STUDY OF OPTIONS FOR A STATE DEMAND RESPONSE PROGRAM

Submitted to

The Joint Standing Committee on Energy, Utilities and Technology of the Maine Legislature

Staff Report
of the
Efficiency Maine Trust
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I. Preface

When the 127th Session of the Maine Legislature called for this report, it was motivated in large part by a pending lawsuit that challenged the authority of the existing regional demand response (DR) programs run by ISO-New England and regulated by the Federal Energy Regulatory Commission (FERC). The Legislature called upon the Efficiency Maine Trust to study, with the help of leading stakeholders in Maine and New England, contingency plans for promoting DR that could be pursued in the event the existing DR regime was invalidated. This is the report of the discussions and options outlined during the course of the past six months in which the study was conducted.

On January 25, 2016, the United States Supreme Court ruled that the existing DR regime is legal. The Court's decision was an important victory for electricity ratepayers in Maine. The decision means that Maine ratepayers can continue to benefit from DR's ability to enhance grid reliability and lower electricity bills using a well-established, regional, market-based system run by ISO-New England. It also will maintain DR's role, along with certain other demand-side energy resources, in promoting cost-effective, market-based solutions that reduce pollution from the electricity sector.

The urgency for Maine to consider contingency plans for developing DR programs has abated now that the legal threat to the regional DR programs has passed. Nonetheless, because DR is both a valuable and a complex resource, it is still useful to have done the study and completed this report. The study provided the opportunity for stakeholders and policymakers in Maine to review the elements of successful DR programs and consider how emerging technologies and DR program designs might evolve to further improve grid reliability, reduce electricity costs, and advance environmental objectives.

II. Introduction

The Efficiency Maine Trust has prepared this study as directed by the Resolve of the Legislature, "To Study Options for a State Demand Response Program" (the Resolve).[1]

The preamble of the Resolve observes that:

> … there is significant value to individual consumers of electricity who participate in demand response programs that provide incentives to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized and to consumers who benefit from reduce peak electricity pricing and increased electrical grid stability…[2]

Notwithstanding the potential benefits that DR offers, concerns recently emerged about the future of DR programs in Maine and New England. One reason for concern related to uncertainty stemming from a legal challenge to the existing regional DR programs operated by ISO-New England (ISO-NE) and other regional transmission operators around the US. Another issue related to the ISO-NE's DR program rules, which have been viewed by some as discouraging participation.

To prepare for the possibility that the legal challenge would invalidate ISO-NE's DR program, the Resolve sought to use the study to help Maine plan for contingencies, such as pursuing an alternative form of DR program either "alone or in conjunction with the other New England states."[3]

The Resolve also directed the Efficiency Maine Trust to "study options for a state demand response program that will produce electricity consumer and electrical grid benefits and that will allow and encourage participation of Maine electricity consumers in the program" and to "survey other states in New England regarding their interest in demand response programs at the state or regional level."

The Resolve further directed the Trust to consult with stakeholders, including the Governor's Energy Office, the Public Utilities Commission, the Office of the Public Advocate, ISO-New England, transmission and distribution utilities, and electricity consumers

To solicit input from stakeholders, the Trust convened the Demand Response Working Group of Maine. The Demand Response Working Group held four in-person meetings. The meetings were held on August 13, 2015, November 24, 2015, December 10, 2015, and January 14, 2016. A list of participating stakeholders can be found in Appendix A. To solicit public input, the Trust posted the draft report on its website and invited comments.

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[1] Chapter 14, Resolves, 127th Session of the Maine Legislature, LD 357, May 17, 2015.
[2] *Ibid.*
[3] *Ibid.*

The Resolve calls for a report to the Joint Standing Committee on Energy, Utilities and Technology that presents the study's conclusions and any recommended legislation.

III. Today's Demand Response Programs

The Federal Energy Regulatory Commission (FERC) defines DR as:

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[4]

One way that DR is accomplished is by compensating customers for reducing their electricity demand at peak times of consumption or during emergency shortages. While both DR and efficiency are forms of "distributed energy resources" (DER), DR is distinct in that the goal of deploying DR is to temporarily reduce peak demand rather than reduce total energy consumption. DR can be replicated reliably in response to high energy prices, emergencies, or congestion on transmission or distribution lines.

DR programs typically are administered by regional transmission organizations, like ISO-NE, or utilities. Third-party aggregators, such as EnerNOC, create portfolios of customers who serve as a single response unit that can curtail electricity load when requested by the grid operator or local utility. In essence, the customer or aggregator that commits to reducing electricity load functions like an energy provider, and in effect serves to increase the capacity of the overall electric grid by curtailing electricity consumption when needed or economically beneficial.[5]

A. Benefits of Demand Response

DR has the potential to reduce electricity costs for all ratepayers. DR also contributes to a more responsive, resilient, clean and reliable electricity system. Benefits of DR include:

- **Customer Savings**. DR can lower electricity prices for all ratepayers and reduce price volatility for all consumers of electricity. DR provides this benefit because DR participates in the Forward Capacity Market (FCM), offering a resource that, when cost-effective, counts toward the region's Installed Capacity Requirement (ICR), the calculation of the grid's future capacity needs. In New England, ISO-NE uses DR to meet the grid's capacity needs. Cost-effective DR lowers capacity prices around the clock and wholesale energy prices when dispatched. This, in turn, can lower capacity and energy charges for all customer classes. For example, the Brattle Group found that

[4] Federal Energy Regulatory Commission. *Assessment of Demand Response Potential.* Prepared by the Brattle Group, Freeman, Sullivan & Co., and Global Energy Partners, LLC. June 2009, p.17.

[5] National Council on Electricity Policy. "Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers." September 2009, p. 7. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Updating_the_Electric_Grid_Sept09.pdf.

a three percent load reduction during the top 100 peak hours of electricity demand would create net annual benefits between $138 million and $281 million in five mid-Atlantic states.[6] DR, when called, can also lower the energy price during a particular period of peak demand. This will lower the wholesale electricity prices that large commercial and industrial users pay. For example, in June of 2010, ISO-NE called for 670 MW of DR, which resulted in a drop in Locational Marginal Price (LMP) of $180/MWh.[7]

- **Grid Reliability.** Utilities and grid operators have primarily deployed DR to help maintain the reliability of the grid. In emergencies, such as when electricity demand is very high relative to available supply and transmission resources, customers may be asked to curtail their consumption of electricity to avoid brownouts or blackouts. For example, during the 2006 heat wave, ISO-NE found that DR played an important role in maintaining grid reliability, achieving a 528.8 MW reduction between July 31 and August 3.[8]

- **Deferred or Avoided Investment in Generation and Transmission & Distribution (T&D).** DR can provide capacity by reducing peak demand on the system, thus allowing for the deferral or avoidance of construction of new generation or T&D infrastructure. In Maine, DR is one of several types of cost-effective alternatives now in place as part of a pilot program in the Boothbay peninsula that has deferred the need for building new transmission capacity.

- **Environmental.** DR can avoid the need for powering up older “peaker” generators, which provide the costliest and dirtiest power, or the need for constructing new power plants. Like energy efficiency and clean distributed generation, DR helps reduce the pollutants and greenhouse gases that dirtier power plants would have otherwise emitted.

In the future, DR may be able to play a larger role in delivering these benefits in New England in the context of constrained natural gas supply and continued retirement of older power plants throughout New England. In addition, introducing more solar and wind generation to the grid can result in fluctuations in load of up to 20 or 30 percent when clouds impede PV panel production or the wind drops off. This can contribute to an imbalance between electricity supply and demand.[9] DR can play a role in mitigating imbalances.

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[6] Brattle Group, “The Power of Five Percent.” May 2007, as cited in EnerNOC’s “Demand Response: A Multi-Purpose Resource For Utilities and Grid Operators.” 2009, p. 4.

[7] Feldman, Brett, Matthew Tanner and Cliff Rose. “Peak Demand Reduction Strategy.” Prepared by Navigant Consulting for Advanced Energy Economy. October 2015, p. 21.

[8] National Council on Electricity Policy, p. 9.

