Memorandum

TO: RHODE ISLAND ENERGY EFFICIENCY AND RESOURCE MANAGEMENT COUNCIL

FROM: DOUG HURLEY AND SPENCER FIELDS

DATE: JUNE 6, 2016

RE: STATE OF DEMAND RESPONSE IN NEW ENGLAND

Demand Response in New England

In May 2013, on behalf of the Regulatory Assistance Project's European Programmes, Synapse published a lengthy paper assessing demand response (DR) in the United States. The Executive Summary of that report describes DR as "the intentional modification of electricity usage by end-use customers during system imbalances or in response to market prices."

While this is true in a broader sense, DR in New England in recent years is primarily the voluntary reduction of electrical usage at small and large commercial or industrial end-use customer facilities during peak load hours[1]. The reduction can happen to avoid charges imposed upon those customers for usage during monthly or annual coincident peak load hours, or as a response to a dispatch signal from an aggregator – or Demand Response Provider (DRP) – who has enrolled in our region's Forward Capacity Market (FCM). Although it feels as if we are forever on the cusp of other types of DR, as of yet we still see little of it a) from the residential sector; b) that increases load to absorb excess renewable generation; or c) for such services as frequency regulation or even real-time energy market prices.

There are a small number of large customers who participate in DR on their own – most notably paper mills and other large industrial facilities in Maine. The majority of end-use customers find it prudent to rely upon the technical expertise, market experience, and financial backing of DRPs to handle the mechanics and risks of DR. This is true when DR is used just to avoid costs, but doubly so when participating in ISO New England's wholesale markets as a capacity resource. In our region the DRPs have focused on customers such as hospitals, universities, and grocery-store chains and other large retail facilities. The DRPs have recognized that their customer's preference is to reduce their load only a few times per year, if possible. As such, aggregation of retail customers in a demand response resource in the wholesale markets is almost exclusively used as a capacity product. In other words, customers have little intention of watching daily energy market prices and responding for revenue on an opportunistic basis. Rather, they are happy to provide response a few times each year if necessary in

[1] This reduction in consumption from the grid is often met by starting small behind-the-meter generation units with air emissions equipment that allows them to meet state-level air permit requirements.

exchange for a known, steady, monthly capacity payment. The DRPs handle the mechanics of combining many retail customers into a single portfolio and managing the dispatch of the group of them to meet the required performance during any one event. This leaves the end-use customer to focus on their business, enjoy the additional electric usage information and management capabilities often provided as part of the service, and receive a monthly check from the DRP. The amount that they receive of that share of the DRP's capacity revenue is private commercial information between those entities, and can vary widely by customer and over time.

Amount of Demand Response

For the first section of this report, we refer to DR as either actual reduction in load on a customer site or on-site generation units that have air emission controls such that they meet relevant state and federal permits. Those who are familiar with ISO-NE terminology will know this as Real Time Demand Response (RTDR). In a separate section below, we discuss on-site backup generation from units that do not have such controls, and are therefore severely limited by their permits to run in a small number of hours.

In the early stages of ISO-NE's forward capacity auctions, the total cumulative amount of cleared DR in the region gradually increased over time, even as the capacity clearing price in each auction was the pre-determined floor price. This dynamic makes sense to some degree – naturally, as DRPs and their customers learned more about how the newly-formed capacity market would function, they became more comfortable with bidding in and ultimately procuring greater and greater amounts of DR capacity. As seen in Figure 1, even with the lowest possible capacity clearing prices in the first five forward capacity auctions (FCAs), DRPs were confident enough to nearly double DR capacity cleared in the market between FCAs 1 and 5, reaching 1,400 megawatts of capacity, or nearly 5 percent of overall system capacity needs by FCA 5.

