Synapse
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Incorporating Energy Efficiency into the ISO New England Forward Capacity Market:

Ensuring the Capacity Market Properly Values Energy Efficiency Resources

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1. Introduction and Summary

The Settlement Agreement filed with the Federal Energy Regulatory Commission on March 6, 2006, was the result of a four-month effort by a broad and diverse group of New England stakeholders to resolve complex and controversial issues related to the ISO New England administered capacity market. This draft whitepaper examines one particular aspect of the Settlement Agreement: the decision to provide a mechanism for energy efficiency resources to be able to participate in the new Forward Capacity Market (FCM). We focus on one of the central issues that arise with the introduction of energy efficiency in the FCM: how should energy efficiency resources be treated in the determination of peak demand?

There are two points in time where the treatment of energy efficiency in determining peak demand is relevant: (a) when the forward capacity auction is conducted (in the auction year), and (b) when the costs incurred in the FCM are allocated to load serving entities (in the delivery year). Consistent with the goals of the Settlement Agreement and ISO New England's responsibilities as the FERC-approved regional transmission operator, we recommend that energy efficiency resources be treated as follows:

- In the auction year, estimates of peak demand savings from energy efficiency programs that are eligible to bid in the FCM should not be used to reduce the Installed Capacity Requirement. Instead, the energy efficiency programs should be treated separately from the ICR process, because they are a resource that is eligible to bid in the FCM comparable to supply-side resources.

- In the delivery year, the load ratio shares that are used to allocate the costs of the FCM to load serving entities (LSEs) should be based on actual, metered peak demands that occur in the previous year. This is the best way to ensure that the costs of the FCM are properly allocated to the LSEs that are responsible for the actual capacity demand in the delivery year.

One of the important principles that was embodied in the Settlement Agreement was the creation of an incentive for capacity resources to be available during actual times of the New England system peak loads and to financially reward resources that improve the overall reliability of the system. The Settlement Agreement attempts to advance this principle through the initial qualification process for resources, the assignment of a qualified capacity value for each resource, availability requirements during the delivery year, and the linkage of payments to actual "shortage hours" in the delivery year.

Another important principle that should be applied to the new capacity market structure, and indeed to all market structures implemented by ISO New England, is that the market rules should support competitive and efficient market structures as a means of ensuring an appropriate outcome for all market participants and, ultimately, the end use consumers of electricity. This is a bedrock principle incorporated in the initial formation of ISO

New England as the system operator in 1997 and maintained through its evolution into a regional transmission organization (RTO) in 2004.[1]

These two principles, resource payments that are scaled to the reliability that a resource provides to the system and the use of competition to maximize market efficiency, are just as applicable for demand resources as supply resources. Our recommendations for how energy efficiency resources should be treated, as summarized above, will ensure that these two principles are met.

In addition, we provide an illustrative example of how the treatment of energy efficiency resources in the FCM will affect the relevant LSEs using hypothetical, but realistic, assumptions. Our example indicates that any reallocation of FCM auction costs during the delivery year as a result of qualified energy efficiency resources will be small. We provide additional examples (using different assumptions) in the Appendix that confirm this.

2. Treatment of Energy Efficiency in Peak Demand Determinations

2.1 The Roles of Peak Demand in the Forward Capacity Market

With the introduction of energy efficiency resources into the Forward Capacity Market (FCM), it will be necessary to determine how the savings from these resources will be treated in forecasting and then determining peak demand. LSEs' peak demands play a role at two key points in the FCM: (a) when the forward capacity auction is conducted, and (b) when the costs incurred in the forward capacity auction are allocated to LSEs in the delivery year. Each of these points in the FCM is discussed separately below.

When the Auction is Conducted – Installed Capacity Requirement

When the FCM auction for any one year is conducted, ISO New England (ISO-NE or ISO) will set the Installed Capacity Requirement (ICR) for the New England system. The ICR represents the amount of total capacity that will be purchased through the FCM auction.

Because this is a three-year forward auction, the ICR will be set three years in advance of when the capacity will actually be delivered. For example, for capacity resources that will be delivered in the 2011/12 power year (beginning June 1, 2011), the FCM auction will

[1] The September 14, 2004 RTO-NE tariff filed with FERC (and approved November 3, 2004) specifies in section 1.1.3 (b) of the tariff that the objectives of RTO-NE include:

> to create and sustain open, non-discriminatory, competitive, unbundled markets for energy capacity, and ancillary services (including Operating Reserves) that are (i) economically efficient and balanced between buyers and sellers, and (ii) provide an opportunity for a participant to receive compensation through the market for a service it provides, in a manner consistent with proper standards of reliability and the long-term sustainability of competitive markets.

be conducted in the early months of 2008. The ICR will need to be established prior to that auction, perhaps as early as January of 2008.

The ICR is based on several factors. It starts with a load forecast that estimates what the New England peak demand will be three years into the future. The ICR also includes other factors, of which two important ones are (a) line losses between generators and end-use demand, and (b) a reserve margin. As calculated in the ICR the line loss adjustment for peak load conditions is approximately 8%. The reserve margin adjustment for the ICR is approximately 15%. The compound effect of these two adjustments is roughly 24%.[2]

When the Capacity is Purchased – Determining Capacity Payments

At the time that the capacity is required and purchased by LSEs (the delivery year, three years after the auction is conducted) ISO New England will make another determination of peak demand. This second determination is necessary to identify the amount that each LSE must pay for their portion of the capacity provided through the FCM. This determination of peak demand for the delivery year represents the *actual* peak demand experienced in New England the prior summer.

Consistent with our timeline of an FCM auction in early 2008 for delivery in the 2011/12 power year, the peak demand for cost allocation would be based on the 2010 summer peak load. Under current rules it is determined after-the-fact, based on actual meter reads on the peak day in the summer, and is expressed as a "load ratio share" for each LSE. In the delivery year, the ISO first calculates the total of the capacity payments to qualified resources for each month.[3] Second, the ISO bills each LSE their pro-rata share of the monthly total capacity payment based on each LSE's summer peak day load ratio share.

