 mils, Efficiency Maine invested \$9.2 million in the Efficiency Maine programs, resulting in 74,759 MWh savings, with a lifetime net economic benefit of \$54 million and 344,283 metric tons of avoided CO_2 emissions.

Table 3: 2006 Annual Budget of \$9.2 million (1.5 mil rate)

Program	Annual Budget (Millions)	Percent	Annual MWh Savings	Lifetime MWh Savings	Lifetime Net Economic Benefits (Millions)	Lifetime CO2 Reductions (Metric Tons)
Business New Construction	n/a	n/a	n/a	n/a	n/a	n/a
Business Existing Facilities	\$4.2	45.5%	23,094	321,434	\$23.1	160,673
Business Bid for Savings	n/a	n/a	n/a	n/a	n/a	n/a
Efficient Products	\$2.3	25.1%	39,047	296,760	\$23.1	148,340
Low Income	\$2.0	21.2%	5,934	37,141	\$2.7	18,565
Building Operator Training	\$0.1	1.4%	6,684	33,418	\$4.9	16,704
High Performance Schools	\$0.1	1.3%	n/a	n/a	n/a	n/a
Residential New Construction	n/a	n/a	n/a	n/a	n/a	n/a
Home Performance	n/a	n/a	n/a	n/a	n/a	n/a
Education and Training	\$0.2	1.8%	n/a	n/a	n/a	n/a
Other Evaluation & Research	\$0.3	3.8%	n/a	n/a	n/a	n/a
TOTAL	\$9.2	100.0%	74,759	688,753	\$54	344,283

As demonstrated in Table 4, a 33% increase in the assessment rate to 2.0 mils would result in annual budget of approximately $20 million dollars per year. We project this would yield 131,433 MWh savings, with a lifetime net economic benefit of $103 million and 665,648 metric tons of avoided CO_2 emissions. The Commission believes at a funding level of $20 million per year, insufficient resources are available to fund a bid for savings type program targeted for large commercial and industrial customers.

Table 4: Annual Budget of $20 million (33% increase to 2.0 mil rate)

Program	Annual Budget (Millions)	Percent	Annual MWh Savings	Lifetime MWh Savings	Lifetime Net Economic Benefits (Millions)	Lifetime CO2 Reductions (Metric Tons)
Business New Construction	$4.0	20.0%	22,009	306,330	$22.1	153,124
Business Existing Facilities	$5.7	28.5%	31,363	436,521	$31.4	218,201
Business Bid for Savings	$0.0	0.0%	n/a	n/a	n/a	n/a
Efficient Products	$3.4	17.0%	57,401	436,250	$34.0	218,066
Low Income	$4.0	20.0%	12,150	76,043	$5.6	38,011
Building Operator Training	$0.1	0.5%	5,202	26,009	$3.8	13,001
High Performance Schools	$0.4	2.0%	2,201	30,633	$2.2	15,312
Residential New Construction	$1.5	7.5%	830	14,904	$2.8	7,450
Home Performance	$0.5	2.5%	277	4,968	$0.9	2,483
Education and Training	$0.2	1.0%	n/a	n/a	n/a	n/a
Evaluation & Research	$0.2	1.0%	n/a	n/a	n/a	n/a
TOTAL	**$20.0**	**100.0%**	**131,433**	**1,331,659**	**$103**	**665,648**

In Table 5, a 66% increase in the existing assessment rate to 2.5 mils would result in annual budget of approximately $25 million dollars per year. We project this would yield 165,597 MWh savings, with a lifetime net economic benefit of $130 million and 841,010 metric tons of avoided CO_2 emissions.

Table 5: Annual Budget of $25 million (66% increase to 2.5 mil rate)

Program	Annual Budget (Millions)	Percent	Annual MWh Savings	Lifetime MWh Savings	Lifetime Net Economic Benefits (Millions)	Lifetime CO2 Reductions (Metric Tons)
Business New Construction	$4.5	18.0%	24,760	344,622	$24.8	172,264
Business Existing Facilities	$5.5	22.0%	30,262	421,204	$30.3	210,545
Business Bid for Savings	$2.5	10.0%	13,756	191,457	$13.8	95,702
Efficient Products	$4.3	17.0%	71,752	545,313	$42.5	272,582
Low Income	$5.0	20.0%	15,187	95,054	$7.0	47,514
Building Operator Training	$0.1	0.5%	6,502	32,511	$4.8	16,251
High Performance Schools	$0.4	1.5%	2,063	28,718	$2.1	14,355
Residential New Construction	$1.8	7.0%	969	17,388	$3.2	8,692
Home Performance	$0.6	2.5%	346	6,210	$1.2	3,104
Education and Training	$0.2	0.8%	n/a	n/a	n/a	n/a
Evaluation & Research	$0.2	0.8%	n/a	n/a	n/a	n/a
TOTAL	**$25.0**	**100%**	**165,597**	**1,682,478**	**$130**	**841,010**

In Table 6, a 100% increase in the existing assessment rate to 3.0 mils would result in annual budget of approximately $30 million dollars per year. We project this would yield annually 203,210 MWh savings, with a lifetime net economic benefit of $157 million and over 1 million metric tons of avoided CO_2 emissions.

Table 6: Annual Budget of $30 million (100% increase to 3.0 mil rate)

Program	Annual Budget (Millions)	Percent	Annual MWh Savings	Lifetime MWh Savings	Lifetime Net Economic Benefits (Millions)	Lifetime CO2 Reductions (Metric Tons)
Business New Construction	$5.1	17.0%	28,061	390,571	$28.1	195,233
Business Existing Facilities	$4.5	15.0%	24,760	344,622	$24.8	172,264
Business Bid for Savings	$5.0	16.5%	27,236	379,084	$27.3	189,490
Efficient Products	$5.7	19.0%	96,232	731,361	$57.0	365,581
Low Income	$6.0	20.0%	18,225	114,065	$8.4	57,017
Building Operator Training	$0.1	0.3%	3,901	19,506	$2.9	9,751
High Performance Schools	$0.6	2.0%	3,301	45,950	$3.3	22,969
Residential New Construction	$2.0	6.5%	1,080	19,376	$3.6	9,685
Home Performance	$0.7	2.5%	414	7,422	$1.4	3,710
Education and Training	$0.2	0.5%	n/a	n/a	n/a	n/a
Evaluation & Research	$0.2	0.8%	n/a	n/a	n/a	n/a
TOTAL	**$30.0**	**100.0%**	**203,210**	**2,051,957**	**$157**	**1,025,699**

Section 4.A.3 asked if the Commission recommends an increase to the assessment level, should the increase be introduced gradually to correspond with ramp up in activity for new programs? If so, at what rate should the assessment escalate?

Responses to this question, although varying in specific amounts and timelines, uniformly support a gradual phase in of increased assessments if the Legislature were to authorize an increase in the assessment level. Although BHE and MPS were not supportive of an increase in the assessment level overall, they both stated that any increase be phased in gradually, at a rate of approximately 0.2 mils per year or approximately $2 million per year as agreed to by the Commission previously in Docket 2002-162. NRCM supported a more accelerated increase in assessment levels, increasing to 1.75 mils to eventually 3.0 mils in two to three years.

In section 2.D. of the Notice of Inquiry, the Commission requested input on MPUC program staffing levels for oversight of the Efficiency Maine contract. The current Commission staffing level for administration of Efficiency Maine programs is limited by statute to five full time equivalent (FTE) staff positions. Program implementation is accomplished through oversight of hired implementation contractors. The Commission inquired whether five FTEs was the appropriate number of staff for program management. Additionally, the Commission inquired if any new programs being proposed could be implemented through the same contractor oversight model or would they require more direct MPUC implementation. Finally, the Commission asked what would be the appropriate number of contracts for each employee to manage.

Responses to this question were provided by the Natural Resources Council of Maine and the Office of Public Advocate. Both organizations expressed non-specific support for an expansion of staffing, noting that the current staffing levels are inadequate. Aside from these general comments, no specific suggestions were provided to the questions requested by the Commission.

In question 2.D.2 the Commission inquired if the proposed programs relied more on the direct delivery of the program by Commission staff, what the number of individuals required to effectively deliver the program might be.

Except for the OPA comment that a residential new construction program would require an additional FTE, no comments were received in response to this question.

As part of the February 2nd, 2007 Procedural Order, the Commission released for comment a staffing plan that compared current PUC Efficiency Maine staff and a projected staffing level at an illustrative funding level of $30 million per year for comment. Comments on this staffing table were submitted by NRCM who stated that the proposed 17 FTEs at a $30 million/year budget may be high. NRCM suggested that a staffing level in the range of 15 FTEs would be more appropriate. NRCM and NEEP requested further definition of the specific positions and functions that would be handled by “coordinators”, “managers”, and “directors”. Additionally, NEEP advocated that the “energy analyst” position be responsible for market research and evaluation activities

APPENDIX E:
PRIOR RECOMMENDATIONS

In Section 2.E. of the Notice of Inquiry, the Commission revisited several items that were addressed in previous Docket proceedings. In the January 18th Order in Docket No. 2005-446 , the Commission decided it would place a greater emphasis on the technical assistance component of the business program. As currently structured, the business program can provide technical assistance studies on a shared cost basis with the customers. Those studies are generally use-specific, not comprehensive energy audits. Question 2.E.1 of this proceeding asked whether the Commission should expand the availability of energy audits. If so, should audits of different levels of sophistication be provided?

North Atlantic Energy Advisors and ERS commented that audits, by themselves, result in little action while Bangor Hydro-Electric and MPS support an expanded use of in-field and on-line audits.

In question 2.E.2 the Commission sought comment on the likely annual cost of running a residential new construction program (RNC).

OPA reported that the estimated cost for running an RNC program would be $600,000 in the first year, ramping up to $2.0 million/year after five years.

In question 2.E.3 the Commission inquired whether there is support for an expansion of funding for the whole house efficiency program, and if so what level of funding would be appropriate for a Maine-based program.

Currently, the Maine Home Performance with ENERGY STAR program (HPWES), administered by the Office of Energy Independence and Security (OEIS), receives $150,000 per year in support from Efficiency Maine. Efficiency Maine is currently supporting this program during the pilot phase period which ends in December 2009. The HPWES program also receives funding from Maine State Housing Authority and a U.S. Department of Energy grant.

NRCM supported continuation of the current funding level, while OPA supported a gradual increase in funding and a merger of the program into the Efficiency Maine portfolio of programs. BHE had no comment on the program except to state that cost-effectiveness should be the metric to evaluate the basis for increased program funding. OEIS submitted comments expressing support for increased funding for the program and noted that calculating the benefit-cost of a program of this type needs to take into account the additional non-energy benefits of this initiative including improved indoor air quality, comfort, and safety. OEIS additionally gives support to the need to more fully integrate the promotion of electrical energy efficiency with fossil fuel efficiency, especially in the context of the growing need to address global warming.

APPENDIX F:
OTHER QUESTIONS

At the public hearing on February 2, 2007, Chairman Adams introduced several additional questions, and submitted them as a Procedural Order on February 2, 2007 and invited comment.

Question 5.A.1: Should the Commission stop funding efficiency programs through the imposition of a system benefits charge on all kWh sold and instead reflect Efficiency Maine assessment costs only in distribution rates (whether by a kWh charge or simply as a cost built into rates). In other words, design rates so that transmission level customers do not pay any Efficiency Maine costs, and transmission-level customers are not allowed to participate in any Efficiency Maine programs?

CMP and NEEP took no position on this question. NEEP recommends caution however, in making such transitions to ensure that sufficient funding for small business and low income customer programs is preserved. NEEP also cautions it is important to maintain measurement and verification protocols for large customer self directed programs. While not opposed to the proposal, OPA cautions that the removal of transmission customer load from the assessment would result in an increase to rates of non-transmission customers. OPA also recommends further research into alternative delivery mechanisms such as an “Energy Savings Account Program” should be conducted before making a final decision. NRCM recommended an alternative way to ensure greater equity for transmission customers might be to raise the incentive cap. Environment Northeast, NRCM and Environment Maine were opposed to exempting transmission level customers, pointing out that energy savings from smaller customers provide indirect benefit to large customers, and large customer efficiency projects provide indirect benefit to smaller customers as well. Madison Paper Industries recommends exempting transmission level customers from both participation and funding in the efficiency programs and supports this idea.

Question 5.A.2: Should the Commission implement separate Efficiency Maine programs for transmission-level and distribution customers, and recover costs of each of those programs through separate assessments on transmission customers and distribution customers?

Neutral responses to this question were received from both OPA and NEEP, with both organizations recommending design changes that would allow larger customers greater program design flexibility while maintaining accountability for energy savings. Environment Northeast, Environment Maine, and NRCM were all opposed to the development of a separate transmission level customer fund citing issues of program parity. So long as they are required to continue contributing to the efficiency programs, Central Maine Power Company believes the existing methodology is fair and opposes separate assessment mechanisms for transmission level customers. Madison Paper also does not support the idea of creating a separate fund for transmission level customers.

Question 5.A.3: Should any T&D utilities' incentive rate mechanisms be designed to mitigate or even eliminate any disincentive for the T&D to encourage conservation and to reduce its incentive to sell more kWh, and if yes, how should the rate plan be designed (e.g. through sales forecasts, revenue and profit decoupling mechanisms)?

With the exception of OPA, which remained neutral, all parties favored further Commission examination of this issue. While not opposed to the concept, OPA points out that the current rate mechanisms used for Maine's investor-owned utilities do not coexist easily with revenue neutral efficiency schemes. OPA recommends including the issue for examination in BHE's on going rate case and in CMPs impending rate case. Other parties were in favor of the concept, with CMP and Environment Northeast both proposing sales adjustment clauses to factor in and compensate for efficiency program related revenue losses.

Question 5.B1: Proposed a structure for the creation of an Efficiency Maine Advisory Council. Please comment generally on the desirability of an Advisory Council, and specifically on the composition and activities described in Appendix No. 1.

Comments on the idea of establishing an Efficiency Maine Advisory Council were well received by OPA, NEEP, NRCM, Environment Northeast, and Environment Maine. No docket participant spoke in opposition to this proposal. NEEP and Environment Northeast made reference to similar advisory councils established in Connecticut, Rhode Island, and Massachusetts, and advocated using a small amount of conservation funds to hire expert third- party technical consultants to serve on the Advisory Council to help ensure excellence in program design and delivery. Environment Northeast further commented that Advisory Committees in other states take votes on program design plans and suggests that these non-binding votes be used in Maine to help inform the PUC on the sentiment of the Advisory Council. NRCM and Environment Northeast both agreed that utility representatives should not be on the Advisory Council.

Synapse
Energy Economics, Inc.

Increasing Demand Response in Maine

January 4, 2008

AUTHORS

Rick Hornby, Chris James, Kenji Takahashi,
Dr. David White

Prepared for

Staff of the Maine Public Utilities Commission

22 Pearl Street
Cambridge, MA 02139

www.synapse-energy.com
617.661.3248

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1. Executive Summary

A. Introduction

This report was prepared in response to a request by Staff of the Maine Public Utilities Commission for an estimate of the potential for incremental demand response (DR) in Maine. It is limited to DR that customers agree to, or make, voluntarily in response to some form of economic incentive. The report provides an estimate based upon a review of DR in Maine under current policies, a review of the literature on DR potential under alternative policies in other jurisdictions, and an assessment of the applicability of those alternative policies to Maine. Many of our analyses of electricity use in Maine are based upon data from Central Maine Power (CMP), whose customers accounted for over 70 percent of the electric energy consumption in the state in 2006.

