Milestone/Task	Description
Background Meetings with Experts	The PAs plan to meet with various experts in order to fully understand the challenges, costs, and benefits associated with demand reduction, identify value streams, assess potential revenue sources, and solicit recommendations. This background information will be used to guide future inquires and help the PAs and members of the DSG work through the analytical framework. These meetings will be held on an ad hoc basis and will seek to better understand the challenges and opportunities associated with demand reduction. Specifically, the PAs plan to meet with demand response program vendors, other utilities operating demand reduction programs, ISO-NE, consultants and evaluators, and demand response participants. These meetings are expected to discuss at least one of the three distinct issues associated with peak demand (i.e., summer system peak; winter peak price; and distribution)n
Wholesale Market Research	The PAs will meet with ISO-NE and other experts, and conduct research and analysis to identify the different (1) approaches and requirements for participating in the wholesale market and (2) ways demand reduction programs impact capacity and energy prices. The PAs seek to assess the benefits (e.g., revenue, reducing ICR and reallocating the ICAP tag, lowering prices) and risks (financial penalties, loss of CSO) of participating in wholesale market. The PAs will prepare a summary of this research for reference purposes (see Appendix for summary).
Develop Analytical Framework	In collaboration with the members of the DSG and the Demand Reduction Subcommittee, the PAs will develop an Analytical Framework to guide the PAs' strategic and expert driven analysis of potential demand reduction programs/projects. The draft analytical framework includes identifying problems and drivers, reviewing and evaluating initial recommendations, and analyzing potential costs and risks. See Appendix for the draft Analytical Framework.
Identify Problems and Drivers	This will be the first step in the Analytical Framework - the PAs and members of the DSG will: • Identify system and customer challenges. • Determine the specific drivers of those challenges. • Identify where in the system those challenges are occurring. • Identify drivers of capacity and energy costs. • Determine how changes in ICR, ICAP tags, and demand forecasts impact customers and rates. The PAs note that this is an ongoing process and additional problems and drivers may be identified. The PAs plan to use the Analytical Framework to guide the analysis of any additional issues and, in collaboration with the members of the DSG and Demand Reduction Subcommittee, will reassess tasks, objectives, and timelines as appropriate.
Review and Evaluate Initial Recommendations	The PAs, in collaboration with the DSG, will review and assess the various recommendations and potential approaches identified during the PAs' research and meetings with experts and the Demand Reduction Subcommittee. The PAs will seek to answer the following questions: • Who and where should we target? • What types of technologies and solutions will customers adopt? • Do the technologies work as anticipated? • Are there timing and/or geographic constraints? • Is the solution material to overall customer and system issues? • What are the potential impacts and value at the wholesale, distribution, retail, and customer levels? • What are the potential benefits? The PAs recognize that additional or new technologies and approaches may be identified at any point in time. Further, new studies or results from demonstration projects may impact the review and evaluation of proposed programs/projects. The PAs will continuously review recommendations and reassess the tasks and timelines as appropriate.

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Analyze Potential Costs, Risks, and Benefits	In collaboration with the DSG and experts, the PAs will analyze the potential costs, risks, and benefits associated with demand reduction strategies. The PAs plan to carefully assess potential strategies for unintended consequences and impacts on T&D planning. The PAs will evaluate hypotheses developed about potential cost drivers.
Develop cost-effectiveness model	Any demand reduction program must be screened for cost-effectiveness. The PAs will seek to develop a cost-effectiveness screening model consistent with the Department's requirements. The PAs will analyze potential approaches to cost-effectiveness, including models used in other jurisdictions or proposed in studies. The PAs will also seek to obtain or estimate costs and identify avoided costs of potential demand reduction programs/projects. As part of a regional effort, the PAs have already sponsored an initial study to assess the potential avoided costs of demand response in Massachusetts. The AESC 2015 Addendum has been completed and is attached in the Appendix.
Decision on DR Program for 2019-2021 Three-Year Plan	In April 2019, the PAs must submit an initial draft of the 2019-2021 Three-Year Plan to the EEAC. Based on the progress and lessons learned during 2016 and 2017, the PAs intend to make a decision by the end of 2017 on whether to include a demand reduction program or whether to include some other demand related proposal in the 2019-2021 Three-Year Plan.
Develop DR Program	If the PAs intend to include a demand reduction program in the 2019-2021 Three-Year Plan, the PAs, in collaboration with the members of the DSG and the Demand Reduction Subcommittee, will seek to develop a program, including implementation strategies, cost-recovery, an appropriate incentive structure, and evaluations, consistent with the DSG goals and the Green Communities Act, to achieve cost-effective demand reductions.
Develop cost recovery and incentive structure	The PAs, in collaboration with the members of the DSG, will assess potential revenue streams and develop a cost-recovery structure that appropriately allocates costs consistent with the Green Communities Act and Department precedent. The PAs will also seek to develop a mechanism that provides reasonable performance incentives to the PAs if challenging but achievable goals are met.

