UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators	**)**	**Docket No. AD13-7-000**

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Good morning, my name is Bob Ethier and I am the Vice President of Market Development at ISO New England Inc. ("ISO-NE"). I want to thank the Commission for setting up this conference to explore key issues in capacity markets and for providing me with an opportunity to speak. Given the complexity of these markets and their simultaneous evolution in different parts of the country, it is worthwhile to examine the key features of capacity markets at a policy level and in a public setting. At several points in my comments I will be referring to the Commission Staff Report on Centralized Capacity Market Design Elements dated August 23, 2013 which, in my view, provides a good summary of the design decisions being evaluated throughout the Northeast, and the tensions among competing goals. These written comments address each of the questions laid out in the notice for this technical conference. I will focus a majority of my time in the oral session responding to the final question posed by the Commission, regarding challenges to the capacity market and how these challenges should be addressed.

To date, New England's capacity market has achieved the high-level goals that capacity markets are designed to accomplish. It has procured resources needed to meet the region's capacity requirement. It has addressed the so-called "missing money" problem and paid resources for providing capacity. It has effectively replaced out-of-market reliability must-run ("RMR") contracts with market-based compensation. And it has allowed entry of new resources and created a platform on which demand response can participate as a resource. The mechanics of the New England market are working. The capacity market does, however, require improvement

in three areas: product definition, resource performance, and price formation. I will address all of these issues in my responses to the Commission's questions, below.

1. What are the key goals of the existing centralized capacity market in your region?

In New England's restructured electricity system, the capacity market has two central, related goals: (1) to ensure that there are sufficient resources to meet New England's electricity demand and reliability standards; and (2) to ensure that the first objective is achieved in a cost-effective manner. In addition to these primary design goals, a reduction in RMR contracts was a critical objective of the Commission, state regulators in New England, and ISO-NE when developing the current capacity market. Furthermore, in designing New England's capacity market, we are seeking to foster competition by creating a playing field that is as level as possible with respect to technology types, types of investors, and existing versus new entrants.[1]

2. & 3. What are the metrics used to measure the success of the centralized capacity market, and how successful has the current capacity market design been in meeting its goals?

a. Ensuring Sufficient Resources

With respect to the first goal of the capacity market – ensuring that there are sufficient resources to meet New England's electricity demand and reliability standards – the metrics are straightforward. To succeed, the market must procure sufficient capacity in each capacity zone to meet the region's installed capacity requirement. Specifically, the region needs to satisfy the appropriate regional resource adequacy criteria established by various reliability organizations. With respect to reliability,[2] the simplest metric is whether there has been any outage caused by resource unavailability (*i.e.*, is the region meeting the 1-event-in-10-years standard?).

[1] For background and context, I have provided a brief history of the capacity market in New England at the end of my written comments.

[2] As opposed to the Northeast Power Coordinating Council system security standard, which is not directly implicated by the Forward Capacity Market ("FCM").

Using these measures, there is ample evidence that the capacity market in New England has been a success.[3] We have run seven primary auctions, numerous reconfiguration auctions, and have completed three full capacity commitment periods. We have obtained sufficient resources in each auction to meet capacity requirements and there have not been any outages due to lack of resources. We have seen the participation of diverse resources in the market. Demand response and energy efficiency have received significant capacity supply obligations and have performed well. Significant uprates of existing units have taken place, which are a low cost means of obtaining new capacity. When the NEMA-Boston capacity zone was short of resources to meet that area's needs, a new combined cycle power plant bid into the auction and received a capacity supply obligation. As I discuss below, however, simply counting megawatts is not enough. If the capacity is installed, but does not perform reliably when needed, then the reliability standards will not be met. So there must be enough capacity, and in aggregate it must perform well enough to allow reliable system operation.

b. Ensuring Cost-Effectiveness

With respect to the second goal of the capacity market – ensuring that the first goal is met in a cost-effective manner – the metrics to measure success are more complicated. There are three important perspectives to consider in analyzing whether capacity costs are appropriate. First, from the perspective of the market administrator, the capacity market is successful to the extent that the lowest cost resources are developed and brought to market, based on true resource costs. This is efficiency – whether the market results in an outcome in which society's resources are deployed in the most cost-effective way. Evidence indicates that many low-cost resources have indeed been developed under FCM, indicating that New England's capacity market is a success by this measure. This includes uprates and significant amounts of demand response, each of which has entered the capacity market at prices far below those estimated for the cost of a new generating resource. For example, in the most recent primary auction, the capacity market