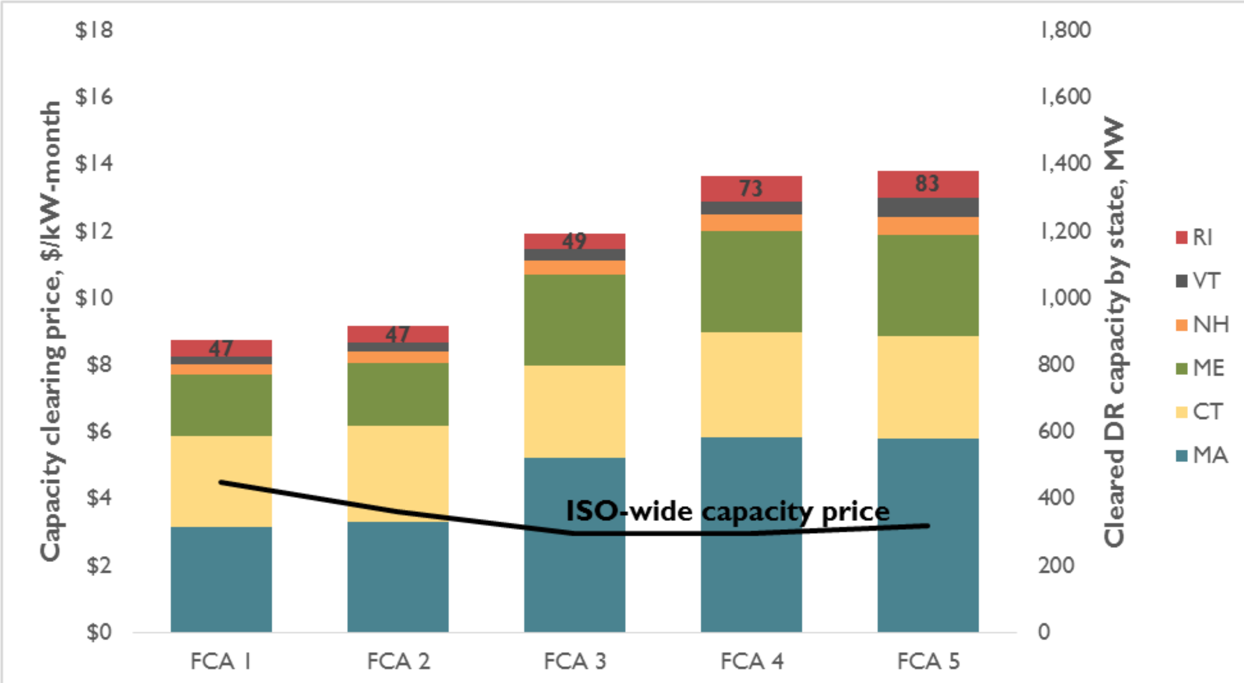
DR in the capacity market is either load reduction, or backup generation with air emission controls, that can response to ISO dispatch instructions when called upon. Under the current FCM rules, DR is dispatched only during ISO-NE's Operating Procedure 4 (OP-4), Action During a Capacity Deficiency. OP-4 is activated rarely, only a few times each year, and DR that has a capacity obligation is only dispatched during some OP-4 events.[2] Several years may pass without a need to implement Action 2 of OP-4, when DR is activated by the ISO-NE. The most recent three such events were in July 2011, July 2013, and December 2013. No such events have occurred since then. Events last a few hours on that day.

While reviewing the figures below, it may be helpful to remember that obligations taken in FCA-1 correspond to delivery in the 12-month period beginning June 1, 2010 and ending May 30, 2011. Each

[2] OP-4 contains several actions ranging from notification of a capacity deficiency by the ISO-NE (Action 1) to a 5% voltage reduction (Actions 6 and 8) and television and radio appeals by the New England Governors for voluntary load reduction (Action 11).

subsequent FCA corresponds to the following 12-month power year. FCA-2 for June 2011 – May 2012, FCA-3 for June 2012 – May 2013, and so on.

Figure 1. Total cleared demand response resources in ISO-NE versus capacity clearing price, FCAs 1-5

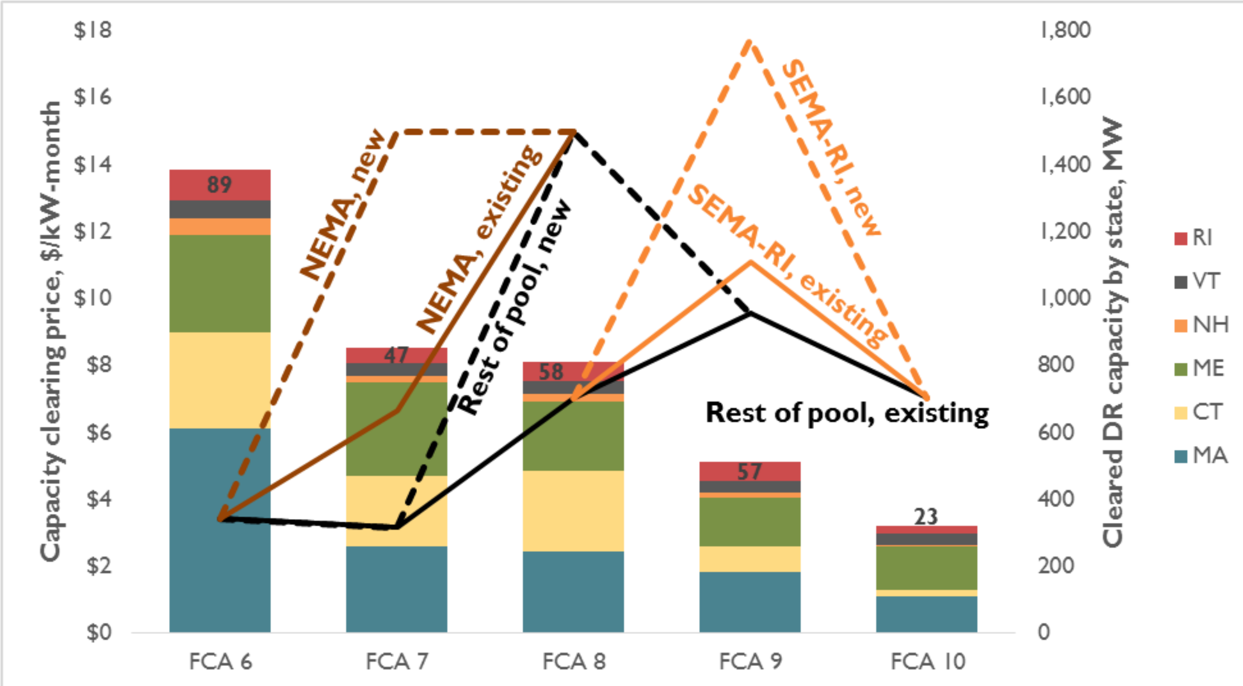


At that point, DR seemed to be ready to respond to any future increases in capacity clearing prices in ISO-NE by clearing even more DR capacity.

