Incorporating Demand Resources into the PJM Reliability Pricing Model:

Ensuring the RPM Capacity Construct Properly Values Demand Resources

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We will be sharing this paper widely both within the PJM stakeholder community and outside that community and seeking other organizations' endorsement of the general approach that we recommend while reserving their right to disagree about details or even change their minds based on additional information. This paper was written by Synapse Energy Economics on behalf of our supporting clients, but the words are our own.

With all those caveats, we would like to thank the following organizations for their support:

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1. Introduction

*"PJM requests that the Commission find that . . . allowing planned generation, **planned and existing demand resources**, and planned transmission upgrades to compete on an equal basis with existing generation resources to meet capacity requirements . . . [is] just and reasonable." [emphasis added] August 31, 2005.*[1]

PJM began the implementation of the Reliability Pricing Model (RPM) capacity construct in the spring of 2007 pursuant to its FERC-approved proposal filed in August 2005 and modified by the Settlement Agreement accepted by the FERC (with conditions and modifications) in Orders issued in December 2006 and June 2007.[2]

To date, PJM has conducted four base residual auctions (BRAs) for the power years 2007-2008, 2008-2009, 2009-2010, and 2010-2011. These are all "transition auctions" that did not occur three years prior to the Delivery Year as intended in the design of RPM. The first three auctions occurred approximately three months apart beginning in April 2007. The most recent auction was completed in January of 2008. The next BRA in May 2008 will be the first full three-year-forward auction. Subsequent BRAs (one per year) will also take place in May of each year, three years in advance of the corresponding Delivery Year.

The four completed auctions produced clearing prices that far exceeded the simulation estimates distributed by PJM prior to the implementation of RPM.[3] The table below shows the wide gulf between PJM's simulated results and the actual BRA results.

Figure 1 – Actual and Simulated RPM Auction Results

Region	Result	2007-08	2008-09	2009-10	2010-11
Eastern MAAC	Actual	$ 197.67	$ 148.80	$ 191.32	$ 174.29
	Simulation	$ 106.06	$ 86.91	$ 64.65	NA
Southwest MAAC	Actual	$ 188.54	$ 210.11	$ 237.33	$ 174.29
	Simulation	$ 35.94	$ 54.53	$ 61.96	NA
RTO	Actual	$ 40.80	$ 111.92	$ 102.40	$ 174.29
	Simulation	$ 16.14	$ 12.62	$ 8.31	NA

[1] *PJM Interconnection, L.L.C.*, Docket Nos. ER05-1410 and EL05-148, (August 31, 2005), Filing letter at 2-3.

[2] *PJM Interconnection, L.L.C*., Docket Nos. ER05-1410-000 and EL05-148-000 (August 31, 2005); *see also, Settlement Agreement and Offer of Settlement,* Docket Nos. ER05-1410-000 n EL05-148-000 (filed September 29, 2006), and *PJM Interconnection, L.L.C.* 117 FERC ¶ 61,331 (2006) (December 22 Order"), *order on rehearing,* 119 FERC ¶ 61,318 ("June 25 Order").

[3] *PJM Reliability Pricing Model Updated Prototype Simulation Using FERC Settlement VRR*, December 1, 2006 (updated December 27, 2006) and *PJM 2010/2011RPM Base Residual Auction Results*, February 1, 2008.

Numerous explanations have been advanced for why the BRA results diverged so dramatically from PJM's projections, most of which are beyond the scope of this analysis. However, one protection against market power on the part of suppliers, and a low-cost source of capacity that could be part of the solution, is the full participation of demand resources. Regardless of whether RPM stays in its current form or is modified, the participation of greater quantities of demand resources will be beneficial to the operation of any wholesale capacity market structure.

This paper examines the issue of how the overall efficiency of the RPM capacity construct can be improved through the aggressive incorporation of demand resources.[4] The central question we analyzed is "how can the acquisition of demand resources through a capacity auction help the capacity market allocate resources most efficiently?" From that analysis we develop several recommendations on the appropriate treatment of demand resources in RPM.

2. Improving the RPM Capacity Construct

In simple terms, the RPM capacity construct uses an administratively-determined demand curve, and supply curves based on locational capacity offers from resource providers, to clear the market and establish locational prices for capacity for each delivery year. The resulting capacity prices are expressed in $/MW of unforced capacity[5] per day. The clearing prices for Delivery Year 2011-2012 will be established through a Base Residual Auction in May 2008 (three years in advance of the Delivery Year).

2.1 Market Efficiency

Economic theory states that competitive markets are the most efficient means of allocating resources among buyers and sellers and setting resource prices. Under ideal conditions, which include price transparency, numerous freely-acting buyers and sellers who can express their price preferences in the marketplace, and easy entry and exit from the market, a market will provide the most efficient outcome. One crucial feature of such a marketplace is that both sellers and buyers can respond to price signals. When supply costs are low, freely-acting buyers will tend to purchase more; when supply costs are high, those buyers will tend to purchase less.

When markets operate under less than ideal conditions, allocation decisions are impaired and the market is considered inefficient. For example, if buyers are not able to express

[4] Our definition of demand resources includes all resources behind the customer's meter. These include demand response, load management, energy efficiency, and small scale distributed generation. PJM currently allows demand response (DR) resources to participate in RPM; this paper recommends some enhancements to the RPM construct that will provide incentives for both DR and energy efficiency (EE) resources, in particular, to compete with traditional generation resources to improve overall market efficiency.

[5] "Unforced" capacity is the demonstrated capacity of a specific resource adjusted for the observed forced outage rate of that resource; thus, for example, a unit which is available 90% of the time will be credited for 90% of its demonstrated capacity.

their preferences in the marketplace, they may purchase a product (such as electricity) at a price that exceeds the value they realize from it. Wholesale electricity markets have suffered from such impaired allocation decisions for a variety of reasons; one of the more ubiquitous impairments in wholesale electric energy and capacity markets is an inelasticity of demand. Inelastic demand is a problem for all markets because the quantity of services purchased does not vary (or varies very little) with changes in supply costs. One result of inelastic demand in wholesale electricity markets is that the marketplace is required to maintain very expensive and little-used capacity to meet peak electricity demands that could be addressed much more efficiently through load reduction. The severity of this problem can range from small reductions in efficiency of the market all the way to market failure.[6]

Inelastic demand in wholesale electricity markets (energy and capacity) has many contributing factors: lack of price transparency, poor and inefficient communication about prices, and conflicting incentives between wholesale purchasers and retail purchasers of electricity. One resolution is an efficient price discovery process for demand-side resources. In PJM's RPM capacity market, this requires full participation and efficient price discovery for all demand resources, in particular energy efficiency resources.[7] Full participation of demand resources is essential in order for the potential efficiencies of market-based capacity pricing to be realized.

The Market Monitoring Unit (MMU) of PJM produced a whitepaper in December 2007 that directly addresses the issue of the market efficiency impacts of demand resources.[8] While noting that the benefits of the PJM Economic Program (an energy market program) for demand resources are "difficult to quantify," the MMU goes on to note that:

> ". . . the benefits are the efficiency gains which result from customers responding to market prices rather than artificial prices based on average retail rates."[9]

This explanation of market efficiency is consistent with the general economic theory mentioned above. When purchasers are exposed to the actual cost of the product they consume, they can more precisely determine the quantity that they want to consume at

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[6] The problems in the California wholesale energy market started as small inefficiencies in 2000 and expanded to severe market failure in 2001.

[7] The key issue is the acquisition of demand resources from consumers who are not directly exposed to wholesale market prices in their electricity rates. There are some large (mostly industrial) customers who are paying hourly wholesale market energy prices. However, customers who do not have interval meters (recording usage on an hourly or better level) are currently **not** exposed to variations in wholesale market rates. The energy efficiency resources discussed in this paper would come mostly from consumers without interval meters, as may a large quantity of demand response resources.

[8] *MMU White Paper: PJM Demand Side Response Program*, December 4, 2007. http://www.pjm.com/markets/market-monitor/downloads/20071204-dsr-whitepaper.pdf. This paper focuses on the impacts of PJM's Economic Program for demand side resources (almost exclusively demand response resources) on the PJM energy market.

[9] *MMU White Paper* at 6.

that price. Either over-consumption or under-consumption (all other factors being equal) implies a lack of efficiency in resource allocation.[10]

The MMU white paper goes on to state, with respect to the PJM Economic Program for demand resources, that:

> ". . . the potential benefits of increasing demand side responsiveness in improved efficiency of the market are large and certainly exceed the relatively small [incentive] costs [of the program] by a wide margin."[11]

It is likely that these "large" benefits from improved market efficiency in the PJM energy market can also be obtained from "increasing demand-side responsiveness" in the RPM capacity market construct. The same basic circumstances pertain to the capacity market as the energy market: most consumers are exposed either to retail rates that have no explicit peak demand charge or rates with a peak demand charge that is not a direct reflection of the wholesale market price of capacity. Consumption decisions, by and large, are insulated from and thus insensitive to the temporal wholesale prices of either energy or capacity. As we will demonstrate in the next section, the data currently available from the New England capacity market suggests that there is a relatively simple mechanism for achieving this improved capacity market efficiency in PJM.