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Anticipated Timeline for Tasks and Demonstration Projects

Tasks	Quarter	Year	Notes:
Obtain ISO forecasts of demand vs. energy	Q1	2016	
Show level of demand resources in FCM over time (to give sense of scale)	Q1	2016	
Show historical peaks and prices	Q1	2016	
Show current Pricing and Rate design and implications	Q1	2016	
Prepare summary of background information for reference purposes	Q1	2016	See Initial Report Appendix
Solidify initial analytical framework	Q2	2016	Ongoing
Answer questions posed in the framework: Identify Problems and Drivers; Review and Evaluate Initial Recommendations; and Analyze Potential Costs, Risks, and Benefits	Q2 2016 through Q2 2017	2016-2017	
Analyze approaches to cost-effectiveness	Q2 2016 through Q4 2017	2016-2017	
Obtain or estimate costs of DR approaches	Q1-Q3	2017	
Identify avoided costs applicable to DR and differences from current EE methodology	Q4 2016	2016	Ongoing
Release IFQ for short term evaluation from existing vendors	Q1	2016	IFQ Issued
Issue RFP for longer term evaluation team	Q3-4	2016	
Review cost recovery and performance incentive methodologies/structures from other jurisdictions	Q2-Q4	2016	Ongoing
Develop cost recovery and performance incentive structure	Q1-Q2	2018	
Propose methodology to EEAC and DPU	TBD	TBD	
Reach out to potential experts	Q1	2016	Ongoing
Arrange meetings as appropriate	Q1	2016	Ongoing
Receive, develop, and revise recommendations	Q2	2016	Ongoing
Determine demand reductions from different measure classes	Q2	2016	Ongoing
Analyze each measure classes or approaches kW reduction coincidence with certain peaks	Q2	2016	Ongoing
Ensure timelines are appropriate	Q3	2016	Ongoing
Ensure that milestones are useful in meeting goals	Q4	2016	
Presentation on initial demonstration projects to Demand Reduction Sub-Committee	Q2	2017	
Assess potential for broader program application of initial demonstration project	Q2	2017	
National Grid Demonstration Projects			
Plan Approach/Program Design	Q3	2015	Ongoing
Select technology, and vendor – Residential and SMB	Jan 2016	2016	For Resi, C&I Q4 2016

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Customer Enrollment – Residential and SMB	April 2015	2016	Ongoing
Deliver program / call events as appropriate	June 1st 2016	2016	Summer 2016 Start – Resi,
Select vendor – C&I	Q3	2016	
Measure results – Residential	Q4	2016	Ongoing
Customer Enrollment – C&I	Q1	2017	
Deliver Program / call events as appropriate – C&I	Q3	2017	Summer 2017 Start C&I
Cape Light Compact Demonstration Projects			
Plan Approach/Program Design	Q3	2015	
Select customer, technology, and vendor	Q1	2016	Finished except Wi-fi thermostat (coordinating with National Grid)
Install equipment and metering as necessary	Q2	2016	
Deliver program / call events as appropriate	Q2-Q3	2016	Plan to call events in Summer 2016
Measure results	Q4	2016	
Eversource Demonstration Projects			
Plan Approach/Program Design	Q2-Q3	2016	
Demonstration Project Decision and Set Implementation Schedule	Q4	2016	

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Summary of Approved Demonstration Projects for 2016

National Grid

National Grid plans to implement demonstration projects in the summer of 2016, to gain insights and develop best practices and strategies to guide the deployment of demand response solutions at scale. In April of 2016 National Grid will start enrolling residential and SMB customers to its demand response program through various channels. National Grid will launch an online portal for customer enrollment as well as enroll residential customers thru the HES program, during home energy efficiency audits. In 2016 National Grid will focus on direct load control demand response technologies, like Wi-fi thermostats, washers and dryers and heat pump water heaters. In 2017 and 2018 additional technologies like electric hot water heaters, smart AC's and network lighting will be tested for demand response. Certain demand response technologies like Wi-Fi thermostats require National Grid's to be more targeted in its approach in enrolling customers with central air conditioning.