[3] It should also be noted that, while capacity markets are the focus of this proceeding, they alone do not determine investment. Investment is determined by the combination of the energy, ancillary services and capacity markets, as well as the non-ISO administered forward and spot markets that trade around ISO-NE's markets. Depending on the resource, the capacity market may comprise a large or small share of net revenues.

procured approximately 1,600 megawatts of passive demand resources, which include energy efficiency, and many hundreds of megawatts of active demand resources.

Second, from the perspective of the resource owners, the capacity market is successful if in the long-run owners expect to receive adequate risk-adjusted return on their investments, comparable to the returns obtained from similarly large-scale and similarly risky investments in other sectors of the economy. If this is not the case, then the market cannot achieve its principal objective of procuring sufficient resources to meet demand and reliability needs. It is difficult to evaluate the success of the capacity market pursuant to this metric, however, because the region has had a significant surplus of capacity, lowering capacity prices, since the inception of the market. Some of this surplus is the result of the continued participation of existing resources, and some is the result of new out-of-market entry. This suggests that the recently implemented minimum offer price rules are an important component in ensuring that the market provides appropriate long-run investment signals. As the surplus diminishes over time, capacity prices could increase sharply. Such volatility in capacity revenues for resource owners makes it more difficult to assess returns, in addition to creating a more challenging business environment for resource owners (as well as uncertain costs to consumers). It is desirable to dampen the price volatility in the market to reduce the risk for investors, and thereby reduce the cost of entering the market. For these reasons, ISO-NE will be considering with stakeholders whether to implement a demand curve as part of the capacity market design.

Third, from the consumer perspective, the capacity market is successful if the total expenditures by consumers are no greater than needed to assure that the most economic resources enter the market. Given the surplus capacity in recent years as well as the administrative floor price that has been in place in all primary capacity auctions conducted to date, it is also difficult to evaluate the success of the capacity market using this metric. On one hand, with the persistence of the price floor through the seventh capacity auction and the fact that, with the exception of one zone in one auction, the floor has been reached in each auction, the evidence demonstrates that resource owners are receiving at least the market value of capacity. Some customer groups have argued that, in fact, reaching the price floor demonstrates that resource owners are receiving excess compensation. On the other hand, a significant volume of out-of-market capacity has

gone into service, adding to the region's capacity surplus and causing controversy regarding the price suppression from such capacity. The Commission, in extending the price floor in the FCM, recognized that out-of-market capacity could affect capacity prices and undermine investor returns. While this has been echoed by resource owners, who contend that out-of-market capacity has suppressed price and undermined investment in the region, the states have argued that they have the right to build desired capacity and that the market design should not penalize consumers for such actions. We hope, however, that with the new minimum offer price rules in place and with the imminent elimination of the price floor (beginning with the eighth primary auction, to be conducted in February of 2014), these issues have been resolved.

Notably, the capacity market in New England has achieved the goal of eliminating reliance on RMR arrangements. At the start of New England's FCM, the region had approximately 3,200 megawatts of RMR contracts with a total annual fixed revenue requirement of roughly $290 million. These have been eliminated.

c. Resource Performance Problems

Although New England's capacity market has been generally successful in meeting its primary goals, ISO-NE has been grappling with a significant problem related to the capacity market that warrants discussion here. Even with an excess of resources,[4] the performance of a variety of resources has been poor. It is difficult to declare the capacity market a success if a significant number of the resources that have been selected and compensated as capacity resources fail to perform as needed. Yet, the region has experienced a NERC violation,[5] nearly 200 reported

[4] Since the FCM began the region has had significant excess capacity. Thus, there are more resources available to operate the system than we should expect from the current market design when equilibrium is reached. With the expiration of the price floor in the upcoming auction (which will run in February, 2014, for the capacity commitment period beginning June 1, 2017) it is certainly possible that resources will exit the market and the excess will be materially diminished.