If the market provides an incentive to providers of demand resources to encourage more widespread implementation of those resources, it will facilitate a more accurate reflection of the market value of demand resources and will achieve greater market efficiency. This incentive is not a subsidy; a subsidy is a payment to support a resource that is not otherwise economically justified. The incentive for demand resources is designed to correct an existing market failure and it is justified by the greater overall market efficiency that is achieved which exceeds the cost of the incentive. It is analogous to payments that generators receive for providing ancillary services; neither represents a "double payment". The MMU of PJM explicitly concurs with such an approach for the Economic Program for demand response.

> "If the customer paid the [hourly price] for each MWH used, rather than the generation component of retail rates, the savings to the customer from a load reduction would equal the LMP [locational marginal price]. This is an appropriate price signal and this is the price signal that the Economic Program should be designed to replicate. This price signal does not reflect a subsidy."[12]

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[10] There are a number of reasons why the "pure" economic theory approach may not be sufficient to appropriately price electricity and, thus, ensure electricity market efficiency. The common term applied to these reasons is "externalities". In the electric industry, the concept of externalities is not a new one; many resource acquisition processes in specific states have incorporated externalities to a greater or lesser extent. Most recently, the global impact of electricity production (as well as other carbon producing human activities) have led people to suggest market interventions, such as carbon adders, to reduce the global impact of fossil fuel consumption.

[11] *MMU White Paper* at 6.

[12] *Id*. at 3.

The MMU concurs that demand resources, with properly designed price signals, can improve the overall market efficiency of the RPM capacity construct and that it is appropriate for demand resources to have these price signals available for providing a capacity service during the high-priced hours when they are needed.

2.2 New England Experience

New England recently conducted its first capacity auction under its new Forward Capacity Market (FCM) construct.[13] New England's FCM is similar to PJM's RPM in that they both clear locational supply offers against an administratively determined demand for a specific delivery year, with the auction held three years forward of delivery. The two capacity constructs have little else in common, however, because each was the result of stakeholder settlement processes that created very different approaches for securing existing and new capacity resources to meet future system reliability needs in each region.

For the purposes of this study, we are primarily concerned with the mechanisms that the two capacity constructs use for valuing and acquiring demand resources. In New England, the Settlement Agreement approved by the FERC required that a mechanism be developed to allow demand resources to compete in the FCM on a comparable basis with supply resources.[14] In the stakeholder process that developed the rules for the FCM (subsequent to the Settlement Agreement), demand resources were provided distinct opportunities to qualify for the FCM auctions based on the various sets of hours in which they could document their capacity reductions.

In addition, load serving entities were charged capacity costs based on their pro rata share of actual peak demand as measured at their customer locations with no attempt to "add back" the impact of demand reductions at those locations. This "no add back" approach (discussed more fully in section 2.3, below) was endorsed by the New England stakeholders and included as part of the market rule revisions for both the transition period (December 1, 2006 through May 31, 2010) and for the first three FCM auctions (for power years starting on June 1 in 2010 through 2012). Beginning in 2009, there will be a stakeholder process to review the results of the transition years and the first three auctions to determine if the "no add back" approach will be continued.[15]

The New England FCM rules contain several milestones that all resources (demand and supply) must meet in order to qualify to participate in the FCM auctions. The first is a "show of interest" form for all new resources that is submitted approximately 12 months

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[13] February 4-6, 2008.

[14] *Explanatory Statement of the Settling Parties in Support of Settlement Agreement and Request for Expedited Consideration*, March 6, 2006, Dockets ER03-563-000, *et al*, Attachment 1 (Settlement Agreement Resolving All Issues) at 14. The Settlement Agreement language is brief:

> "For the Forward Capacity Market, a distinct method shall be developed to allow energy efficiency and demand response resources . . . to be fully integrated as Qualified Capacity in the Forward Capacity Market."

[15] *ISO Filing Letter*, Docket ER07-546-000, February 15, 2007, at 167.

prior to the auction. The Show of Interest form contains enough information about the resource for ISO-NE to begin its system impact evaluation process for new resources. The second milestone is a qualification package that is submitted, again by both generation and demand resources, approximately eight months before the applicable FCM auction. The qualification package for demand resources must include a measurement and verification (M&V) plan that specifies both the basis for the capacity value that will be used in the FCM auction and the subsequent validation of the capacity value of that resource in the Delivery Year.

Approximately four months prior to each FCM auction, ISO-NE notifies all resources that have qualified for the auction based on the ISO's evaluation of each resource's qualification package. Generation resources can be disqualified due to project uncertainty, interconnection issues, or in cases where multiple projects anticipate using the same elements of the transmission system but not all projects can be accommodated. Demand resources can be disqualified due to project uncertainty, insufficient M&V plans, or other factors.

To date, New England has completed its first auction (FCA#1) and received Show of Interest forms for the second auction (FCA#2). The figures below summarize the public information available regarding the participation of Demand Resources in these two events.

Figure 2 – MW of Cleared Demand Resources in FCA#1

Resource Type	Treatment	Status	ME	NH	VT	MA	CT	RI	Total
Critical Peak Demand Resource	Existing	Cleared	24	1	0	52	1	0	77
On-Peak Demand Resource	Existing	Cleared	0	8	2	50	40	9	110
Real-Time Demand Response Resource	Existing	Cleared	43	1	8	20	217	5	295
Real-Time Emergency Generation Resource	Existing	Cleared	37	44	20	359	342	73	875
Seasonal Peak Demand Resource	Existing	Cleared	0	0	0	0	10	0	10
Critical Peak Demand Resource	New	Cleared	0	0	0	14	15	0	28
On-Peak Demand Resource	New	Cleared	26	35	56	247	44	36	444
Real-Time Demand Response Resource	New	Cleared	144	29	16	294	55	42	579
Real-Time Emergency Generation Resource	New	Cleared	0	0	0	0	0	0	0
Seasonal Peak Demand Resource	New	Cleared	0	0	0	12	124	0	136
Total			**273**	**118**	**102**	**1,047**	**848**	**165**	**2,554**

Figure 3 – MW of Demand Resource Show of Interest Forms submitted for FCA#2

93 Projects

Resource Type	ME	NH	VT	MA	CT	RI	Total
Critical Peak Demand Resource	34.7	2.1	2.0	127.7	20.1	12.1	198.7
On Peak Demand Resource	2.1	10.7	10.9	99.7	43.5	28.4	195.3
Real Time Demand Response Resource	0.4	1.7	0.1	147.7	92.6	40.7	283.2
Real Time Emergency Generation Resource	0.0	1.1	0.0	22.3	33.3	0.0	56.7
Seasonal Peak Demand Resource	2.0	2.0	2.0	8.0	105.3	2.0	121.3
Total	39.2	17.6	15.0	405.4	294.8	83.2	**855.2**

Noteworthy in the above table is the large quantity of demand resources that have cleared in FCA#1 (2,552 MW or about 7.5% of New England peak load and reserves) and the equally large quantity of additional demand resources that have filed Show of Interest forms for FCA#2 (an additional 855 MW, or 2.5%).[16] The quantity of FCA#1 demand resources are larger than that of FCA#2 because FCA#1 is the first auction for all demand resources that were installed after June 16, 2006. They represent almost four years of cumulative demand resource activity from June 2006 through May 2010. FCA#2 is for demand resources that were not installed in time for FCA#1 (for June 1, 2010) but would be installed prior to June 1, 2011 and they represent about one year of demand resource activity. Together, the resources that cleared in FCA#1 combined with the Show of Interest submittals for FCA#2 represent 10% of New England's expected Installed Capacity Requirement.

On an annualized basis, the first FCM auction represents about 600 MW of demand resources developed each year over the four year period (2006-2010). The second FCM auction Show of Interest forms include over 850 MW of demand resources for that one year. In all likelihood, therefore, the actual quantity of demand resources has been steadily increasing each year since 2006. There may have been less than 400 MW in 2006, growing to 850 MW in 2011.

The New England experience demonstrates that aggregators and providers of demand resources will commit to reducing peak loads in significant and substantial ways when they are provided with the opportunity to receive payment for the value they bring to the wholesale capacity market. To the extent that states or private aggregators aggressively pursue programs to acquire demand resources over the next several years, these low-cost and quickly available resources are available in every electricity market, waiting for the appropriate market rules that will allow them to participate.