The residential demand response programs have been designed to provide customers with benefits of a connected home experience where customers can connect with their smart in-home devices and appliances from anywhere and anytime. Demand response events are automated and maintain customers comfort and lifestyles. Customers are incentivized for enrolling in programs as well as for participating in demand response programs through the year. National Grid plans to test the various technologies, strategies and determine best approach by end of 2016.

National Grid has started the development of a business portal that will allow for small business customers to register thermostats on a web platform and control the units remotely. This platform will also enable National Grid to control the thermostats during demand optimization events.

National Grid is planning on executing the installation of these thermostats through the Small Business C&I program. The program will purchase qualified thermostats for the portal, and install these units at time of audit or an energy efficiency upgrade. The installing vendor will be trained on the thermostat installation, as well as the process to enroll the thermostat in the DRMS portal.

The company is also pursuing testing solutions that will control EMS systems that will allow for the control of lighting, VFD, chillers and other associated equipment. The company has spoken to several companies about testing and providing this functionality in 2016. The company plans on broadening this offering later as a more robust distribution platform is identified and designed and integrated into the DRMS platform in 2017.

Cape Light Compact

As set forth in the 2016-2018 plan, the Cape Light Compact is implementing a Demand Response Demonstration Offering beginning on 2016. The purpose of the Demonstration Offering is to reduce customer demand through curtailment events, encourage load-shifting through behavioral change, engage and educate Cape Cod ratepayers on the benefits and concept

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of demand response, and use the experience and results gained to inform future expansion of demand response on Cape Cod and Martha's Vineyard. The Compact has budgeted for enrollment of 200 customers per year over the three years, and plan to hold 7-10 curtailment events each year. The Compact anticipates that most, if not all, of the curtailment events will be held during the summer, which is when the Cape's highest peak load occurs. The Compact plans to begin rolling out the program by the end of June 2016 in order to start holding curtailment events in summer 2016.

The Compact will initially be limiting eligibility to residences and businesses with central air conditioning. Program participants will receive a real-time energy monitoring kit, a wireless device gateway, and a Wi-Fi thermostat. This hardware will be installed free of charge, and will allow the customer to 1) see electricity usage and demand in real-time from their computer, tablet, or smart phone; 2) set their thermostat remotely to enable load reduction during cooling hours; and 3) enable future incorporation of other load-management devices that can be controlled remotely. The participants' usage data will be used to establish individual usage baselines, and an incentive payment will be issued based on the usage reduction during curtailment events relative to the established baseline. The Compact expects the Demonstration Offering will be an iterative learning process, and program design may change slightly based on feedback and data collected over the course of the program.

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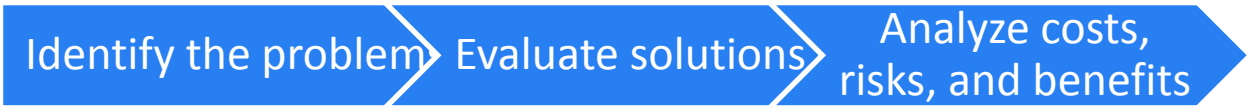
Draft Analytical Framework

Goal of Task: Develop a strategy and analytical framework to dictate how we should be thinking about issues surrounding demand reductions.



- Identify system and customer challenges
- Determine the specific drivers of those challenges
- Identify where in the system those challenges are occurring.
- Identify drivers of capacity and energy costs.
- Determine how changes in ICR, ICAP tags, and demand forecasts impact customers and rates.

- Who and where should we target?
- What types of technologies and solutions will customers adopt?
- Are there timing and/or geographic constraints?
- Is the solution material to overall customer and system issues?
- What are the potential impacts and value at the wholesale, distribution, retail, and customer levels?
- What are the potential benefits?

- How much will this cost?
- Are there any unforeseen risks or unintended consequences?
- What additional benefits can be quantified?
- Are there issues with T&D planning?