2.2 Treatment of Energy Efficiency in Peak Demand Determinations

When the Auction is Conducted – Installed Capacity Requirement

Current Forecasting Methodology

ISO New England currently makes independent forecasts of the electricity demand in New England, both for the short-term and for the long-term. These forecasts are based on historic demands, plus consideration of future economic activity, demographic activity and other drivers. It is anticipated that these forecasts will continue to be used for setting

[2] There are other inputs into the ICR calculation, including estimates of specific demand response resources, HQICC values, and ties benefits, to name a few. We are not suggesting any changes to these inputs as part of the approach for valuing and paying energy efficiency resources.

[3] Each resource's capacity payment will be based on availability metrics and actual performance as briefly discussed in the Introduction to this paper. The adjustments to each resource's payment will not affect the total pool of dollars that will be allocated to LSEs; to the extent that a particular resource's payment is reduced for unavailability or poor performance, other resources will see their payments adjusted upward. This was an explicit design feature of the FCM that was incorporated into the Settlement Agreement.

the ICR for the FCM. LSEs in New England provide the ISO with forecasts of their expected amount of peak energy efficiency savings for future years. These energy efficiency savings are then subtracted from the ISO load forecast. Thus, ISO forecasts are currently intended to represent, to the best extent possible, the system demand that will need to be met with supply resources in the relevant future years.

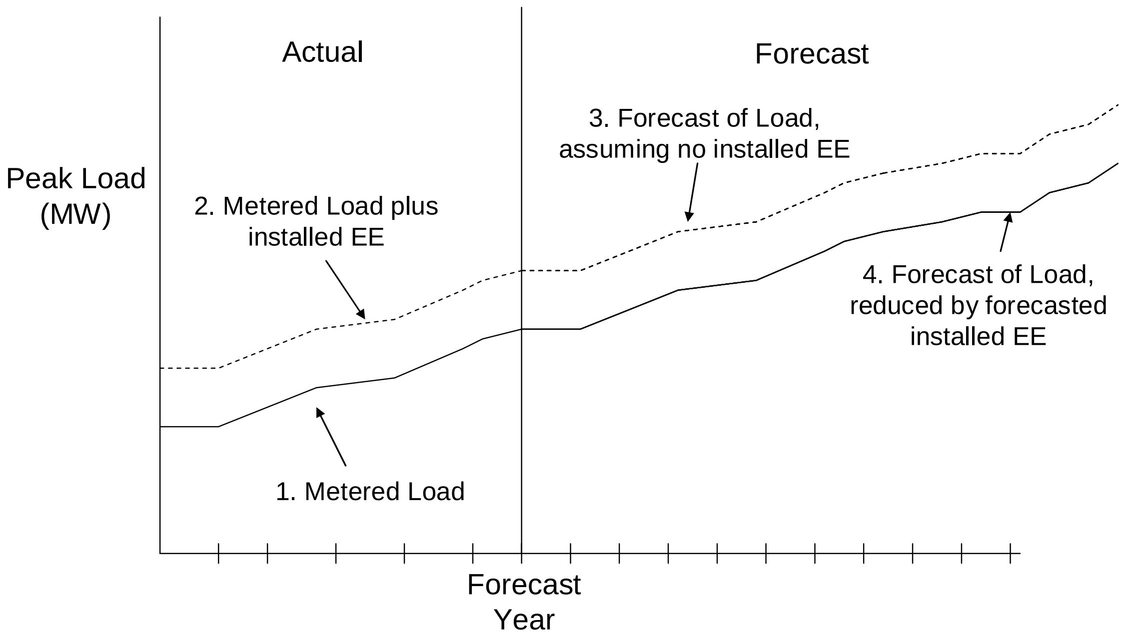

Figure 1 - Current Treatment of Energy Efficiency in ISO Peak Load Forecast

Figure 1 above gives an illustrative representation of how the ISO currently creates its load forecast. The first step is to gather the metered load for the recent past. Next, the ISO increases these data by the amount of installed energy efficiency measures that we know have been installed. This new line is now used as a baseline. Along with various economic models and understandings of load growth and naturally occurring energy efficiency, the ISO is able to extend this line out into the future, creating the dotted forecast line (#3) in the figure above: the forecast of peak load assumes no future installations of energy efficiency measures.

The last step in the current load forecast procedure is to then reduce this amount by the energy efficiency measures that will be installed, as reported to the ISO by the various LSEs in New England. This is represented by the solid line (#4) in the figure.

Forecasting Methodology for the New Forward Capacity Market

In setting the ICR for the FCM, the LSEs' forecasts of peak savings from new energy efficiency programs should *not* be subtracted from the peak demand forecast. Instead, peak savings from new energy efficiency programs should simply be left out of the ICR. In this way, the energy efficiency programs will be treated as a resource that can be used to meet the ICR.[4] Figure 2 indicates how energy efficiency should be treated in setting the ICR for the FCM.

By "new" programs we are referring to those energy efficiency programs, either from regulated utilities, municipals, or merchant providers that are eligible to be bid into the FCM auction. Energy efficiency programs that were implemented before the beginning of the FCM should continue to be accounted for in the ICR. Also, energy efficiency programs that are implemented in the future, but are not eligible to be bid into the FCM should also be accounted for in the ICR. In sum, the ICR should only be reduced to account for the energy efficiency programs that are not eligible to participate in the FCM.

The ICR is intended to be a "requirements forecast" – i.e., a forecast of the amount of capacity required from the FCM. It is not simply a forecast of peak demand. Since the energy efficiency programs can be offered as a capacity resource in the FCM, those savings (reduced load) should not be included in the ICR determination.