The report is organized as follows:

- Chapter 1 provides an overview of Demand Response, including its potential benefits, major policies for encouraging DR, and the costs associated with those policies;
- Chapter 2 describes the quantity of DR in Maine under current policies, and compares it to the potential identified in other states;
- Chapter 3 presents our analysis of the potential for incremental DR in Maine, and the potential economic benefits of achieving that potential;
- Chapter 4 discusses steps for achieving incremental DR in Maine.

B. Conclusions

The major conclusions from our review are as follows.

Maine is achieving high levels of DR under current policies and programs. When measured relative to its peak demand, Maine currently has the highest level of participation of any New England state in ISO-New England's existing DR programs. Maine is expected to maintain that lead position under the ISO-New England forward capacity market (FCM), scheduled to begin June 2010. The quantity of DR in Maine in year one of the FCM is expected to represent approximately 17.8% of the ISO-NE forecast of peak demand for Maine in 2010. At that level, Maine would have one of the highest, if not the highest, levels of DR in the country. The vast majority of the DR that Maine is achieving under current policies is in the industrial, commercial, and institutional sectors.

The most promising source of incremental DR in Maine appears to be from energy efficiency programs, increases in appliance efficiency standards, and changes in building energy codes. Those measures could achieve incremental reductions in load in all sectors, including residential and small commercial in the order of 1 to 2 % of total peak demand. Moreover, the reductions achieved through energy efficiency programs could increase or accumulate over time, as each year a new set of customers participates in these programs.

Energy efficiency, increases in appliance standards, and changes in building energy codes appear to be the most cost-effective sources for achieving incremental DR because they require little or no incremental investment in enabling technologies to communicate time-differentiated price signals, record and report time-differentiated usage, and process that time-differentiated usage data. The potential for capturing substantial incremental DR from other types of programs, such as time-differentiated rates, appears to be limited, particularly for low usage customers in the residential and small commercial sectors. The costs of implementing those types of programs may not be offset by the resulting reductions in customer bills and other benefits. The economics and potential of direct load control and time-differentiated pricing DR programs requires further detailed analysis on a sector-by-sector basis.

DR has the potential to provide economic benefits in the form of lower market prices for capacity and lower electric energy prices in Real-Time and Day-Ahead markets. The magnitude of those benefits will vary according to the magnitude and profile of the load reductions by DR program. The portion of those benefits received by retail customers will depend on their supply arrangements.

2. Background Regarding Demand Response

The basic goal of demand response is to reduce load during periods of peak demand. The value, or benefits, of DR will vary according to the supply/demand situation in peak periods. If there is ample supply the value may be low. However, if supply is tight, or projected to be tight, the value could be quite high. For example, the value of DR may be high for reasons of

- long-term economics, e.g., to avoid costs associated with investments in expansions of generation, transmission, and/or distribution capacity;
- near-term reliability, e.g., to avoid a curtailment; or
- near-term economics, e.g., to avoid spikes in hourly electric energy prices in the wholesale daily spot market.

Demand response is not a new topic in the electric industry. There is a long history of utilities in vertically integrated, regulated markets encouraging demand response to achieve those reliability and economic objectives. That history includes offering special rates for customers willing to be interrupted during peak periods and offering time-differentiated rates such as time-of-use rates and real-time pricing to provide customers with an accurate price signal to guide their decisions regarding the value of consuming electricity in various time periods. For example, CMP offered direct load control programs and time-of-use rates throughout the 1990s.

What is new is the resurgence of interest in DR over the past several years. Driving factors have included advances in communication and load control technologies. However, the dominant driver has been the deregulation of wholesale electricity markets and the corresponding restructuring of retail electricity markets in many states.

New England states, with the exception of Vermont, restructured their retail electricity markets in the late 1990s. Under that new structure, generation was unbundled from transmission and distribution. Utilities in each state were limited to providing distribution service. Generation was to be provided by wholesale suppliers at prices set by competition in wholesale electricity markets. Each state established a "basic" or "standard offer" default electricity supply service for retail customers who did not migrate to competitive Load Serving Entities. The electric energy and capacity for that supply service was acquired from the wholesale electricity market through periodic requests for bids.

ISO-New England (ISO-NE) was created to oversee the operation of wholesale spot electricity market in New England, consisting of a Day Ahead Market and a Real Time Market. ISO-NE was also responsible for ensuring reliable service by ensuring sufficient installed capacity is available to meet projected loads. Finally, ISO-NE plans for, and operates, the region's transmission system.

Policy makers and stakeholders soon recognized that, in addition to sellers, the successful operation of wholesale electric energy and capacity markets requires price-responsive buyers, such as the customers who participate in DR programs. Policy makers and stakeholders have developed a better understanding of the economic benefits of DR and of the keys to designing successful DR programs.

This Chapter begins by defining DR and then describes those benefits and program designs. This Chapter provides a general overview of the development and application of demand response (DR). Chapters 3 and 4 will discuss the application of specific DR policies in Maine.

A. Definition

It is important to begin with a clear statement of what we mean by DR for the purposes of this report. The definition of DR is important because it establishes the range of response options included in the estimation of the potential for DR.

DR can be defined as a "temporary" change in on-peak electric usage in response to a signal indicating a "…change in price, opportunity for payment, threat of penalty, or some other incentive."[1] That definition implicitly limits DR to changes to on-peak electric usage that customers agree to, or make, voluntarily in response to some type of economic signal. This excludes curtailments that customers are required to make in response to emergency situations, which is DR driven by reliability concerns. This definition is also narrow, as it excludes "permanent" changes in on-peak electric usage due to energy efficiency and/or permanent shifts in load from on-peak to off-peak.

For the purpose of this study, we define DR broadly to include options that result in either temporary or permanent changes in on-peak electric usage that customers make, or agree to, voluntarily in response to an economic signal. This broad definition is consistent with the range of DR options or resources that will be eligible to participate in the forward capacity market scheduled to begin operating in New England effective June 2010.

Policy makers and stakeholders in New England have evolved from defining DR narrowly to defining it more broadly. Following are two definitions of DR by key organizations, the

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[1] *California Demand Response Potential Study – Phase 1 (Draft)*, July 7, 2007, Heschong Mahone Group.

Federal Energy Regulatory Commission (FERC) and the Demand Response and Advanced Metering Coalition (DRAM), an industry group:

- FERC defines demand response as "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[2]
- DRAM defines DR as "the reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral."[3]

The FERC definition is broader in terms of the timeframe of the prices that might drive DR, i.e., "changes in the price of electricity over time," whereas DRAM focuses on prices that occur at peak periods. However, the FERC definition is narrower in terms of the range of factors that might drive DR, limiting them to prices and reliability whereas DRAM includes the ability to avoid infrastructure costs as a potential driver.

The view of DR in New England has evolved since 2000. The initial view was close to the DRAM definition, focusing on response options and programs that are applied only during peak periods and consist primarily of customer generation. ISO-NE and various state regulatory agencies implemented programs driven by concerns related to peak electricity demand, its growth, and the impacts on system reliability and economics. However, this view gradually broadened due to analyses provided by groups such as the New England Demand Response Initiative (NEDRI) who demonstrated that energy efficiency program reductions in peak periods should be included as DR resources in order to achieve the greatest economic and environmental benefits. As a result, New England has set an example of how demand response can be used effectively, how program design and implementation can benefit from stakeholder feedback, and how getting the economic signals correct is critical to a successful demand response program.

B. Potential Benefits

Demand response has the potential to provide direct and indirect economic benefits to electric customers. Electric customers who participate in DR programs receive the direct economic benefits while all electric customers receive the indirect economic benefits. These benefits are measured relative to the economic and environmental impacts that would occur in the absence of the DR. This section will focus on the benefits of DR in a deregulated wholesale electricity market and a state that has restructured its retail electricity market, as those are the conditions applicable to Maine.

[2] www.ferc.gov

[3] www.dramcoalition.org

Participant Benefits

The direct economic benefits to electric customers who participate in DR programs will vary according to the design of the program and the design of their rates for electricity service. In general, these benefits may include

- incentive payments for participating in the DR program;
- a reduction in the energy cost component of bills in the months of DR participation, reflecting the net saving due to reducing energy (kwh) use during high price periods in those months. (The net saving reflects the impact of any reductions achieved by shifting usage from high price periods to lower-price periods). This energy cost may reflect only generation energy costs or may include transmission and distribution system costs;
- a reduction in the capacity cost component (i.e., quantity times price) of monthly bills, assuming their participation in the DR program reduces the level of demand (kw) for which they are billed. This capacity cost may reflect only generation capacity costs or may include transmission and distribution system costs.

Economic Benefits

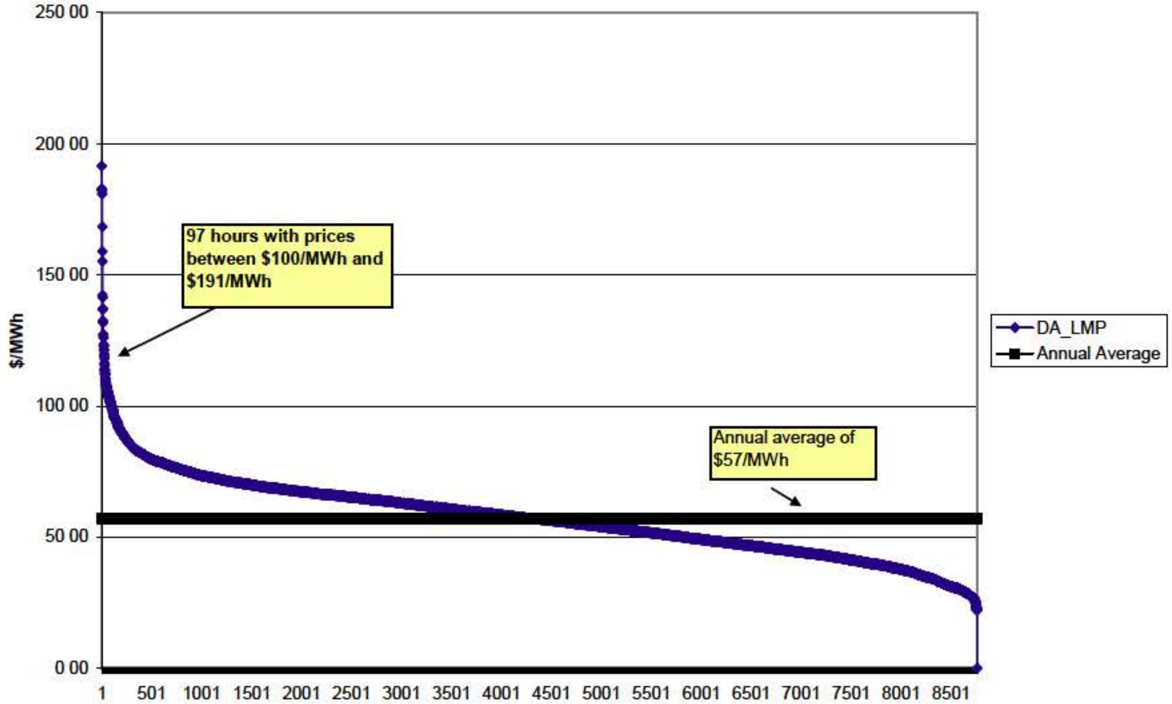
DR has the potential to provide two economic benefits to all electric customers. Those benefits are lower annual prices for capacity and lower electric energy prices in high-price hours. The magnitude of each of those benefits will vary according to the supply/demand situation in peak periods. If there is ample supply the value may be low. However, if supply is tight, or projected to be tight, the value could be quite high.

Capacity Prices. In the forward capacity market (FCM), the wholesale electric capacity market scheduled to start in New England in June 2010, the annual price will be set by the price of the marginal supplier. If sufficient DR is bid into that market, the resulting annual market price for capacity will be lower. Again, the timing and extent to which that reduction will translate into lower capacity prices for retail customers will vary according to their electricity supply contract.

In addition to reducing the price for generation capacity, reductions achieved through DR may reduce the cost of transmission and/or distribution capacity reflected in wholesale prices and retail rates by delaying investments in expansions or reducing the size of expansion and investment required.

Electric Energy Prices. In wholesale electric energy markets, the locational marginal price (LMP) in each hour is set by the price bid by the marginal supply. In these markets there are typically a limited number of hours, e.g. 100 hours or 1% of the time, in which customer demand peaks and LMPs spike to levels several times higher than the annual average. In some wholesale markets, hourly prices have spiked to as much as 5 to 10 times the annual average, e.g. $500/MWh or 50 cents/kwh versus $50/Mwh or 5 cents/kwh. However, in recent years price spikes in the New England wholesale market have been less extreme. For example, in 2006, the LMPs in the Maine zone of the Day Ahead Market in the highest 97 hours ranged between $100/MWh and $190/MWh as compared to an annual average of $57/MWh. The average of those highest 97 hours was $116/MWh or approximately twice the annual average. This LMP duration curve is presented in Figure 2.1.

Figure 2.1 – Hourly LMPs ($MWh) in Day Ahead Market – Maine 2006



In wholesale electric markets subject to such price spikes, a small reduction in demand during those highest price hours will result in a much lower market-clearing price. This much lower price is due to the fact that the supply curve is steep in those hours and a slightly lower demand can be met by a much less expensive marginal supply. Thus, DR, by reducing demand in high demand/high price hours, has the potential to reduce electric energy prices in those hours.

C. Potential for DR in Maine – Prospective Programs and Target Customers

DR, for the purposes of this report, includes options that result in either temporary or permanent changes in on-peak electric usage that customers voluntarily agree to, or make, in response to an economic signal. In order to estimate the potential for DR in Maine, according to that definition, it is important to understand the key characteristics of each customer class to which a DR program may be targeted and the key attributes of those prospective DR programs. Those characteristics and attributes will determine the cost-effectiveness of the programs from a customer perspective, and hence the willingness of customers in each rate class to participate in those programs.

Key Characteristics by Customer Class

There are two key characteristics of each customer class that will affect the cost-effectiveness of DR programs from a customer perspective. Those characteristics are electricity usage per customer and electricity supply arrangements.

Electricity usage per customer varies significantly by sector in Maine. As in most states, a relatively few large- and medium-use customers in the industrial, commercial and institutional sectors account for a disproportionate portion of peak demand, while hundreds of thousands of low use customers in the commercial and residential sectors account for the remainder. For example, in 2006, 0.1% of CMP customers accounted for 34.8% of the electric energy (MWh) and 29.4% of the peak demand (MW) on its system. That data is presented in Table 2.1

Table 2.1. Distribution of Customers and Electricity Usage, CMP, 2006[4]

Customer	# of Customers		Annual energy (MWh)	Peak Load Coincident with NEPOOL (MW)
CMP Small (<20 kw)	586,426	98.1%	43.8%	48.5%
CMP Medium (20kw – 400 kw)	11,011	1.8%	21.5%	22.1%
CMP Large (>400 kw)	428	0.1%	34.8%	29.4%
CMP Total	597,865	100%	100%	100%

This concentration of electricity usage tends to make DR much more cost-effective for large usage customers than for low usage customers. First, much of the necessary enabling technology is already being used to serve large and medium use customers, in particular interval meters and the software and hardware needed to process hourly usage data. This reduces the amount of investment in incremental enabling technology required to participate in DR programs. In contrast, small customers typically are being served with basic meters that do not have the capability to transmit or store hourly usage. Second, a dollar invested to enable one large use customer to participate in a DR program will typically produce a much greater reduction in peak demand than a dollar invested to enable one small use customer to participate in a DR program. The implications of this concentration in usage are illustrated in Table 2.2, based upon statistics for CMP in 2006.