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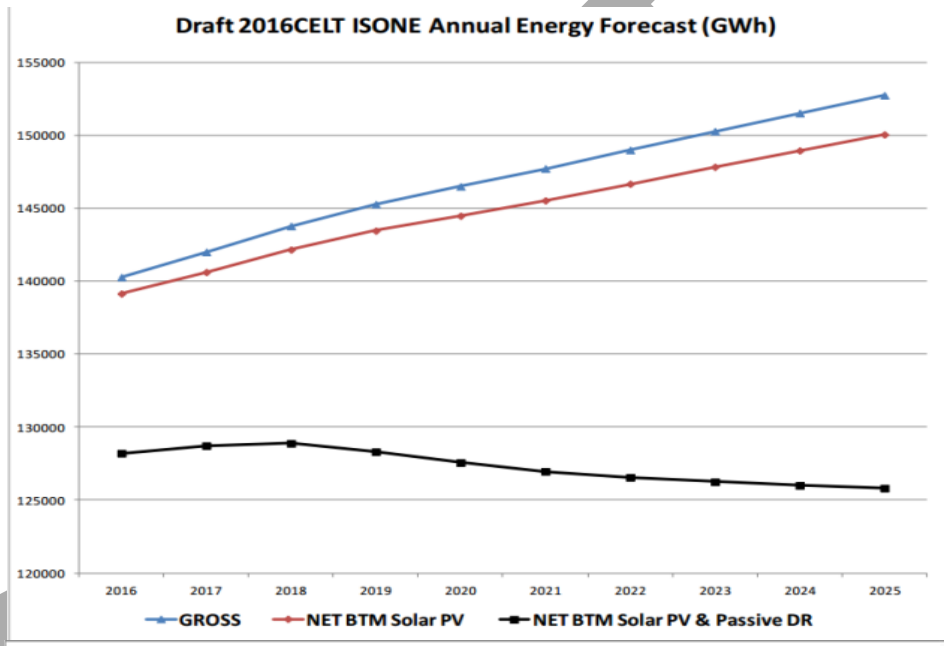
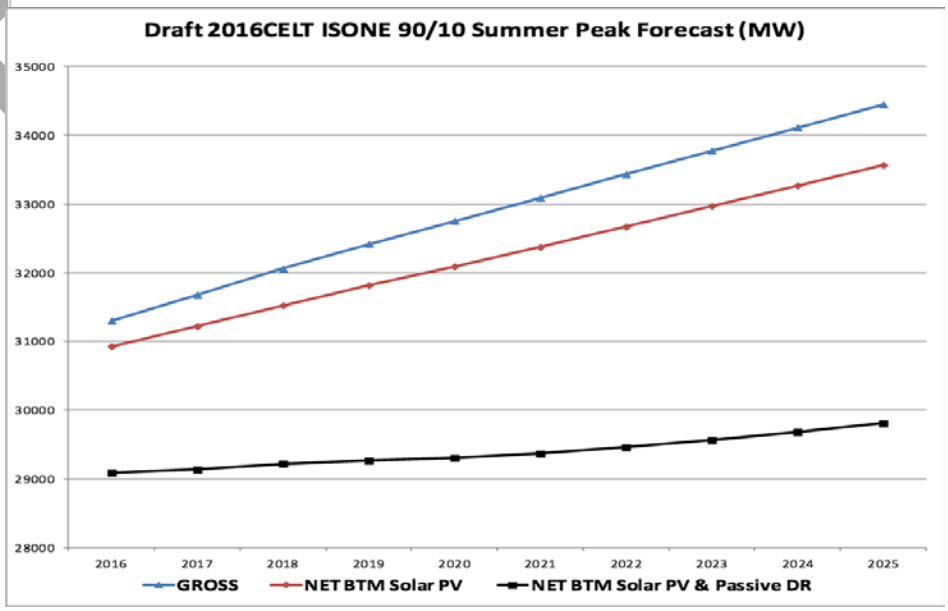
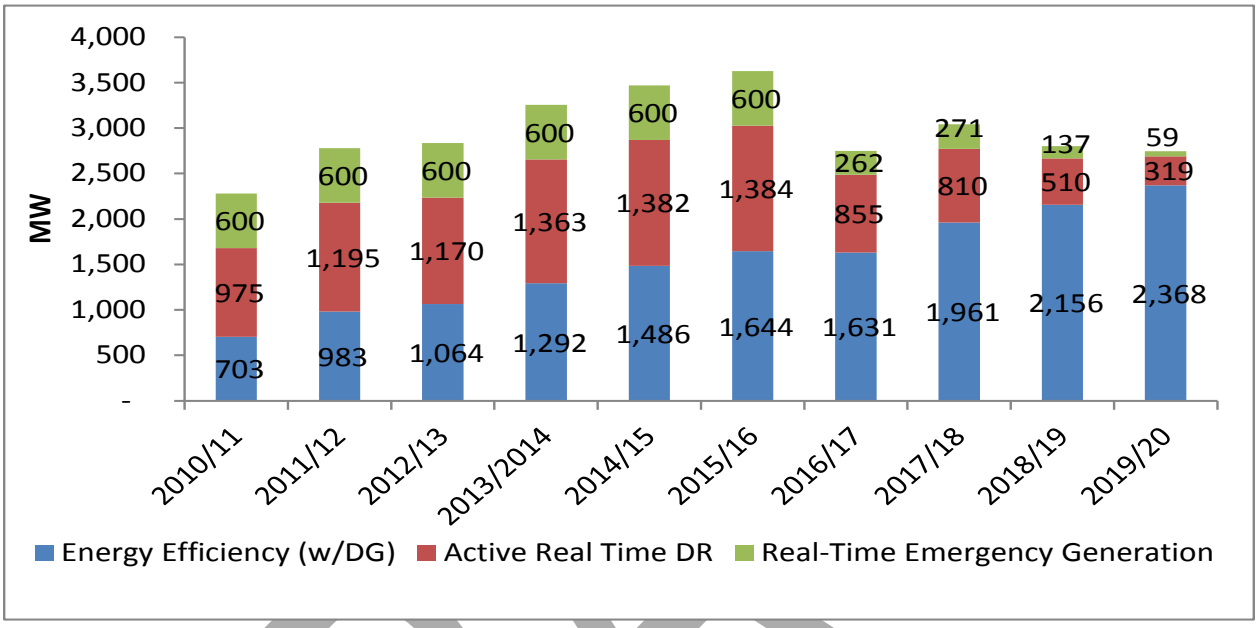
Summary of the Wholesale Market