PJM, with a peak load plus reserve requirement of over 160,000 MW, is approximately five times larger than New England with its peak load and reserve requirement of about 32,000 MW. Assuming a comparable demand resource potential in PJM, the RPM auction could attract new demand resources in quantities of 2,000-4,000 MW on an annual basis. If such quantities were achieved, they would exceed PJM's projected annual load growth of approximately 2,500 MW.[17]

2.3 Proposal for RPM

Our proposal for incorporating demand resources into the RPM capacity construct is based on the premise that these resources can provide capacity services comparable to generation resources. Given this premise, it is logical to allow them to fully participate in

[16] There were 589 MW of demand resources that participated but did not clear in FCA#1. These excess MW are a sign of a healthy market that attracts resources to participate over a range of prices.

[17] Annual load growth in PJM is estimated at about 1.7 percent. In annual MW terms, this amounts to about 2500 MW. http://www.pjm.com/markets/rpm/downloads/2007-cp-forecast.pdf.

the BRA mechanism, be paid the auction clearing price, and be able to set the auction clearing price when they are the marginal resource in the auction.

The first step is to identify the performance hours over which demand resources must be available in order to qualify as a capacity resource for the RPM auctions.[18] These performance hours may be a single set of hours for all demand resources or there may be varying sets of hours that demand resources can elect as their performance hours (which is the approach New England chose). Performance hours, in general, should be those hours when capacity resources are most needed for system reliability, such as summer weekday hours from 2:00 pm through 7:00 pm.

Concurrent with the development of performance hours, a Measurement and Verification manual needs to be developed by PJM. The M&V manual will specify how a demand resource for the RPM capacity market will demonstrate its capacity value prior to the RPM auction **and** how the demand resource will demonstrate that it has achieved that capacity value after installation (during the Delivery Year). There are a variety of ways that a demand resource might choose to demonstrate its capacity value such as engineering estimates, statistical sampling, direct measurement, or past history.[19]

Just as developers of generation resources expect to be paid each year for their resource's capacity value, providers of demand resources (usually utility or private aggregators) expect to be paid each year that their demand resource is reducing load. Energy efficiency (EE) resources have "measure lives" that establish the number of years that a demand resource reduces peak load. Some EE resources have short measure lives of just a few years (such as commercial lighting) while other EE resources have measure lives that can stretch for as much as 20 years (such as a heating system fan or a refrigerator).

In order for the RPM capacity construct to procure enough capacity to reliably serve peak loads, demand resources that clear in the BRA for a delivery year three years in the future must be accounted for in future determinations of the reliability requirement for years beyond that delivery year. For example, if an EE resource of 10 MW clears in the May 2009 BRA for installation prior to the Delivery Year of 2012-13, the next BRA (May 2010) must include the 10 MW of load corresponding to that demand resource as part of the reliability requirement for Delivery Year 2013-14. Subsequent BRAs must include the 10 MW for the length of the demand resource's measure life.

While we endorse the need to "add back" demand resources in this manner for the purpose of constructing the **reliability requirements**, we do not endorse adding back the demand resource MW that cleared in the BRA for purposes of **cost allocation** in the

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[18] This paper focuses on the treatment of demand resources in the BRA. The RPM construct also has incremental auctions, as necessary, in the three years between the BRA and the delivery year. Demand resources should be eligible to participate in these incremental auctions, as appropriate. Demand resources should also be eligible for designation as Interruptible Load for Reliability (ILR) resources (as Demand Response resources currently are).

[19] New England has developed an M&V manual for its capacity construct (FCM) that could be a template or starting point for PJM to develop its own manual. http://www.iso-ne.com/rules_proceds/isone_mnls/m_mvdr_measurement_and_verification_demand_reduction_revision_1_10_01_07.doc.

Delivery Year. One reason for a "no add back" policy for cost allocation in the Delivery Year is that it is a technical and administrative challenge to precisely add back MW to each specific customer or load serving entity (LSE). More importantly, it is unnecessary to undertake this arduous task because any amount of cost shifting that may occur between customers, LSEs, or locational deliverability areas (LDAs) will be extremely small compared to overall cost savings. We explain this conclusion further in Section 4 of this paper.

Moreover, an add back approach for the Delivery Year also creates conflicting incentives between customer aggregators who want to earn capacity market revenues and their larger customers who want to reduce their capacity costs through a lower peak demand. An add back approach creates a disconnect between wholesale peak demand calculations based upon the 5CP method[20] and Demand Response events that are dispatched by PJM. Under current PJM rules, the MW amount curtailed by a customer during a Demand Response event is added back to that customer's load to determine that customer's peak load contribution. Customer aggregators (and the reliability needs of PJM) want the customer to curtail load during all peak hours, including Demand Response events. Customers have a competing incentive to respond in only those 5CP hours that are not also Demand Response events for fear of the "add back." But because the 5CP hours are unknown in advance, they are forced to guess. Our recommended "no add back" approach avoids this confusion and creates the incentive for customers to respond in all peak hours.

We propose that customers continue to be billed capacity costs based on their summer peak demand load ratio share as measured on the five summer days with the highest peak demand on PJM's bulk power system. This approach has been adopted by New England for the three year transition period (through May 2010) and for the first three FCM auctions that start with the 2010-11 power year. The use of this approach in New England may have facilitated a substantial increase in demand resources for the transition period and the first two FCM auctions.[21]

The "no add back" approach we recommend creates an incentive for LSEs to develop mechanisms that can acquire the maximum amount of demand resources that are less costly than the RPM clearing price. This will include mechanisms to provide the knowledge, tools, and capital to overcome participation barriers. To the extent that one LSE's load is more efficient than another LSE's load, the LSE whose customers have made greater energy efficiency investments will pay a slightly smaller percentage of the RPM capacity costs in the Delivery Year. However, if all LSEs experience similar or

[20] PJM determines the capacity contribution of loads by averaging the coincident peak loads on the five summer peak days (usually the five hottest days of summer). That summer MW value is converted to a percentage of the system peak. The percentage is the peak load contribution of that load for the next power year (June through May).

[21] It is too early to claim a cause and effect between a "no add back" policy and an increase in the quantity of demand resources. Yet on a comparable MW-size basis, New England has over four times the quantity of demand resources that PJM has available.

equal levels of customer demand resource installations, then their load ratio shares will remain the same.[22]

To the extent that LSEs compete to encourage customers to develop demand resources, overall system efficiency will improve (higher load factors); transmission and distribution infrastructure enhancements may be deferred; and the RPM capacity structure will provide high levels of system reliability at a lower cost. Just as generation resources that operate with fewer forced outages can gain a competitive advantage, LSEs that can serve customer loads more efficiently through aggressive development of demand resources should also experience a competitive advantage. As we will demonstrate in Section 4 of this report, the small advantage that an LSE experiences from its aggressive investment in demand resources also produces a much larger benefit to customers of **all** LSEs by shifting the RPM supply curve to the right and thereby producing a lower clearing price in each annual auction.

This competition to serve load as efficiently as possible may take shape in a number of ways. State regulators could mandate greater levels of DSM funding; LSEs might encourage the activity of energy service companies (ESCos) and customers; and ESCos may seek out economic opportunities on their own. Expanding opportunities for the development of residential and commercial demand resources will help to ensure that demand resources are equally distributed among all loads. The quantity of demand resources installed in any one area should, over time, balance with the amounts installed in other areas.

Our recommendations focus on using market mechanisms (such as RPM) to encourage competition among load serving entities to make their loads more efficient. In that competitive process, overall market efficiency and reliability are improved. The "no add back" approach for the Delivery Year helps encourage that competition among LSEs. Equally important, the "no add back" approach will assist utility and private sector aggregators in their efforts to overcome the persistent barriers to the installation of demand resources faced by individual electricity consumers.

3. Demand Resources

In this section we briefly discuss the quantity of demand resources (both EE and DR) that are available to participate in wholesale capacity markets. We also review some estimates of the cost of these demand resources.

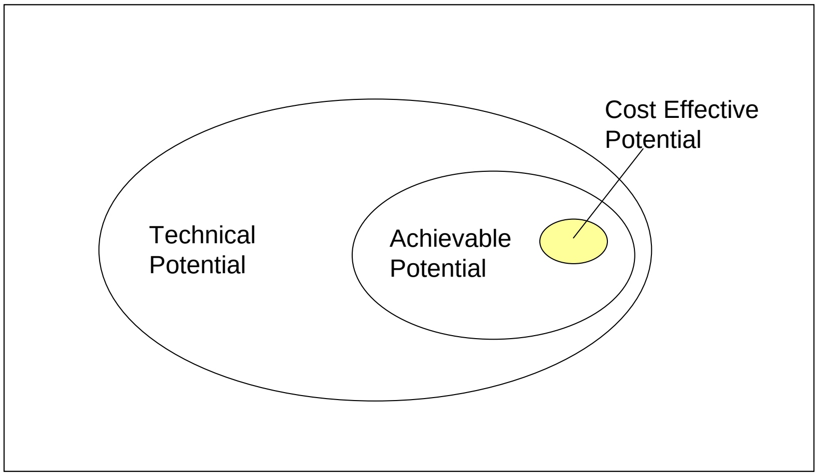
3.1 Abundance of Demand Resources

Numerous studies have estimated the enormous potential for improvements in the efficient use of electricity. Most of these analyses create three categories of demand reduction resources: the technical potential for demand reduction; the achievable

[22] Example 4 in the Appendix to this report demonstrates this important aspect of the "no add back" approach that we recommend.