[9] Smith, Kelly and Ryan Hledik. “Drivers of Demand Response Adoption: Past, Present and Future.” The Brattle Group and the Institute for Building Efficiency, an initiative of Johnson Controls. March 2011, p. 10. http://www.institutebe.com/InstituteBE/media/Library/Resources/Smart%20Grid_Smart%20Building/Issue-Brief---Demand-Response-Drivers,-ENG.pdf

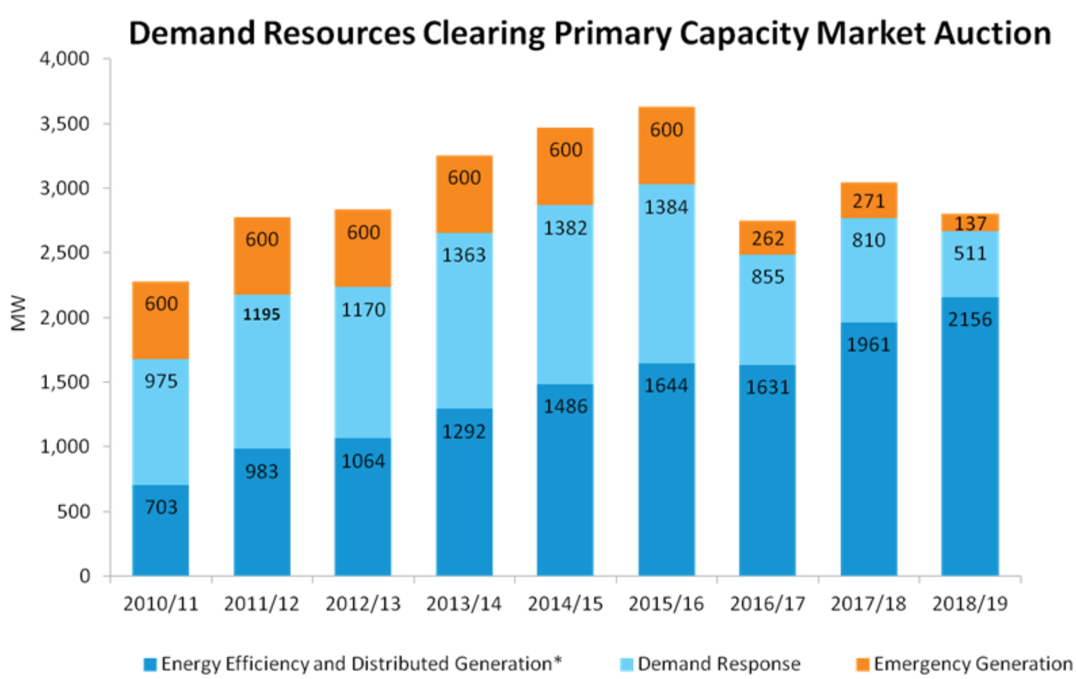
B. Demand Response Landscape

Nationally, efforts to increase energy efficiency have flattened annual electric load growth, but growth in peak demand has not been curbed as successfully.[10] As much as 10 percent of peak demand occurs in less than one percent of the hours of a year.[11]

In New England, distributed resources such as DR play an important role in ensuring grid reliability and delivering ratepayer benefits. ISO-NE has reported that, "Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market."[12]

As recently as 2002, ISO-NE only had approximately 100 MW of DR. By 2010, ISO-NE's capacity market cleared 975 MW of DR as part of a broader suite of demand resources (which include energy efficiency and distributed generation, emergency generation, as well as DR) reaching 2,000 MW.[13] The size of the DR resource continued to grow from 2010 to 2015, clearing 1384 MW in the 2015/2016 auction, but subsequently has fallen below the 2010/2011 auction amount. Some of the reasons were articulated by the Demand Response Working Group, and are detailed later in this report.

Figure 1: Demand Resources that Cleared ISO-New England's Capacity Market[14]



[10] Buckley, Brian. "Why Program Administrators should care that demand response is before the Supreme Court." Northeast Energy Efficiency Partnerships. October 29, 2015. http://www.neep.org/blog/going-deeper-why-program-administrators-should-care-demand-response-supreme-court

[11] EnerNOC. "Demand Response: A Multi-Purpose Resource For Utilities and Grid Operators." 2009, p. 3.

[12] ISO-NE. "Overview of New England's Wholesale Markets and Market Oversight." May 15, 2012, p. 21.

[13] Data provided by ISO-NE to Efficiency Maine Trust in email correspondence, 1/15/16.

[14] Graph provided by ISO-NE to Efficiency Maine Trust in email correspondence, 1/15/16.

In Maine, the state typically experiences peak demands in the summer, usually in the months of July and August. Maine's winter peak demand is driven principally by lighting.

While DR can help reduce consumption during times of peak demand in Maine, the state market for DR is limited. Maine DR resources derive much of their value from selling into the New England-wide market. In fact, in 2015, Maine represented more than one-third of the DR in the ISO-NE region and represented the largest amount of DR of all the states, as shown in the table below.

Table 1: Snapshot of Availability of DR by State, 11/1/15 Preliminary Capacity Supply Obligation for 2015[15]

Load Zone	Real Time Demand Response (MW)	Percentage of Region's Availability of DR
ME	**115.047**	**37%**
NH	7.431	2%
VT	28.477	9%
CT	74.257	24%
RI	10.936	4%
SEMA	11.038	4%
WCMA	30.132	10%
NEMA	30.879	10%
Total	**308.197**	

Recent Evolution of Demand Response

Historically, DR programs have been primarily structured to maintain grid reliability. In Maine, DR is provided by large industrial and commercial users who curtail loads in response to dispatch requests from grid operators. In Maine, and nationally, DR programs have not traditionally yielded high levels of participation among smaller industrial and commercial electricity consumers.[16] Less than five percent of residential customers in the U.S. participate in DR programs.[17] In Maine, there are no residential customers participating in DR.

However, in the past decade, DR has been evolving into a more dynamic resource that can do more than just respond to grid operator instructions to improve grid reliability. Around the

[15] Table is adapted from Henry Yoshimura's presentation "LD 357: Resolve To Study Options for a State Demand Response Program." Presented to Efficiency Maine Trust Demand Response Working Group. 11/24/15.
[16] EnerNOC, "Demand Response: A Multi-Purpose Resource For Utilities and Grid Operators." p. 2.
[17] Walton, Brian, "The Value of Less: Quantifying the benefit of peak demand savings," *Utility Dive*, November 4, 2015. http://www.utilitydive.com/news/the-value-of-less-quantifying-the-benefit-of-peak-demand-savings/408565/

country, DR programs are being designed to respond to spikes in wholesale electricity price. These DR programs focus on peak-shaving, which reduces peak consumption on high load days, and/or load-shifting, which shifts consumption from times of high electricity prices to times of lower prices.

Improvements in metering and communications technology and increasing automation are creating a smarter grid, making it easier for small businesses and residential customers to provide DR. These changes are facilitating an expansion in the ways DR is deployed. As one pair of experts observed, "Today's DR is providing dispatchers with an additional option to address both planned and unforeseen system needs. DR is now providing not only emergency capacity, but year-round peak-shaving resources and quick-response ancillary services."[18]

Types of Demand Response

There are three main types of DR programs:

- **Reliability Response** (also known as emergency DR).[19] Utilities or grid operators pay participating customers capacity and energy payments to be on standby to quickly and briefly shed a portion of their electric load during system events in which the system is capacity deficient. Reliability response DR is a tool that grid operators can use to satisfy reliability requirements established under local, regional, and North American Electric Reliability Corporation (NERC) authority. When DR is called by the grid operator, participating customers are obligated to deliver the DR. Common triggers for reliability response DR include grid emergencies, falling reserve margins, voltage reductions, and distribution emergencies.[20] Reliability response DR can be used to avoid brownouts and blackouts. While it is infrequently used, it comprises 87 percent of the demand reduction capacity of the nation's reliability regions.[21]

- **Price Response** (also known as economic DR). In this type of DR program, customers respond to price signals during periods of high wholesale prices. Price response DR reduces wholesale energy prices on days of heavy electricity use and shifts demand to non-peak hours so that the electricity system functions more efficiently. Unlike reliability response DR, customers are not required to reduce consumption when wholesale prices are high, and therefore this type of DR resource is not considered firm capacity. In order for price response DR to function, electricity prices must be visible to the electricity consumer in a meaningful timeframe.