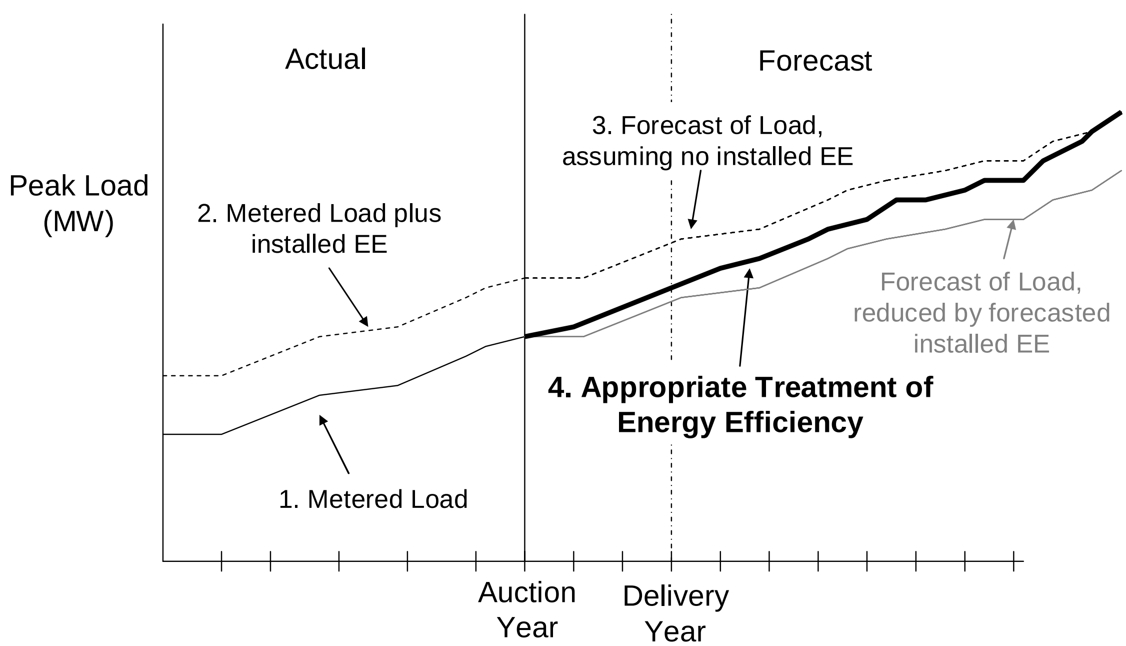

Figure 2 - Appropriate Treatment of Energy Efficiency in Setting the ICR for the FCM

As we can see in Figure 2 above, the appropriate treatment of energy efficiency in setting the ICR for the FCM is to reduce the load forecast **only** by the amount of existing, installed energy efficiency and any future energy efficiency programs not eligible to

[4] As discussed in the ISO New England draft rules for the transition period, energy efficiency resources will have their MW values increased to account for the T&D losses and reserve requirements that are included for traditional supply resources. As an example, a 100 MW energy efficiency resource would be bid in as a 124 MW resource in the FCM auction because it incurs neither line losses nor needs reserves.

receive capacity payments. As existing programs reach the ends of their measure lives, their impact on peak load will fade. Any efficiency measures bid into the auction should not reduce the load forecast.

If the peak savings from the new energy efficiency programs were included in the ICR determination, thereby lowering the amount of total capacity purchased from supply-side and demand-side resources, then the FCM would risk not having enough supply-side resources to meet the actual peak demand. In other words, treating energy efficiency as a capacity resource in the FCM instead of a reduction in the ICR serves to both increase the requirement [demand] for new capacity and increase the supply of new capacity.

Separately, energy efficiency savings from energy service companies (ESCOs) and large electricity customers that are eligible to bid into the FCM (i.e., merchant energy efficiency resources) should not be subtracted from the peak demand forecast in setting the ICR. The rationale here is the same as for the LSE efficiency savings: efficiency savings from measures that are eligible to be bid into the FCM should be excluded from the ICR to ensure that the proper amount of capacity will be purchased to meet the actual peak demand in the delivery year.

Note that in setting the ICR, the peak load forecast should account for "naturally occurring" energy efficiency, as well as energy efficiency that is expected to result from the introduction of building codes, appliance standards, or other public policies that might encourage customers to adopt more efficient consumption patterns. These are efficiency savings that would be expected to occur regardless of the FCM, and whose demand reductions would not be offered as part of the resources bidding into the FCM. These adjustments would occur as reductions to the initial load forecast and be represented in line #3 in Figure 2.

When the Capacity is Purchased – Determining Capacity Payments

The treatment of energy efficiency at the time capacity is purchased and payments are made is much simpler than in setting the ICR. At this point in time, the actual peak demand for each LSE will be known, based on measured readings at the time of the summer annual system peak. This *actual* peak demand should be used in determining each LSE's load ratio share, and thus each LSE's portion of the total cost of the FCM. In this way, energy efficiency savings from efficiency resources provided to the FCM by LSEs, ESCos and customers will be automatically "subtracted" from what otherwise would have been the peak demand. This is the only way to ensure that the FCM costs are properly allocated to the LSEs based on their contribution to peak demand.

It may seem counterintuitive to ignore forecasted energy efficiency savings from LSEs (and ESCos and customers) in setting the ICR, but to account for those savings in the peak demand used to set the load ratio shares. Nonetheless, this is entirely appropriate. The ICR is not intended to be a forecast of what the peak demand will actually be in three years. Instead, it is intended to be a requirements forecast for the FCM, to indicate the amount of total supply-side and demand-side resources that are needed in the market. The peak demand used to set the load ratio shares is appropriately based on the actual peak demands of each LSE – in order to ensure that each LSE contributes to the FCM payments based on their fair share of their contribution to system peak.

More importantly, by basing the cost allocation of the FCM on each LSE's load ratio share as measured just prior to the delivery year, an incentive is created for LSEs to encourage their customer base to develop the maximum amount of energy efficiency resources that are cheaper than the clearing price in the FCM. To the extent that one LSE's load is more efficient and another LSE's load is less so, the LSE where greater energy efficiency investments occurred will pay a slightly smaller percentage of the FCM costs in the delivery year. However, if all LSEs experience similar or equal level of energy efficiency resources installed through the FCM, then their load ratio shares will remain the same relative to each other.