Recent ISO-NE forecasts suggest that energy usage, as measured in GWh, will plateau and subsequently decrease in the 2018-19 timeframe. While there are many potential reasons for this trend (economic, demographic, weather, etc.) energy efficiency programs are undoubtedly a primary cause. The situation with the demand forecast, as measured in MW, is slightly different. While the PA programs have had a substantial impact in reducing demand, the ISO forecast is still predicting increasing MW consumption. This may indicate that the system is becoming "peakier" and that there is a higher penetration of summer peaking end uses than in previous years. The two graphs below highlight the ISO's forecasts for both energy and demand.

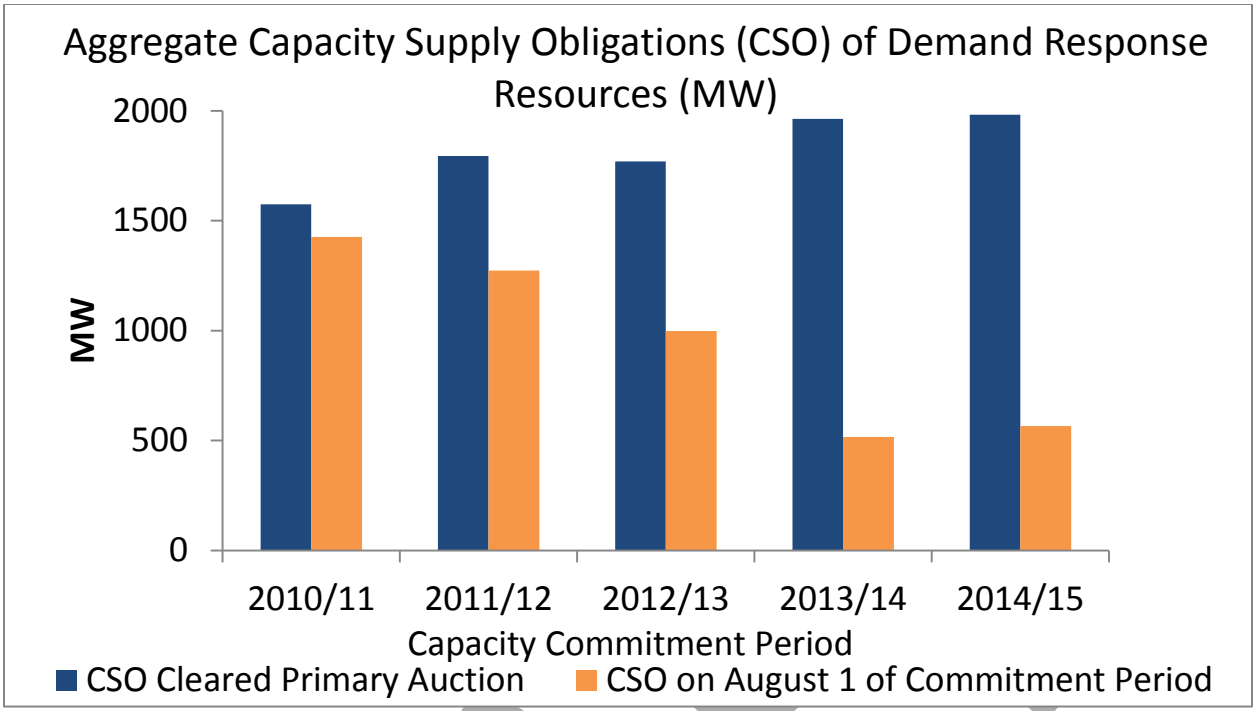




The delta between the Gross MW forecast and the NET BTM PV & Passive DR forecast represents the ISO forecast of ongoing ratepayer funded energy efficiency programs and policy based PV growth. The energy programs currently participate in the ISO NE's Forward Capacity Market (FCM), from which the ISO has a 10 year record of performance. The graph below shows the breakdown of Capacity Supply Obligations taken by demand side resources in the primary auction of FCM starting in 2010/2011 through 2019/2020.



Two very noticeable trends are the increase of passive demand reduction resources (i.e. energy efficiency and to a small extend distributed generation) into the market and the decline of active real time demand response. Increasing energy efficiency in the FCM can be attributed to increased PA activities and budgets. The decreasing levels of active DR likely have many causes including customer fatigue, market rules, and economic forces. One issue to note with active demand response is the discrepancy between the Capacity Supply Obligation (CSO) that was awarded to demand response resources in the primary auction and the actual CSO of those resources during the CCP. The chart below highlights the trend that demand response providers were taking on CSOs during the primary auctions at a relatively high price and then shedding those CSOs at a lower price, keeping the difference.



As noted above, energy efficiency and demand response can participate in ISO-NE's wholesale markets. As the PAs consider ways to potentially lower costs for Massachusetts's customers, two main levers related to the wholesale market could be targeted – the Installed Capacity Requirement (ICR) and the Installed Capacity (ICAP) tag. The ICR represents the amount of capacity the ISO needs to procure for the region and the ICAP tag represents how the capacity costs are allocated out to load serving entities (LSE). By lowering the ICR through EE and DR, the ISO may need to procure less capacity and would therefore save on costs. Alternatively, each LSE could attempt to lower their ICAP tag, i.e. lower their allocation of costs, by reducing their usage on the peak hour on the peak (the metric used to develop the ICAP tag). Lastly, PAs may be able to influence costs by bidding relatively lower cost EE and DR into the FCM in order to push out higher cost resources. This should have the net impact of reducing overall costs to ratepayers.

Each one of these strategies has its own set of pros and cons. For purposes of calculating the ICR, the ISO reconstitutes the known EE and DR reductions back into its forecast. This is done so that EE and DR are not double counted – once as a supply resource and once as a load reduction resource. Therefore, any EE or DR bid into the FCM would not have the impact of lowering the ICR. An exception to this approach is outlined in section 12.8 in the ISO market rules. In this scenario, an EE or DR resource would essentially go through the process of obtaining a CSO, i.e. ISO verification of project, but would not actually enter the FCM. This type of resource would not be reconstituted for ICR purposes but at the same time, it would not receive any revenue from the FCM.

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Attempting to influence the ICAP tag allocation can also be challenging. The peak hour on the peak day can occur at any time and is not known with certainty until the end of the year. Therefore, in order to ensure that the peak hour is impacted, it may be necessary to call DR events anytime there is a remote possibility that the peak will be reached. This can potentially lead to customer fatigue, meaning that customers will stop responding to events if they are called too often. The other main issue with trying to influence the ICAP tag is how costs trickle down from the ISO to the load serving entity (or power marketer) to the utility to the customer. Due to this configuration, most end use customers are not directly charged their portion of the ICAP tag and therefore there is no direct rate mechanism to influence customer behavior.