4 Appendix C, Table 1

Table 2.2. Distribution of Customers and Electricity Usage, CMP, 2006[5]

Customer	Annual energy per customer (kwh)	Annual Peak Load Coincident with NEPOOL per customer (kw)
CMP Small	6, 593	1.3
CMP Medium	172,211	37.1
CMP Large	7,178,484	990.7
CMP Average	14, 777	2.7

The second key characteristic that will affect the cost-effectiveness of DR programs from a customer perspective is the electricity supply arrangement. Currently most large customers acquire their electricity supply through customized arrangements. Those customized arrangements allow them, or could be modified to allow them, to receive some or all of the economic benefits of any reduction in wholesale market prices for electric energy and/or capacity resulting from DR. In contrast, most small and medium customers currently acquire their electricity supply under Standard Offer Service (SOS), which in turn is acquired from suppliers at the fixed prices they bid in to the periodic auctions through which SOS suppliers are selected. Thus, Standard Offer Service prices should eventually reflect most, if not all, of any reduction in wholesale market prices for capacity resulting from DR. However, there will be a time lag between the point at which wholesale prices decline and when that decline is reflected in the bids submitted by bidders into the SOS auction. Those prices will also reflect a portion of the reduction in wholesale spot prices for electric energy expected to result from DR.

Prospective Programs

DR programs can be grouped into three broad categories, according to the nature of the response - permanent, dispatchable and discretionary.

- In the permanent category are programs and policies through which customers reduce their energy usage in all hours, including peak hours, through improvements in energy efficiency. These programs and policies include energy efficiency programs, improvements in appliance standards, and upgrades to building energy codes. The magnitude of such reductions in peak hours will vary according to the particular energy end use whose efficiency has been improved.
- In the dispatchable category are programs in which customers agree in advance to allow another party, such as their load serving entity or an energy service company, to control a specific portion of their load at certain times. These programs include dispatchable standby generation, direct load control, and curtailment contracts.

[5] ibid

- In the discretionary category are programs in which customers control their response to the economic signal in, or close to, real time. These programs typically involve some form of time-differentiated pricing, including time-of-use rates, critical peak pricing, or real time pricing.

Permanent and dispatchable programs tend to have the highest value as they provide a guaranteed level of DR and therefore can be treated as a firm resource for reliability planning purposes. In contrast, discretionary programs tend to not have an economic capacity cost benefit, as they do not provide a guaranteed level of DR and therefore cannot be treated as a firm resource for reliability planning purposes.

The range of enabling technologies required for DR programs relative to standard practice or business as usual is presented in Table 2.3. Every DR program will require some level of investment in an incremental technology. At a minimum the participating customer, or someone acting on his/her behalf, must make an investment of time and/or money in order to reduce load in peak periods. The maximum investment could include installation of incremental enabling technologies to:

- signal and display energy prices in peak hours;
- measure and record energy use in peak hours;
- process energy use data for peak hours; and
- control load in peak hours.

Permanent and dispatchable programs tend to have the lowest requirements for incremental enabling technologies, and thus the lowest incremental implementation cost.

Table 2.3 Enabling Technologies for DR Programs Relative to Standard Practice

	DR Provider			DR Participant	
Function	Signaling Energy Prices in peak periods	Metering and reporting energy usage in peak periods	Processing energy usage for peak periods	Display Energy Price Signals	Reducing Load
PERMANENT					
Ratepayer funded utility energy efficiency	No change	No change	No change	No change	Yes. Cost will vary according to load.
Appliance standards & Building Energy Codes	No change	No change	No change	No change	Yes. Cost will vary according to load.
DISPATCHABLE					
Ratepayer funded utility direct (remote) load control	No change for residential (Provider has the price signal, knows the capacity it can curtail, and has the necessary data processing capability). Additional metering may be required for C&I due to multiple, interacting loads.			No change	Yes. Cost will vary according to load.
DISCRETIONARY					
Time of use	No change	Yes. TOU meter or interval meter.	Little or no change	No	Yes. Cost will vary according to load.
Critical peak pricing (CPP) or Real time pricing (RTP)	Yes	Interval meter	Yes	Yes	Yes. Cost will vary according to load.

3. Current Demand Response in Maine

This Chapter describes the DR resources in Maine under current policies and programs. The only programs currently available to customers in Maine are operated by ISO-NE. The range and nature of those programs will change when ISO-NE implements the Forward Capacity Market, effective June 2010.

Maine has the highest level of participation in ISO-NE current programs, relative to its peak demand. Maine is expected to maintain that lead position under the FCM.

A. Participation in Current DR Programs

ISO-NE currently operates four DR programs, one in the Day Ahead (DA) Market and three in the Real Time (RT) Market. Key elements of these programs are summarized in Table 3.1

Of these four programs, two can be categorized as dispatchable and two as discretionary. ISO-NE refers to these categories as reliability and price, respectively.

Customers in Maine have a higher level of participation in these programs, as a percentage of the state's peak demand, than customers in other New England states. For example, as of August 1, 2007, ISO-NE reports that a total of 1,149 MW were enrolled in these programs.[6] The highest quantities were in the real-time 30 minute demand response and real-time price response programs, as indicated in Table 3.2. That table indicates that assets in Maine represented 199 MW, or 17%, of the total enrollment. It also indicates that this participation represented 10% of the state's 2007 peak demand forecast, much higher than the DR of the rest of the pool at 4% of their forecast peak demand.

All of these programs, except for the RT Demand Response 30-minute program, are scheduled to terminate when the FCM begins.

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[6] Demand Response Department, *ISO-New England Demand Response Working Group Meeting*, ISO-New England, August 1, 2007.

Table 3.1 Highlights of ISO-NE Existing Demand Response Programs[7]

	Reliability Programs	Price Programs	
Program Name	**Real Time Demand and Profiled Response**	**Real Time Price Response**	**Day-Ahead Option**
Notification	Notified by ISO Control Room of a regional reliability problem. Notification message received through Internet Based Communication System (IBCS)	Notified by ISO that wholesale prices are forecasted to exceed $0.10/kWh either the night before or during the event day.	If load reduction offer "clears" in the Day-Ahead Market, the customer is notified by their Enrolling Participant around 4:00p.m. the day before the load reduction is expected
Response Time	Within 30-Minutes or 2-Hours of ISO request. Customer must elect option when enrolling.	**Voluntary!** Customer decides when and for how long	Load reduction must occur during cleared hours
Energy Payment Rate and Terms	Greater of Real Time Price or Guaranteed Minimum$0.50/kWh for 30-Minute and$0.35/kWh for 2-Hour Response. *Guaranteed Minimum payment is$0.10/kWh for Profiled Response Program*	Greater of Real Time Price or Guaranteed Minimum of$0.10/kWh	Greater of the Offer Price or the Hourly Day-Ahead Market Price for each hour the Offer cleared.
Duration of Demand Response Event	Minimum 2-Hour guaranteed interruption	Price response "window" open as early as 7AM and remains open until 6PM.	Customer can specify a minimum interruption duration as part of their Offer
Monthly Capacity Payment ($/kW)	Payment based on ICAP Market Price or Transition Payment after 12/1/2006	No	Same as Real-Time Program
Metering Requirement	5-Minute Data via Internet Based Communication System (IBCS) *Hourly data can be used in the Profiled Response Program*	Hourly Data submitted either Daily or Monthly	Same as Real-Time Program

[7] http://www.iso-ne.com/genrtion_resrcs/dr/broch_tools/2006_summary_table.pdf

Table 3.2 – Demand Response under Existing ISO-NE Programs, Maine and Rest of Pool, 2007

	Maine	Rest of New England pool	Total
2007 Forecast Summer Peak (MW)	2,033 7.4%	25,327 93%	**27,360** 100%
DR Program Particpation (MW)			
Permanent			
On Peak	n/a	n/a	n/a
Seasonal Peak	n/a	n/a	n/a
Sub-Total	0	0	0
Dispatchable			
RT 2 hour	32	25.1	56.7
RT Profiled	11	5.9	16.9
RT 30 minute	156.1	826.3	982.4
Critical Peak	n/a	n/a	n/a
Sub-Total	199	857	1056
Discretionary			
RT Price	0	93.2	93.2
Day Ahead	0	0	0
Sub-Total	0	93	93
Total	199 17%	951 83%	1149 100%
Total DR as % of Peak Forecast	**9.8%**	3.8%	4.2%

B. Expected Participation in the FCM by Customers in Maine

In June 2010 a new framework for ensuring sufficient capacity, the Forward Capacity Market (FCM), will go into effect. Under the FCM, ISO-NE will set the price for capacity each year based upon the results of a Forward Capacity Auction (FCA). One of the major changes under the FCM will be the inclusion of energy efficiency programs as DR resources. Under this new framework both DR and generation resources will be eligible to bid into this market.

ISO-NE will accept five types of DR resources under the FCM, distinguished by the hours in which those resources perform. Of these, two can be categorized as permanent and three as dispatchable. Discretionary resources cannot bid into the FCM because ISO-NE cannot rely upon them to provide a guaranteed load reduction in specific hours. However, load serving entities will still have the opportunity to offer discretionary programs to their customers in order to achieve savings in energy costs in high price hours.

The two new resources in the permanent category are guaranteed load reductions in on-peak hours and seasonal peak hours respectively. On-peak hours are a pre-determined period, such as 1 p.m. to 5 p.m. on non-holiday weekdays. Seasonal hours are those in which load in the real time market exceeds 90% of the projected seasonal coincident peak. Customers who are accepted for these programs will be responsible for reducing their load in those hours by the quantity specified in their bids. It appears that these customers will accomplish this primarily through energy efficiency measures, based upon a review of the resources qualified to bid in the FCA for year 1 of the FCM.

The three new resources in the dispatchable category are guaranteed supply in RT Emergency Generation Event hours and guaranteed load reductions in RT Demand Response Event Hours and "critical peak hours." The RT Emergency Generation and RT Demand Response resource programs will both essentially be continuations of existing programs and will both require a 30-minute response. The critical peak hours consist of hours in which there is a shortage and hours in the Day Ahead market in which load is forecast to be greater than 95% of the projected seasonal coincident peak. Customers who are accepted for this program will be responsible for reducing their load by the quantity specified in their bid into the FCA. It appears that these customers will accomplish this primarily through load management and distributed generation.

Other key features of the FCM include:

- Resources will be procured via annual auctions three years in advance of requirement date.[8]
- Auctions will be operated on a declining cost basis, starting at a ceiling price equal to $180/kW-year, or twice the cost of new entry (CONE).[9] Bid resources and prices will be compared to ISO-NE's forecast of the quantity of capacity required. When the MW of resources bid exceeds the MW required, the auction price will decrease. The FCM will clear at a price that produces the MW of resources equal to the ISO forecast.
- All resources selected in the auction will be paid the price at which the forward capacity auction clears.[10] These prices are uncertain at the time of this writing, and will not be known until after the first auction. However, the price is generally expected to be less than CONE because the quantity of qualified existing resources exceeds the quantity of capacity required, perhaps in the order of $60 per kw-yr to $80/kw-yr.
- For at least the first three FCM years (June 2010 through May 2013), the price for capacity will be constrained between a minimum and a maximum equal to -40% and +40% of a reference price respectively. Since the reference price for the first FCM year has been set at $90/kW-yr or $7.50/kW-month, the minimum price in the first FCM will be $54/kW-yr or $4.50/kW-month.

The quantity of DR resources from Maine that have been qualified to participate in the FCA for year one of the FCM is, again, disproportionately high when measured as a percentage

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8 There are some minor variations to this during the phase-in period. For example, the first auction is scheduled for February 2008, and that will be for resources starting in the power year that begins June 1, 2010. The full three year forward look will be implemented by February 2013, for delivery in the June 2016 power year.

9 ISO-NE is using $90/kW-yr or $7.50/kW-month as CONE, reflecting the estimated cost of a new gas fired combustion turbine (CT).

10 This rule will not apply to RT emergency generation. NEPOOL market rules allow up to 600 MW equivalents for emergency generation. Qualified bids that exceed this quantity will be paid on a pro rata basis, compared to 600 MW, e.g. if 1000 MW of emergency generation are qualified, each MW will receive 0.6 of the cleared auction capacity price.

of peak demand. For example, as of November 7, 2007, ISO-NE reports that a total of 3,424 MW were qualified to bid in the FCA.[11] The highest quantities are, again, in the real-time 30 minute demand response and price response programs, as indicated in Table 3.3. That table indicates that assets in Maine represented 382 MW, or 11%, of the total enrollment. It also indicates that this participation represents 17.8% of the state's 2010 peak demand forecast, again much higher than the DR of the rest of the pool at 11.4% of their forecast peak demand.

Table 3.3 – DR Resources Qualified to Bid into FCM Year 1, 2010, Maine and Rest of Pool

	Maine	Rest of New England pool	Total
2010 Forecast Summer Peak (MW)	2,151 7%	26,628 93%	**28,779** 100%
DR Program Particpation (MW)			
Permanent			
On Peak	28	461.7	490
Seasonal Peak	0	160	160
Sub-Total	28	622	650
Dispatchable			
RT 2 hour	n/a	n/a	n/a
RT Profiled	n/a	n/a	n/a
RT 30 minute existing, adjusted for de-listing	148.0	793.0	941
RT 30 minute new	148.8	586.3	735.1
RT Emergency Generation new	37	677.1	714.1
Critical Peak	21	363.6	384.4
Sub-Total	355	2420	2775
Discretionary			
RT Price	n/a	n/a	n/a
Day Ahead	n/a	n/a	n/a
Sub-Total	0	0	0
Total	382 **11%**	3042 89%	3424 100%
Total DR as % of Peak Forecast	**17.8%**	**11.4%**	**11.9%**

[11] Hepper, Raymond. ISO-New England Inc. Docket No. ER08, *Informational Filing for Qualification in the Forward Capacity Market*, ISO-New England, November 6, 2007.

4. Potential for Incremental Demand Response in Maine

Is there potential for incremental DR in Maine, despite the high level being achieved under the policies and programs currently in place? In order to answer this question we assessed the levels of DR currently being achieved in Maine relative to the experience with and projections for DR in other jurisdictions.

First, we examined the most recent detailed evaluation of DR potential for a utility in the Northeast prepared by LBL and Utilipoint International ("LBL/Utilipoint Scoping study").[12] Second, we examined the quantities of DR projected for Maine relative to projections for other jurisdictions. Finally, we reviewed the costs and benefits associated with achieving incremental DR in Maine.

A. Potential in the Commercial and Industrial Sector based upon Application of the LBL/Utilipoint Scoping Study Methodology to Maine

The LBL/Utilipoint Scoping study was designed to:

- demonstrate the implementation and use of the proposed methodology;
- gather currently available data on large customer participation and response, which could be used by policy makers and other analysts in market potential studies; and
- demonstrate, through the use of scenarios, the impacts of various factors on demand response market potential.

The study focused upon the commercial, institutional and industrial sectors (C&I), and five specific segments within those sectors most likely to participate in DR programs. The five segments, identified by SIC code, were manufacturing, government/education, commercial/retail, healthcare and public works. The authors were able to obtain detailed information on electric energy use in each of those segments, including:

- Peak load;
- Distribution of customers by size of peak load within those segments (e.g., under 0.5 MW, 0.5 - 1 MW, 1 - 2 MW, etc);
- types of most promising loads within the facilities of those customers (e.g., pumping, refrigeration, space conditioning); and
- price elasticity.

Using that detailed information, the authors estimated the level of response or participation by segment for five different DR pricing programs. One of those programs could be categorized as dispatchable, i.e., the Short-Notice Emergency Program, while the

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[12] Goldman, Charles et al. *Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study,* Lawrence Berkeley National Laboratory, January 2007.

remaining four could be categorized as discretionary. They were Optional Hourly Pricing, Default Hourly Pricing, Price Response Event Program, and Critical-Peak Pricing.