Between FCAs 6 and 7, however, this dynamic changed drastically. As seen in Figure 2, DR capacity in New England dropped by nearly 40 percent from FCA 6 to FCA 7 while capacity prices in some regions tripled for new resources and doubled for existing ones. This was largely the result of a combination of increased compliance costs and uncertainty about the future of DR due to court challenges to FERC Order 745, which we will describe in greater detail later. As a result, overall cleared DR capacity has dropped in every auction since FCA 6, with levels at the lowest point ever in FCA 10, a full gigawatt below the peak of cleared DR capacity just five auctions earlier.

The amount of DR we see in each state is roughly proportional to the ratio of peak load for that state, with two major exceptions. While we aren't surprised that Massachusetts has a large share of the DR, with nearly half of the region's peak load, Maine has a larger share than expected because the large paper mills in Maine participate in DR. Connecticut has a larger share than expected because that state had programs in place that had specific incentives for DR beyond those in the other New England states.

Figure 2. Total cleared demand response resources in ISO-NE versus capacity clearing price, FCAs 6-10



Note: Figures 1 and 2 use the same scale on the vertical axes in order to avoid distortion.

Further, it appears that this drop in cumulative installed capacity is primarily a result of the largest aggregator reducing its customer base in the ISO-NE market. Although these market participants have chosen to not explicitly use their names when clearing DR capacity, based on similar naming conventions throughout the auctions it is possible to group various DR capacity into groups by two main DRPs and one "Other" category. The two most active DRPs in New England, in order, have been Constellation[3] and EnerNOC. The "Other" category is comprised of the few large industrial customers that participate on their own, without a DRP, such as the paper mills and BOC Gas in Maine and the Deer Island water treatment plant east of Boston. As seen in Figure 3, the 500 megawatt drop in cumulative DR capacity in ISO-NE between FCAs 6 and 7 came entirely from the largest DRP in the region. This would appear to also be the case in Rhode Island, where the market is dominated by the same major DRP, as seen in Figure 4.

[3] Constellation's DR programs have, over the years, been owned by CPower, Constellation, Exelon, and most recently by a new company that took the CPower name.

Figure 3. Demand response cleared capacity by demand response provider in ISO-NE, FCAs 6-10