Such "competition" among LSEs will lead to greater overall efficiency improvements to loads. Assuming that new energy efficiency resources will displace more expensive marginal units in the FCM auction, the outcome will be lower costs to all LSEs relative to what they would have been if fewer energy efficiency resources had been acquired. Just as generators have a market obligation to provide the most efficient supply possible, so too LSEs have an obligation to serve their load as efficiently as possible. As mentioned in the introduction, this is one of ISO New England's fundamental obligations as the FERC-approved system operator.[5]

This competition to serve load as efficiently as possible may take shape in a number of ways. State regulators can mandate greater levels of DSM funding, LSEs might encourage the activity of ESCos and customers, and ESCos will seek out economic opportunities on their own. In the long run, because energy efficiency opportunities are generally equally distributed among loads, the amount installed in any one area should balance with the amounts installed in other areas.

2.3 Impacts on Energy Efficiency Providers and Load Serving Entities

Energy Efficiency Providers

Those entities that bid a portfolio of energy efficiency resources into the FCM auction will receive payments during the delivery year for the capacity that has been purchased. These payments will be equal to the monthly FCM auction clearing price times the amount of efficiency peak demand savings that was bid into the FCM auction, adjusted up for the reserve margin and losses.[6]

For example, assuming that the FCM auction clears at a price of roughly $6.05/kW-month,[7] each energy efficiency resource that provided one kW of reduction to load during

[5] RTO-NE Tariff section 1.1.3 (b).

[6] These peak demand savings will have to be properly monitored and verified in order to receive such payments. The issues related to energy efficiency monitoring and verification are not addressed in this paper.

[7] The clearing price may vary significantly from year to year. This price presented here is merely illustrative.

peak hours would be paid $7.50/kW-month (1kW times 1.24 times $6.05). For the entire year, each energy efficiency provider would be paid $90/kW-year for each kW of load reduction. Assuming that an energy efficiency resource has an average measure life of ten years, then the energy efficiency provider could receive a total of $900/kW over the total ten-year life of its energy efficiency resource.[8]

Load Serving Entities

In general, LSEs will see two effects of energy efficiency in the FCM.[9] First, the clearing price for the FCM will be lower as a result of the introduction of new low-cost energy efficiency resources.[10] Therefore, all LSEs will see lower prices for capacity from the FCM, and therefore lower overall capacity costs.

Second, the load ratio shares will be different as a result of the peak demand savings from the energy efficiency resources. The total peak demand on the ISO New England system will be lower than it otherwise would have been in the absence of the peak demand savings from energy efficiency. Those LSEs who experience energy efficiency savings below average in New England will represent a larger portion of the total ISO peak demand, will thus have a higher load ratio share, and will therefore pay a greater share of the total cost for the FCM. This greater share of the total cost for the FCM may or may not be offset by the lower price for FCM capacity, depending upon the size of each effect.

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[8] For simplicity, we do not make any adjustments for the "net present value" for this example or other examples in this paper.

[9] LSEs will also see savings in the energy markets (Day-Ahead and Real-Time) because the hourly demands will be reduced by energy efficiency programs, thereby lowering the energy clearing prices in those markets. Although this paper addresses only the new FCM, these additional savings to *all* LSEs should not be overlooked.

[10] The extent to which this is true depends upon the quantity of energy efficiency resources that clear and how steep the resource supply curve is at the point where it intersects the peak demand curve. If the resource supply curve is steep, e.g., in times when capacity in New England is tight, the inclusion of energy efficiency resources will result in a significant reduction in FCM clearing prices.

Illustrative Values for Power Year 2011-2012

Installed Capacity Requirement (MW)
36,750 (summer 2010 peak load x 1.5% growth x 15% reserve margin)

Capacity Clearing Price ($/kWh)
$ 6.05

Total Cost of Capacity ($m)
$ 2,668

				Reconsituted Load		Metered Load		Delta		
LSE	**Summer 2010 Peak Load (MW)**	**%EE**	**EE (MW)**	**Peak Load Ratio Share**	**Capacity Cost ($m)**	**Peak Load Ratio Share**	**Capacity Cost ($m)**	**Peak Load Ratio Share**	**Capacity Cost ($m)**	**Capacity Cost (%)**
NU	7,000	0.6%	42	22.25%	593.61	22.22%	592.90	-0.03%	(0.71)	-0.12%
UI	1,500	0.5%	8	4.76%	127.12	4.76%	127.05	0.00%	(0.07)	-0.05%
NGrid	9,000	0.5%	45	28.58%	762.46	28.57%	762.30	-0.01%	(0.16)	-0.02%
NStar	4,500	0.5%	22	14.29%	381.19	14.29%	381.15	0.00%	(0.04)	-0.01%
VELCO	1,300	0.8%	10	4.14%	110.43	4.13%	110.11	-0.01%	(0.32)	-0.29%
PSNH	1,800	0.3%	5	5.70%	152.15	5.71%	152.46	0.01%	0.31	0.20%
CMP/BH	4,000	0.4%	16	12.69%	338.53	12.70%	338.80	0.01%	0.27	0.08%
MA Munis	1,200	0.1%	1	3.79%	101.24	3.81%	101.64	0.02%	0.40	0.40%
CT Munis	1,200	0.2%	2	3.80%	101.32	3.81%	101.64	0.01%	0.32	0.31%
Totals	31,500		151	100%	2,668	100%	2,668	0%	0.00	

Table 1 – The Impact of Energy Efficiency on Peak Load Ratio Shares

Table 1, above, illustrates the effect of calculating capacity payments in two different ways. Using illustrative numbers for the major LSEs in New England[11], we can see that by including energy efficiency measures in the calculation of Peak Load Ratio Share (i.e., using recorded meter data, without reconstituting loads) we create a small financial incentive for LSEs to serve their loads efficiently. Those LSEs that can encourage energy efficiency programs more aggressively will – in any one year – reduce their share of the total capacity cost. This effect can be seen in the delta of Peak Load Ratio Share column in Table 1 above. If we assume that in the long run all LSE loads will implement all economic energy efficiency measures, this effect will eventually balance out.