The analyses presented in that report project potential savings under those five DR programs in the C&I sectors in the order of 3% to 6% of the non-coincident peak demand of the C&I customer classes.[13]

Application to Maine

We encountered two main problems in our attempt to apply this methodology to Maine – data and relevance.

Data. As anticipated at the outset of the project, obtaining recent, good quality, detailed load data comparable to that used by LBL/Utilipoint proved to be not only difficult, but impossible. We were unable to obtain detailed load data by SIC code for Maine utilities. We learned that the state of Maine no longer tracks information by SIC code, but uses a newer NAIC whose coverage does not completely intersect that of SIC, and that CMP did not have detailed load data by SIC code. This was also true of the 2007 LBL study.[14] However, the budget and timeframe for that study enabled LBL researchers to manually match participant names with SIC codes to estimate amount of demand response by customer class. We had also attempted to obtain revenue and tax information from various Maine planning offices, but again found that the information was not maintained in a format usable for this purpose.

Relevance. Synapse staff interviewed Charles Goldman regarding the LBL/Utilipoint Scoping Study and its relevance to assessing the potential in Maine. The key insight from that interview was that the LBL study was completed prior to the implementation of the market rules for the FCM and therefore its results need to be considered in light of the significant changes to New England's energy capacity market under the FCM structure. In other words, it is not clear that the results of the LBL/Utilipoint Scoping Study will be directly relevant to customers who will be operating under the FCM.

B. Potential for Incremental DR Based upon Comparisons with Projections for Other Jurisdictions

Our next step was to compare the quantities of DR projected for Maine under current policies to projections of DR potential for other jurisdictions.

On an aggregate or all sectors basis, there appears to be little or no potential for incremental DR in Maine. As noted earlier, the quantity of DR in Maine in year one of the FCM is expected to represent approximately **17.5%** of the ISO-NE forecast of peak demand for Maine in 2010. At that level, Maine would have one of the highest, if not the highest, levels of DR in the country. In comparison,

- the DR resources of the remaining New England states qualified for the FCA for year one of the FCM are equal to **11**% of their forecast peak demand for 2010;

[13] Goldman, Charles et al. *Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study,* Lawrence Berkeley National Laboratory, January 2007.

[14] Goldman, 2007, ibid, and telephone interviews conducted with him during October 2007.

- California, which has aggressively pursued DR for several years, has a goal of achieving DR of **5%** percent of peak load by 2007;[15]
- a 2006 study by Lawrence Berkeley National Laboratory estimated the national average potential for demand response to be **3%** of the total US peak. However, the data presented in that report indicates that actual reductions from DR in 2004 represented only 1.3% of national peak demand. In addition, the report indicates that the total potential for demand response was much higher in 1996 than in 2006.[16]

A more detailed comparison of DR potential by sector and program indicates that there may be a small potential for incremental DR in Maine, in the order of 1 to 2 % of total peak demand. This incremental potential appears to be most achievable in all sectors, including residential and small commercial, via energy efficiency programs, increases in appliance efficiency standards, and/or upgrades to building energy codes. This conclusion is based upon our review of the quantities of DR projected under the FCM by category, and our review of recent estimates of the potential for DR in other jurisdictions.

The total quantity of DR in Maine in year one of the FCM is expected to be much higher than the rest of the New England states. However, the quantity of DR from Maine expected under the permanent category, at 1.3% of its 2010 peak forecast, is approximately half of the quantity expected from the rest of New England, i.e. 2.3%. This comparison by category of DR is presented in Table 4.1.

Table 4.1 – DR Resources Qualified to Bid into DCM Year 1, 2010, Maine and Rest of Pool as % of Peak

DR Program	Maine	Rest of New England pool
Permanent	**1.3%**	**2.3%**
Dispatchable	16.5%	9.1%
Discretionary	N/A	N/A
Total	**17.8%**	**11.4%**

The DR resources qualified for the FCM that fall into the permanent category, i.e., guaranteed reductions in on-peak hours and seasonal peak hours, are primarily utility energy efficiency programs. These programs apply to all sectors, including residential and small commercial. Increases in appliance standards and building energy codes are

[15] Energy Future of the West: (1) Demand Response and Dynamic Pricing; (2) Energy Use and Sustainable Growth; Utility Energy Forum; Granlibakken Conference Center, Tahoe City, California; May 6, 2005; Arthur H. Rosenfeld, Commissioner, California Energy Commission.

[16] Department of Energy (DOE) 2006. Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: Report to U.S. Congress pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006, eetd.lbl.gov/ea/EMP/reports/congress-1252d.pdf.

additional sources of potential incremental DR in those sectors, particularly for residential and small commercial customers.

C. Costs and Benefits Associated with Achieving Incremental DR in Maine

In order to understand why the potential for incremental DR in Maine may be relatively small, particularly in the residential and small commercial sectors, we reviewed the estimated costs and benefits associated with achieving that potential.

Costs Associated with Achieving Incremental DR

As noted earlier, every DR program will require some level of investment in an incremental technology. At a minimum, every program will require some level of investment of time and/or money by, or on behalf of, the participant in order to reduce load in peak periods. In addition to that investment, dispatchable and discretionary DR resources typically require some level of incremental investment in enabling technologies to:

- signal and display energy prices in peak hours;
- measure and record energy use in peak hours; and
- process energy use data for peak hours.

In recent years the electric industry has begun referring to this functionality as "advanced metering infrastructure" or AMI. FERC defines AMI as

> "a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."[17]

It is important to note that AMI systems provide a wide range of functions that will improve the efficiency of various distribution utility operations and that have nothing to do with supporting new DR programs. Those utility operation functions include:

- Ability to remotely change metering parameters
- Outage detection, notification, and management
- Pre-paid metering
- More accurate load forecasting to meet customer demand
- Reduced congestion cost
- Reduced blackout probability, forced outages/interruptions
- Improved asset management, including transformer sizing
- Enhanced customer service
- Interface with water or gas meters
- Power quality monitoring

[17] Federal Energy Regulatory Commission (FERC) 2006. Assessment of Demand Response & Advanced Metering Staff Report under Docket AD-06-2-000, August 2006, Page 17.

- Tamper detection
- Power theft detection

Therefore, utilities who have proposed investments in AMI in recent years have tried to justify a significant portion – if not all – of that investment on savings in utility operations, such as meter reading and outage costs, rather than on the benefits from new DR programs that AMI would enable.

A load serving entity (LSE) wishing to implement some types of DR programs must invest in these enabling technologies because they do not, as a matter of standard practice, have systems with the functionality to provide all customers with energy price signals in peak hours or to measure, report and process their time-differentiated energy use. LSEs can offer simple Time-of-Use pricing without much incremental investment since the necessary functionality is already in place for large usage customers and it can be provided to residential and small commercial customers through the installation of a time-of-use meter. However, in order to implement sophisticated time-differentiated pricing, such as Critical Peak Pricing or Real Time Pricing, LSEs often must not only retrofit existing meters or install new advanced meters, but they must also upgrade usage data collection and processing systems in order to handle the dramatic increase in time-differentiated usage data that will be collected.

The concentration of annual energy and peak demand by customer is particularly relevant to the costs of offering certain types of DR programs, particularly to small usage customers. Recall, for example, the 2006 statistics for CMP. A relatively few (428) very large usage customers accounted for 34.8% of the electric energy (MWh) and 29.4% of the peak demand (MW) on its system, with an average peak demand per customer almost 1000 times greater than an average residential or small commercial customer.

- First, the costs associated with offering a sophisticated, discretionary DR program such as critical peak pricing or real time pricing has been estimated at $500 per customer as a one-time development cost for control hardware, meter upgrade, installation and marketing, plus $50 per year for annual maintenance and incentives.[18] Obviously, that investment would be more cost-effective for customers with an average peak load of 1000 kW than for customers with an average peak load of 1 kW.
- Second, it is not clear that the preceding cost estimate included the cost of upgrading the capability of billing systems, to move from processing 1 usage reading per customer per month to 720 usage readings per customer per month for every customer.

Estimates of the levels of investment in enabling technologies required for various categories of DR seem to vary significantly by utility. These variations are due, at least in part, to the functionality of the utility's existing communication, meter reading, and data processing systems. These estimates will also vary according to the scale of the programs, including the number and classes of customers to be covered. Estimates of the levels of

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[18] Quantec 2006. *Demand Response Proxy Supply Curves*, prepared for PacifiCorp, September 8, 2006, Table 12.

incremental investments in enabling technologies required for various types of DR programs drawn from a recent study of potential in California[19] are presented in Table 4.1.

Table 4.1 – Estimates of Incremental Spending on Enabling Technologies (e.g., communicating price, recording and reporting usage data, processing usage data for billing and operational purposes)

Strategy	Costs
PERMANENT	
Energy efficiency	None
Appliance standards & building energy codes	None
DISPATCHABLE	
LSE direct load control – water heating	Development - $320/customer Annual - $112/customer
LSE direct load control – central air conditioning	Development - $320/customer Annual - $ 55/customer
DISCRETIONARY	
Time of use	Minimal
Critical peak pricing (CPP) or Real time pricing (RTP)	Development - $ 500/customer Annual - $ 50/customer

We reviewed several recent detailed estimates of DR potential prepared for utilities in California and Washington. In addition to the Quantec study referred to above, Quantec prepared an assessment for Puget Sound Energy in 2005 and Heschong Mahone Group prepared a potential study for San Diego Gas & Electric in 2007.

The potential identified in those studies hinges upon a host of assumptions, including assumptions regarding

- Cost of enabling technologies
- Capacity and energy prices
- Annual and peak electricity use per customer by end-use
- Customer participation rates
- Electricity reduction per customer
- Duration of savings (# of years)

Determining the applicability of those results to Maine in detail was beyond the scope of this report. Further, the unit cost of capturing DR ($/kW) reported in those studies cannot be applied to Maine without a detailed analysis of the comparability of all of their underlying assumptions to the conditions in Maine, adjusting for differences in weather, electricity prices, and appliance saturation. For example, central air conditioning is identified as a major target load for residential sector DR programs in California and various southern states. However, the saturation of air conditioners in the residential sectors in those states

[19] Ibid.

is much higher than in Maine and therefore the average peak load per residential customer attributable to air conditioning in those states is much higher than in Maine. Therefore, a dollar invested in California to reduce the peak load of air conditioners in the residential sector will yield many more kW of DR than that same dollar investment in Maine.

Economic Benefits – Impact on Wholesale Market Prices

DR has the potential to produce economic benefits in the form of reductions in market prices for capacity and for electric energy. This impact has been referred to as a Demand-Reduction-Induced Price Effect (DRIPE). There are two factors to consider when evaluating these benefits – their size and their distribution. We address each of these below.

In terms of size, these reductions may be small when expressed in terms of an impact on the total market price. Moreover, the reductions attributable to a specific DR reduction in a given year may only be felt for a limited period, as markets will eventually react to the new, lower levels of capacity and/or energy required. However, small reductions in market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

Capacity Prices

The impact of DR on prices for capacity in the FCM was recently estimated in *Avoided Energy Supply Costs in New England: 2007 Final Report* (AESC 2007) prepared by Synapse. This impact, referred to as capacity DRIPE, was calculated by estimating the impact of energy-efficiency bid into the FCM on the FCM price.

Energy efficiency bid into the FCM would shift the supply curve to the right. The size of the impact on FCM prices is dependent on the quantity of load reduction that is bid. The AESC 2007 estimate is based upon the following major assumptions:

- new gas-fired CT units would be on the margin,
- developers of these units would submit bids in increments of 200 MW,
- the difference between bid prices would be $1/kW-yr or $0.083/kW-month,
- in the absence of any incremental DR, the FCM for year 1 would clear at a price of $8.33/kW-month,
- each MW of incremental DR bid into the market would reduce the market-clearing price by an average of $0.0057/MW-year, and
- that price impact would dissipate linearly over the fourth and fifth years following the implementation of the DSM programs.

Based upon those assumptions, AESC 2007 estimated a 15 year levelized value for capacity DRIPE of $22.80/kw-year in constant 2007$. At that value, an incremental reduction of 21.5 MW in 2010 (a 1% reduction in the forecast peak of Maine) would have an economic benefit of approximately $490,000 per year for 15 years.[20]

Electric Energy Prices

The impact of DR on prices for energy in the Day Ahead and Real Time wholesale markets was examined in depth in the 2005 "ISO-NE Demand Response Program Evaluation" (NEDR) report.[21] The results from that study, from AESC 2007, as well from analyses we prepared for this report, indicate that reductions in load from DR will have a downward impact on prices in each of those markets. Those results also indicate that the magnitude of those price impacts will decline over three years as the market responds to the new demand/supply balance. We discuss the two studies and our analyses below.

The NEDR report measured the impact of load reductions in terms of a Supply Price Flexibility (SPF) coefficient. SPF is a ratio equal to the percentage price change divided by the percentage change in load. This is a normalized dimensionless coefficient which makes comparisons across different studies consistent and much easier. For example, an SPF value of 1.0 means that an x% change in load will produce a corresponding x% change in the market price.

An SPF value of 1.0 also means that the value to the DR participant from the reduction in the market price is nearly equal to the value to that participant from the reduction in demand. Consider an hour in which the market price, absent DR, would be $100 per MW or $0.10/kw and a DR participant with a normal demand load of 100 kw.

- If the customer reduces its load by 1 kw, it saves $0.10 * 1 or 10 cents.
- As a result of that reduction, the market price drops 1% to $0.099, a reduction of $0.001 per kw.
- The customer's savings from that price reduction on its remaining demand is 99 kw * $0.001 or $0.099 or almost another 10 cents.

The NEDR report estimated SPF coefficients for both the DA and RT markets based on an analysis of data for a year ending August 2005. The NEDR SPF coefficients for Maine in the summer were 0.1 in the DA and 0.9 in the RT. The results for the winter were 0.2 in the DA and 1.9 in the RT.[22]

The AESC 2007 report also estimated the impact of load reduction on energy market prices, but also considers the effects of supply contracts.[23] In that study, the market price effects of load changes goes under the acronym of Demand-Reduction-Induced Price Effect (DRIPE) which was introduced in the 2005 version of the AESC report. The price effect results are presented in that report in "$ per MWh Saved" which can be converted

[20] 21,599 kw * $22.8 per kw-yr = $490,200.

[21] "An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2005," prepared by RLW Analytics and Neenan Associates for ISO New England, December 2005.

[22] Ibid Table 3-1.