Bidding EE and DR into the FCM, however, may have the impact of reducing overall costs by driving out higher cost resources at the margin. EE and DR represent lower cost resources as compared to certain types of generation. If EE and DR can represent a higher percent of the necessary capacity requirements, then other, higher cost resources may not be necessary. There can be risk, however, associated with this strategy. For example, if a PA was to aggressively bid into the FCM and obtain a large CSO, there is the possibility that the PA could not deliver on that CSO. If the ISO does not think that the PA will be able to deliver on that CSO as it gets closer to the CCP, it could force the PA into the third Annual Reconfiguration Auction (ARA) and pay another market participant to assume the CSO. The financial risk here is that the PA is forced to pay the other market participant a higher price to take on its CSO than it originally received in the primary auction. The delta between the price in the primary auction and the ARA can be substantial and is a real risk.

There may also be other opportunities for demand resources to participate in the wholesale market such as qualifying as an energy only demand resource similar to a settlement only resource. The PAs are continuing to explore these options.

In addition to looking at capacity costs, the PAs have been analyzing trends in real time locational marginal prices (LMPs). LMPs can show a high degree of variation throughout the course of the year, and year over year. Understanding the root causes of high LMPs will be critical in trying to reduce those costs going forward. The charts below highlight the loads and LMPs over the last few years. Further analysis is being conducted on the drivers of the exceptional spikes that can occasionally be seen.