[11] We are aware of the inherent problems of making assumptions about specific LSEs, about both their loads and their DSM programs. The specific values used in our example are only approximations and assumptions. We think that the load numbers are rough estimates of the real numbers. However, the assumptions about DSM quantities were arbitrarily varied so that the illustrative example would produce a range of results for different levels of DSM investments (ranging from 0.1% to 0.88%)

Illustrative Values for Power Year 2011-2012

Installed Capacity Requirement (MW)

36,750 (summer 2010 peak load x 1.5% growth x 15% reserve margin)

Capacity Clearing Price ($/kWh)

$	6.05	without EE
$	6.00	with EE

Total Cost of Capacity ($m)

$	2,668	without EE
$	2,646	with EE

				Reconsituted Load		Metered Load		Delta		5 Cent Impact	
LSE	Summer 2010 Peak Load (MW)	%EE	EE (MW)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Capacity Cost ($m)	Capacity Cost (%)	Capacity Cost ($m)	Capacity Cost (%)
NU	7,000	0.6%	42	22.25%	593.61	22.22%	592.90	(0.71)	-0.12%	(4.90)	-0.83%
UI	1,500	0.5%	8	4.76%	127.12	4.76%	127.05	(0.07)	-0.05%	(1.05)	-0.83%
NGrid	9,000	0.5%	45	28.58%	762.46	28.57%	762.30	(0.16)	-0.02%	(6.30)	-0.83%
NStar	4,500	0.5%	22	14.29%	381.19	14.29%	381.15	(0.04)	-0.01%	(3.15)	-0.83%
VELCO	1,300	0.8%	10	4.14%	110.43	4.13%	110.11	(0.32)	-0.29%	(0.91)	-0.83%
PSNH	1,800	0.3%	5	5.70%	152.15	5.71%	152.46	0.31	0.20%	(1.26)	-0.83%
CMP/BH	4,000	0.4%	16	12.69%	338.53	12.70%	338.80	0.27	0.08%	(2.80)	-0.83%
MA Munis	1,200	0.1%	1	3.79%	101.24	3.81%	101.64	0.40	0.40%	(0.84)	-0.83%
CT Munis	1,200	0.2%	2	3.80%	101.32	3.81%	101.64	0.32	0.31%	(0.84)	-0.83%
Totals	31,500		151	100%	2,668	100%	2,668	(0.00)		(22.05)	

Table 2 – Impact of a Reduced Capacity Clearing Price

In addition, customers and ESCos bidding portfolios of new economic energy efficiency measures into the FCM auction will exert downward pressure on the capacity clearing price. Table 2 demonstrates this effect. Our example assumes that energy efficiency bids reduce the capacity clearing price by the small amount of $0.05/kW-month.[12] This represents a reduction of roughly one percent in the capacity clearing price. As a result, all LSEs benefit from a reduction of roughly $22 million in total capacity cost. All LSEs benefit, regardless of the amount of energy efficiency in any one LSE's customer base. All load benefits from the inclusion of economic energy efficiency as a capacity resource in the FCM auction.

Note that those LSEs whose load ratio shares increased as a result of less than average energy efficiency programs will see lower capacity costs nonetheless due to the lower FCM auction clearing price. In other words, the benefits of the lower capacity clearing price will under most scenarios far outweigh any disadvantages to some LSEs regarding higher load ratio shares.[13]

[12] We chose $0.05 (a nickel) to show the relative impact on total costs of such a small reduction. A $0.5 reduction (fifty cents, which is not unreasonable to assume) would produce ten times the reduction to total costs.

[13] This is happening today as well. To the extent that energy efficiency reductions are achieved by some loads, all loads benefit from the overall lower installed capacity target that is set by ISO New England.

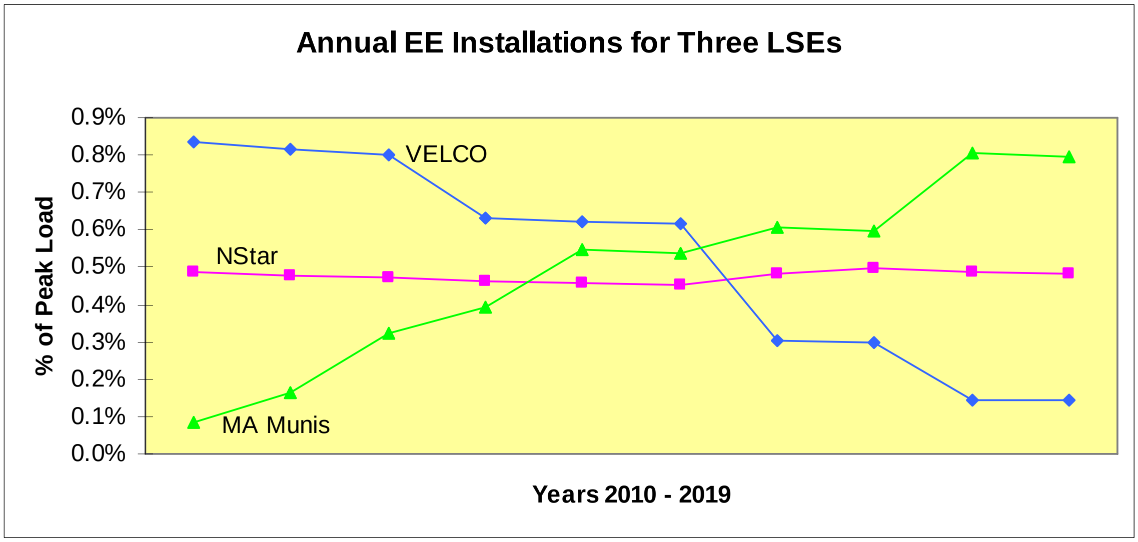
The incentive created for LSEs to reduce their customer loads by making those loads more energy efficient provides benefits to both the LSE and to the entire system. The benefits to the LSE and its customers have already been detailed above. The benefits to the system from energy efficiency resources are in the form of greater reliability. Energy efficiency resources have scheduled maintenance outage rates of zero percent and forced outage rates of zero percent as well. They are not vulnerable to fuel price volatility as are fossil fuel fired resources (over 70% of current New England resources).[14] Just as the FCM is designed to provide greater rewards to generation resources that are actually available during times of system peak, demand resources should also receive a greater reward for the greater certainty they provide during peak load periods.