[23] "Avoided Energy Supply Costs in New England: 2007 Final Report", prepared by Synapse Energy Economics for Avoided-Energy-Component Supply Group, August 2007.

into SPF measures using the average load and market price information. Table 4.7 summarizes the results of those calculations.[24]

Table 4.7 - Maine SPF Coefficients Derived from AESC DRIPE Results for the Day Ahead Market

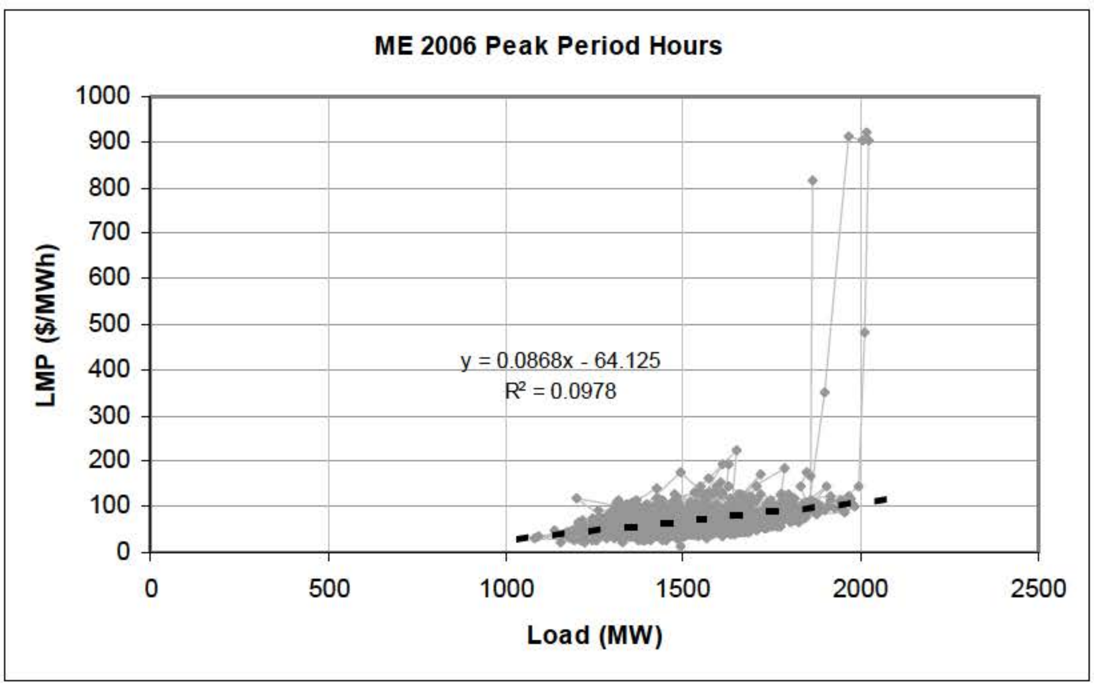
	Peak	Off-Peak	Average
Summer	1.100	0.683	0.892
Winter	0.634	0.650	0.642
Average	0.867	0.667	0.767

(Based on year 2 results to factor out effects of one year supply contracts.)

The AESC 2007 report notes that price reductions resulting from load reductions decline over time as the wholesale market adjusts to the new demand/supply balance.

For this report we analyzed the impact of load reductions by applying statistical regression techniques to 2006 loads and prices in Maine. During 2006 there were a handful of hours in which RT prices exceeded $300/MWh, i.e., "extreme hours". Since the prices in those hours significantly affect the statistical results we examined the data with them and without them. That analysis is presented in Figure 4.2.

Figure 4.2 – Regression Analysis of Hourly Prices in RT Market, Maine 2006



[24] Ibid, results derived from Exhibit 6-11.

Our analyses of the RT market yield SPF coefficients of 1.29 when those extreme hours are included and 1.14 when those hours are excluded. Prices in the day ahead market never reached such high levels and the all-hours SPF coefficient for that market came out to 0.79.

Distribution of Reductions in Wholesale Prices

The distribution of such reductions in wholesale prices between retail customers and their suppliers will vary according to the terms of their supply contracts. Consider, for example, a large retail customer in 2010 who will be acquiring 100% of its capacity at prices directly tied to the FCM and 100% of its energy supply at prices tied directly to the Day Ahead and/or Real Time wholesale energy markets. That customer would receive the entire benefit of any reductions in the wholesale market prices for capacity and energy respectively.

Alternatively, consider a small retail customer acquiring its supply via Standard Offer Service as presently designed. That retail customer should receive most, if not all, of the benefit of any reduction in the wholesale market price for capacity as the competing bids from suppliers to provide that service should reflect the FCM price, since it will be set three years in advance. In contrast, the portion that retail customer will receive of DR induced reductions in the DA or RT price is less clear. Suppliers competing to provide Standard Offer Service submit their price bids in advance of the supply delivery period. Those bids reflect their expectations about the cost of supplying that electricity during that future supply delivery period, including the futures prices for electricity at the time they prepare their bids. Once bids are selected the retail supply price is fixed for the duration of the service period. In contrast, the actual reductions in the DA or RT price resulting from DR will occur during the supply delivery period. Thus, the portion that retail customers receive of DR induced reductions in the DA or RT price will depend upon the extent to which suppliers include the potential impacts of those anticipated reductions when preparing their bids. However, it is reasonable to expect that, over time, the impacts of DR programs will be reflected in futures prices for electricity and hence in prices for Standard Offer Service.

5. Achieving Incremental Demand Response in Maine

This Chapter discusses initiatives, policies and programs that could help increase the quantity of demand response in Maine.

Those initiatives, policies and programs fall into the following categories:

- obtain more detailed information regarding customer loads by end-use and sector;
- increase the scope and diversity of programs;
- increase funding for and certainty of programs; and
- invest in the human capacity and infrastructure needed for these programs.

A. Obtain Detailed Information Regarding Customer Loads by End-Use and Sector

The quantity of load reduction likely to be achieved through a particular DR program will be driven by the costs and benefits that participating customers will see under that program, and the price elasticity of those participating customers. Costs, benefits, and price elasticity vary by customer class (e.g., residential and small commercial, medium usage commercial and institutional, large usage commercial, institutional, and industrial). They also vary by market segment within each customer class. For example, within the commercial sector there are a wide range of segments such as office buildings, retail stores, hotels/motels, restaurants, and so on. Thus, in order to estimate the potential for incremental DR, and to design programs to capture that potential, one needs a significant quantity of detailed information by customer class and market segment regarding electricity usage by major end-use by customer and price elasticity.

Program design could be improved with better information on customer loads, their shape and diurnal or seasonal patterns. Addressing this area would help Maine assess the remaining achievable potential for demand response as well as a whole suite of complementary programs, including energy efficiency, building commissioning and retrofitting, and integrated system design. This detailed data would also help Maine's utilities to better understand the factors driving usage levels, patterns and costs on their systems, and thereby better identify opportunities for improving service quality and controlling costs.

In preparing this report, we found that Maine does not have this detailed information. For example, Maine does not maintain data on customers by Standard Industrial Code (SIC), but uses a newer North American Industry Classification System (NAICS) whose coverage does not completely intersect that of SIC. This was also true of the 2007 LBL study.[25] However, the budget and timeframe for that study was sufficient to allow LBL researchers to manually match participant names with SIC codes to estimate quantity of demand response by customer class. We were also unable to relate information about customer load profile by class to actual customers.

B. Increase the Scope and Diversity of Programs

Increasing the scope and diversity of programs will produce greater benefits as well as reduce the impact of a few large customers exiting the DR programs.

Combine Energy Efficiency with Demand Response

Coupling demand response with energy efficiency can increase the quantity of resources, their cost-effectiveness, and help to overcome barriers to further penetration in the small C&I and residential customer classes. Efficiency Vermont is currently achieving significant success in energy efficiency measures focused on these customer classes.[26] In contrast,

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[25] Goldman, 2007, ibid, and telephone interviews conducted with him during October 2007.

[26] Vermont was tied for 1st among EE programs, See ACEEE Scorecard 2007, www.aceee.org.

Maine, with annual expenditures of about 1.1% of total utility revenue, is currently spending only half as much as Vermont and Massachusetts, and less than two-thirds of Connecticut, another top ranked state nationally. On a per capita basis, Maine's $10 amount is the lowest in New England. Vermont is at $22.54 and this has been increased further during 2007, Massachusetts is $20.84, and Connecticut is $16.60. Connecticut will increase its efficiency spending by more than one-third during 2008.[27]

Efficiency Maine can take advantage of the good work performed by other New England states to replicate their success. A plan to achieve all cost-effective efficiency measures and suggested approaches to fund them, would make an excellent roadmap. Including demand response as part of this plan will facilitate even further benefits and could catapult Maine into the leading tier of states nationally, given the success Maine has already achieved in demand response for the larger customer classes. Reducing both peak and base demand will also likely yield significant direct and indirect economic benefits for Maine. Most top-tier energy efficiency programs implement measures with cost-benefit ratios much greater than 1:1, and at actual costs which range from 2 to 4 cents/kWh[28]. These are much lower than the current cost of new generation and upgrades or additions to the region's transmission capacity.

Symbiosis of energy efficiency and demand response can also address the public education and awareness barrier mentioned earlier. To the extent that audits and personal visits are already part of Efficiency Maine's program, adding a demand response component would not create a significant incremental cost. Examples that Maine may wish to consider would include: direct load control programs of electric water heaters with measures that promote more efficient water use, including appliances and low-flow shower heads. Another example could be a pilot at one of Maine's larger ski areas to test a winter demand response programs. Combining a direct control of electric heating at one of the many condominium complexes with improved insulation and more efficient appliances could also yield significant and positive results for both base and peak demand reductions. For the small C&I sector, more substantial reductions could be available through programs focused on lighting, chillers and HVAC systems, again combining direct load control or automation with installation or upgrading to more efficient equipment.

Investigate More Stringent Appliance Standards

Implementing more stringent appliance standards on a state-wide basis has significant potential to reduce electricity demand throughout the year, including peak demand. Precise quantification of the effects on peak demand is difficult, due to large variations in types and uses of appliances and standards. However, the experiences of other states and the results of preliminary studies indicate that more efficient appliance standards results in peak load reduction.

In the summer of 2002, the Keep Cool Bounty Program, a statewide partnership among several New York power authorities funded through the System Benefit Charge, offered residents a $75 bounty to replace their old, inefficient room air conditioners with an Energy

[27] ACEEE ibid, and Connecticut's Public Act 07-01, 2007.

[28] ACEEE ibid, Connecticut ECMB reports to legislature, Efficiency Vermont annual reports.

Star model. The program saw over 175,000 room air conditioners exchanged, which saved approximately $4.73 million in annual energy costs.[29] The resulting summer peak reduction was 62 MW and an additional 94 MW of summer peak demand shifted brought a total of 156 MW in peak load relief to New York[30].

A 2006 joint study by the Appliance Standards Awareness Project (ASAP) and the American Council for an Energy-Efficient Economy (ACEEE) examined the energy, capacity, and cost benefits of implementing certain proposed appliance standards on a state-by-state basis.[31,32] The results for Maine are shown in Table 5.1. In the ASAP/ACEEE results, summer peak capacity reductions are calculated for each of the appliances,[33] indicating that enforcement of these 15 appliance standards could result in a summer peak capacity reduction of 37 MW of electricity in 2020 and corresponding annual savings of 208 GWh.

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[29] "Keep Cool with an Energy Star Room Air Conditioner", NYSERDA Press Release, 2003. http://www.getenergysmart.org/PressReleases/05.03KeepCoolES_RAC.asp.

[30] Keep Cool Program, Presentation by NYSERDA at ACEEE National Conference on Energy as a Resource, June 2003. http://www.aceee.org/conf/03ee/Hammer-5w.pdf.

[31] Nadel, Steven, Andrew deLaski, Maggie Eldridge, and Jim Kleisch. Energy Efficiency Standards Benefits – 2006 Model Bill: South Carolina, ASAP and ACEEE, http://www.standardsasap.org/documents/a062_me.pdf.

[32] The recently passed Energy Independence and Security Act of 2007 enacted federal standards for five of these appliances, including metal halide lamp fixtures, residential boilers, external power supplies, and incandescent reflector lamps.

[33] Peak capacity savings are calculated as the end-use electricity savings / T&D loss factor x peak factor x reserve factor, where the reserve factor is 1.1 (with a 10% assumed reserve margin) and the peak factor is 1/8760 hours/year for most appliances, with a few exceptions.

Table 5.1 – Energy Efficiency Standards Benefits – 2006 Model Bill

Maine																
Summary of Benefits by Product				2020								2030				
								Emissions Reductions								
Products	Annual Savings per Unit	Incre-mental Cost per Unit	Annual Energy Savings from One Year's Sales	Energy Savings	Summer Peak Capacity Reduction	Direct and Indirect Natural Gas Savings[1]	Value of Bill Savings[2]	Carbon	NOx	SO2	Energy Savings	Summer Peak Capacity Reduction	Value of Bill Savings[2]	Pay Back Period	Net Present Value[3]
	kWh or [therms]	$	GWh [Million CF]	GWh [Million CF]	MW	Million CF	$Million	1000 MT	Metric Tons	Metric Tons	GWh [Million CF]	MW	$Million	Years	$Million (2005$)
Bottle-type water dispensers	266	12	0.1	1.2	0.2	6.1	0.1	0.3	1.1	1.4	1.2	0.2	0.1	0.4	1.1
Commercial boilers[4]	[268]	2,968	[2.3]	[19.7]	NA	19.7	0.3	0.3	1.3	0.0	[42.9]	NA	0.6	4.3	3.0
Commercial hot food holding cabinets	1,815	453	0.1	1.7	0.6	8.6	0.2	0.4	1.6	2.1	2.0	0.7	0.2	2.4	1.3
Compact audio products	53	1	1.7	8.4	1.2	42.8	1.1	1.9	7.8	10.2	8.4	1.2	1.1	0.1	11.1
DVD players and recorders	11	1	0.2	1.2	0.2	6.2	0.2	0.3	1.1	1.5	1.2	0.2	0.2	0.7	1.4
Liquid-immersed distribution transformers	6	2	3.2	40.0	5.5	202.5	4.1	8.8	37.1	48.4	72.0	9.9	7.5	3.9	44.6
Medium voltage dry-type distribution transformers	6/kVA	2/kVA	0.2	2.5	0.3	12.4	0.3	0.5	2.3	3.0	4.4	0.6	0.5	3.2	2.9
Metal halide lamp fixtures	307	30	3.3	40.7	13.3	206.1	4.2	8.9	37.7	49.3	65.1	21.3	6.8	0.9	45.9
Pool heaters[4]	[58]	295	[3.8]	[32.7]	NA	32.7	0.5	0.6	2.2	0.0	[57.7]	NA	0.9	3.3	3.7
Portable electric spas (hot tubs)	250	100	0.1	0.7	0.2	3.7	0.1	0.2	0.7	0.0	0.7	0.2	0.1	3.0	0.5
Residential furnaces and residential boilers[4,5]	778	100	4.8	41.0	0.6	303.3	10.6	14.7	60.8	49.7	86.9	1.3	22.5	1.0	124.5
	[111]	[373]	[3.5]	[95.4]							[205.9]			[2]	
Residential pool pumps	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Singe-voltage external AC to DC power supplies	4	0.5	3.4	23.9	3.3	121.0	3.2	5.2	22.2	28.9	23.9	3.3	3.2	0.9	26.3
State-regulated incandescent reflector lamps	61	1	27.8	26.1	6.4	132.3	2.7	5.7	24.2	31.6	26.1	6.4	2.7	0.1	26.6
Walk-in refrigerators and freezers	8,220	957	1.7	20.7	4.8	104.7	2.1	4.5	19.2	25.0	20.7	4.8	2.1	1.1	16.3
Total			47	208	37	1,202	30	52	219	253	313	50	48		309
[natural gas]			[9.7]	[147.8]							[306.6]				

Notes:

[1] Direct natural gas savings are savings from use of more efficient natural gas appliances. Indirect natural gas savings are reductions in natural gas at power plants due to use of more efficient electric appliances. Indirect gas savings assume that half the power saved at power plants would be generated with natural gas.

[2] Value of energy savings is based on energy savings and average state energy prices. This value does not take account of the incremental cost of more efficient products.

[3] Net present value is the total monetary value of bill savings achieved by products sold under the standards between now and 2030 minus the total incremental product cost incurred by purchasers as a result of the standards over the same period expressed in current dollars. Both costs and savings are discounted using a 5% real discount rate.

[4] Commercial boilers, pool heaters, and residential boilers and furnaces save natural gas. Gas savings are expressed in cubic feet and enclosed in brackets to distinguish from electricity savings.

[5] Residential furnaces and boilers include both natural gas and oil furnaces and boilers as well as furnace fans. Annual savings per unit, incremental cost per unit and pay back period shown here are just for gas furnaces and furnace fans, which are the most common of these products. For these calculations, gas furnace values are enclosed in brackets and listed below furnace fan values.