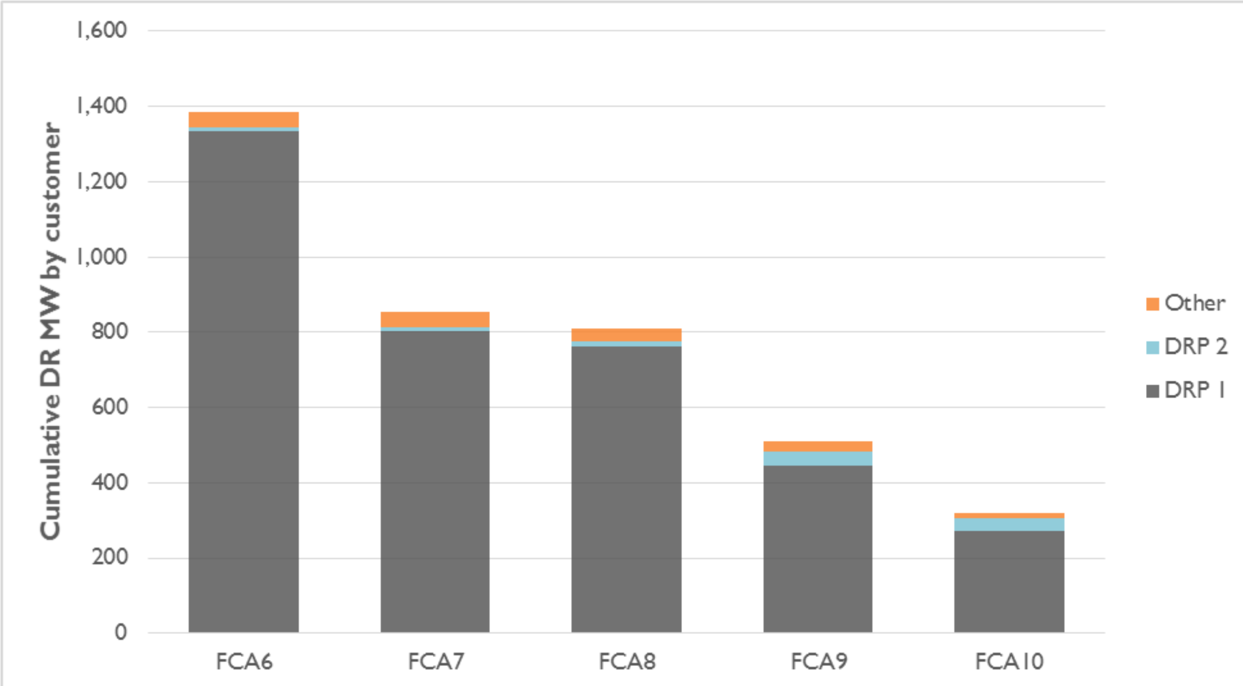
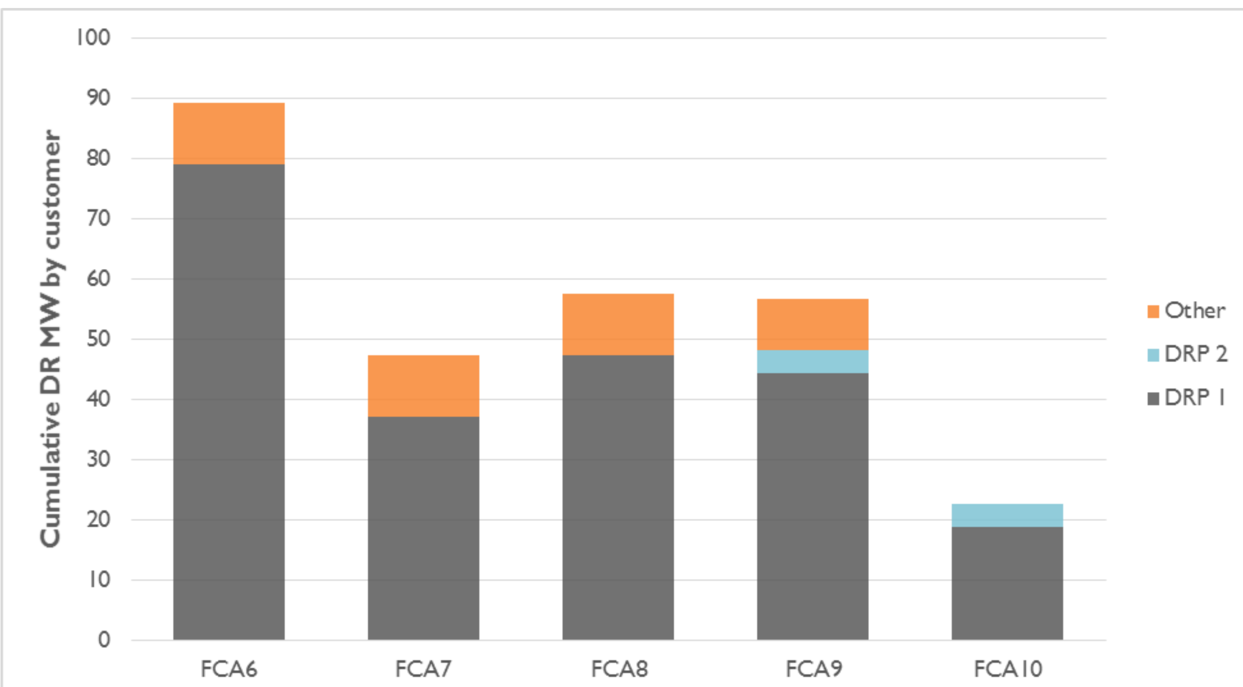


Figure 4. Demand response cleared capacity by demand response provider in Rhode Island, FCAs 6-10



Figures 1-4 show the amount of DR that cleared in each FCA. However, each DRP or individual customer has the opportunity to trade away the obligation that cleared in the FCA through any one of numerous reconfiguration auctions. On average for commitment periods 1-7, 56% of the total amount of DR capacity that cleared in an FCA is still held by a DRP at the start of the associated commitment period.[4]

Baseline Methodology, Order 745, and Performance Incentives

There is a clear trend for DR in New England in Figures 1 and 2. There was a steady increase for the first four auctions, which covered delivery from June 1, 2010 through May 31, 2014. The amount offered into the FCAs then leveled off for FCA-5 and FCA-6 before dropping sharply in FCA-7 and continuing to decline steadily each year through the most recent auction, FCA-10, which was held in February of this year.

There are three primary reasons for the steady decline which seems counter to rising capacity prices in the same timeframe. The first reason is cost. All demand response, by its nature, is measured by determining the amount of electricity actually consumed during an event and comparing it to a "baseline", the amount of electricity we would have expected that customer to consume on that day, in those hours. Consumption on a hot, humid summer day is likely to be different than on a cool spring day. For certain facilities, normal consumption on a Wednesday might be very different from that on a Friday or Saturday. The methodology for setting and constantly refreshing baselines can be very complicated, and indeed it was. For several years, the major DRPs in New England complained that the baseline methodology required by ISO-NE was much more complicated – and much more expensive to implement – than anywhere else in the country. These additional costs drove them to participate more heavily in other areas of the country (and the world), instead of doing so here. Like any business, DRPs have a limited amount of capital to spend and must do so where it is most fruitful for them. Recently, negotiations have convinced the ISO-NE that the methodology can be changed to one that is more feasible for the DRPs, while still providing a reliable measure of actual response provided. With this change in place, one would expect the amount of DR to rise over the next few capacity auctions.