- **Frequency Response** (also known as regulation response). This type of DR provides continuous and frequent resources to balance the supply of and demand for electricity

[18] Brief, Kristin and Brad Davis, "C&I Customers Get Smart: Technology creates new opportunities for demand-side management," *Public Utilities Fortnightly,* January 2011, p. 42.
[19] Reliability Response DR is referred to by a variety of names, including "emergency", "standby", "curtailable", "event-based", and "interruptible tariff".
[20] EnerNOC. "Designing and Successful Commercial and Industrial Demand Response Program." 2012, p. 3.
[21] Managan, Katrina. "Demand Response: A Market Overview." Institute for Building Efficiency, an initiative of Johnson Controls. February 2014, p. 4. http://www.institutebe.com/smart-grid-smart-building/demand-response-state-of-market.aspx

almost instantaneously using spinning reserves or by regulating the frequency of the electricity. Whereas reliability response and price response DR provide a large volume of capacity and electricity use reductions, system support DR provides smaller resources for short periods of time to keep system voltage and frequency at near constant levels.

These types of DR correspond to the three types of wholesale electricity markets in which DR can compete. These markets include: the **capacity market** (which is the forward market that ensures that resources including DR are available in the future); an **energy market** (which is the market in which suppliers and customers sell and buy electricity to satisfy real-time demand for electricity) and **ancillary services market** (which is a market for resources to provide immediate support to maintain grid reliability through reserves and frequency regulation).

Customers generally need incentives to participate in DR programs. This is particularly true for consumers using electricity in manufacturing or similar processes, where being dispatched to provide DR can mean decreased sales or delayed production. These incentives are delivered through capacity and energy payments, with some secondary effect through the avoidance of high cost electricity. These incentives can also be delivered through price-responsive programs and indexing retail electricity rates to wholesale prices.

Nationally, some regional transmission organizations have been working to integrate DR into all of the wholesale electricity markets. DR also could, in theory, participate in the retail market if retailers were to establish dynamic, time-differentiated tariff and rate structures that encourage reductions in peak electricity consumption.[22] This retail participation will be explored in the upcoming section and Appendix B on alternative regional and state models for DR.

C. ISO-NE Demand Response

ISO-NE reports indicate that it "has had a long commitment to demand resources" and launched its first DR programs in 2001. Since then, demand resources, which include energy efficiency, distributed generation, and DR, have grown from 63 MW to thousands of megawatts.[23]

In New England, demand resources are part of the wholesale electricity market. ISO-NE has implemented incentive-based programs for both active demand response and passive demand resources. Passive demand resources are not dispatchable; active demand response resources are dispatchable. Passive demand resources are designed to reduce energy consumption throughout the year and shave peak demand and seasonal peak demand at set times throughout the year. These passive demand resources provided 1,667 MW of capacity supply obligation in 2015.[24]

[22] Smith, Kelly and Ryan Hledik. "Drivers of Demand Response Adoption: Past, Present and Future." The Brattle Group and the Institute for Building Efficiency, an initiative of Johnson Controls, March 2011, p. 5.

[23] http://www.iso-ne.com/markets-operations/markets/demand-resources/about

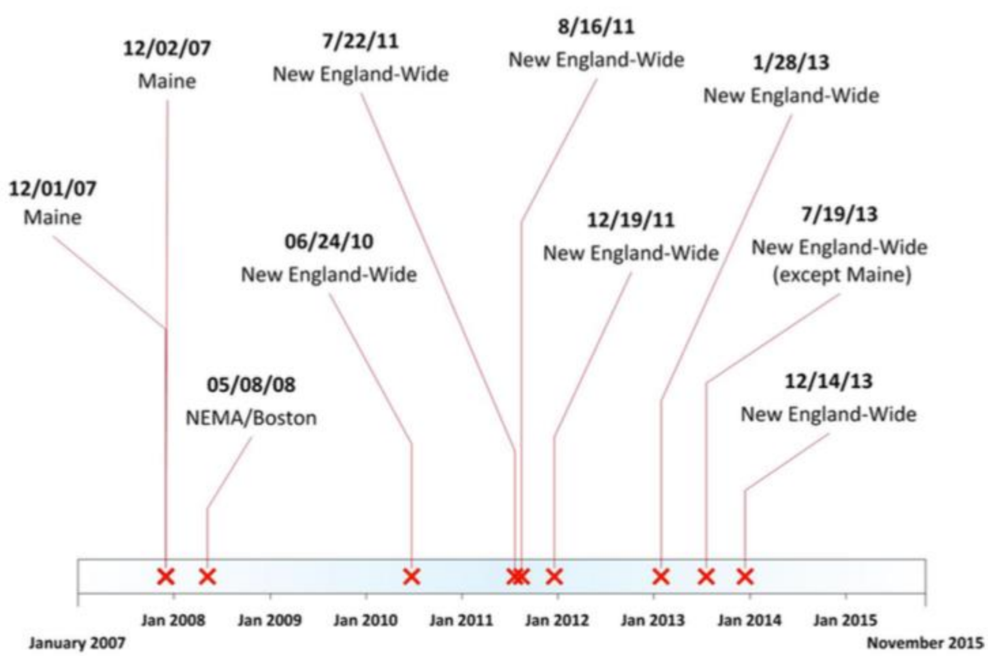
[24] Yoshimura, Henry. "LD 357: Resolve To Study Options for a State Demand Response Program." Presentation to Maine Demand Response Working Group. 11/24/15, slide 12.

In New England, ISO-NE has made plans to fully integrate DR into all markets, but currently only allows DR to participate in the regional wholesale energy and capacity markets. DR is fully integrated into the capacity market. In this market, the grid operator purchases commitments from power suppliers and demand resources, which includes DR, to serve loads in future years. In New England, capacity resources are purchased in this way for delivery three years in the future. In the energy market, DR can participate, but DR is not fully integrated into the market at the present time because DR offers do not affect the clearing price in the energy market. DR does not participate in ISO-NE's ancillary market. Full integration of DR into all electricity markets was originally planned to be completed in 2017, but has been delayed a year due to the uncertainty associated with the legal challenge to FERC Order 745 and ISO-NE's authority to run its DR programs.

At ISO-NE, DR participates in the capacity and energy markets:

- **Real Time Demand Response**. This is a reliability response activated when system conditions require electricity curtailment to maintain grid reliability. Participants receive a capacity payment, and energy payments when dispatched. ISO-NE has activated emergency DR ten times in the last nine years.

Figure 2: ISO-NE's Activation of DR to Support Grid Reliability[25]



- **Real Time Price Response**. This is a price response that requests voluntary load reductions by electricity consumers when the real-time Locational Marginal Price

[25] Taken from Henry Yoshimura's presentation "LD 357: Resolve To Study Options for a State Demand Response Program." Presented to Efficiency Maine Trust Demand Response Working Group. 11/24/15.

reaches a specific price threshold.[26] Program participants receive an energy payment when dispatched.