C. Increase Program Funding and Certainty

The most promising source of incremental DR in Maine appears to be load reductions through energy efficiency improvements. In order to capture that incremental potential, Maine will have to increase the annual amount spent on energy efficiency programs. As noted earlier, Maine is currently spending much less on these programs than other states in New England.

There are several potential sources of additional funding for energy efficiency programs in Maine.

- First, Legislative bill LB 1851 authorizes Maine to auction 100% of its RGGI allowances for consumer benefit purposes. The revenue from the sale of these allowances can be directed to maximize energy efficiency and demand response. Maine Public Law 317 authorizes the state to develop regulations to implement RGGI and provides direction on how the proceeds from the auction of RGGI allowances are to be used.[34]
- Second, Efficiency Maine will be paid for its load reduction resources accepted in the Forward Capacity Auction. During the current transition period, some states are already receiving funds from the capacity value of demand resources developed through their system benefit charge programs. Maine's energy efficiency program is expected to receive about $300,000 from this source in 2007. These funds are expected to grow each year through 2010 and could be used to fund additional energy efficiency measures.
- Other potential financing avenues could add incremental quantities of demand response resources and allow Maine to achieve its greenhouse gas and criteria pollutant goals. These include establishing a revolving loan fund through the economic development agency and using state employee pension funds to establish either a revolving loan fund and/or to increase the investments in demand response and energy efficiency. Loans could be repaid through energy and capacity payments, and through direct savings on bills. Insurance companies may also be interested, both from traditional audit functions of their business scope and to develop new business lines that would guarantee that performance persists over the anticipated life of the measure or project.[35]

The quantity of incremental DR achieved can also be increased if prospective participants see a long-term, sustained commitment to these programs. For example, Maine's commitment to DR programs could coincide with the period provided in the FCM, which would guarantee participants a minimum five-year revenue stream for qualified resources. Sustained commitments also help assure high retention rates. Participants who receive clear signals about the market, its design and implementation, are able to make informed decisions about their potential investments and efforts. At the same time, the associated policy and regulatory structure will be more robust if a feedback mechanism is included

[34] An Act to Establish the Regional Greenhouse Gas Initiative of 2007, Maine Public law 317, signed June 18, 2007.

[35] see http://eetd.lbl.gov/EMills/PUBS/EnergySavingsInsurance.html

that enables state agencies and participants to evaluate the success of the program, and whether or not changes are needed to improve it.

The resources likely to provide this incremental DR are expected to be smaller, on a per customer basis, than the sources to date. Two possible paths are suggested to realize the increased quantity of demand response potential:

- Establish DR goals in terms of MW
- Establish DR goals on a percentage basis in terms of peak demand

The former path is analogous to a procurement standard and might work well with Maine's legislation on cost-effective resource procurement and loading order. The latter is analogous to a renewable portfolio standard and may be more easily understood by the legislature and state decision makers.

D. Invest in Human Capacity and Infrastructure

Achieving the objectives of increased demand response will also require consideration of the human resources needed to achieve and sustain the state's energy and environmental goals. New skills may be required, which could offer professional development opportunities for existing staff, as well as opportunities for new employees. These skills may range from new approaches to program design for new sectors and market segments through oversight of equipment installers and building personnel to assure that they have the appropriate knowledge, skills and abilities needed. Integrating the human capacity with the physical infrastructure can also produce a symbiotic relationship whose investment has a substantial and local benefit.

The following elements would be typical to consider in any program design to assure effective implementation:

- Training for DPUC and DEP staff.
- Development of budgets that reflect the resource commitment required to provide effective oversight and assure good monitoring and verification.
- Using state economic development resources to link with state technical and community colleges to develop appropriate curriculum and to increase awareness of job and professional development opportunities.
- Integrating appropriate accounting procedures that measure the benefits of demand response, and complementary demand response and energy efficiency programs, and compare those benefits and costs against an existing or business as usual baseline to assess program efficacy.
- Developing programs that both provide certainty for business investment in equipment and human capital, but which include feedback mechanisms that allow for program adjustment, without requiring major regulatory or legislative actions.
- Build on Efficiency Maine's building operator training program to include elements on advanced metering and peak load reductions that complement course material on energy efficiency.

APPENDIX A - EVOLUTION OF DEMAND RESPONSE IN NEW ENGLAND

Electricity markets in New England, with the exception of Vermont, were restructured in the late 1990s. Under this new structure, generation was unbundled from transmission and distribution, and prices for generation service were set by competition. ISO-NE was created to operate the region's transmission system. Utilities were limited to providing a distribution service and to acquiring supply from the wholesale market in order to provide a "basic" or "default" supply service for retail customers who did not migrate to competitive suppliers.

The evolution of DR that has occurred and is continuing to occur under this new structure can be described relative to three distinct time periods: the early years (1999 to 2003), the transition years (2003 to 2010), and the Forward Capacity Market (FCM), 2010 onward.

Early Years: 1999-2003

The initial role of DR was limited. DR programs were operated on a year-to-year basis. This short timeframe made it difficult for potential participants to assess whether the capital they invested in equipment or instrumentation would receive a return, and it hampered evaluation of whether DR could be an effective resource. ISO-NE also sent mixed messages about DR in its 2000 launch of the load response program. The heavy reliance on on-site diesel generators conflicted with air quality regulations and plans that restrict operation of these sources due to their local impacts on the environment and public health.

ISO-NE operated two DR programs in 2000 and 2001: a Class 1 Demand Response program for participants who committed to either curtail load and/or operate quick start generation within 30 minutes, and a Class 2 Price Response program for participants who committed to reduce load when the forecasted energy price is above $100/MW. Customers who reduce load were paid based on the market clearing price established during the hours in which the reduction occurred. ISO-NE completed several program revisions in time for the summer of 2002. These included establishing a minimum capacity credit for Class 1 participants, a floor price of $100/MW for Class 1 interruptions, a low-tech option for Class 2 participants, and a congestion cost multiplier for all Class 1 and Class 2 interruptions.[36]

These early programs had few participants and limited success. Despite the overall program objective to decrease demand and ISO-NE forecasts that air emissions would decrease, both net load and air emissions actually increased for the events called in 2001[37].

In response to growing concerns from FERC about grid congestion, especially in southwest Connecticut and northeastern Massachusetts, an eighteen-month stakeholder process was convened to bring the region's energy and environmental decision makers

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[36] "Moving Towards Clean Demand Response: A Profile of Energy and Air Quality Issues in Southwest Connecticut", Center for Energy and Climate Solutions, June 2002.

[37] Ibid.

together to develop policies and programs to improve system reliability and to reduce peak electricity demand. With funding assistance provided by the US EPA and DOE, the New England Demand Response Initiative (NEDRI) began in early 2002 and continued through the summer of 2003.[38] Representatives from the Maine Public Utilities Commission and the Maine Public Advocate office participated in the stakeholder group.

The feedback that ISO-NE received from state regulators and market participants indicated that the limited participation rate and success would continue unless the DR programs were significantly revamped. The NEDRI effort, in which ISO-NE actively participated, provided eleven comprehensive recommendations to improve DR program design and about 20 additional ones focused on policies that would complement the recommended DR program changes.[39]

NEDRI recommendations included actions to improve the economics of DR to increase participation, metering, and telemetry standards to permit real-time response and assurances that any supply resources used were as clean as possible, including implementation of combined heat and power generation.

Transition Years: 2003-2010

ISO-NE worked in conjunction with the region's utility and environmental regulators to implement many of the recommendations made by NEDRI. As a result, DR program participation and savings increased substantially.

ISO-NE operates the following DR programs:[40]

- Real-time demand response (30-minute and two-hour)
- Real-time profiled response
- Real-time price response
- Day-ahead load response

The current program design will continue through the implementation of the forward capacity market in June 2010.

2010 – Onward: Forward Capacity Market

The Federal Energy Regulatory Commission has approved a new framework, the Forward Capacity Market (FCM). The FCM is scheduled to go into effect in June 2010.

A transition period framework is in effect until the FCM begins. The transition period is December 2006 through May 2010. ISO-NE has set the installed-capacity (ICAP) prices to

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[38] The full NEDRI report, its recommendations and supporting documents are located at http://nedri.raabassociates.org.

[39] Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets. Report and Recommendations of the New England Demand Response Initiative July 23, 2003.

[40] For more detail, see ISO Load Response Manual (rules and any revisions made by ISO-NE) and also "An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2005", prepared for ISO-NE by RLW Analytics and Neenan Associates, December 30, 2005. (this is the last such comprehensive DR report done by or for ISO-NE).

be paid to suppliers for each power year (June–May) during that period. Those prices are $3.05/kW-month through May 2008, $3.75/kW-month for June 2008 through May 2009, and $4.10/kW-month for June 2009 through May 2010.

Under the FCM, ISO-NE will set the price for capacity each year based upon the results of an auction to be conducted three years in advance. However, the auction for the first FCM year, June 2010 through May 2011, will not be held until February 2008. Later in 2008, ISO-NE will conduct an auction for the second FCM year, June 2011 through May 2012. The ISO will establish the FCM price from the auction results.

The unit cost of capacity for a calendar year, $/kW-year, will be the average of five months at the cost for the power year ending in May of that calendar year and seven months for the power year starting in June. For at least the first three FCM years (June 2010 through May 2013), the price for capacity will be constrained between a minimum and a maximum equal to -40% and +40% of a reference price. The reference price for the first FCM year has been set at $90/kW-yr or $7.50/kW-month based upon the estimated cost of new entry (CONE), assuming a gas fired combustion turbine (CT).

Bidders selected under the FCA will receive revenues equal to the quantity of capacity they provide times the auction price minus penalties for any failure to perform and minus an estimate of the energy profits (called peak energy rent, or PER) that would be earned by a generator with a 22,000 Btu/kWh.[41] The PER that the hypothetical peaker would earn in each hour will be multiplied by the ratio of load in that hour to the peak load for the power year.

Load will pay costs equal to the quantity of capacity they are required to hold times the auction price, less credits for any supplier penalties and the PER. The quantity of capacity that a particular load is required to hold in each month is based on the contribution of that load to the ISO annual peak. As a result, the total cost of that capacity to that load, i.e., dollars per kW times required kW of capacity, is essentially fixed for an entire FCM year.

Key features of the FCM include:

- Demand and generation resources are eligible to bid, meaning that qualified demand response resources will receive the same capacity payments as generation and energy efficiency.[42] The FCM will result in significant changes to the eligibility of certain DR resources, specifically the two-hour and profiled programs will terminate.
- Resources are to be procured via annual auctions approximately three years in advance of requirement date.
- Auctions will be operated on a declining cost basis, starting at a ceiling price equal to twice the cost of new entry (CONE).

[41] "Forward Capacity Market Payments and Charges", ISO-NE, October 11, 2006, page 9.

[42] Exception to this rule for qualified emergency generation. The NEPOOL market rules allow up to 600 MW equivalents for emergency generation. Qualified bids that exceed this quantity will be paid on a pro rata basis, compared to 600, e.g. if 1000 MW of emergency generation are qualified, each MW will receive 0.6 of the cleared auction capacity price.

- Bid resources and prices will be compared to ISO-NE’s forecast of the quantity of capacity required. When the MW of resources bid exceeds the MW required, the auction price will decrease. The FCM will clear at a price that produces the MW of resources equal to the ISO forecast.
- Resources selected in the auction will be paid the price at which the forward capacity auction clears. These prices are uncertain at the time of this writing, and will not be known until after the first auction occurs in February 2008[43]. Resources that clear the auction have the option to elect payments at the FCM year one price for up to five years.

[43] Telephone conversation with Henry Yoshimura, ISO-NE, October 10, 2007

APPENDIX B – POLICIES, PROGRAMS AND TECHNOLOGIES FOR ACHIEVING DEMAND RESPONSE IN NEW ENGLAND

The policies and programs that could increase demand response include:

- Pursue opportunities for demand response in the residential and small commercial/ industrial classes;
- Identify the full value of demand response by aligning and integrating energy and environmental standards;
- Increase the accuracy of price signals through changes in rate design; and
- Design programs to minimize transaction costs, guarantee curtailment time period and payment, and provide a framework to support long-term strategic decisions by participants.

A. Pursue Opportunities for Demand Response in the Residential and Small Commercial and Industrial Classes

Two promising opportunities for DR in the residential and small commercial class are energy efficiency and direct load control.

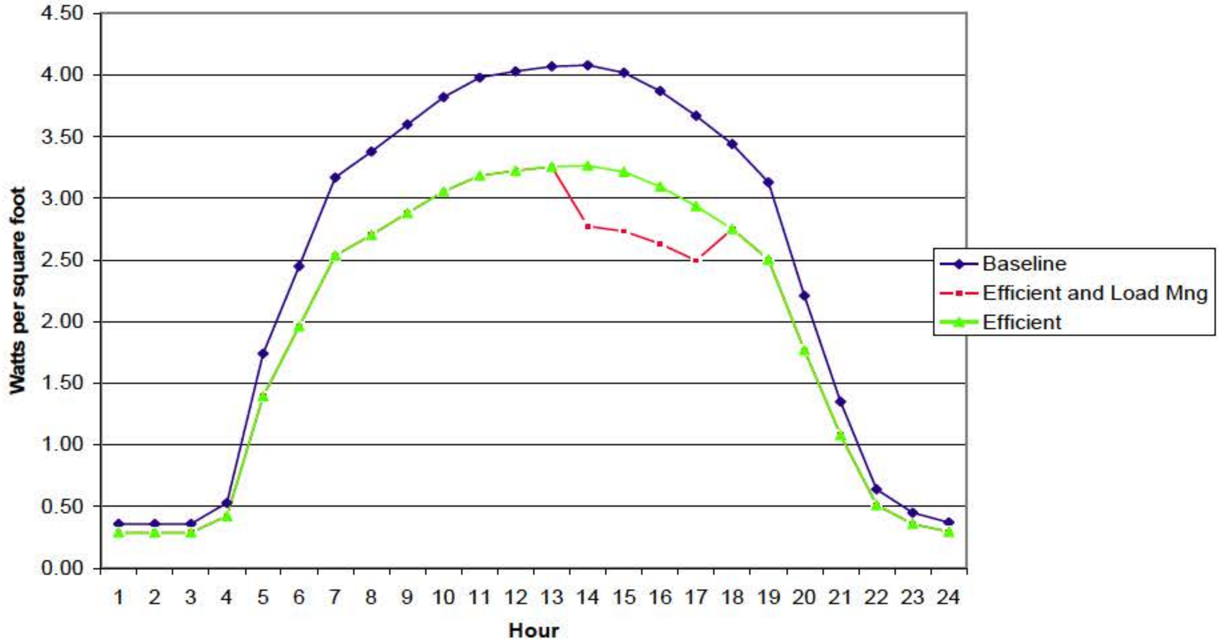
Energy Efficiency

Energy efficiency measures reduce demand in all hours in which the end use is operating and therefore are, in effect, **demand response resources.**

Energy efficiency also improves the cost effectiveness of demand response and increases the quantity of reliable resources available to provide operating reserve. While traditionally energy efficiency measures have been viewed as providing base load reductions, they can also be demand response measures, used either alone or in conjunction with other demand response mechanisms like load curtailment and on-site generation. During NEDRI, the particular benefits of energy efficiency were evaluated, both from the perspective of providing base load benefits and when used in conjunction with demand response measures applied at the peak hours.