As noted in the introduction, this approach is consistent with one of the fundamental principles of the entire Settlement Agreement that financial incentives should be provided to resources that improve the overall reliability of the system.

Over the long term, the small cost shifts that occur between LSEs based on their relative investments in energy efficiency for their loads should balance out. Those LSEs that experience reduced costs in the early years for aggressive implementation of energy efficiency resources in their customer base will see higher costs in later years when other LSEs eventually catch up.

Figure 3 shows this long-term effect using an example of three LSEs over ten years. For illustrative purposes, we have assumed that the maximum amount of energy efficiency than can be purchased more cheaply than generation capacity is 0.5% of peak load. Figure 3 shows the fluctuations in energy efficiency investment over ten years and the relative cost allocation changes among the three LSEs.

[14] ISO New England 2006 CELT Report.



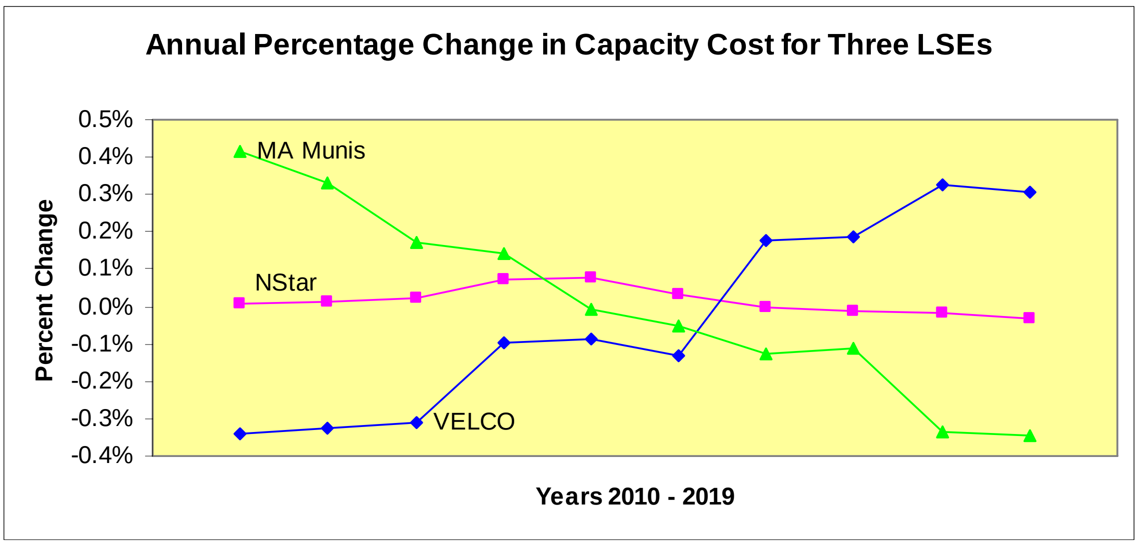


Figure 3 – Annual Installations and Change in Capacity Costs for Three LSEs over Ten Years

3. Conclusions

We conclude that the proper treatment of energy efficiency in the Forward Capacity Market will provide significant benefits to the individual customers who install energy efficiency measures and their load serving entities. All other load serving entities will also see benefits through a lower FCM auction clearing price. And the ISO, through the incentives created to encourage greater customer investments in energy efficiency resources, will see benefits to the regional system through lower load growth and enhanced reliability. These benefits can be achieved by implementing a FCM design that:

- Establishes the installed capacity requirement for the FCM auction without any reductions for projected energy efficiency measures that qualify as capacity resources;
- Allows energy efficiency capacity resources to bid and clear in the FCM auctions; and
- Makes cost allocation determinations in the delivery year based on actual metered loads for each load serving entity.

An alternative approach for the design of the FCM that has been discussed (reconstitution of metered loads for cost allocation purposes) will require a great deal of data collection, estimation, and assumptions that may, ultimately, produce inequities (including cost-shifting) among load serving entities.[15] Reconstitution may also create disincentives for improving the efficiency of customer loads.[16] The administrative ease of our proposal, along with the appropriate incentives that it creates to encourage greater efficiency in loads, makes it a better choice.

[15] We are aware of some additional issues on the retail level that will need to be addressed by this (or any other) proposal. They include how to allocate the benefits and costs associated with energy efficiency programs among different rate classes. Payments and costs associated with the FCM will become additional elements to consider in retail rate design.

[16] If LSE loads are reconstituted in the delivery year, an LSE whose customer loads are made more efficient by an ESCo will see an increase in its load ratio share that is not offset by any revenues from the FCM. If the LSE attempts to recover the FCM revenues from the customer whose loads were reduced by the ESCo, then the ability of ESCos to provide energy efficiency services to customers may be impaired.

Appendix

The illustrative examples in the body of this paper represent our estimates about the price impacts on the various LSEs in the region based on approximate load shares for the LSEs and assumptions we chose about levels of LSE energy efficiency investments. The energy efficiency investment levels (percentages of load) represent actual current levels for VELCO (0.08) and NGrid (0.05). We then assigned percentages (from 0.01 to 0.06) to other LSEs in order to get a range of values in the results. In this appendix, we make some different assumptions about those levels of energy efficiency investments to show some extreme cases. We also extend the results from Table 2 for ten years.

An Equal Investment Case

Table 3 shows the relative cost allocation if all LSEs acquire the same percentage (0.5%) of energy efficiency resources. It does not change from the "Reconstituted Load" column.