[5] On September 2, 2010, when loads were extremely high, the system experienced a single contingency loss of roughly1,500 megawatts. Dispatch instructions were sent to over 1,900 megawatts of resources. As the ties with neighboring regions were already fully loaded, New England could not share reserves from other regions. Because of poor unit performance, ISO-NE violated a NERC standard by not recovering reserves within fifteen minutes. There was not a dollar of penalty to a capacity resource.

instances of fuel unavailability,[6] and poor contingency response, with the ISO getting only about 60 percent of the requested megawatts in response to contingency reserve activations.[7] As a result, ISO-NE is extremely concerned that the current market design will not succeed in assuring long-term reliability. Put simply, the performance of many resources has been poor and there have not been any consequences in the capacity market for such poor performance.[8]

For example, during this summer's heat wave in New England which persisted from Monday, July 15 through Friday, July 19, ISO-NE's operators were issuing forecasts that the system would be short of reserves and, in effect, let all resources know that availability was critical for the entire week. Nonetheless, several troubling events occurred during that week:

- One oil-fired unit attempted to start each day and never became available until 5:00 P.M. on Friday, the last day of the heat wave.
- Another oil-fired unit's owner on Wednesday informed the operators that its unit was running low on fuel. By Thursday, the operators were forced to reduce the output of the unit and ultimately shut it down to preserve fuel.
- On Friday, the system was short of reserves for roughly five hours despite having excess capacity as measured by "steel in the ground." That day, New England experienced the fourth highest demand on record (27,360 megawatts), and had forced outages and reductions that totaled over 4,600 megawatts. ISO-NE had sent start orders to all generation in advance, and out of the total 29,751 megawatts of supply having capacity supply obligations and 1,387 megawatts of supply without capacity supply obligations, nearly 15 percent was unavailable. As a consequence, there was a reserve deficiency across several hours, and in the peak hour the deficiency was 547 megawatts, nearly 25 percent of the reserve requirement of 2,374 megawatts.

[6] *See* 2012 Annual Markets Report, Section 2.1.3.3, available at http://www.iso-ne.com/markets/mkt_anlys_rpts/ annl_mkt_rpts/2012/amr12_final_051513.pdf

[7] *See* Presentation by The Analysis Group at slide 13, available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf

[8] I recognize that the change to the Shortage Event definition in the FCM is currently pending before the Commission and I do not intend to discuss that topic.

Despite all these events, no capacity resource lost any portion of its capacity payment for poor performance.

This past winter, ISO-NE operators experienced difficulty meeting a winter peak load of approximately 21,000 megawatts with resources that have a combined capacity supply obligation of approximately 33,000 megawatts because of uncertainty about the fuel availability for both oil and gas plants, reduced availability of resources within the operating day due to long start-up times, and poor resource performance. New England has among the largest single contingencies on the Eastern Interconnection (generally ranging from 1,200 megawatts – 1,500 megawatts) and protecting the system from these contingencies requires strong resource performance, especially when the neighboring control areas (Hydro Quebec and the NYISO) are also stressed. These conditions have required ISO-NE to act as a 'fuel manager' to protect for system reliability, which is untenable. This also depresses energy market prices as ISO-NE commits additional slow-to-start resources to ensure that if fuel limitations occur, the system can still be operated reliably; this further undermines the necessary market signals for resources to perform.

During the first three capacity commitment periods, several large capacity resources have experienced extremely long outages during which they were not providing any service to the system, yet their capacity payments were never reduced. Fortunately, because of the surplus of capacity, this did not cause any direct reliability problems to the system. However, when the market is procuring only the amount of capacity required to meet the installed capacity requirement, such outages could cause significant risks to reliability.

ISO-NE considers this resource performance problem to be a serious threat to reliability and one that must be addressed in the design of the capacity market. To this end, as I discuss below, ISO-NE has been working closely with stakeholders recently to design a new performance incentives mechanism ("Pay-for-Performance") for the New England capacity market.

4. What design elements are key to the functioning of the centralized capacity market in your region? How were those elements derived? How have those elements

evolved over time? How does capacity market design account for the interrelationship between design elements?