Energy efficiency measures such as lighting and cooling are often coincident with peak demand periods. Applications in the residential, commercial, and industrial sector, especially for office use, can have significant and persistent benefits. The NEDRI energy efficiency report evaluated a combined commercial cooling and lighting load shape for an office building located in an interior Northeast climate zone with and without energy efficiency measures applied at the same time as load management techniques at a peak four-hour period. When only load management techniques were employed, building energy use declined from a peak of about 4 watts per square foot (W/ft^2) to a peak of about 3.5 W/ft^2. An efficient building, without load management, had a peak energy use of about 3.25 W/ft^2. When load management techniques were applied to the efficient building, the peak energy use decreased from about 3.25 W/ft^2 to about 2.75 W/ft^2, a reduction of another 20% compared to the building without energy efficiency measures[44]. Figure B-1 reflects the benefits from combined load management and energy efficiency.[45]

Figure B-1 – Combined Commercial Cooling and Lighting Load Shape with Efficiency and Load Management (Four-Hour Curtailment by 15%)



Direct Load control

Dispatchable loads that can be controlled remotely have been successful in aggregating demand response from residences and small commercial and industrial customers. These loads include air conditioners, HVAC systems, elevators, lighting systems, chillers and pumps. Direct load control is more advantageous for smaller customers. Individually, one customer's load would not be sufficient to meet minimum curtailment requirements (100 kW in New England). Also, smaller customers are less likely to have staff intimately familiar with these operating systems; instead those services may be performed by an outside contractor. Examples of successful direct load control for the customer classes discussed here include:

- programs for direct load control of hot water heaters at residential customers and lighting and HVAC components at small commercial and industrial customers, funded by the New York State Energy and research Authority (NYSERDA)[46];
- programs for direct control of residential air conditioners by Connecticut Light and Power;[47] and

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[44] NEDRI, Framing Paper #4, Energy Efficiency, May 29, 2002, Jeff Schlegel

[45] "Dimensions of Demand Response", NEDRI, July 23, 2003, page 75.

[46] NYSERDA Case Studies in Demand Response

- direct control of residential central heating and cooling, electric water heater, swimming pool pumps in Florida and Georgia by Gulf Power. [48]

B. Identify the Full Value of Demand Response by Aligning and Integrating Energy and Environmental Standards

Air quality and utility regulations can be harmonized to optimize benefits and reduce impacts. Both NEDRI and the Regional Greenhouse Gas Initiative (RGGI) demonstrate the benefits of having the energy and environmental regulators participating together in development of recommendations and program design. The process that culminated in the establishment of the FCM was another example, leading to the decision that all capacity resources, whether from the supply or demand side, should be treated equally. Examples like these highlight the benefits of agencies working together. Public utility commissions may approve construction of new generation to meet certain reserve or capacity requirements without considering environmental factors. Air regulators may consider additional controls on generators of all sizes without realizing that the additional costs may actually cause air emissions to increase across the system, rather than decrease.

Three states – Connecticut, Maryland, and New Jersey – have taken further steps to try to integrate energy and environmental issues by including the environmental benefits of energy efficiency and renewable energy development into state implementation plans (SIPs) for the eight-hour ozone standard. EPA allows states to set aside a portion of their NOx allowances for qualifying energy efficiency and renewable energy projects. EPA began a Clean Air-Clean Energy Partnership program in 2005 to facilitate discussion among air and energy regulators, highlight successful case studies, and replicate their success more broadly. Fifteen states are now members of this, including Connecticut and Massachusetts.[49]

To date, no state has attempted to characterize the environmental benefits of demand response and incorporate them into a SIP. The National Action Plan for Energy Efficiency does include demand response as an important measure.[50] ISO-NE has indicated that, based upon modeling, DR can provide substantial environmental benefits, but as noted above, in pilot level DR programs like that in southwest Connecticut, air emissions actually increased. Obtaining actual data on emissions benefits and units dispatched and/or curtailed has been hampered by confidentiality requirements. Recent proposals to improve NEPOOL GIS data transparency for RGGI to determine the extent of leakage may also help improve analysis of emissions information from participating demand response units. The monitoring and verification protocols used to qualify and measure resource performance in the FCM would be amenable for application to air quality programs. These protocols are "SIP quality" (EPA has allowed the use of protocols developed by IPMVP for example, which are also used in the FCM) and their use by states for capturing the benefits of demand response and energy efficiency would be a positive step. SIPs are also in place

[47] "Energy Efficiency and Load Management in Connecticut", Cathy Lezon, CL&P, NASUCA Annual Conference, Miami, Florida, November 2006.

[48] www.comverge.com

[49] http://www.epa.gov/cleanenergy/stateandlocal/partnership.htm

[50] http://www.epa.gov/cleanenergy/pdf/napee/napee_report.pdf ISO-NE is part of the leadership group

for several years, so adding a demand response measure to them would complement the ISO efforts to provide certainty through longer-term program design and implementation.

C. Increase the Accuracy of Price Signals through Changes in Rate Design

Rate Design

FERC's implementation of EPAct05 includes study and application of differential rate structures by customer class, demand, and period. Among the programs being considered are time of use rates and critical peak pricing. In general, most large electricity customers have long taken advantage of rate designs that reflect marginal costs. This discussion therefore is mostly applicable to residential and small commercial/industrial customers, except where specifically noted.

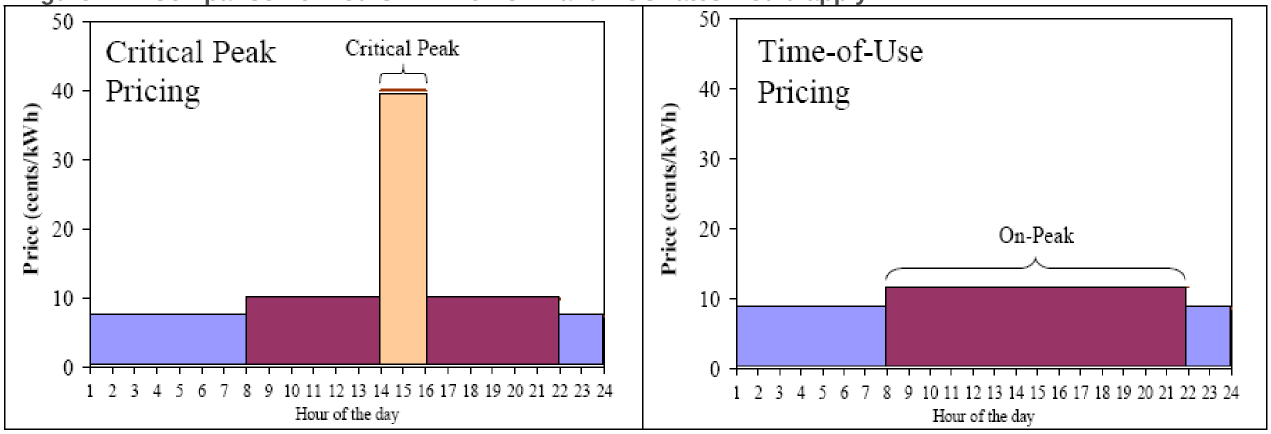
Time of Use (TOU) Rates: Time-of-use rates have been in place for the past two decades and are the most prevalent time varying rate, especially for residential customers, although they have often been discontinued where deregulation took place. In a TOU model, customers are charged based upon any usage during defined time periods. These time periods typically correlate to peak and slack demand periods by the time of day and sometimes by the day of the week. TOU customers are charged higher rates for usage during peak hour blocks and lower rates during off-peak periods**.**

In Maine, the Central Maine Power offers TOU delivery rate options to the majority of its customers, but the Standard Offer rates for the energy supply service under the company have TOU rates only for large customers.

A TOU rate has a number of advantages over real time pricing or critical peak pricing in that (1) prices are set for months or a year which makes customer bills predictable; (2) it does not require expensive two-way communication systems; and (3) TOU meters are less costly than real time or critical-peak pricing meters. However, TOU rates cannot adjust to reflect real time events such as cold snaps and heat waves and thus real time wholesale energy prices.

Critical Peak Pricing (CPP): Critical Peak Pricing (CPP) rates are relatively new to the United States with the first major CPP being implemented by Gulf Power in 2000. CPP is a newer, more sophisticated hybrid form of a TOU rate and real time pricing. It exposes customers to hourly electricity market prices for a limited number of peak hours during the peak seasons (i.e., critical peak periods). See Figure B-2 for a comparison between a TOU rate and a CPP.

Figure B-2. Comparison of hours in which CPP and TOU rates would apply



Source: FERC 2006

While TOU periods and rates are specified in advance in the tariff, CCP days typically are not. Instead, customers are notified of impending CPP days on relatively short notice, on a day-ahead or a day-of basis. Although the day of CPP events is not known, the prices that will be paid during CPP events can be predetermined in the tariff. Alternatively, the prices to be paid during CPP events could be variable, for example directly tied to day-ahead wholesale energy prices.[51]

CPP requires advanced metering infrastructure. This consists of interval meters that can collect interval consumption data and send price signals, as well as the capability to process the dramatically increased quantity of consumption data. Implementing interval meters and the associated data processing capability may require significant investment if that capability is not already in place. We discuss this enabling technology in more detail later in this Appendix.

CPP programs tend to require additional technologies that enhance customer price responsiveness including smart thermostats, load control switches, and single or multiple communication devices. These technologies tie price signals from the utility to home appliances and allow customers to program the level of temperature for HVAC appliances depending on the wholesale electric price conditions. The utility could also control these devices but customers could override the utility's price signals when a two-way communication system is installed.

Experience with Time-Differentiated Pricing

One study of utility experience with alternative rate design found the average reduction in peak consumption under TOU rates to be 20%. This was a report published by the American Energy Institute in 2001, titled *Economics of Real-Time and Time-of-Use Pricing for Residential Consumers*. That report includes references to studies by CMP regarding its TOU rates during the 1980s.[52] Those studies indicate that "TOU rates were cost

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[51] FERC 2006.

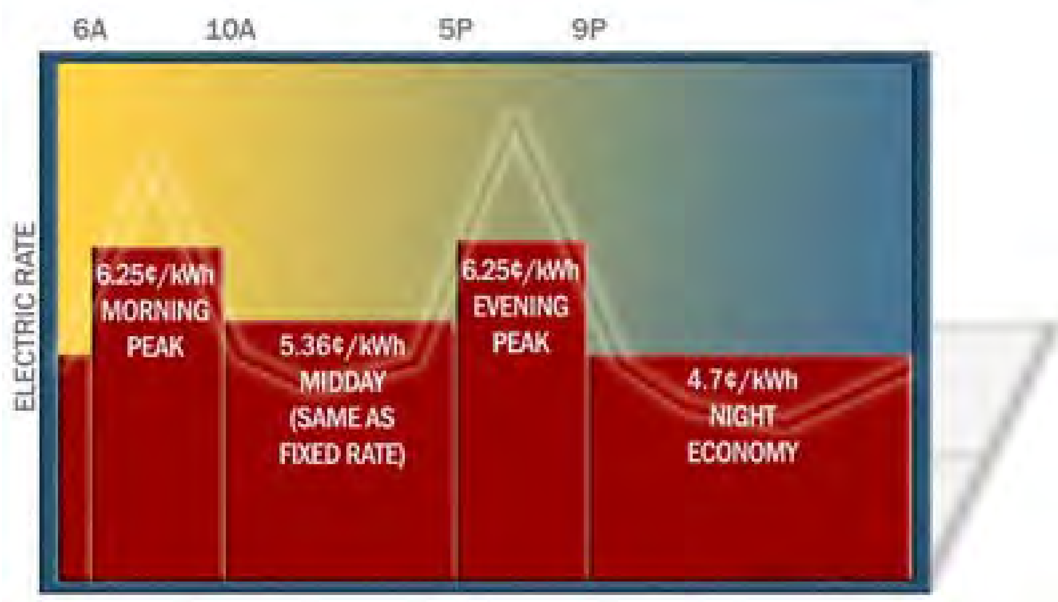
[52] Strategic Marketing Services 1989. Report to Central Maine Power Company Residential Time-of-Use Customer Survey; and Central Maine Power 1990. Impact Study of Residential Time-of-Use Rates.

effective after only three years of operation, with a benefit/cost ratio of 1.15. The ratio improves to 2.08 after six years." In fact, TOU rates for residential and small commercial or industrial customers have been tested extensively.

Puget Power implemented a TOU rate structure for small volume customers in 2001. Following approval from the WUTC, about 900,000 advanced meters were installed at residential and small Commercial/Industrial customers. Effects of the Enron-driven California electricity crisis migrated north, since that state imports significant quantities of hydroelectric resources from the Pacific Northwest. California had raised rates substantially, and a drought threatened hydro resources. Spot market prices had also risen greatly and the utility was concerned about the financial health of many of its customers.

Implementation of the rate structure, illustrated in Figure B-3, resulted in about a 4% reduction in peak demand, sufficient for the utility to consider it successful.[53]

Figure B-3



However, the program was abandoned earlier than expected in 2003. The market-driven crisis that caused electric prices to spike had ended, customers did not feel they were getting enough benefits for their participation, and in some cases bills actually increased for TOU customers. The average savings was less than $2 per customer per month. Larger price differentials were suggested, but not implemented.[54]

Critical Peak Pricing and Real Time Pricing

CPP and RTP programs appear to have achieved some success, both for participants and the utility. Several programs have been implemented, especially for residential customers. One consistent feature among them so far is that the small Commercial/Industrial and

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53 Source: http://www.energypriorities.com/entries/2006/02/pse_tou_amr_case.php

54 "Smart Meters, Demand Response and "Real-Time" Pricing: Too Many Questions and Not Many Answers", Barbara Alexandra, presented at NARUC annual meeting, July 2007.

residential CPP programs are voluntary. Gulf Power's program is the oldest and most cited CPP programs in the United States.

An on-going voluntary RTP pilot by Commonwealth Edison in Chicago also offers some positive lessons for the residential and low-income sectors. In the ComEd pilot, customers pay an additional $2.25 per month to cover the costs of advanced metering, and receive notice of hourly electricity prices. ComEd found that increases in hourly prices of 100% have caused customers to either curtail load and/or delay them to periods with lower prices. Participants have been able to reduce their bills, and the program was expanded in early 2007 to permit up to 110,000 customers to participate. Full analysis of the Chicago program will be completed during 2008.

California has three critical peak pilots focused on the residential sector.[55] Gulf Power's GoodCents® Select program had more than 6,000 participants as of 2003, representing approximately **2%** of the total residential customers.[56] Participants in the program pay about $5 each month for the program costs (e.g., costs of the equipment and service), but the Company estimates that each household saves 1,433 kWh per year on average that translates into a savings of $183 per year.[57]

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55 http://www.emeter.com/news/articles/article041214.php

56 FERC 2006; Oregon Public Utility Commission, 2003, *Demand Response Programs for Oregon Utilities*, page 39, available at http://www.puc.state.or.us/PUC/electric_gas/demand/index.shtml

57 Ib. page 39

Enabling Technologies

Time of Use and Interval Meters

A time of use (TOU) meter has several bands to record energy usage and possibly other parameters such as reactive power for different time periods (e.g., on-peak and off-peak). A meter's cost ranges from $30 to $120, which tends to vary depending on the number of bands to record energy usage and other information.

An interval or real time meter records energy usage and other parameters associated with power quality hourly or more frequently. It is often used for real time pricing programs for large commercial and industrial customers, and more recently for critical peak pricing programs for all types of customers. This type of meter is more expensive than a TOU meter.

Advanced Metering

Advanced meters allow utilities to record and collect ratepayer electricity usage in close to real-time. Information can also be communicated from the utility to the ratepayer in the form of price signals. For utilities, advanced meters enable them to work with system operators and dispatchers in real-time to evaluate the adequacy of the energy resources being run, and to take pre-emptive actions to avoid disruptions, should actual load be higher than expected and/or should any assets be disrupted. For customers, seeing price signals can help them to decide whether to curtail load, operate back up generation, and/or to shift load to a different time period.