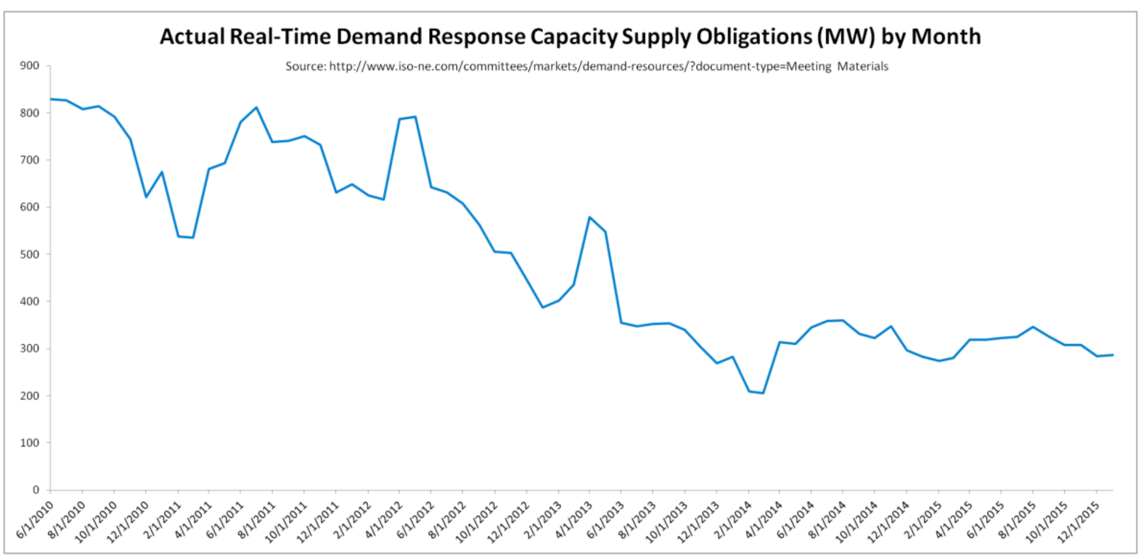
Stakeholder Comments on the Evolution of DR in ISO-NE

Maine's Demand Response Working Group discussed challenges to participation in the current ISO-NE DR Programs.

ISO-NE's treatment of DR has been evolving. Stakeholder comments focused on ISO-NE's Real Time Demand Response program, and focused mostly on the challenges with ISO-NE's current programs, understanding that the market rules will be changing in 2017 and 2018. These changes are a result of the discussions stakeholders and ISO-NE's working groups have done to improve participation in DR in New England.

Some stakeholders recently reduced their participation in ISO-NE's DR programs, as can be seen in Figure 3. One large industrial customer said that its mill dropped its participation because aspects of the program are too complex. EnerNOC, an aggregator that works with large industrial and commercial electricity users to curtail loads in response to emergencies or high prices, indicated that some of the market rules make participation economically untenable, particularly for aggregators. EnerNOC has left the DR market in New England. ISO-NE noted that some DR providers stopped participating when FERC required ISO-NE to remove the price floor from the capacity market auctions. Former participants in ISO'NE's DR markets or participants who have reduced their participation noted a perception that the risks involved in participating in present ISO-NE DR programs exceed the rewards of doing so.

Figure 3: ISO-NE's Real Time DR Capacity Supply Obligations[27]



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[26] ISO-NE. "Overview of New England's Wholesale Markets and Market Oversight." May 15, 2012, p. 22.
[27] ISO-NE, email communication to the Trust, 1/19/16.

The Demand Response Working Group identified three notable challenges to participation in the DR program.

- **Baseline validation**. The market rules related to monitoring and verifying DR capacity and performance have been onerous for some stakeholders. The most challenging issue relates to verifying a customer's energy usage baseline. A base load profile is assigned to each customer, and the customer's delivery of DR is measured against this to verify that a customer can shed demand in an event.

  One stakeholder used the following example to illustrate a customer's risk of failing to demonstrate its ability to deliver the DR anticipated from the baseline: Assume a ski resort has offered a DR resource to shed load when it would otherwise be operating energy intensive snowmaking. This offer presumes that the weather is cold enough to be making snow at the time its DR is called for, as typically occurs during the snowmaking season. However, if the ski resort is audited on an unusually warm day during which it is unable to make snow, the audit would report that the customer did not have as much load to shed as it had bid into the DR market. This finding could result in significantly reduced capacity payment, even if the ski resort could actually perform a greater level of DR when called during an actual crisis. This risk, which may be related to the weather or other factors out of the customer's control, is not manageable for some market participants.

  Another stakeholder described situations where, as a participant in a DR program, it was asked to perform a test load reduction just days before a potential actual DR event. In this case, the customer's operations and production requirements meant that being required to perform the test event could compromise its near-term ability to perform in an actual DR event. This timing was seen as harmful by the participant, but it may have been unnecessary and deterred the customer's participation. While measurement and verification of DR capability are important, some stakeholders also felt that improved audit and testing schedules would facilitate broader and deeper customer participation.

  Another risk related to the baseline is that any error in a five-minute interval of data must be reported to ISO-NE.

  ISO has updated the baseline methodology in response to concerns voiced in previous years by market participants. A new baseline methodology will be used by ISO-NE in 2017.

- **Performance incentives**. The incentives for emergency generators and DR providers to respond to ISO-NE's dispatches include compensation for performance and penalties for increasing consumption during a dispatch. Currently, generators and DR providers face a different incentive structure. Some market participants have complained that the different treatment is unfair and discourages DR, while others say that generators and DR face inherently different situations and it may be appropriate to handle them differently. ISO-NE has taken steps to ensure that generators and DR providers are treated equally in its Pay For Performance program, which will be in effect starting on June 1, 2018. The Pay for Performance rules bring a new obligation for all resources, and EnerNOC said that the risk associated with DR under the new structure is unknown.

- **Legal uncertainty.** The marketplace for DR has experienced significant uncertainty since the legal challenge that led to the D.C. Circuit Court vacating FERC Order 745 and the appeal to the Supreme Court. More detail on the legal issue is provided in the next section.

Stakeholders have been participating in working groups with ISO-NE to address the market rule issues, and agreed that some progress has been made to better facilitate participation in DR in New England. Overall, stakeholders expressed satisfaction with ISO-NE's modifications to the baseline methodology and introduction of pay for performance incentives. If implemented, these changes will go into effect in 2017 and 2018, respectively.

IV. Legal Challenge

In 2011, FERC issued Order 745, which required that DR participating in wholesale energy markets be compensated at the same energy market prices as traditional generation. Subsequently, Order 745 was challenged by the Electric Power Supply Association (EPSA). In 2014, the DC Circuit Court, in a split ruling, vacated the order, finding it to be arbitrary and capricious and that FERC lacked the jurisdiction to promulgate the rules of Order 745 because it "entails direct regulation of the retail market – a matter within state control."[28] This ruling, were it to stand, would have prohibited DR from being traded on the wholesale energy market, invalidating the existing framework for valuing and compensating DR resources in New England.[29]

In early 2015, the General Solicitor of the U.S. filed an appeal on behalf of FERC, and the U.S. Supreme Court agreed to hear the case. Oral arguments were made in the fall of 2015, and a decision by the U.S. Supreme Court was issued on January 25, 2016.

In a 6-2 decision, with Justice Alito recused, the Court overturned the lower court decision and upheld the legality of the existing DR programs. Writing for the majority, Justice Kagan concluded:

> FERC's statutory authority extends to the Rule at issue here addressing wholesale demand response. The Rule governs a practice directly affecting wholesale electricity rates. And although (inevitably) influencing the retail market too, the Rule does not intrude on the

[28] Yoshimura, Henry. "Contingency Plan Addressing the Potential Loss of FERC Jurisdiction Over Demand Resources." April 17, 2015, p. 4.
[29] Gimon, Eric and Mike O'Boyle, "The Future of Demand Response without FERC Order (O'Boyle, 2015) 745," *Greentech Media*. http://www.greentechmedia.com/articles/read/the-future-of-demand-response-without-ferc-order-745

States' power to regulate retail sales. FERC set the terms of transactions occurring in the organized wholesale markets, so as to ensure the reasonableness of wholesale prices and the reliability of the interstate grid—just as the FPA contemplates. And in choosing a compensation formula, the Commission met its duty of reasoned judgment. FERC took full account of the alternative policies proposed, and adequately supported and explained its decision.[30]

V. State and Regional Options for Demand Response Programs

Had the Supreme Court decision turned out differently, it would have invalidated the existing regime for regional DR programs and disrupted the DR market in New England. Given that maintaining DR in the electricity market is valuable for ratepayers, the economy, and the environment, it was prudent for Maine to start contingency planning before the court issued its decision. Maine's Demand Response Working Group set about the first steps in this task, surveying the efforts of ISO-NE and the other states, and discussing various models that would address the pending legal issues and meaningfully promote DR in Maine and the region.