Illustrative Values for Power Year 2011-2012

Installed Capacity Requirement (MW)
36,750 (summer 2010 peak load x 1.5% growth x 15% reserve margin)

Capacity Clearing Price ($/kWh)
$ 6.05

Total Cost of Capacity ($m)
$ 2,668

				Reconsituted Load		Metered Load		Delta		
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NU	7,000	0.5%	35	22.22%	592.89	22.22%	592.90	0.00%	0.01	0.00%
UI	1,500	0.5%	8	4.76%	127.09	4.76%	127.05	0.00%	(0.04)	-0.03%
NGrid	9,000	0.5%	45	28.57%	762.29	28.57%	762.30	0.00%	0.01	0.00%
NStar	4,500	0.5%	22	14.28%	381.10	14.29%	381.15	0.00%	0.05	0.01%
VELCO	1,300	0.5%	7	4.13%	110.15	4.13%	110.11	0.00%	(0.04)	-0.04%
PSNH	1,800	0.5%	9	5.71%	152.46	5.71%	152.46	0.00%	0.00	0.00%
CMP/BH	4,000	0.5%	20	12.70%	338.79	12.70%	338.80	0.00%	0.01	0.00%
MA Munis	1,200	0.5%	6	3.81%	101.64	3.81%	101.64	0.00%	0.00	0.00%
CT Munis	1,200	0.5%	6	3.81%	101.64	3.81%	101.64	0.00%	0.00	0.00%
Totals	31,500		158	100%	2,668	100%	2,668	0%	0.00	

Table 3. Equal Investment Case

An Extreme Investment Case

It is possible that energy efficiency measures will not be installed evenly throughout the region, and that capacity costs will shift from those customers who are aggressive in their installation of energy efficiency to those who simply maintain their status quo. Although we believe this scenario is unlikely, Table 4A below shows the results of one such scenario. In this example, all regulated utilities in the region pursue a level of energy efficiency equal to the most aggressive level currently in place. Two municipals, however, remain with a low level energy efficiency installed at their customers. This example shows the impacts when most LSEs (over 92% of load) implement aggressive energy efficiency programs (0.08% of loads) and two LSEs (less than 8% of load) do a minimal amount (0.01% of loads)

Illustrative Values for Power Year 2011-2012

Installed Capacity Requirement (MW)
36,750 (summer 2010 peak load x 1.5% growth x 15% reserve margin)

Capacity Clearing Price ($/kWh)
$ 6.05

Total Cost of Capacity ($m)
$ 2,668

				Reconsituted Load		Metered Load		Delta		
LSE	Summer 2010 Peak Load (MW)	%EE	EE (MW)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Capacity Cost (%)
NU	7,000	0.8%	55	22.23%	593.17	22.22%	592.90	-0.01%	(0.27)	-0.05%
UI	1,500	0.8%	12	4.76%	127.13	4.76%	127.05	0.00%	(0.08)	-0.06%
NGrid	9,000	0.8%	72	28.59%	762.76	28.57%	762.30	-0.02%	(0.46)	-0.06%
NStar	4,500	0.8%	35	14.29%	381.29	14.29%	381.15	-0.01%	(0.14)	-0.04%
VELCO	1,300	0.8%	10	4.13%	110.14	4.13%	110.11	0.00%	(0.03)	-0.03%
PSNH	1,800	0.8%	15	5.72%	152.60	5.71%	152.46	-0.01%	(0.14)	-0.09%
CMP/BH	4,000	0.8%	32	12.71%	339.00	12.70%	338.80	-0.01%	(0.20)	-0.06%
MA Munis	1,200	0.1%	1	3.78%	100.98	3.81%	101.64	0.02%	0.66	0.66%
CT Munis	1,200	0.1%	1	3.78%	100.98	3.81%	101.64	0.02%	0.66	0.66%
Totals	31,500		233	100%	2,668	100%	2,668	0%	0.00	

Table 4A. Extreme Investment Case

We can see that in this example, even those two LSEs that experience cost-shifting based on the cost allocation formula for the Delivery Year see only a very small impact for their decision. The cost-shifting impact (shown as roughly $660,000 in the illustrative example in Table 4A) is still smaller than the impact of a change in the capacity clearing price in the FCM auction of only five cents, in Table 2 above (a savings of $840,000). The LSEs doing minimal energy efficiency investments still see a net positive impact of $180,00.

A More Extreme Investment Case

One needs to advance this scenario even further to allow an LSE to actually lose money based on cost-shifting in the Delivery year. Table 4B below shows a more extreme case where all LSEs see a full 1% of the peak load capacity with energy efficiency projects within their customer base, but two municipals still see no increase in these demand side resources. Only then does their change in cost ($850,000) outweigh the impact of a five cent reduction in capacity price ($840,000), and then only by $10,000. Based on a total capacity cost of more than $100 million for the LSE in our example, this is less than a 0.01% increase in capacity costs.

Illustrative Values for Power Year 2011-2012

Installed Capacity Requirement (MW)
36,750 (summer 2010 peak load x 1.5% growth x 15% reserve margin)

Capacity Clearing Price ($/kWh)
$ 6.05

Total Cost of Capacity ($m)
$ 2,668

				Reconsituted Load		Metered Load		Delta		
LSE	Summer 2010 Peak Load (MW)	%EE	EE (MW)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Capacity Cost (%)
NU	7,000	1.0%	70	22.24%	593.31	22.22%	592.90	-0.02%	(0.41)	-0.07%
UI	1,500	1.0%	15	4.77%	127.14	4.76%	127.05	0.00%	(0.09)	-0.07%
NGrid	9,000	1.0%	90	28.59%	762.83	28.57%	762.30	-0.02%	(0.53)	-0.07%
NStar	4,500	1.0%	45	14.30%	381.41	14.29%	381.15	-0.01%	(0.26)	-0.07%
VELCO	1,300	1.0%	13	4.13%	110.19	4.13%	110.11	0.00%	(0.08)	-0.07%
PSNH	1,800	1.0%	18	5.72%	152.57	5.71%	152.46	0.00%	(0.11)	-0.07%
CMP/BH	4,000	1.0%	40	12.71%	339.03	12.70%	338.80	-0.01%	(0.23)	-0.07%
MA Munis	1,200	0.1%	1	3.78%	100.79	3.81%	101.64	0.03%	0.85	0.85%
CT Munis	1,200	0.1%	1	3.78%	100.79	3.81%	101.64	0.03%	0.85	0.85%
Totals	31,500		293	100%	2,668	100%	2,668	0%	0.00	

Table 4B. More Extreme Investment Case

A Tenth Year Current Investment Example

We took the example in Table 1 and made an assumption that the relative energy efficiency investments would continue for ten years. Table 5 below makes the assumption that all LSEs continue their current level of demand side management for a full ten years and then estimates the relative cost impacts and cost-shifts that would occur in Delivery Year 2020/21. While we do not think that it is likely that the relative investment levels among LSEs would remain so disparate over ten years, we are providing this example to answer the "what if" question.