The Energy Policy Act of 2005 (EPAct05) required states to consider requiring utilities to offer time-based metering and communication to each customer class.[58] The law was specific in describing the types of schedules that were to be offered; these include: time-of-use, critical peak pricing, and real-time pricing. States were also required complete studies within 18 months of enactment and to make a decision as to whether or not it was appropriate to adopt time of day pricing and advanced metering regulations.

As part of FERC's implementing responsibilities under EPAct05, the agency completed a study to evaluate the penetration of advanced metering throughout the United States. The survey results reflect that, as of April 2006, Maine has a total of approximately 785,300 meters. Of those, about 112,000 are considered advanced. Maine's penetration rate of 14% is the fifth highest in the United States, after Pennsylvania, Wisconsin, Connecticut, and Idaho. Elsewhere in New England, Vermont had only one advanced meter at the time the FERC survey was completed; Massachusetts had about 6,000, out of a total of about 3,650,000.[59] However, it is important to note that the statistics reported in that study incorrectly include meters that could be read through automated meter reading in their count of advanced meters.

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[58] See Energy Policy Act of 2005, section 1252, signed into law August 8, 2005.

[59] FERC Assessment of Demand Response Resources, Docket No. AD06-2-000, March 15, 2006, responses were required to be returned to FERC by April 12, 2006.

The Demand Response and Advanced Metering (DRAM) coalition, an industry-based association in Washington, DC, has been working with the Federal Energy Regulatory Commission (FERC) to implement applicable sections of EPAct05. To facilitate that discussion, DRAM has developed consistent definitions for “advanced meter” and “advanced metering system.”[60] Advanced meters are similar in appearance to conventional meters, as shown in Figure B- 4.

Figure B - 4

The meter shown in Figure B-4 is manufactured by Altimus and is capable of registering several functions, including time of use, demand, and load profile recording.[61]

Advanced Metering Infrastructure

Advanced metering infrastructure (AMI) is a communication network infrastructure that enables and enhances the use of advanced meter reading. The Federal Energy Regulatory Commission or FERC defines AMI as “a metering system that records

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[60] Comments of Demand Response and Advanced Metering Coalition (DRAM) to FERC Docket AD06-2-000 Assessment of Demand Response Resources In Response to November 3, 2005 Notice of Proposed Voluntary Survey and Technical Conference. “Advanced Meter :An electric meter, new or appropriately retrofitted, which is 1) capable of measuring and recording usage data in time differentiated registers, including hourly or such interval as is specified by regulatory authorities, 2) allows electric consumers, suppliers and service providers to participate in all types of price- based demand response programs, and 3) which provides other data and functionality that address power quality and other electricity service issues.

[61] Image captured from http://www.landisgyr.us/Landis_Gyr/Meters/AX.asp October 2007.

customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."[62] Advanced metering could also measure gas and water consumption at customer sites.

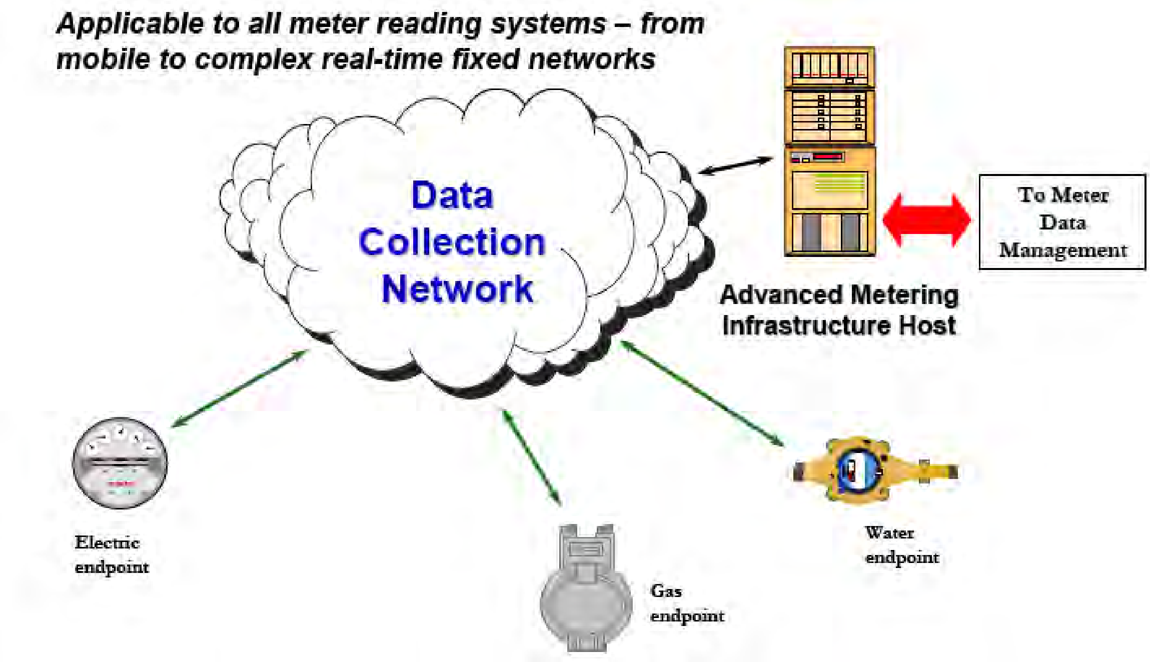
AMI has been gaining significant attention in recent years because of its potential to support and promote the increased use of demand response, energy efficiency, and distributed generation and to manage the power grid more efficiently and reliably. Specifically, the potential benefits of AMI include:

- Ability to remotely change metering parameters
- Outage detection, notification, and management
- Pre-paid metering
- More accurate load forecasting to meet customer demand
- More accurate supply and demand match and reduced costs associated with imbalance, standby, storage, injection, and withdrawal.
- Reduced congestion cost
- Reduced probability of blackouts, forced outages/interruptions
- Improved asset management, including transformer sizing
- Enhanced customer service
- Interface with water or gas meters
- Pricing event notification
- Power quality monitoring
- Tamper detection
- Power theft detection
- Greater control over customer load in real time which allows for provision of ancillary service using customer load (note: this benefit can be provided without metering but with the communication network and load control devices such as smart thermostats and load control switches)

Despite these numerous potential benefits that AMI could provide, there are various barriers to its implementation.These barriers include the high cost of investment and difficulty in finding cost-effective technologies, program designs, and cost recovery mechanisms.

[62] Federal Energy Regulatory Commission (FERC) 2006. Assessment of Demand Response & Advanced Metering Staff Report under Docket AD-06-2-000, August 2006, Page 17

Figure B-5 AMI Data Communication System



Source: FERC 2006. Original source for the figure is UtiliPoint International

AMI mainly consists of advanced metering, a data collection and communication network, and an AMI host system and database.[63] The data collection and communication network allows advanced meters to send hourly or more frequent load data to a utility. They also typically allow for two-way communication between the utility and its customers regarding various information such as wholesale energy data, outage events, and load curtailment actions. For this information communication, AMI can use home computers, smart thermostats, and/or load control switches to enhance the customer responsiveness to wholesale price signals. This network of home appliances and control switches is often called a Home-Area Network (HAN).[64] The following figure presents an interaction of an AMI and a HAN.

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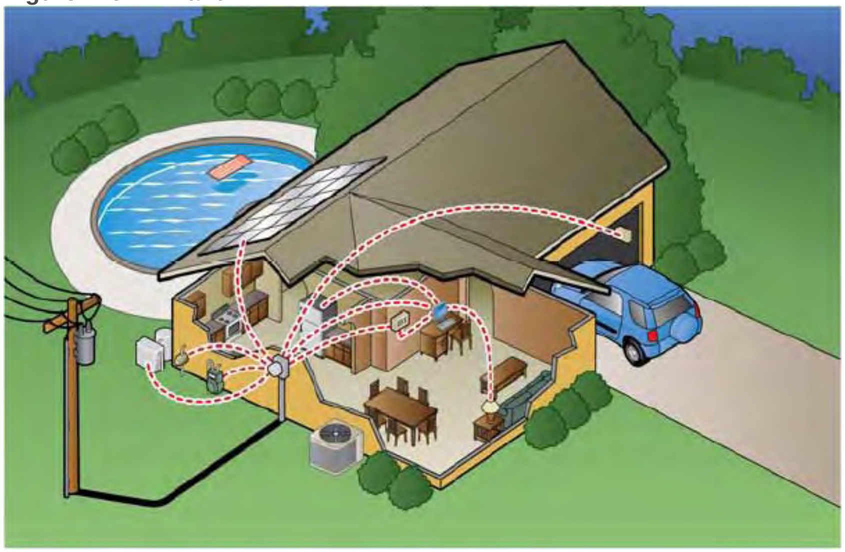
[63] Note advanced meter technology is different from automated meter reading (AMR) technology that has been installed by many utilities. AMR allows for meter reading remotely by driving by or walking by outside of a building and does not have any functionality to enhance demand responsiveness unl ke AMI.

[64] FERC 2007. Assessment of Demand Response & Advanced Metering 2007 Staff Report, September 2007.

Figure B-6. AMI and HAN



Source: FERC 2007. The original source is Southern California Edison.

The network technologies used to communicate data between a data center and end users are generally categorized into broadband over power line (BPL), power line communications (PLC), fixed radio frequency (RF) networks, and systems utilizing public networks such as phones, pagers, and the Internet. BPL uses the existing electric transmission and distribution system to send data to and from customers at high frequency radio signals. It can send large amount of data at high speed and could even allow customers to use high speed internet via the power grid. PLC also uses the grid system but sends data signals at low frequency signals. Fixed RF networks send radio signals using private networks. Among these technologies, BPL appears to require largest investment because a utility needs to install various types of equipment on the electric grid. The least expensive technology is likely to use public networks such as the Internet. According to FERC, fixed RF has been the most deployed technology among all types of technologies for AMI.[65]

Smart Grids

One of the newer and potentially promising technology developments is referred to as a smart grid. A basic hypothesis is that much of the existing generating assets in the United States are under-utilized, and that through a technique referred to as “valley filling,” the capacity factors of all generating units can be optimized. Combining measures that reduce peak demand, like effective demand response programs, with those that create off-peak demand, such as plug-in hybrid electric vehicles, could substantially increase generating capacity factors, improve reliability, and defer the need to upgrade or build new transmission capacity.

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[65] Federal Energy Regulatory Commission (FERC) 2006. Assessment of Demand Response & Advanced Metering, Staff Report under Docket AD-06-2-000, August 2006, page 32.

The US DOE has a comprehensive smart grid initiative to integrate distributed energy resources and demand response in order to reduce peak electric demand nationally 20% by 2015. DOE has embarked on several complementary initiatives to increase awareness of this mission and to promote development of policies and regulations that can help to meet their peak demand reduction goal. Interconnection protocols are one such focus; IEEE standard 1547 is designed to enable safe and standard connection of small generation to the grid.[66]

Smart grids would have to be integrated with other policies and programs – including significantly increasing the quantity of distributed generation, especially renewables; advanced metering technologies; consistent interconnection standards; and rapid, even real-time price signals to enable consumers to appropriately respond.

Customer Side Technologies

Load Control Switches

A load control switch can disconnect or cycle the operation of end use appliances such as air conditioner, water heater or space heater. This technology has been used by utilities for decades for their direct load control programs. Yet, they are still valuable for reducing customers' load and in fact can be used to enhance customers' ability to respond to high energy prices using other technologies such as a smart-thermostat and an advanced metering infrastructure.

Smart Thermostat

There are a variety of smart thermostats. A simple, inexpensive one is a programmable thermostat that allows customers to pre-set temperature levels for specific hours and days of a week to control HVAC appliances. This is a typical appliance to save energy but can be used to reduce peak demand. A more complex smart thermostat allows a utility to override customers' presetting temperature levels so that a utility can mitigate the system peak demand. This type of thermostat enables communication between advanced metering and appliances and allows a customer to set temperature depending on pricing levels.

On-site Generation

Large customers who own on-site/back-up generators can use the generators to enhance their ability to respond to price signals when cost-effective. However, since many back-up generators use diesel fuels to generate electricity, air pollution could be increased dramatically. Also, a state air regulator may restrict operational hours of diesel generators.

Communication Technologies

[66] IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems", 2003.

Pagers, telephone lines, digital cellular phones, and the Internet can be used to communicate price or load control signals between customers and a utility. More specifically, a utility can utilize these technologies to send price or load dispatch signals directly to customer cell phones, pagers, advanced meters, and/or smart thermostats. Customers can respond to such signals by reducing their consumption manually or automatically using programmable thermostats. In contrast, a traditional load control program directly controls appliances using radio signals and does not allow consumers to override the controls.

D. Program Design: Provide Certainty and Framework to Enable Long-term Business Decisions

Increasing the level of demand response and sustaining this over time requires that the agency or agencies responsible for program design and oversight provide certainty for customers and to the market. Economic signals need to be aligned with customers' business needs and risk. This is especially true for successful programs focused on peak load reductions, since customers are required to purchase (or lease), install, and maintain equipment that can have substantial costs compared their annual energy expenses. Many businesses operate on short planning horizons and are unwilling to commit extensive capital unless they can be assured of a return on their investment in two or three years. Program designs that seek to procure demand response resources over a several year period promote certainty and stability, even when annual reviews and adjustments are made. Providing incentives and/or rebates to defray or share in the purchase of equipment also helps to maintain participant interest in the program and to build support for incremental additions. Demand response program payments that flow back to the in-state cost center, rather than to the corporate headquarters, are also important for businesses with many locations in the same state and/or those with multi-state operations.

ISO-NE's existing DR program, operating since 2003, is an example of the type of longer-term certainty that can be beneficial to participants and customers. The four-year planning horizon enabled businesses to analyze the expected payments against what they would need to invest in both equipment and people to participate. Four years was not sufficient to attract any real quantities of energy efficiency, but for straight ahead generation and load management projects, this time horizon enabled a number of participants to be compensated adequately.

Provide Certainty in Program Design

Results of demand response program studies completed since 2003 conclude that:

- Demand response participants desire payment at levels that reflect the amount of effort they have made and their business risk.
- Participants want a flexible menu of payments that include direct components, such as a check each month, and indirect, such as rebates for equipment purchases or access to revolving funds. Alternatively, participants want the ability to take advantage of lower rates in return for their demand response efforts.

- Incentive payments should ideally be equal to, or greater than, 10-15% of the participant's energy bill. Payments should flow back directly to the cost center, not to the corporate parent. Government agencies are comfortable with lower incentive payments. Those in the area of 5% were seen to be attractive enough to entice response, reflecting government's longer economic time horizon.

This last point bears highlighting. Many corporations now have locations across several states and/or many locations within one state. Energy bills tend to be paid for by the local store or company, but the corporate parent is often the recipient of benefits paid under DR programs.

Demand response in New England has improved in the last several years. The longer program design and incentive payments have promoted increased participation. However, in the near term, the barriers and gaming have hampered DR from achieving its optimal potential. The following gaming has occurred in New England and in Maine, according to companies engaged in enrolling participants:

- Potential responders sign up in the fall, aware that they can receive several months of payments before they may be called on to respond.
- Some participants install a much larger generator than necessary so they can receive higher capacity payment, i.e. they install a 500 kW generator for a 100 kW load.
- Other participants agree to curtail loads that are higher than their demand, aware that, if they time their participation correctly, they can receive payments for several months without having to actually respond.

Penalties for non-performance are forward looking. In these cases, the participant's curtailment is reset to either zero (if they don't respond at all) or to the level they actually provided.[67]

[67] Based on telephone conversations with Donald Sipe and Henry Yoshimura