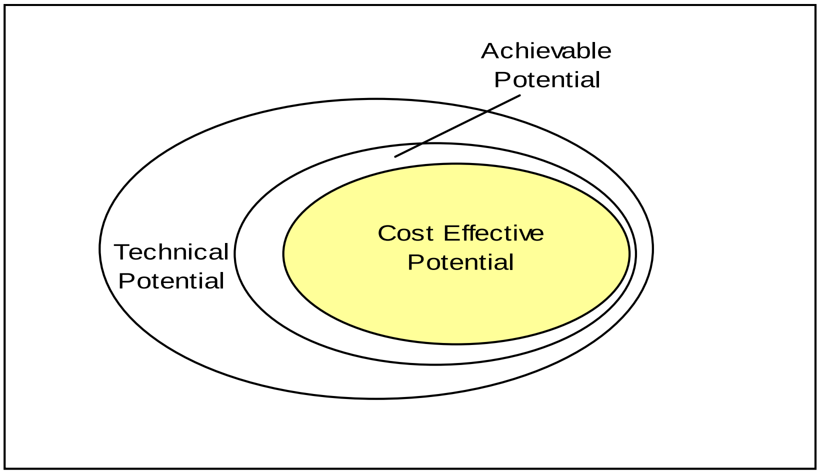
potential for demand reduction, a subset of technical potential; and a further subset, the cost-effective potential for demand reduction. The diagram below shows these three levels of potential as they have been described in most of the literature on the quantity of demand resources available.

Figure 4 – Venn Diagram of the Stages of Energy Savings Potential



Because electricity prices have been increasing over the last several years and technology applications have improved, the relationship between these three circles has been changing. A 2007 study for the Vermont Department of Public Service shows a dramatic narrowing of the difference between the achievable and cost effective circles.[23]

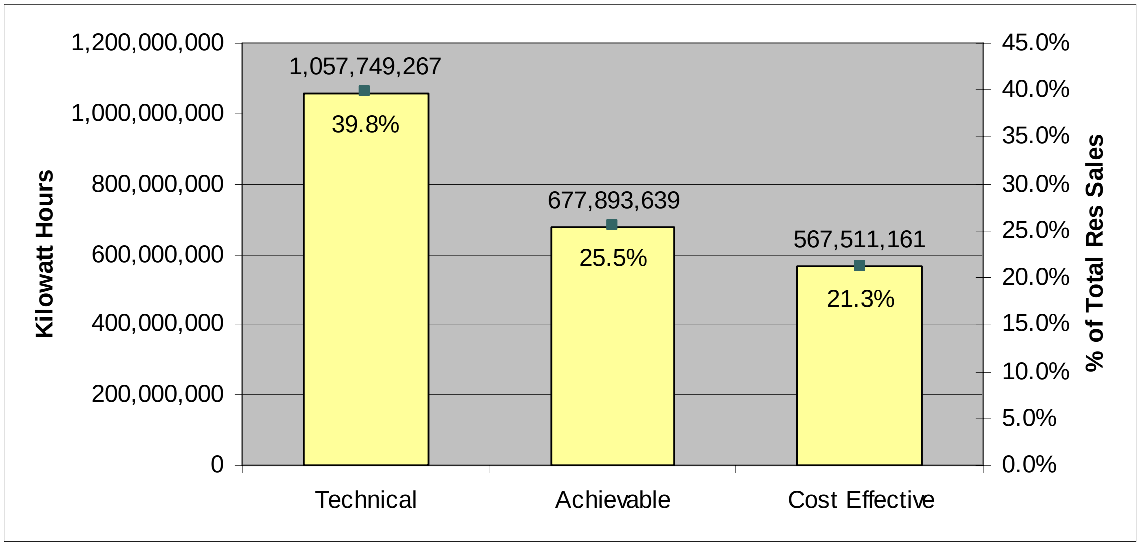
Figure 5 – Updated Venn Diagram of Energy Savings Potential to Reflect Current Conditions



[23] *Vermont Electric Energy Efficiency Potential Study*, VT DPS, January 2007, prepared by GDS Associates at 37, 51. http://publicservice.vermont.gov/energy/vteefinalreportjan07v3andappendices.pdf.

Perhaps more important than the narrowing of the gap between the "circles" is the actual quantity of the achievable cost effective savings: a reduction of over 20% of energy sales in the Vermont study.

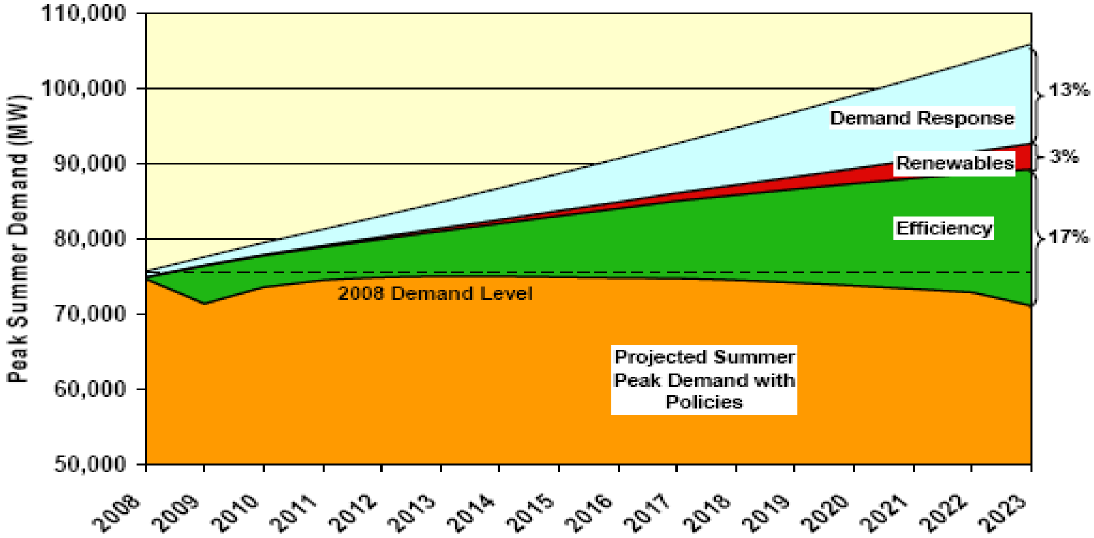
Figure 6 – Summary of Potential Savings in Vermont



This estimate is consistent with the many recent announcements of state policies to reduce electricity consumption. New York has a target of 15% reduction of energy sales by 2015. New Jersey has announced a target of 20% reduction in energy consumption by 2020. Maryland has announced a target of 15% reductions (per capita) of both energy consumption and peak load by 2015. Massachusetts has announced a goal of meeting all new load growth through demand reductions. Illinois wants to achieve annual energy reductions of 2% by 2015 (more than annual load growth). The graphic example below shows how state policies could reduce Texas's peak demand by 30% in 2023.[24]

[24] ACEEE has done studies on demand resource potential for three states: Texas, Florida, and Maryland. http://www.aceee.org/energy/reports.htm#sep. The Texas graph is from *Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs*, March 2007, at 22.

Figure 7 – State Policies Could Reduce Texas Load



The 2007 FERC Staff report on demand response identifies reduction levels in peak demand among ISOs and RTOs ranging from 1.4% (PJM) to 4.1% (CA ISO).[25] The important conclusion here is that the introduction of capacity payments to demand resource providers has led to a large increase in these resources. Providing appropriate capacity payments to these resources is likely to stimulate even greater participation and large reductions in peak loads.

There is no certainty that state demand reduction targets will actually be achieved. In fact, most of the studies that identify these targets also identify numerous barriers that customers face in order to implement efficiency measures and other demand reduction technologies. The point for this paper is that if states are going to pursue these targets, there are changes to wholesale markets that can assist them with these goals and, at the same time, provide economic and efficiency benefits to power markets.