The options that were discussed can be roughly divided into two categories. The first category comprised options that would reconstitute as nearly as possible the existing programs that are operated by ISO-NE, whether through a regional approach or using a state-by-state approach. The second category entailed options that could complement the existing programs.

The Demand Response Working Group's discussion about contingency solutions to reconstitute a DR program is now largely academic given that the Supreme Court upheld the existing regime. For completeness, this report has memorialized in Appendix B the key points about reconstituting or restructuring a regional DR solution. The remainder of this section focuses on state-based DR programs that regulators and policymakers might consider as a means to complement ISO-NE's regional programs.

There are several actions a state could consider to complement a regional DR program should the benefits outweigh the costs. These options, discussed in more detail below, include:

- Set DR targets;
- Create additional DR programs to complement or replace ISO-NE's DR programs; and
- Implement variable retail pricing.

[30] 577 U.S. ___, (2016), *Federal Energy Regulatory Commission v. Electric Power Supply Association et al.*, slip op., Jan. 25, 2016, p. 33-34.

These state-based programs would not immediately reduce the region's ICR. Therefore, these programs would not immediately provide the value ratepayers obtain through a reduced capacity charge on electricity bills. Where the DR programs do have an impact, this would be reflected in ISO-NE's load forecasting, and have an effect on the ICR in future years at which point, customers would benefit from a lowered capacity charge. Some consumers have concerns that introducing state DR programs on top of regional wholesale programs would create additional and unnecessary costs.

Setting statewide DR targets

Several states are setting DR targets for utilities to create more market certainty for DR. Maryland's 2008 EmPOWER Maryland Act and Massachusetts' 2008 Green Communities Act are two state statutes that set such targets. Massachusetts policy calls for program administrators "to provide for the acquisition of all available energy efficiency and demand reduction resources that are cost effective or less expensive than supply."[31] Maryland's policy requires utilities to implement cost-effective DR designed to achieve reductions in per capita electricity demand. The policy set targets of 5% by the end of 2011 and 10% by the end of 2015, as measured against a 2007 baseline.[32]

Pennsylvania's PUC set new energy efficiency and DR targets in 2015. It mandated a peak demand reduction target of 425 MW for the electric distribution companies, over and above the commitments in the regional transmission organization's capacity auctions.[33] Some Pennsylvania consumers have expressed concerns that the recent introduction of this state program, which is complementary to wholesale programs administered by regional transmission organization PJM Interconnection LLC, would create additional and unnecessary costs.

If states develop targets for peak demand reduction, J.R. Tolbert of the Advanced Energy Economy says they should be "based on a rigorous assessment of statewide demand response potential." Tolbert also argues that these targets create more certainty in the DR market, adding:[34]

> Utilities can help grow [DR] by calling on policy makers in their states to establish a demand response market. These markets can successfully flourish on their own, and will be even more successful when paired with the organized wholesale market.

In Maine, state law sets a "soft" goal for the Efficiency Maine Trust to reduce peak demand by 300 MW by 2020.[35] (When the Trust originally was established, this target was set at 100 MW; in the Omnibus Energy Act of 2013 the target was adjusted up to 300 MW). The Trust measures its progress against this goal by tracking the peak demand shaving that results from its portfolio

[31] G.L. c. 25, §§ 19(a), 21(a), 21(b)(1), 21(b)(2).
[32] Feldman, p. 57.
[33] Federal Energy Regulatory Commission, 2015, p. 27.
[34] Walton.
[35] 35-A MRS § 10104(4)(F)(3).

of energy efficiency programs. This tracking does not factor in the savings that is achieved independently by Maine participants in the ISO-NE's DR programs.

Creating additional DR programs to complement ISO-NE's DR programs

Additional obligations assumed by utilities

Several utilities in the U.S. have developed DR programs to complement the existing regional transmission organization DR programs. Stakeholders in the Demand Response Working Group shared that Burlington Electric in Vermont assumed an additional obligation in the regional capacity market and that ConEd in New York implemented a similar program by adding on an obligation to address distribution constraints. In Maryland, there was a concern about whether adequate generation resources were being built within the state's borders. To address this, the state created an incentive program for DR. This additional DR resource participates in the regional capacity market.

Massachusetts' Three-Year Electric and Gas Efficiency Plan, developed by the state's utilities, describes a portfolio of DR pilot programs that will be implemented over the next three years.[36] These will provide more information on the costs and the benefits of deploying DR for small business and residential customers. Connecticut's plan for the same period also includes commitments to DR programs and pilots.[37]

If Maine were interested in requiring or incentivizing utilities, the Trust, or Competitive Energy Providers to develop DR programs, guidance for structuring effective programs is offered in EnerNOC's white paper, "Utility Incentives for Demand Response and Energy Efficiency."[38]

Programs for residential and small business customers

Direct Load Control and Behavioral Demand Response are types of DR programs that can fit the consumer preferences of residential and small business customers.

- **Direct Load Control (DLC).** Utilities sometimes offer Direct Load Control (DLC) programs to residential customers to control household equipment that draws electricity. For residential customers, most DLC programs are used to control central air conditioning and pool pumps. Traditionally, DLC programs have low penetration rates, and FERC estimates that only 5 percent of households participate nationally.

  Technological advances may unlock more DR potential in the residential sector. A smarter grid employs communications and devices that allow LSEs to monitor and dispatch resources more efficiently. For example, there may be potential for DLC programs to curtail electricity used for water heating. Maryland's EmPOWER program

[36] MassSave. *2016-2018*: *Massachusetts Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan*. October 2015. http://ma-eeac.org/wordpress/wp-content/uploads/Gas-and-Electric-PAs-Plan-2016-2018-9-25-2015-Final-WITH-Appendices.pdf

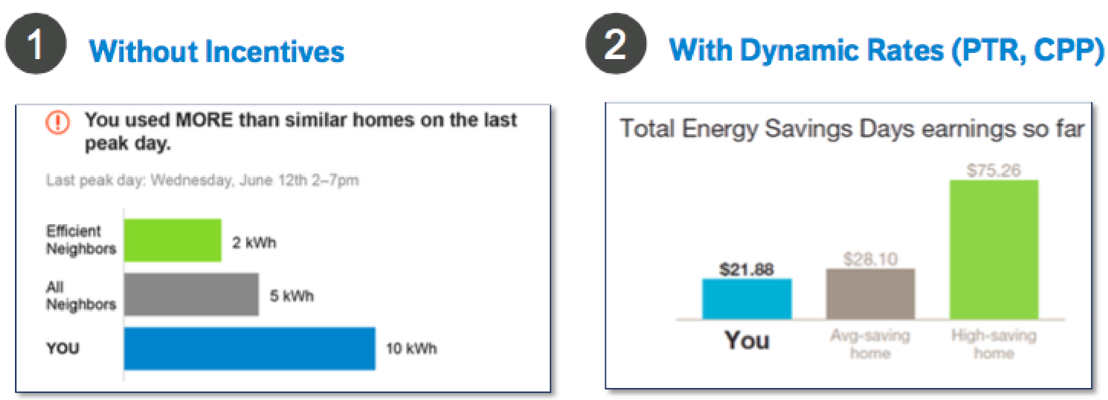
[37] Eversource Energy, The United Illuminating Company, Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company. *2016-2018 Electric and Natural Gas Conservation & Load Management Plan*. October 1, 2015.

[38] EnerNOC. "Utility Incentives for Demand Response and Energy Efficiency." 2009.

includes more than 500,000 connected devices that are used for direct load control.[39] National Grid, a utility in Massachusetts and Rhode Island, is exploring providing incentives to small commercial customers to install equipment, like heat pumps, smart water heaters, and Wi-Fi thermostats that will automatically reduce demand during the peak. For residential customers, National Grid will pilot small-scale DLC DR with washers, dryers, window air conditioners, dishwashers, pool pumps and EV charging stations.

- **Behavioral Demand Response (BDR).** Unlike DLC, BDR relies on behavioral science, not the installation and direct control of equipment, to change customer electricity consumption. BDR programs typically yield lower savings per customer than DLC, but are also lower-cost to operate.[40] BDR produces more savings if it is paired with dynamic pricing of electricity, but BDR can also operate as a stand-alone program.