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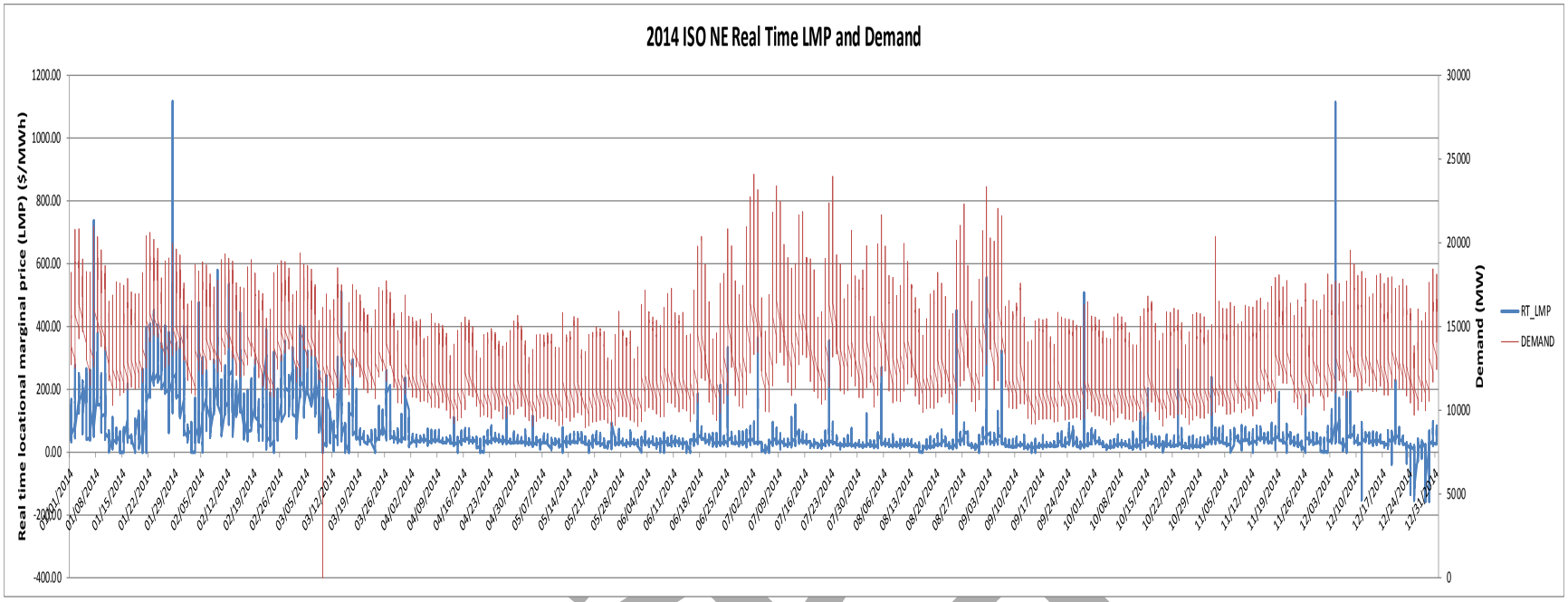
2014 ISO NE Real Time LMP and Demand
Real time locational marginal price (LMP) ($/MWh)
Demand (MW)
1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
-200.00
-400.00
30000
25000
20000
15000
10000
5000
0
RT_LMP
DEMAND
01/01/2014
01/08/2014
01/15/2014
01/22/2014
01/29/2014
02/05/2014
02/12/2014
02/19/2014
02/26/2014
03/05/2014
03/12/2014