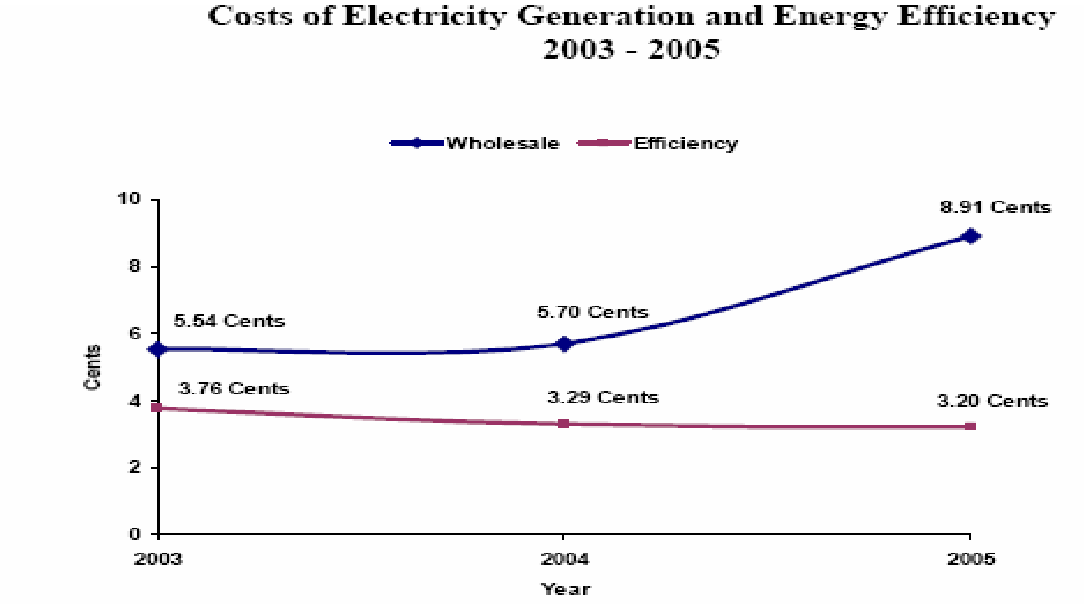
3.2 Costs of Energy Efficiency and Demand Response

Most energy efficiency programs implemented under state mandates (whether administered by distribution utilities, special efficiency utilities, or energy service companies) have been required to pass cost-effectiveness tests. These cost-effectiveness tests have typically focused on the program costs and the energy benefits, with small adders for capacity and T&D benefits. As wholesale electricity prices have increased, more measures have passed the screening tests and overall reductions in energy consumption have increased. Historically, energy efficiency measures have cost from 3 to 4 cents per KWh.

[25] *2007 Assessment of Demand Response and Advanced Metering,* FERC Staff Report, September, 2007. http://www.ferc.gov/industries/electric/indus-act/demand-response.asp.

The graph below shows the relationship between implementation costs and wholesale prices from 2003 through 2005 for programs in Massachusetts.[26] Today's wholesale electricity prices would continue the trend shown below.

Figure 8 – Costs of Generation and Energy Efficiency in Massachusetts



Providing a mechanism for demand resources to receive capacity payments in wholesale capacity markets would provide a revenue stream to merchant providers of demand resources and improve the overall cost-effectiveness of existing programs. Capacity payments could also assist in the implementation of the aggressive policies being adopted by many states to reduce electricity consumption in order to lower costs to consumers, improve reliability of the electric system, and/or meet carbon reduction targets.

Data on the cost of DR resources is more difficult to obtain because the proliferating energy service companies that provide these services are not regulated and are often not part of state or utility sponsored programs. However, based on the limited information from the first New England auction and resource qualification process, we can observe that some of these resources were qualified to bid at 25% less than CONE.[27] Most, if not all, of these low cost resources were selected in the recent auction that cleared at 40% less than CONE (see Figure 2, above).

[26] *Massachusetts Saving Electricity*, April 2, 2007. http://www.mass.gov/Eoca/docs/doer/pub_info/ee03-05.pdf.

[27] CONE stands for the Cost of New Entry. In both New England and PJM, CONE is a proxy value for the cost of new entry as expressed by the annualized capacity cost of a gas-fired peaking unit. The FCM and RPM models have mechanisms by which CONE, over time, will be determined by an average of actual capacity market clearing prices (rather than a proxy gas-peaker resource).

3.3 Barriers to Implementation

Historically, programs developed to acquire demand resources have been designed to help customers (and other stakeholders) overcome the many market barriers that hinder electricity customers from adopting energy efficiency and load management measures on their own. Examples of market barriers include:

- Lack of awareness. Electricity customers do not often consider demand resources as an alternative to electricity generation. Even in those states where customers are provided "choice" of electricity suppliers, they rarely consider that they have a choice between reducing demand and maintaining historic levels of generation.
- Lack of information and training. Customers, businesses, industries, and contractors are often unaware of demand resource options or lack information on the economic, productivity and environmental benefits of these measures.
- Limited product availability. Some demand resource measures are produced and distributed on a limited scale and are not readily available to customers, builders, contractors or industries.
- Lack of money or financing. Customers, businesses and industries may lack the up-front capital for a particular product that will enable demand reductions.
- High transaction costs. An investment of time, money, and hassle may be required to obtain information and make an informed purchase and installation of demand resource measures. This is a particular problem when construction, renovation and replacement require that decisions be made and products obtained quickly. Many small consumers, both residential and business, lack the physical ability to put time into these activities due to work and family commitments.
- Split incentives. The financial interests of those in a position to implement demand resource measures are often not aligned with electricity customers who would benefit from the measures. For example, landlords and building owners make capital purchases and maintain buildings, while tenants frequently pay the energy bills. Similarly, at the time of new construction the builder has incentive to minimize short-term costs, while it is the new owner who would benefit from lower electricity bills over the long-term.
- Purchasing procedures and habits. Many buildings are constructed, products purchased, and facilities renovated on the basis of minimizing short-term costs, not on minimizing long-term life-cycle costs, including electricity costs.
- Bounded rationality. For many customers, electricity costs represent a small portion of the total costs of maintaining a home, running a business or operating a factory, so little or no attention is paid to opportunities to reduce these costs.
- Unaccounted for societal benefits. The societal benefits of demand reductions, particularly the environmental and economic development benefits, are often not considered by customers and producers seeking to minimize their own costs.

- Institutional and regulatory barriers. Rate-of-return regulation rewards electric utilities for increased sales and penalizes them for improvements in end-use efficiency or reductions. Hence, utilities that could be an influential promoter of demand resources instead have powerful financial incentives to oppose it. This point holds true both under traditional regulation and electricity restructuring.
- Uncertainty and risk avoidance. Customers may be skeptical of potential demand resource savings, or may have doubts about whether an unfamiliar demand reduction measure will work properly.

Thus, demand reduction programs should be explicitly designed to overcome these barriers. This applies to wholesale market structures, such as RPM, as well as regulatory policies that are necessary to help guide and support the demand resource programs. Our proposal to allow demand resources to participate in the RPM auctions and to adopt a "no add back" approach is an example of the structures that would help overcome some of the barriers mentioned above.

4. Impact of Demand Resources on RPM Capacity Costs

We have developed illustrative examples of how demand resources can impact the RPM capacity construct and how that impact can affect the costs that are assigned to specific locational deliverability areas (LDAs) using the "no add back" approach, similar to that adopted in New England, that we recommend. We have tried to make the examples realistic, but they are only intended to show how demand resources could lower the RPM clearing prices for a given power year and how a "no add back" policy would produce, at most, small cost shifts between load zones.

An "add back" occurs when a customer provides a demand resource that is purchased as a supply resource in a capacity market clearing process and then the demand resource MW value is administratively "added back" to that customer's peak demand obligation in the Delivery Year. A "no add back" approach maintains the customer's load obligation in the Delivery Year at the meter read quantity from the prior summer. That quantity is based on an average of the customer demand during the peak hour of the five peak days.[28] One of the problems with an "add back" approach is that it is difficult to accurately assign the correct quantity to specific customers or LSEs. A "no add back" approach is simple to administer, provides incentives for the aggregation of demand resources, and provides overall market efficiency benefits. It may create some small shifts in cost allocation during the Delivery Year, but these cost shifts are greatly outweighed by the overall capacity savings.

In all of the examples, each LDA is modeled based on an estimated summer 2010 peak load.[29] We then make arbitrary assignments of the quantity of energy efficiency capacity

[28] See footnote 20, above, for a description of PJM's 5CP peak load determination method.

[29] These summer peak load estimates are meant to be representative, not precise; precise amounts are not necessary for the purpose of these examples.

resources installed in each LDA.[30] We vary these on purpose to create variations in the results from each example; the quantities range from zero (no energy efficiency capacity resources) to a maximum of 0.7% of the LDA peak load. An installation rate of 0.7% of peak load on an annual basis for EE programs is a reasonably aggressive implementation rate. It is on par with the results of states currently leading in demand resource acquisition across the country. We also include a column that shows the MW value of the EE percentage.

The next two columns show the peak load ratio share for each LDA with the EE resources included (added back); and the annual cost of that MW quantity at an arbitrary clearing price of $100/MW-day. The two "metered load" columns show the load ratio share for each LDA based on customer meter reads (or profiles) after the EE resources are installed; and then we show the annual cost of that "new" MW quantity at the $100/MWday clearing price. These metered load columns demonstrate our recommended "no add back" approach.

The three columns under "delta" show the change in the peak load ratio share for each LDA, the change in the capacity costs for each LDA, and that change in the capacity costs as a percentage.