The second primary reason was a court challenge to FERC Order 745, which was recently decided by the United States Supreme Court.

In March 2011 the FERC issued their Order 745, which mandated that all ISOs and RTOs allow demand response to participate in their wholesale energy markets and that such participation would be paid at the same rate paid to generation participants – the Locational Marginal Price (LMP). Prior to this order's issuance, some regions in the country paid DR at a lower rate, subtracting either the generation portion (G) or the entire retail rate (G&T, for "generation and transmission") from the wholesale energy market payment rate. These alternative payment structures were often called "LMP minus G" or "LMP minus G&T". After a lengthy process, the FERC decided that participation by DR in the wholesale energy market performed the same service to balance load and supply as was being provided by a generator, thus

[4] The Commitment Periods for FCAs 8-10 have not yet begun, and thus we do not yet know the final obligations taken for those years.

warranting equal payment. During hours when the energy market price is high, and thus when DR would most likely participate, the full LMP could be 2-3 times greater than “LMP minus G”.

This decision was heavily challenged by many parties, led by the Electric Power Supply Association (EPSA), an industry group of generation owners. EPSA initially prevailed when the court of appeals for the District of Columbia circuit vacated Order 745 in its entirety in May 2014. The FERC chose to challenge this decision to the U.S. Supreme Court. The case was heard in October 2015, and in late January 2016 the highest court overturned the lower court ruling, ending nearly five years of uncertainty over the fate of DR’s ability to participate in wholesale markets in the U.S. While Order 745 was specific to energy markets, prohibition from the energy market would have eventually meant prohibition from all wholesale markets. The vast majority of wholesale market revenues for DRPs come from the capacity market.

Over that five-year period the uncertainty had a chilling effect not only on the DRPs, but also on their customers. End-use customers focus on how to run their own business, and are often reluctant to participate in DR programs, and even then are cautious at the outset. If the value of that program varies widely, or is gone entirely, they are unlikely to participate again anytime soon. As a result, although Order 745 is now resolved and baseline costs in New England are now on par with those in other regions, Synapse expects to see a slow, modest rise until participation levels reach those previously achieved.

Concurrent with the first two primary challenges for DR, ISO-NE added a further layer of uncertainty to DR participation in the region. Responding to their own lack of confidence that generation stations – particularly those fired by natural gas that could not procure enough fuel during gas-constrained winter months – the ISO-NE proposed FCM Performance Incentives (FCM PI, also known as “Pay for Performance”). Under FCM PI, all capacity resources face either large financial payments or severe financial penalties based on their ability to provide energy or reserves during shortage conditions. Any amount of payment or penalty is assessed based upon their performance relative to their capacity obligation.[5] While energy efficiency resources are only subject to these payments or penalties during their specific On Peak Demand Resource hours, all other types of capacity resources are subject during any hour of the year. Whether FCM PI is deemed an opportunity for extra revenue or a risk of penalties entirely depends upon that resource’s ability to meet their obligation during a shortage condition.

While this was a heavily debated package of changes for all resources, DR stands to feel the impact of the new program more than most. Coincident with the implementation of the FCM PI rules, DR would be subject to a “must offer” rule requiring them to offer the full amount of any capacity supply obligation into the day ahead energy market every day of the year. This change takes effect June 2018, corresponding with FCA-9. Until that time, participation in the energy market is voluntary.

[5] Expected performance is a percentage of capacity supply obligation, as adjusted by several factors including actual load on the system during the shortage conditions.

In order to receive FCM PI payments, and therefore avoid penalties, a capacity resource must be providing either energy or reserves during shortage conditions. So far, DR has been prohibited from participating in the reserves market in New England, though this will change coincident with FCM PI in June 2018. Theoretically DR is a good fit as a reserves resource: DR can respond very quickly (within the 10 minute or 30 minute deadlines) and is usually only asked to respond for short durations. However, the implementation of DR for reserves is untested, and our region's DRPs are understandably unsure that all will go well. This challenge also represents the opportunity to earn reserve payments for those DRPs that participate and perform in those few hours each year when reserves are activated.

Over time Synapse expects DRPs to gradually become more comfortable with the FCM PI rules, the energy market "must offer" rule, and the reserves market, leading to increased participation. Until such a time, however, DR is likely to grow slowly. Given that FCM PI implementation begins June 2018, Synapse expects that, at best, the region will begin to see sharp increases in the amount of DR clearing in FCA-13, to be held in February 2019.

Demand Response in Planning

Aggregators and customers are not the only ones interested in the amount of DR operating in New England. Our regional grid operator, the ISO-NE, has been consistent in their view of DR as a reliable system resource. Our report on Demand Response as a Power System Resource concludes that demand response performs reliably when called upon. The ISO-NE performs several levels of system planning, and here we describe how DR is included in each of three broad categories.