Figure 4. Two Ways to Deploy Behavioral Demand Response[41]



Opower, a participant in the Maine's Demand Response Working Group, provided information on the potential for residential DR in Maine.[42] Barriers to residential customer participation in DR include customer resistance to compromising control or comfort, and the falling proportion of electricity costs amongst household expenses.[43]

Time varying rates

Some argue that one of the reasons for FERC Order 745 was the lack of real time pricing at the retail level. Residential consumers traditionally prefer stable retail rates and larger electricity

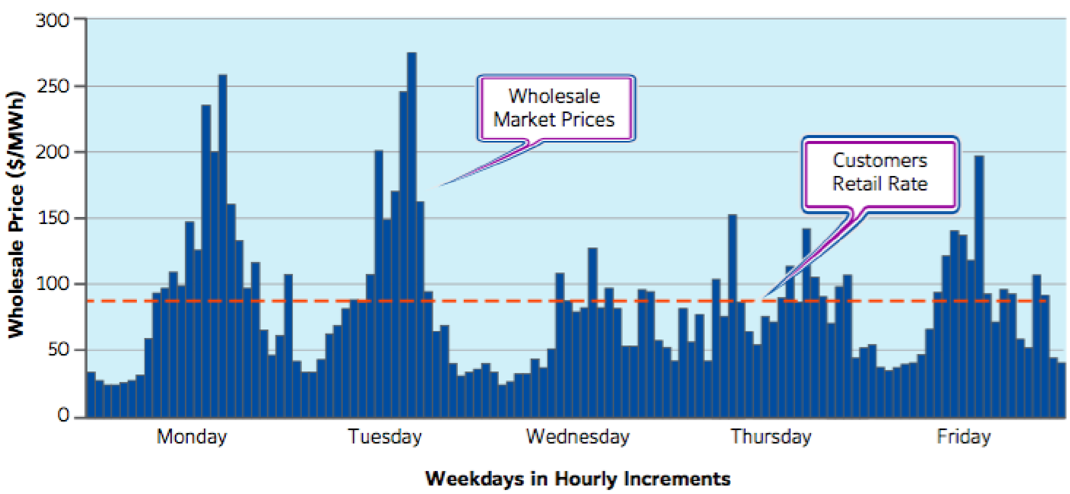
[39] Buckley.
[40] Feldman, p. 56.
[41] Figure is from Opower presentation, "Behavioral Demand Response: Results and M&V" provided to Efficiency Maine Trust Demand Response Working Group. December 2015.
[42] Opower. *Unlocking the Potential for Residential Demand Response in Maine.* January 2016.
[43] Walton.

users are fairly sophisticated and experienced in taking steps to hedge against price spikes, so the full value of DR is obscured for all customer classes.[44]

One of the challenges of price response DR programs is that many retail customers are indifferent to the price of electricity. Currently in Maine, residential customers and small businesses are charged a fixed rate. There is no time-of-use (TOU), peak, or real-time pricing for these customers. Another challenge for price response DR is that even if there were TOU rates, some customers may not have significant opportunities to shift the timing of their load and some customers may not be sensitive to fluctuations in electricity prices.

The graph below shows how wholesale prices exceed retail prices. Smaller electricity consumers have no incentive to respond to fluctuations in the cost of electricity. In addition, wholesale prices are not visible to residential and small business customers.

Figure 5: Example of Wholesale Prices for a Hot Summer Week[45]



Rates indexed to wholesale prices have been available to large commercial and industrial customers since the electricity market was deregulated, but few customers take advantage of this type of pricing.[46] In fact, many large consumers of electricity take other steps to hedge against price spikes by locking in long-term contracts with more constant rates.

Real-time pricing passes the actual cost of electricity in a given hour through to the customer. Price variability can be incorporated into the generation or the T&D portions of the cost. Other dynamic pricing models exist that would only pass through the actual cost of electricity during a limited number of hours each year. These models include critical peak pricing, variable peak pricing, and peak-time rebates. Time-of-use pricing offers different prices for different times of

[44] Gimon.
[45] Managan, Katrina. "Demand Response: A Market Overview." Institute for Building Efficiency, an initiative of Johnson Controls. February 2014: 5. http://www.institutebe.com/smart-grid-smart-building/demand-response-state-of-market.aspx
[46] Feldman, p. 54.

the day and days of the week, but those prices are always the same at those times and are not indexed to real-time wholesale electricity prices. All of these time varying rate structures could possibly incent customers to reduce electricity consumption at peak times.

In FERC's 2009 national assessment of DR, it concluded that the largest benefits from DR would derive from pairing dynamic pricing with enabling technology.[47] ISO-NE reported, in its presentation to the Demand Response Working Group, that other states are considering time-based variable pricing since setting retail rates falls within the jurisdiction of the states.

Baltimore Gas and Electric is the first utility in the country to make peak time rebates the default rate for all customers.[48] In California, TOU rates will be established by 2019. In SMUD's territory, the TOU tariff will be the default rate in 2018.[49] Oklahoma is implementing critical peak pricing. Closer to home, investor owned utilities in Massachusetts will be implementing TOU pricing pending increased penetration of Advanced Metering Infrastructure.

It is possible that more DR could become available as a resource if regulators create markets to value electricity at real time prices. However, this method of achieving DR is in its infancy and is relatively untested. The size and cost of the resource, the reliability of the resources, and the customer groups for whom it is a good fit are still being demonstrated and analyzed throughout the U.S.

Program Design Considerations from the Customer's Perspective

For the current regional DR program, one of the challenges DR faces is retaining and building participation. ISO-NE has been working with stakeholders to address these market design challenges.

As the state considers ways to expand DR benefits, it should consult the field's literature on customer preferences for DR program elements.[50] This section briefly outlines principles for designing effective DR programs.

DR participants seek attractive incentives, appropriate levels of complexity (or simplicity), and an ability to supply the requested resource. Key features of DR programs need to be balanced with one another, including:[51]

- Form of payments and incentives
- Level of complexity
- Degree of customer control

[47] Federal Energy Regulatory Commission. 2009.
[48] Feldman, p. 55.
[49] Feldman, p. 54.
[50] We refer readers to Ellis, John and Katrina Managan. "Increasing Demand for Demand Response." The Institute for Building Efficiency, an initiative of Johnson Controls. February 2014 and EnerNOC. "Designing and Successful Commercial and Industrial Demand Response Program." 2012.
[51] Managan, p. 10.

- Frequency of calls on the DR resource
- Length of curtailments
- Amount of notice

In addition, DR programs need to be designed to fit the specific needs and preferences of different customer segments. For example, manufacturers desire short curtailments and adequate notice, but managers of office buildings will care less about these attributes and more about occupant cover.[52]

VI. Survey of Contingency Planning in New England

In the context of developing contingency plans in the event that the legal challenge would invalidate the existing DR programs at ISO-NE, the Resolve directed the Trust to "survey other states in New England regarding their interest in demand response programs at the state or regional level." This section briefly reports on the Trust's findings of its survey.

ISO-NE was actively developing options to preserve DR in the event of an adverse ruling by the Supreme Court. In April 2015, ISO-NE produced the *Contingency Plan Addressing the Potential Loss of FERC Jurisdiction Over Demand Resources*. This document followed and built upon the ideas presented in PJM's white paper, *The Evolution of Demand Response in the PJM Wholesale Market*. EnerNOC developed a further permutation of the alternatives outlined in ISO-NE's contingency plan in a presentation to NESCOE and PUC staff from the New England states called "Alternatives for Securing DR Benefits." These potential solutions to preserving DR in New England are summarized in Appendix B.

The Trust surveyed other states in New England and gathered additional information from stakeholders to understand how other states are planning to respond to an adverse Supreme Court ruling. While the possibility of ISO-NE losing its authority to administer the region's DR was concerning to other states, the Trust did not find that they had committed to devoting significant resources to developing contingency plans at this time.

For example, New Hampshire's PUC developed an internal working paper exploring options, but had decided to wait for the Supreme Court's decision before dedicating more time and effort to developing alternative DR programs.