As shown in Example #1 below, the LDAs for which we assumed EE resource installations at 0.4% or higher of annual peak load all show reductions in capacity costs. The LDAs where we assumed EE resource installation rates of less than 0.3% of annual peak load show either no capacity savings or increases in capacity costs. It is correct to say that adopting a "no add back" policy produces small cost-shifts between LDAs.[31] It is also important to note that if all LDAs installed the same percentage quantity of EE resources, there would be no cost-shifts among the LDAs with a "no add back" policy and there would be no difference between the add back and metered load columns. We have included such an example in the appendix to this paper.

[30] We focus on energy efficiency capacity (EE) resources because RPM does not currently recognize EE resources. We could also use new demand response capacity (DR) resources, but they are recognized by RPM and some quantities of DR are already participating in RPM. The "no add back" issue is applicable also for DR resources as discussed in section 2.3 of this paper.

[31] It is also true that within LDAs there can be cost shifts among those customers who install EE resources and those that do not. The magnitude of these cost shifts is very dependent on rate design issues among customers and is beyond the scope of this white paper. As with the LDA cost shifts, the simple way to address them is to make sure that all customer classes have similar opportunities to develop their EE resources.

Example 1 – Small Impact of "No Add Back" Approach on Total Capacity Costs

Illustrative Values for Power Year 2011-2012

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00

Total Cost of Capacity ($m)
$ 6,205

				Load with Add-Back		Metered Load		Delta		
LDA	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 (%)
PS	11,100	0.7%	77.7	7.67%	475.84	7.64%	473.86	-0.03%	(1.98)	-0.42%
PE	8,900	0.5%	44.5	6.14%	380.77	6.12%	379.94	-0.01%	(0.83)	-0.22%
PLCO	7,500	0.5%	37.5	5.17%	320.88	5.16%	320.18	-0.01%	(0.70)	-0.22%
UGI	200	0.5%	1.0	0.14%	8.56	0.14%	8.54	0.00%	(0.02)	-0.22%
BC	7,200	0.5%	36.0	4.96%	308.04	4.95%	307.37	-0.01%	(0.67)	-0.22%
JC	6,700	0.7%	46.9	4.63%	287.22	4.61%	286.02	-0.02%	(1.20)	-0.42%
ME	3,000	0.4%	12.0	2.07%	128.22	2.06%	128.07	0.00%	(0.15)	-0.12%
PN	3,000	0.4%	12.0	2.07%	128.22	2.06%	128.07	0.00%	(0.15)	-0.12%
PEP	7,000	0.4%	28.0	4.82%	299.19	4.82%	298.83	-0.01%	(0.35)	-0.12%
AE	3,000	0.7%	21.0	2.07%	128.61	2.06%	128.07	-0.01%	(0.54)	-0.42%
DPL	4,300	0.2%	8.6	2.96%	183.42	2.96%	183.57	0.00%	0.15	0.08%
RECO	450	0.3%	1.4	0.31%	19.21	0.31%	19.21	0.00%	(0.00)	-0.02%
AP	8,700	0.3%	26.1	5.99%	371.47	5.99%	371.40	0.00%	(0.07)	-0.02%
CE	23,600	0.1%	23.6	16.21%	1,005.67	16.24%	1,007.49	0.03%	1.82	0.18%
AEP	24,600	0.1%	24.6	16.89%	1,048.28	16.92%	1,050.18	0.03%	1.89	0.18%
DAY	3,700	0.2%	7.4	2.54%	157.83	2.55%	157.95	0.00%	0.13	0.08%
DUQ	3,000	0.0%	0.0	2.06%	127.71	2.06%	128.07	0.01%	0.36	0.28%
DOM	19,400	0.0%	0.0	13.31%	825.87	13.35%	828.19	0.04%	2.32	0.28%
Totals	145,350		408	100%	6,205	100%	6,205	0%	0.00	

One important impact not included in Example 1 is the impact that the demand resources (whether EE or DR) can have on the RPM clearing price for each year's Base Residual Auction. The precise impact of demand resources on the BRA clearing price will vary from year to year depending on the overall quantity of resources bidding and the offers that they make, *i.e.*, the shape of the supply curve and its intersection with the VRR demand curve.

In Example 2, we select an arbitrary impact of two dollars to illustrate the significance of the impact of a small quantity of demand resources.[32] We know from PJM's third base residual auction for the 2009-2010 Delivery Year, for example, that a small change in quantity can produce a significant change in price. In that auction, a change of 138.9 cleared MW corresponded to a price change in the auction clearing price of $4.22/MW-day.[33]

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[32] As discussed in section 3 of this paper, we are assuming that demand resources (in particular energy efficiency resources) offer at prices significantly below CONE. In effect, demand resources are assumed to be price takers in the BRA.

[33] Email from PJM to PJM committees of October 16, 2007 (3:55pm EDT) discussing a correction to the BRA results for the 2009-2010 delivery year.

Because of the shape of the supply curve, the quantity of demand resources needed to create a $2/MW-day price impact will vary from one annual BRA to another. The information from the 2009-2010 BRA suggests that less than 70 MW of demand resources offering as price-takers would have shifted the supply curve price intersection with the demand curve by $2. For BRAs where the supply curve is "flatter" than in the 2009-2010 auction, it would take a larger quantity of demand resources to produce a $2 impact. Likewise, for BRAs where the supply curve is steeper, it could take less than 50 MW of demand resources to produce a $2/MW-day savings.

Example 2 uses the same assumptions as Example 1 but assumes a $2/MW-day reduction in the clearing price. The table below includes two additional columns that show the cost savings from the demand resource impacts on the RPM clearing price in dollar amounts and as a percentage of overall capacity costs for each LDA.[34] The capacity cost reductions are over 2% for all LDAs. The cost-shifts between LDAs for the "no add back policy" is substantially less, with most LDAs seeing cost shifts of less than 0.3%.

Example 2 shows that even those LDAs who pursue EE less aggressively still obtain a net benefit from the inclusion of these low-cost resources. A "no add back" approach would be administratively simpler and encourage greater participation of energy efficiency resources.

[34] For simplicity, we assume that the capacity obligation for each LDA is unchanged by the change in the clearing quantity and price. In reality, due to the VRR curve used for RPM auctions, a lower clearing price would be associated with a slightly higher capacity requirement for each LDA.

Example 2 – A Small Impact on Clearing Price Greatly Outweighs any Costs Shifting Effect

Illustrative Values for Power Year 2011-2012

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00 without EE
$ 98.00 with EE

Total Cost of Capacity ($m)
$ 6,205 without EE
$ 6,081 with EE

				Load with Add-Back		Metered Load		Delta		Two Dollar Impact	
LDA	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 (%)
PS	11,100	0.7%	77.7	7.67%	475.84	7.64%	473.86	(1.98)	-0.42%	(9.48)	-2.00%
PE	8,900	0.5%	44.5	6.14%	380.77	6.12%	379.94	(0.83)	-0.22%	(7.60)	-2.00%
PLCO	7,500	0.5%	37.5	5.17%	320.88	5.16%	320.18	(0.70)	-0.22%	(6.40)	-2.00%
UGI	200	0.5%	1.0	0.14%	8.56	0.14%	8.54	(0.02)	-0.22%	(0.17)	-2.00%
BC	7,200	0.5%	36.0	4.96%	308.04	4.95%	307.37	(0.67)	-0.22%	(6.15)	-2.00%
JC	6,700	0.7%	46.9	4.63%	287.22	4.61%	286.02	(1.20)	-0.42%	(5.72)	-2.00%
ME	3,000	0.4%	12.0	2.07%	128.22	2.06%	128.07	(0.15)	-0.12%	(2.56)	-2.00%
PN	3,000	0.4%	12.0	2.07%	128.22	2.06%	128.07	(0.15)	-0.12%	(2.56)	-2.00%
PEP	7,000	0.4%	28.0	4.82%	299.19	4.82%	298.83	(0.35)	-0.12%	(5.98)	-2.00%
AE	3,000	0.7%	21.0	2.07%	128.61	2.06%	128.07	(0.54)	-0.42%	(2.56)	-2.00%
DPL	4,300	0.2%	8.6	2.96%	183.42	2.96%	183.57	0.15	0.08%	(3.67)	-2.00%
RECO	450	0.3%	1.4	0.31%	19.21	0.31%	19.21	(0.00)	-0.02%	(0.38)	-2.00%
AP	8,700	0.3%	26.1	5.99%	371.47	5.99%	371.40	(0.07)	-0.02%	(7.43)	-2.00%
CE	23,600	0.1%	23.6	16.21%	1,005.67	16.24%	1,007.49	1.82	0.18%	(20.15)	-2.00%
AEP	24,600	0.1%	24.6	16.89%	1,048.28	16.92%	1,050.18	1.89	0.18%	(21.00)	-2.00%
DAY	3,700	0.2%	7.4	2.54%	157.83	2.55%	157.95	0.13	0.08%	(3.16)	-2.00%
DUQ	3,000	0.0%	0.0	2.06%	127.71	2.06%	128.07	0.36	0.28%	(2.56)	-2.00%
DOM	19,400	0.0%	0.0	13.31%	825.87	13.35%	828.19	2.32	0.28%	(16.56)	-2.00%
Totals	145,350		408	100%	6,205	100%	6,205	(0.00)		(124.10)	

Over the long term, the small cost shifts that occur between LDAs based on their relative investments in energy efficiency for their loads should balance out. Those LDAs that experience reduced costs in the early years for aggressive implementation of energy efficiency resources in their customer base are likely to see slightly higher costs in later years if and when other LDAs eventually turn to more aggressive demand resource acquisition programs. Over a period of time, these cost shifts will probably balance out among all loads.