Short Term Planning

The ISO-NE forecasting and planning teams are constantly updating expected system load and available resources on a daily, hourly, and even sub-hourly basis. In this context, the ISO begins forecasting loads for the upcoming season, the upcoming week, on a day-ahead basis, and continually within each operating day. These forecasts can and do rely upon two sets of DR. The first set is any amount of DR that has an obligation to reduce their load based upon participation in the Day Ahead or Real Time energy markets. At present, participation by DR in the energy markets is entirely voluntary, and only a small amount of the DR on the system chooses to do so. However, any amounts that do clear are expected to reduce load according to their dispatch schedule. This planning procedure will not change with the implementation of FCM PI and the "must offer" rule for DR: any amount that clears in the energy markets will be expected to deliver. Any amount that did not clear – their offer price was higher than the clearing price – will not be included in ISO planning.

Additionally, any and all DR that has cleared in the capacity market (Figures 1-2, above) is expected to respond should emergency conditions arise. The specific conditions under which the ISO-NE is permitted to activate DR are written in "Operating Procedure 4 (OP-4), Action During a Capacity Deficiency". Although DR has seldom been activated under OP-4, these amounts are included in daily planning by the ISO.

Capacity Planning

The ISO-NE's capacity market is well-labeled as the Forward Capacity Market, as the procurement for capacity is performed more than three years in advance of the delivery period. For example, FCA-10 was held in February 2016 for a commitment period of June 2019 – May 2020. The forecast of needed capacity in that auction was performed throughout the summer and fall of 2015. As part of that calculation of capacity requirement, the ISO not only forecasts expected peak load in the relevant future year, but also forecasts the expected performance from those capacity resources – including DR – that are already on the system. In the fall of each year, the ISO-NE presents to NEPOOL their assumptions for the capacity procurement amount, including an expected performance rate for existing DR resources. This is analogous to a forced outage rate for generation stations. The assumed performance rate published by the ISO for demand response over the past four auctions is shown in Table 1, below. These values are based upon seasonal audits and/or actual dispatch events during the summer prior to the relevant auction.

Table 1. DR Performance Rates

Auction	Assumed DR Performance Rate	Month of Publication
FCA-10	89%	Sept 2015
FCA-9	88%	Sept 2014
FCA-8	89%	Sept 2013
FCA-7	86%	Aug 2012
FCA-6	83%	Oct 2011

Transmission Planning

On an annual basis the ISO-NE transmission planners look forward ten years to estimate needs for additional transmission projects throughout the region. More detailed studies are performed on certain local areas on a round-robin or as-needed basis, as they are not deemed to be required every year. As it typically takes between five and eight years to design, construct, and begin operation on any major new transmission project, the focus is on the outer years, beyond the 4-year timeframe of FCM planning.

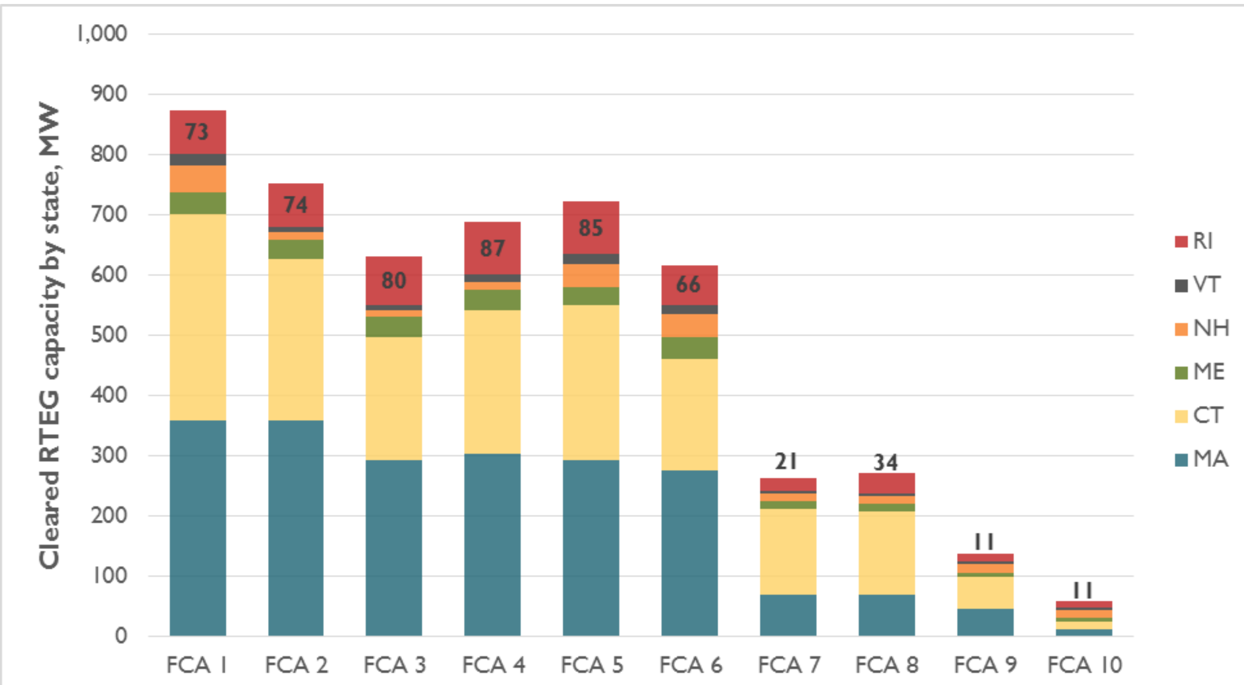
Over this horizon, the ISO-NE has recently begun to include a forecast of future installation of energy efficiency and behind-the-meter solar photovoltaic projects, as both of these will reduce peak load and thus the need for transmission projects to deliver energy from generation stations to end-use customers. However, no such forecast is performed for DR. The ISO-NE assumes that the end-use customers who are the basis for DR resources are free to exit the market, or their contracts with DRPs, at any time. As such, they are not confident that they can rely upon a specific amount of DR for a summer that is five or ten years into the future. To date, they have not been challenged on this assumption, and thus DR is not included in transmission planning procedures.