Illustrative Values for Power Years 2020-2021, with 10 years worth of Extreme DSM

Installed Capacity Requirement (MW)
41,500

Capacity Clearing Price ($/kWh)
$ 6.05

Total Cost of Capacity ($m)
$ 3,013

				Reconsituted Load		Metered Load		Delta		
LSE	Summer 2019 Peak Load (MW)	%EE	10 Years of EE (MW)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Percent Capacity Cost
NU	8,082	5.2%	420	22.91%	690.11	22.69%	683.64	-0.21%	(6.46)	-0.94%
UI	1,674	4.8%	80	4.73%	142.38	4.70%	141.61	-0.03%	(0.77)	-0.54%
NGrid	10,391	4.3%	450	29.21%	879.97	29.17%	878.97	-0.03%	(1.01)	-0.11%
NStar	5,195	4.2%	220	14.59%	439.58	14.59%	439.48	0.00%	(0.10)	-0.02%
VELCO	1,385	7.2%	100	4.00%	120.58	3.89%	117.20	-0.11%	(3.38)	-2.80%
PSNH	2,078	2.4%	50	5.73%	172.75	5.83%	175.79	0.10%	3.05	1.76%
CMP	4,041	3.7%	150	11.29%	340.18	11.35%	341.82	0.05%	1.64	0.48%
MA Munis	1,385	0.7%	10	3.76%	113.27	3.89%	117.20	0.13%	3.92	3.46%
CT Munis	1,385	1.4%	20	3.79%	114.08	3.89%	117.20	0.10%	3.11	2.73%
Totals	35,617		1,500	100%	3012.90	100%	3012.90	0%	0.00	

Table 5. A Tenth Year Current Investment Example

A Tenth Year Normalized Investment Example

In this example, we assumed that over ten years that the incentive to encourage all LSEs to acquire energy efficiency reductions works. All the LSEs, by the tenth year, are now experiencing cumulative reductions to their loads of between 4% and 6%.

Illustrative Values for Power Years 2020-2021, with 10 years worth of Even EE

Installed Capacity Requirement (MW)
41,500

Capacity Clearing Price ($/kWh)
$ 6.05

Total Cost of Capacity ($m)
$ 3,013

				Reconsituted Load		Metered Load		Delta		
LSE	Summer 2019 Peak Load (MW)	%EE	10 Years of EE (MW)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Peak Load Ratio Share	Capacity Cost ($m)	Percent Capacity Cost
NU	8,082	6.0%	485	22.82%	687.44	22.69%	683.64	-0.13%	(3.80)	-0.55%
UI	1,674	4.0%	67	4.64%	139.71	4.70%	141.61	0.06%	1.90	1.36%
NGrid	10,391	6.0%	620	29.33%	883.56	29.17%	878.97	-0.15%	(4.59)	-0.52%
NStar	5,195	4.0%	210	14.40%	433.76	14.59%	439.48	0.19%	5.73	1.32%
VELCO	1,385	6.0%	83	3.91%	117.83	3.89%	117.20	-0.02%	(0.64)	-0.54%
PSNH	2,078	4.0%	83	5.76%	173.42	5.83%	175.79	0.08%	2.37	1.37%
CMP	4,041	6.0%	243	11.41%	343.76	11.35%	341.82	-0.06%	(1.94)	-0.56%
MA Munis	1,385	4.0%	55	3.84%	115.59	3.89%	117.20	0.05%	1.61	1.39%
CT Munis	1,385	6.0%	83	3.91%	117.83	3.89%	117.20	-0.02%	(0.64)	-0.54%
Totals	35,617		1,929	100%	3012.90	100%	3012.90	0%	0.00	

Table 6. Ten Year Normalized Investment Example

Some of the examples above represent some extreme conditions that we believe are unlikely to occur if our recommendations are incorporated into the design of the FCM. As stated in the body of our paper, basing cost allocation for the Delivery Year on actual metered loads creates an incentive for LSEs to make their loads more efficient. If an LSE makes only minimal efforts to acquire customer energy efficiency resources (acquiring only 0.1% of its load while other LSEs are acquiring 0.8% of their loads), it is likely that ESCos or individual customers will take initiatives on their own. Such non-LSE acquired energy efficiency resources will still benefit the LSE through a lower load ratio share for the allocation of costs for the Delivery Year (pursuant to our proposed treatment). The LSE will have an incentive to encourage customers and ESCos to reduce loads if for some reason the LSE itself does not want to do it. Thus, we think it is highly unlikely that large disparities in the energy efficiency acquisition rates between LSEs (as shown in the above examples) will endure for any significant length of time.

If loads are reconstituted during the Delivery Year, an LSE may be indifferent to acquiring customer energy efficiency resources and it may try to prevent customers and ESCos from acquiring those resources outside of the LSE programs. This is because reconstitution will force the LSE to accept a higher load ratio share without any compensation from the FCM auction (the customer or ESCo will bid the energy efficiency resources into the FCM and receive payments). To be made whole, an LSE will need to assess capacity costs to those customers who implement energy efficiency measures (by themselves or through ESCos) to reduce their loads. This "assessment process" may create a disincentive for customers to improve their load efficiency outside of LSE-sponsored programs.