Example 3 shows the impact of an $8/MW-day reduction in the RPM clearing price. The $8 reduction is a conservative estimate of the impact that the 400 MW of EE resources (used in Examples 1 and 2) would have on the RPM clearing price. PJM's correction of the 2009-2010 auction results showed a $2 impact based on a 70 MW change in supply resources. Because our example assumes 400 MW of EE resources from all the LDAs, an $8 price impact (or more) is a reasonable assumption. An $8 reduction in the clearing price would reduce the total cost impact of the BRA by almost $500 million. We try to be cautious in making claims about large cost savings from relatively small quantities of low-cost demand resources. The RPM capacity construct is a very dynamic model due to the VRR curve and other adjustments; its complexity makes any effort at modeling or predicting results difficult. At the same time, the auction results to date show that the slope of the supply curve, at even modest clearing prices below CONE, can produce significant changes in the clearing price with small adjustments to that supply curve.

Example 3. A Likely Reduction in Clearing Price from 400 MW of Energy Efficiency

Illustrative Values for Power Year 2011-2012

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00 without EE
$ 92.00 with EE

Total Cost of Capacity ($m)
$ 6,205 without EE
$ 5,709 with EE

				Load with Add-Back		Metered Load		Delta		Eight Dollar Impact	
LDA	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 (%)
PS	11,100	0.7%	77.7	7.67%	475.84	7.64%	473.86	(1.98)	-0.42%	(37.91)	-8.00%
PE	8,900	0.5%	44.5	6.14%	380.77	6.12%	379.94	(0.83)	-0.22%	(30.40)	-8.00%
PLCO	7,500	0.5%	37.5	5.17%	320.88	5.16%	320.18	(0.70)	-0.22%	(25.61)	-8.00%
UGI	200	0.5%	1.0	0.14%	8.56	0.14%	8.54	(0.02)	-0.22%	(0.68)	-8.00%
BC	7,200	0.5%	36.0	4.96%	308.04	4.95%	307.37	(0.67)	-0.22%	(24.59)	-8.00%
JC	6,700	0.7%	46.9	4.63%	287.22	4.61%	286.02	(1.20)	-0.42%	(22.88)	-8.00%
ME	3,000	0.4%	12.0	2.07%	128.22	2.06%	128.07	(0.15)	-0.12%	(10.25)	-8.00%
PN	3,000	0.4%	12.0	2.07%	128.22	2.06%	128.07	(0.15)	-0.12%	(10.25)	-8.00%
PEP	7,000	0.4%	28.0	4.82%	299.19	4.82%	298.83	(0.35)	-0.12%	(23.91)	-8.00%
AE	3,000	0.7%	21.0	2.07%	128.61	2.06%	128.07	(0.54)	-0.42%	(10.25)	-8.00%
DPL	4,300	0.2%	8.6	2.96%	183.42	2.96%	183.57	0.15	0.08%	(14.69)	-8.00%
RECO	450	0.3%	1.4	0.31%	19.21	0.31%	19.21	(0.00)	-0.02%	(1.54)	-8.00%
AP	8,700	0.3%	26.1	5.99%	371.47	5.99%	371.40	(0.07)	-0.02%	(29.71)	-8.00%
CE	23,600	0.1%	23.6	16.21%	1,005.67	16.24%	1,007.49	1.82	0.18%	(80.60)	-8.00%
AEP	24,600	0.1%	24.6	16.89%	1,048.28	16.92%	1,050.18	1.89	0.18%	(84.01)	-8.00%
DAY	3,700	0.2%	7.4	2.54%	157.83	2.55%	157.95	0.13	0.08%	(12.64)	-8.00%
DUQ	3,000	0.0%	0.0	2.06%	127.71	2.06%	128.07	0.36	0.28%	(10.25)	-8.00%
DOM	19,400	0.0%	0.0	13.31%	825.87	13.35%	828.19	2.32	0.28%	(66.25)	-8.00%
Totals	145,350		408	100%	6,205	100%	6,205	(0.00)		(496.40)	

5. Conclusions

The proper treatment of demand resources in the RPM capacity construct will provide significant benefits. These benefits flow to the overall efficiency of the wholesale capacity market, to the individual customers who install energy efficiency measures, to the aggregators who assist customers in overcoming market barriers and to the customers' load serving entities. All other load serving entities will also benefit through a lower RPM auction clearing price. And PJM, 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 an RPM design that:

- Allows energy efficiency capacity resources to bid, clear, set price, and be paid in the RPM annual base residual auctions; and

- Makes cost allocation determinations in the Delivery Year based on actual metered loads for each load serving entity.

An add back approach for the treatment of RPM-cleared customer demand resources for cost allocation purposes in the Delivery Year will require a great deal of data collection, estimation, and assumptions that may, ultimately, produce inequities (including cost-shifting) among load serving entities and customers.[35] An add back approach may also create disincentives for improving the efficiency of customer loads.[36] The administrative ease of our proposal, along with the appropriate incentives that it creates to encourage greater efficiency in loads, makes it the better choice.

[35] 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 RPM capacity construct will become additional elements to consider in retail rate design.

[36] If LSE loads are subject to an add back approach 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 capacity market. If the LSE attempts to recover the capacity value 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 LDAs in the region based on the approximate load shares for the LDAs and the assumptions we chose about levels of energy efficiency investments. The energy efficiency investment levels (percentages of load) represent a range of investment in energy efficiency that spans the best programs in New England (0.7% or more) to those who have a zero level of investment. In this appendix, we make some different assumptions about those levels of energy efficiency investments to show some average and extreme cases. We also extend the results from Example 1 for ten years.

An Equal Investment Case

Example 4 shows the relative cost allocation if all LDAs have the same percentage (0.5%) of energy efficiency investment. There is no difference between the Load with Add-Back and the Metered Load columns.

Example 4. Equal Investment Case

Illustrative Values for Power Year 2011-2012

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00 without EE

Total Cost of Capacity ($m)
$ 6,205 without EE

				Load with Add-Back		Metered Load		Delta	
LDA	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 (%)
PS	11,100	0.5%	55.5	7.64%	473.86	7.64%	473.86	0.00	0.00%
PE	8,900	0.5%	44.5	6.12%	379.94	6.12%	379.94	0.00	0.00%
PLCO	7,500	0.5%	37.5	5.16%	320.18	5.16%	320.18	0.00	0.00%
UGI	200	0.5%	1.0	0.14%	8.54	0.14%	8.54	0.00	0.00%
BC	7,200	0.5%	36.0	4.95%	307.37	4.95%	307.37	0.00	0.00%
JC	6,700	0.5%	33.5	4.61%	286.02	4.61%	286.02	0.00	0.00%
ME	3,000	0.5%	15.0	2.06%	128.07	2.06%	128.07	0.00	0.00%
PN	3,000	0.5%	15.0	2.06%	128.07	2.06%	128.07	0.00	0.00%
PEP	7,000	0.5%	35.0	4.82%	298.83	4.82%	298.83	0.00	0.00%
AE	3,000	0.5%	15.0	2.06%	128.07	2.06%	128.07	0.00	0.00%
DPL	4,300	0.5%	21.5	2.96%	183.57	2.96%	183.57	0.00	0.00%
RECO	450	0.5%	2.3	0.31%	19.21	0.31%	19.21	0.00	0.00%
AP	8,700	0.5%	43.5	5.99%	371.40	5.99%	371.40	0.00	0.00%
CE	23,600	0.5%	118.0	16.24%	1,007.49	16.24%	1,007.49	0.00	0.00%
AEP	24,600	0.5%	123.0	16.92%	1,050.18	16.92%	1,050.18	0.00	0.00%
DAY	3,700	0.5%	18.5	2.55%	157.95	2.55%	157.95	0.00	0.00%
DUQ	3,000	0.5%	15.0	2.06%	128.07	2.06%	128.07	0.00	0.00%
DOM	19,400	0.5%	97.0	13.35%	828.19	13.35%	828.19	0.00	0.00%
Totals	145,350		727	100%	6,205	100%	6,205	0.00	

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, Example 5 below shows the results of one such scenario. In this example, most LDAs acquire energy efficiency resources equal to the most aggressive levels in the country. A few small LDAs, however, remain with a low level of energy efficiency investment. This example shows the impacts when most LDAs (over ~90% of load) experience aggressive energy efficiency programs (0.8% of loads) and a few LSEs (~10% of load) acquire a minimal amount (0.1% of loads). While this example produces cost-shifts to the few LDAs with less aggressive programs of about two-thirds of one percent (0.63%), the 1,055 MW of energy efficiency resources provides a clearing price benefit that still overwhelms the amount of the cost shift.