In Vermont, if there were an adverse Supreme Court ruling, the Vermont Public Service Board was considering open an investigation to figure out how best to require utilities to develop and deploy DR resources.

[52] Ellis, John and Katrina Managan. "Increasing Demand for Demand Response." The Institute for Building Efficiency, an initiative of Johnson Controls. February 2014, p. 8.

Some states indicated that they expected the New England Conference of Public Utility Commissioners (NECPUC) to take the lead in developing a solution that would preserve DR in the region. One state suggested that NECPUC could develop a model rule for state-based DR programs to create consistency between states for DR providers and aggregators. Stakeholders in the Demand Response Working Group indicated that NECPUC was also waiting for a ruling before dedicating significant resources to developing an alternative DR program.

The stakeholders in Maine's Demand Response Working Group expressed a strong preference for continuing to benefit from a regional approach to DR. Some stakeholders emphasized that it would be best to have a single well-functioning program. One option would be for the states to delegate authority to ISO-NE to continue to administer DR in the event of an adverse ruling. ISO-NE would need to accept this authority. If this approach proved unfeasible, another option would be for DR to be bid into the demand side of the regional wholesale market. If no regional approach through ISO-NE were feasible, DR providers said that they would prefer states develop a regional market structure and consistent rules for DR participation. EnerNOC said that any approach should preserve DR's participation in the capacity market since DR's main value derives from its ability to offset capacity adequacy requirements. If a regional model is not adopted, stakeholders agreed that states should construct state-based DR programs.

VII. Conclusion

The purpose of this study was to review the options for maintaining or establishing new DR programs for Maine electricity customers. As noted in the Resolve that established this study, the value of DR flows both to individual consumers of electricity, who are rewarded for using less, and also to other ratepayers in the form of improved grid reliability and lower prices. While DR has been a valued resource in Maine and New England for many years, there recently has been a decline in the quantity of DR participating in the regional markets.

DR serves multiple objectives, and can be promoted and incentivized through a wide variety of approaches. The basic construct of those approaches has been outlined in this study, and the particular regional programs offered by ISO-NE have been summarized. This study has also provided an overview of the legal challenge that recently threatened the existing regional approach to promoting DR through the ISO-NE programs. The Supreme Court ruling on FERC Order 745 reversed the lower court's ruling, which means ISO-NE's DR program can continue under its current authority and design.

Had the Supreme Court affirmed the lower court decision, this study was prepared as foundation atop which Maine policymakers could begin reviewing contingency options and building an alternative approach to promoting DR in Maine. This report presents a description of several alternative, or "contingency," approaches that were discussed by the Demand Response Working Group organized by the Trust and a brief update of the contingency planning status of other states and regional organizations.

Appendix A – Participating Stakeholders

The following agencies, organizations, companies, and elected officials participated in at least one of the four stakeholder meetings.

State Officials

Lisa Smith
Governor's Energy Office

Representative Larry Dunphy
Maine House of Representatives

Representative Deane Rykerson
Maine House of Representatives

Ed Ford, Rep. Fredette's Office
Maine House of Representatives

Deirdre Schneider
Maine Legislature, Office of Policy and Legal Analysis

Michael Simmons and Paulina Collins
Maine Public Utilities Commission

Agnes Gormley
Office of the Public Advocate

Note: Henry Yoshimura and Mike Giaimo from ISO-NE were not part of the working group, but provided the group with technical assistance, background, and updates relative to demand response participation in the region. Bill Ferdinand of Eaton Peabody, representing ISO-NE, also provided technical support to the working group.

Other Stakeholders

Rick Brady
Catalyst

Jayme Holland and Eben Perkins
Central Maine Power

Ben Tettlebaum
Conservation Law Foundation

Kevin Peterson
Emera Maine

Herb Healy, Ann Cole, Jon Gordon, and Greg Geller
EnerNOC

Paul Serbent
Huhtamaki

Steve Hudson and Todd Griset
Industrial Energy Consumers Group

Brooks Winner
Island Institute

Alex Lopez, Christopher Long, and Rachel Kane
Opower

Kimberly Darling
Town of Falmouth

Joel Pike and Dave Norman
Verso Paper

Marty Troy
UPM Madison

Appendix B – Alternative Models to Preserve and Promote DR in New England

In reviewing options to reconstitute the DR programs run by ISO-NE, Maine's Demand Response Working Group focused on two key questions:

- **How can DR be preserved in New England?** Currently, DR is traded on the wholesale market. Had the Supreme Court upheld the DC Circuit Court's finding that DR is a retail product, the Work Group discussed how a revised regional market or state-based retail market alternatives could be crafted to preserve the value of DR to the grid and to customers. In particular, the group discussed if there would be a way to craft an alternative that allows DR to reduce the grid's capacity requirement with a one-for-one offset of megawatts. This approach would fully preserve the benefits of DR to ratepayers.

- **How would DR be valued and compensated?** Since peaking resources are not used very often, suppliers need to be adequately compensated for maintaining the availability of the resource. Currently this is done by providing capacity payments. For electricity consumers, the primary financial benefit that derives from DR is the avoided capacity cost that would be incurred for more expensive resources if DR were not available to fill the need.[A] DR providers also receive energy payments for the electricity not used during an event. This is a smaller component of the compensation than the capacity payment. If DR were no longer allowed to participate in the wholesale capacity market, an alternative method of valuing DR resources would need to be used.

Currently, ISO-NE calculates the resource it needs for the future (the ICR), clears the market to meet that need, and pays the clearing price to the suppliers of that capacity, which for a DR resource, is a large electricity user or an aggregator. However, if DR had been disallowed to participate in the capacity market, a different market structure would have needed to be created to preserve DR. In this section, we outlined three main ways to preserve or reconstitute the type of DR program ISO-NE has been operating had there been an adverse Supreme Court ruling.

1. States delegate authority to ISO-NE to administer DR;
2. DR continues to participate in the regional wholesale market, but is bid into the demand-side of the electricity market, rather than into the supply side; or,

[A] Smith, p. 5.

3. DR participates in a state retail market and shaves peak demand based on load forecasting.

For several decades, DR programs were administered by utilities within states. In more recent years, regional transmission organizations, like ISO-NE, have taken over the responsibility of administering DR. Reintroducing state-based DR could include:

- incorporating DR into resource planning;
- setting DR targets and requiring DR program administrators to offer programs to meet those targets and respond to signals from ISO-NE; and/or,
- offering rate structures, that would result in similar outcomes to the current DR programs, such as dynamic pricing.

J.R. Tolbert, the senior director of state policy for the Advanced Energy Economy, said:

> The best structure for realizing the full potential for demand response is for states to adopt demand response standards and for these programs to be paired with participation in wholesale markets… Regardless of the outcome of ESPA v. FERC, states should act now to establish standards that require reductions in peak demand via demand response. These standards will create additional certainty with the marketplace for demand response providers.[B]

Actions by states to preserve DR can be independent of a regional wholesale market or support DR's participation in the wholesale market.

Model 1: States delegate authority to ISO-NE

If the result of the U.S. Supreme Court appeal had been that only states (*i.e.*, not FERC) have the authority to establish a demand response program such as ISO-NE operates, it is conceivable that each New England state could have delegated its state-level authority over retail electricity rates for demand response purposes to a single designated manager. For example, the states could each have asked ISO-NE to operate a regional demand response program, with authority over rates in each state coming from that state's delegated state authority.

Model 2: DR Participates in Demand Side of the Market

Another regional strategy for preserving DR would be for DR to participate in the demand side of the market, rather than bid into the supply side. If DR were no longer compensated as a supply-side resource, a new method of valuing DR would be needed.

[B] Walton.