Distributed Generation

So far we have focused upon the type of Demand Response that is provided by actual reduction in usage by end-use customers, or by on-site backup generation units that have installed emission controls, allowing them to meet air permit requirements.

The capacity market in New England also allows for the participation of Real Time Emergency Generation (RTEG) resources, which are on-site backup generation units whose run hours are limited by their air permits to annual testing and any hour in which the ISO-NE implements a voltage reduction on the system as part of their OP-4 emergency procedures. Figure 5 shows the total amount of RTEG resources that have cleared in each of the ten capacity auctions held so far. In the first few FCAs, RTEG resources started out very strong, with greater participation than DR. Starting with FCA-7, we see a similar trend to the one in Figure 2 for DR, above. The amount of RTEG has dropped off precipitously.

Figure 5. Total cleared RTEG resources in ISO-NE, FCAs 1-10



RTEG resources are almost exclusively provided to the market in the same manner as DR – by DRPs who have the technical expertise and financial resources to help end-use customers. Thus, as one might expect, when we sort out the RTEG amounts by DRP, the pattern across New England and within Rhode Island is similar to what we saw in Figures 3 and 4, above.

Figure 6. RTEG cleared capacity by demand response provider in ISO-NE, FCAs 6-10

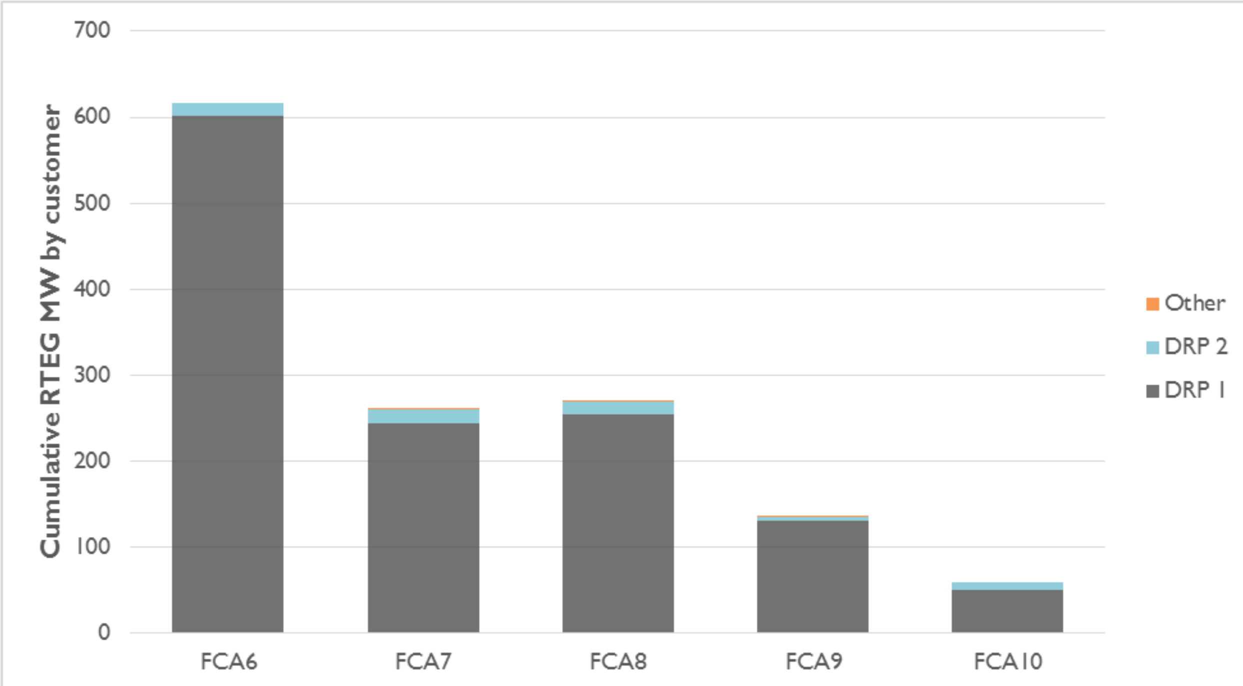
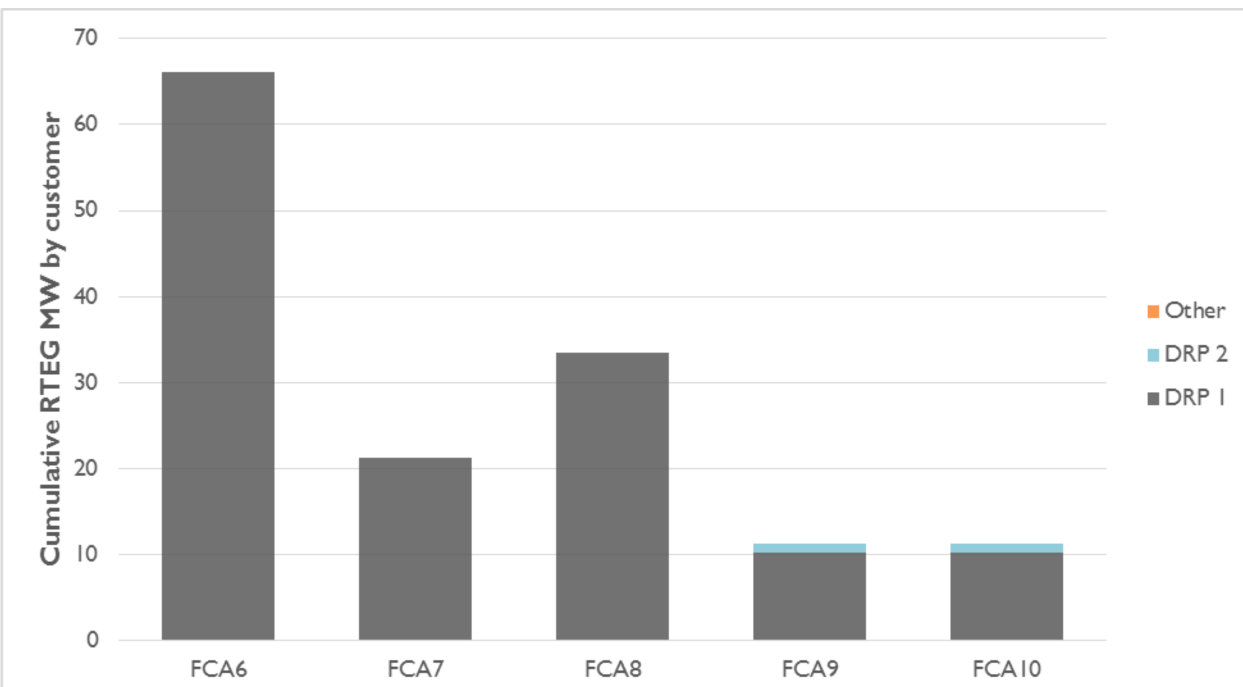