Example 5. Extreme Investment Case

Illustrative Values for Power Year 2011-2012

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00

Total Cost of Capacity ($m)
$ 6,205

				Load with Add-Back		Metered Load		Delta	
LDA	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 (%)
PS	11,100	0.8%	88.8	7.64%	474.21	7.64%	473.86	(0.35)	-0.07%
PE	8,900	0.8%	71.2	6.13%	380.22	6.12%	379.94	(0.28)	-0.07%
PLCO	7,500	0.8%	60.0	5.16%	320.41	5.16%	320.18	(0.24)	-0.07%
UGI	200	0.8%	1.6	0.14%	8.54	0.14%	8.54	(0.01)	-0.07%
BC	7,200	0.8%	57.6	4.96%	307.59	4.95%	307.37	(0.23)	-0.07%
JC	6,700	0.8%	53.6	4.61%	286.23	4.61%	286.02	(0.21)	-0.07%
ME	3,000	0.8%	24.0	2.07%	128.16	2.06%	128.07	(0.09)	-0.07%
PN	3,000	0.8%	24.0	2.07%	128.16	2.06%	128.07	(0.09)	-0.07%
PEP	7,000	0.8%	56.0	4.82%	299.05	4.82%	298.83	(0.22)	-0.07%
AE	3,000	0.8%	24.0	2.07%	128.16	2.06%	128.07	(0.09)	-0.07%
DPL	4,300	0.8%	34.4	2.96%	183.70	2.96%	183.57	(0.14)	-0.07%
RECO	450	0.8%	3.6	0.31%	19.22	0.31%	19.21	(0.01)	-0.07%
AP	8,700	0.1%	8.7	5.95%	369.10	5.99%	371.40	2.31	0.63%
CE	23,600	0.8%	188.8	16.25%	1,008.23	16.24%	1,007.49	(0.74)	-0.07%
AEP	24,600	0.8%	196.8	16.94%	1,050.95	16.92%	1,050.18	(0.77)	-0.07%
DAY	3,700	0.1%	3.7	2.53%	156.97	2.55%	157.95	0.98	0.63%
DUQ	3,000	0.1%	3.0	2.05%	127.27	2.06%	128.07	0.80	0.63%
DOM	19,400	0.8%	155.2	13.36%	828.80	13.35%	828.19	(0.61)	-0.07%
Totals	145,350		1,055	100%	6,205	100%	6,205	0.00	

The Inverse of Example 1

In this example, we merely reverse the estimates of energy efficiency investments that we assumed for Example #1. Instead of the LDAs at the top making the largest investments in energy efficiency, we made them the LDAs acquiring the fewest energy efficiency resources. We did the reverse for the LDAs at the bottom of Example 1.

Example 6. Inverse of Example 1.

Illustrative Values for Power Year 2011-2012

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00

Total Cost of Capacity ($m)
$ 6,205

				Load with Add-Back		Metered Load		Delta	
LDA	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 (%)
PS	11,100	0.0%	0.0	7.60%	471.88	7.64%	473.86	1.98	0.42%
PE	8,900	0.2%	17.8	6.11%	379.11	6.12%	379.94	0.83	0.22%
PLCO	7,500	0.2%	15.0	5.15%	319.48	5.16%	320.18	0.70	0.22%
UGI	200	0.2%	0.4	0.14%	8.52	0.14%	8.54	0.02	0.22%
BC	7,200	0.2%	14.4	4.94%	306.70	4.95%	307.37	0.67	0.22%
JC	6,700	0.0%	0.0	4.59%	284.83	4.61%	286.02	1.19	0.42%
ME	3,000	0.3%	9.0	2.06%	127.92	2.06%	128.07	0.15	0.12%
PN	3,000	0.3%	9.0	2.06%	127.92	2.06%	128.07	0.15	0.12%
PEP	7,000	0.3%	21.0	4.81%	298.48	4.82%	298.83	0.35	0.12%
AE	3,000	0.0%	0.0	2.06%	127.54	2.06%	128.07	0.53	0.42%
DPL	4,300	0.5%	21.5	2.96%	183.72	2.96%	183.57	(0.15)	-0.08%
RECO	450	0.4%	1.8	0.31%	19.21	0.31%	19.21	0.00	0.02%
AP	8,700	0.4%	34.8	5.98%	371.33	5.99%	371.40	0.07	0.02%
CE	23,600	0.6%	141.6	16.27%	1,009.30	16.24%	1,007.49	(1.81)	-0.18%
AEP	24,600	0.6%	147.6	16.96%	1,052.07	16.92%	1,050.18	(1.89)	-0.18%
DAY	3,700	0.5%	18.5	2.55%	158.08	2.55%	157.95	(0.13)	-0.08%
DUQ	3,000	0.7%	21.0	2.07%	128.43	2.06%	128.07	(0.36)	-0.28%
DOM	19,400	0.7%	135.8	13.38%	830.50	13.35%	828.19	(2.32)	-0.28%
Totals	145,350		609	100%	6,205	100%	6,205	0.00	

A Ten 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. Example 7 below makes the assumption that all LDAs continue our assumed estimates for a full ten years and then calculates the relative cost impacts and cost-shifts that would occur in Delivery Year 2020/2021. While we do not think that it is likely that the relative investment levels among LDAs would remain so disparate over ten years, we are providing this example as another "extreme" that might respond to a "what if" question.

Example 7. A Ten Year Current Investment Example

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

Reliability Requirement (MW)
170,000 (forecast peak load plus reserves)

Capacity Clearing Price ($/MW-day)
$ 100.00

Total Cost of Capacity ($m)
$ 6,205

				Load with Add-Back		Metered Load		Delta	
LDA	**Summer 2019 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 (%)**
PS	11,100	7.0%	777.0	7.95%	493.18	7.64%	473.86	(19.32)	-3.92%
PE	8,900	5.0%	445.0	6.25%	388.04	6.12%	379.94	(8.10)	-2.09%
PLCO	7,500	5.0%	375.0	5.27%	327.00	5.16%	320.18	(6.82)	-2.09%
UGI	200	5.0%	10.0	0.14%	8.72	0.14%	8.54	(0.18)	-2.09%
BC	7,200	5.0%	360.0	5.06%	313.92	4.95%	307.37	(6.55)	-2.09%
JC	6,700	7.0%	469.0	4.80%	297.68	4.61%	286.02	(11.66)	-3.92%
ME	3,000	4.0%	120.0	2.09%	129.55	2.06%	128.07	(1.48)	-1.15%
PN	3,000	4.0%	120.0	2.09%	129.55	2.06%	128.07	(1.48)	-1.15%
PEP	7,000	4.0%	280.0	4.87%	302.29	4.82%	298.83	(3.46)	-1.15%
AE	3,000	7.0%	210.0	2.15%	133.29	2.06%	128.07	(5.22)	-3.92%
DPL	4,300	2.0%	86.0	2.94%	182.12	2.96%	183.57	1.44	0.79%
RECO	450	3.0%	13.5	0.31%	19.25	0.31%	19.21	(0.04)	-0.19%
AP	8,700	3.0%	261.0	6.00%	372.09	5.99%	371.40	(0.69)	-0.19%
CE	23,600	1.0%	236.0	15.95%	989.76	16.24%	1,007.49	17.72	1.79%
AEP	24,600	1.0%	246.0	16.63%	1,031.70	16.92%	1,050.18	18.48	1.79%
DAY	3,700	2.0%	74.0	2.53%	156.71	2.55%	157.95	1.24	0.79%
DUQ	3,000	0.0%	0.0	2.01%	124.57	2.06%	128.07	3.50	2.81%
DOM	19,400	0.0%	0.0	12.98%	805.56	13.35%	828.19	22.63	2.81%
Totals	145,350		4,083	100%	6,205	100%	6,205	0.00	

Summary

Some of the examples above represent some extreme conditions that we believe are unlikely to occur. As stated in the body of our paper, basing cost allocation for the Delivery Year on actual metered loads creates an incentive for customers to make their loads more efficient. If an LDA has loads that make only minimal efforts to acquire energy efficiency resources (acquiring only 0.1% of its load while other LSEs are acquiring 0.8% of their loads), it is likely that energy service companies or other aggregators will take initiatives on their own. The benefits of the energy efficiency resources are the same regardless of how they are acquired. A “no add back” approach will make such aggregations simpler and reduce transaction costs. Thus, we think it is highly unlikely that large disparities in the energy efficiency acquisition rates between LDAs (as shown in some of the above examples) will endure for any significant length of time.