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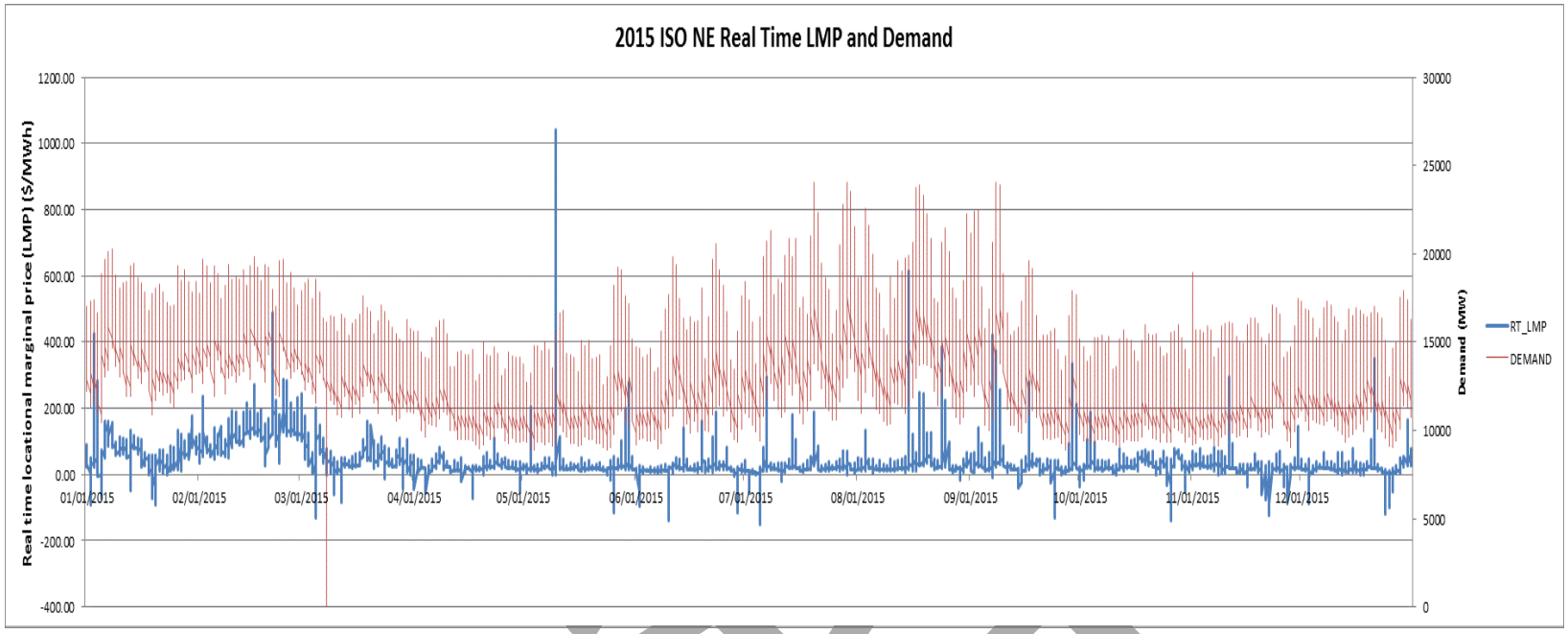
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1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
-200.00
-400.00
30000
25000
20000
15000
10000
5000
0
Demand (MW)
01/01/2015
02/01/2015
03/01/2015
04/01/2015
05/01/2015
06/01/2015
07/01/2015
08/01/2015
09/01/2015
10/01/2015
11/01/2015
12/01/2015
RT_LMP
DEMAND

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