Figure 7. RTEG cleared capacity by demand response provider in Rhode Island, FCAs 6-10



The explanation for the overall pattern of decline in recent years is the same as it was for DR, with a few twists. Whereas the affirmation of Order 745 by the U.S. Supreme Court was a resolution for DR, the coincident changes to FCM PI have effectively eliminated RTEG from this market. Recent rulings and guidance by the EPA on their Reciprocating Internal Combustion Engine National Emissions Standards for Hazardous Air Pollutants (RICE NESHAPS) provide still further difficulties.

FCM Performance Incentives

Under the package of changes generally known as FCM PI, all capacity resources will be either paid additional amounts or penalized based upon their delivery of either energy or reserves whenever a shortage condition occurs. The payment/penalty rate is steep, initially $2,500/MWh but rising to over $5,000/MWh, and thus provides a very keen incentive. RTEG resources are not allowed to participate in the reserves market, and are restricted by their air permits from providing energy until the ISO declares OP-4 Action 6, a 5% reduction of the nominal voltage on the system. It is unlikely that any shortage condition will actually reach this step. Indeed, RTEG resources have never been dispatched during the FCM era, with the last dispatch occurring on August 2, 2006. If not dispatched, RTEG will face the penalties that are too steep to risk for most providers. FCM PI is an obligation that RTEG resources are essentially prohibited from meeting.

RICE NESHAPS Ruling[6]

Although generally outside the scope of this effort, we will offer a brief overview of this issue. The US EPA recently issued a ruling that would allow certain categories of backup generation units to operate up to 100 hours per year for the purpose of participating in wholesale markets, such as the capacity market in New England. That ruling was challenged by the state of Delaware, and the pertinent sections of the rule were vacated by the U.S. Court of Appeals for the District of Columbia Circuit in May 2015. In a guidance letter issue on April 15, 2016[7] the EPA states that "It is the EPA's view that this change will mean that an engine may not operate in circumstances described in the vacated provisions for any number of hours per year unless it is in compliance with the emission standards … for a non-emergency engine." It is our understanding from initial conversations with ISO-NE staff and DRPs that this ruling effectively eliminates the ability of most RTEGs to meet any obligation they have taken in the FCM.

At this point, DRPs are actively looking to either retrofit customer-sited backup generation so that it can participate as part of a DR resource or trade away the capacity obligations they have taken for RTEG resources. It is unclear how much longer the RTEG category will exist within the FCM rules.

[6] Reciprocating Internal Combustion Engines National Emissions Standards for Hazardous Air Pollutants

[7] Available at https://www3.epa.gov/ttn/atw/icengines/