Method for Valuing DR as a Demand Side Resource

Navigant Consulting prepared an analysis for the Advanced Energy Economy that quantifies the benefits of DR and defines the components of DR's value as:[C]

- **Capacity avoided cost.** This value derives from DR entering the wholesale capacity market and reducing the auction clearing price for capacity.
- **Energy avoided cost.** DR prevents load-serving entities (LSEs), which buy energy to serve a retail entity, from procuring energy, reducing the overall marginal cost of generation.
- **Transmission and Distribution avoided cost.** Reducing peak demand reduces the need for additional investment in T&D infrastructure, thus generating a value of avoided investment.
- **Other benefits.** Other benefits of DR are more difficult to quantify, but provide value. These include reducing the costs for complying with EPA's Clean Power Plan, since DR can reduce greenhouse gas emissions cost-effectively, reducing reliance on constrained natural gas supply during the winter and mitigating the market risk premium on natural gas-fired electricity generation during the winter.

Navigant Consulting uses Illinois and Massachusetts as test cases to quantify the value of DR in the two states and found that DR generates a benefit-to-cost ratio above 3:1 for Massachusetts and above 2:1 for Illinois.[D]

Market Design

In its white paper on preserving the value of DR, the regional transmission operator PJM proposes that LSEs, which are known as Competitive Energy Providers in Maine, incorporate DR into demand reduction bids.[E] PJM would base its planning and procurement on these commitments, which would be bid into PJM's market by wholesale market load-serving entities, *i.e.*, LSEs. Currently, LSEs do not participate in today's DR market. LSEs would commit to reducing wholesale loads, based on arrangements the LSEs would make with entities that manage end-use retail loads, like aggregators. These demand reduction bids would reduce the capacity needed to be procured in the wholesale electricity auctions. In an emergency event, PJM would call on LSEs' curtailment commitments to reduce their wholesale demand. For example, if an LSE contracted with an aggregator to reduce 100 MW of demand, the grid operator could lower its ICR from 1000 MW to 900 MW. This would reduce the megawatt clearing price, and would lower all customers' capacity charges on their electricity bills.

Under this model, LSEs would no longer receive a capacity payment. Compensation would be based on a lower capacity charge that would be achieved through a reduced capacity obligation.

[C] Feldman, p. 2.
[D] *Ibid.*
[E] PJM.

LSEs also would not receive an energy payment, but would avoid the Locational Marginal Price for curtailed load.

ISO-NE's Contingency Plan, built on PJM's market design concepts, focused on how to provide stronger incentives to LSEs to participate on the demand side of the market. If states were to put in place a peak demand reduction mandate, for example, the wholesale capacity cost could be reduced in the short-term by shifting the capacity cost allocation between LSEs in which LSEs implementing successful DR programs receive lower capacity charges relative to other LSEs. In the long-term, these DR programs would reduce the Installed Capacity Requirement and reduce overall wholesale capacity costs.

ISO-NE laid out the following options:

- **Option 1: Reduce the Installed Capacity Requirement (ICR) by the expected demand resources.** ISO-NE's load forecasts are used to calculate the ICR (the capacity that ISO-NE procures, which is sufficient to meet peak demand, plus a reserve margin). When DR is bid into the supply side of the electricity market, it is treated as a capacity resource and is used to meet the ICR. Another approach is to treat DR as modifying demand calculated in the load forecasts so as to lower amount of the ICR. Option 1 would lower the capacity purchase amount and lower the capacity clearing price by reducing the ICR by a forecasted amount of DR. To account for additional DR to be implemented after the load is forecast, ISO-NE could reduce the ICR before conducting the action. ISO-NE notes that an incentive structure for DR, like the Pay For Performance market rules that ISO-NE is planning to implement in 2018, would need to be designed to ensure that the anticipated amount of DR materializes.[F]

- **Option 2A: Revise the capacity cost allocation to encourage LSE pursuit of DR.** Currently, supply resources receive a fixed capacity payment paid by LSEs. In Option 2A, ISO-NE would allocate monthly FCM costs by charging each LSE a base charge and a performance charge. The performance charge would adjust the base charge so that monthly capacity charges would vary based on the LSEs' customers' actual electricity consumption when capacity is in short supply. This provides an incentive to LSEs to reduce their customers' electricity consumption during times of electricity scarcity. For LSEs whose customers consume less electricity than their proportional share of capacity purchased, their Forward Capacity Market cost allocation would be decreased. For LSEs whose customers consumed more, their cost allocation would increase.

- **Option 2B: Account for incremental demand reduction commitments in the capacity market.** This option further modifies the Forward Capacity Market cost allocation approach of Option 2A by allowing LSEs to submit load reduction bids into the demand-side of the capacity market, as proposed in PJM's white paper. By clearing load reduction bids, an LSE would reduce its monthly base capacity charge, and performance

[F] Yoshimura, *Contingency Plan*, p. 14.

charges would be based on the reduced proportional share of capacity that the LSE purchases through the FCM. If an LSE's customers consumed more than their prorated share of the total capacity, the performance charge would increase. This approach incorporates the incremental DR commitments that cleared in the Forward Capacity Auction – LSEs clearing load reduction bids reduce their monthly capacity charges (assuming that the demand resources they implement perform when needed), which also reduce the ICR and capacity clearing prices for the market as a whole.

EnerNOC also proposed options for consideration in the event that the Supreme Court had issued a ruling adverse to the existing DR regime:[G]

- **DR as load modifier.** This is a regional wholesale option that would reduce the ICR, similar to ISO-NE's Option 2B. Under this option, LSEs or electric distribution companies ("EDCs" or "utilities") would bid DR into the wholesale market on the demand side (not the supply side), and if the load reduction bid cleared, the amount of capacity procured and the resulting clearing price would be lower than without the DR. ISO-NE would continue to dispatch DR during periods of scarcity conditions. DR would not be compensated from the wholesale market in this option.

  EnerNOC's proposed model is similar to ISO's Option 2B, but not identical. The differences are detailed in Figure 5. Importantly, the state would have a critical role to play in this model to ensure that all DR in the state has access to the market and that it is appropriately compensated. Costs would be recovered through a non-bypassable charge to all ratepayers in the territory. The ratepayers would receive the benefit of DR through reduced capacity market costs.

Figure 5: Comparison of ISO-NE's Option 2 and EnerNOC's regional wholesale model

	1 ISO-NE's model Option 2	2 EnerNOC's EDC model

Market Eligibility and Barriers	• Only LSE delivering commodity to DR customer can offer and deliver DR to market
	• No DR "portability"
	• Creates market barrier for 3rd party aggregators
	  • Need to contract with all regional LSEs who may be competitors
		• LSEs and EDCs can offer and deliver DR to the market
		  • EDC does not have to be a supplier or serve default load
		• Alternatively, model incorporated DR portability

Valuation and Monetization of DR	• Presumably LSE remunerates its DR customers at value determined from auction clearing (but up to LSE)	• Valuation determined by terms of bilateral, presumable based on auction clearing price • EDC pays aggregator or makes direct customer payments for DR
States Role	• None	• Mandate EDC participation as "load modifying Market Participant • Mandate procurement and payment of DR • Establish non-bypassable charge to distribution customers

[G] EnerNOC. "Alternatives for Securing DR Benefits." Presentation slides provided by Herb Healy. April 2015.

Model 3: DR Participates in State Retail Market

EnerNOC also proposed a state retail option in the event that the DR was not able to participate as any kind of resource in the regional wholesale market on either the demand or supply side. In a state retail market, EnerNOC envisioned that DR would be used to lower state peak demand. Since the calculation of the ICR relies heavily on load forecasts based on historical load data, this reduction in peak demand would lower capacity requirements in the future. Under this option, the state PUC would mandate EDC or efficiency program administrator to procure all cost-effective DR (or alternatively, to reduce peak by a certain percentage). The EDC or efficiency program administrator would, in turn, work directly with customers or through aggregators of customers to contract for the provision of DR and to dispatch the DR when needed. The customers or aggregators would be compensated based at least in part on the projected avoided future capacity and the costs would be recovered through a non-bypassable charge to all ratepayers in the territory. The ratepayers would receive the benefit of DR through reduced future capacity market costs.

This model poses a bigger challenge than the prior two models in obtaining a one-for-one, MW-for-MW direct offset. It would necessitate the use of a model to forecast the loads. ISO-NE noted that that this model would be less precise in compensating DR providers than the current practice of ISO-NE. Also, ISO-NE would not have dispatch control.

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