In the history of the New England capacity market presented at the end of these comments, I describe how the FCM was developed and initially implemented. This process established the underlying structure of the market: purchase of enough capacity to meet the installed capacity requirement approximately three years in advance of the delivery period through a centralized auction. All resources are able to participate after going through a qualification process. Resources are able to trade their obligations, subject to review, after the initial auction. The auction will identify locational needs, and will have protections against both monopoly and monopsony market power. These are the core elements of the New England capacity market, and they are a solid core around which to build. The remainder of my response to this question will discuss important changes to the market which have already occurred, and more important changes that ISO-NE is in the process of developing.

I will now briefly describe three significant and positive changes in the evolution of the market and then turn to the key elements required for further market improvement. The three long-standing issues that have been largely addressed are out-of-market capacity, formation of capacity zones, and the price floor. Since FCM was implemented there have been material additions of capacity in the region that are supported by state-backed programs and contracts. There have also been continued concerns about the limited ability of the initial FCM design to signal appropriate locational prices, and continued extensions of the price floor in the market.

a. Major Issues Already Addressed

In February 2010, ISO-NE, joined by NEPOOL, filed tariff changes seeking to improve the market rules addressing both out-of-market capacity and capacity zones. Shortly thereafter, the New England Power Generators Association ("NEPGA") and individual generators filed complaints under Section 206 of the Federal Power Act asserting that the filed changes were inadequate and providing alternative proposals. On April 23, 2010, the Commission accepted the February filing, but set for paper hearing the issues of how to treat out-of-market capacity

and zonal modeling.[9] On April 13, 2011, the Commission issued its order[10] on the issues litigated in the paper hearing. The order contained three major conclusions:

- To address the price suppressing impact of the entry of out-of-market capacity, the Commission ordered the implementation of the minimum offer price rule.
- To assure that capacity is located in appropriate locations and price is set appropriately in each location, the order required the modeling of all capacity zones in the auctions, regardless of whether the zone is short of capacity prior to the auction.
- To compensate for the historical entry of out-of-market capacity, the price floor was extended through the sixth primary capacity auction.

Many stakeholders in New England felt that a better solution than the order on the paper hearing might exist and, during the summer of 2011, sought to negotiate a potential, alternative outcome including a downward sloping demand curve and means of addressing the entry of renewable capacity into the market. Ultimately, those efforts did not produce an agreement among stakeholders.

On March 30, 2012, the Commission accepted for filing a proposal that extended the price floor through the seventh auction (held in February 2013) and provided for the modeling of four capacity zones in that auction.[11]

In ISO-NE's view, addressing the price impacts of out-of-market capacity and improved zonal modeling are significant improvements to the market. Furthermore, removal of the price floor in the next auction (in February 2014) is a major step that is needed for the market to function effectively. Removal of the price floor and implementation of the minimum offer price rules

[9] *ISO New England Inc. and New England Power Pool Participants Committee*, 131 FERC ¶ 61,065 (2010).

[10] *ISO New England Inc. and New England Power Pool Participants Committee* , 135 FERC ¶ 61,029 (2011).

[11] *ISO New England Inc. and New England Power Pool Participants Committee*, 138 FERC ¶ 61,238 (2012).

have already been accomplished, and ISO-NE is working with stakeholders to address the remaining capacity zone issues, such that all of these issues will have been addressed by the ninth auction (held in February 2015).

b. Major Issues To Address Going Forward

Moving forward, there are three elements that rise to the top of the list of things that are key to the effective functioning of the market. Getting the following three elements correct will drive an effective and efficient market which allows reliable system operations for the least cost in the long run.

- First, the capacity product must be properly defined.
- Second, the price setting mechanism must work effectively to set a just and reasonable price for the product.
- Third, performance must be properly measured and the compensation for providing capacity must be completely linked to performance for every capacity resource under the same rules and measures.

The Commission Staff Report recognizes these three issues as key considerations and succinctly describes the challenges. In my response to the final question below, I will describe how ISO-NE is working to improve on each of these key elements.

5. Going forward, what are the key challenges facing centralized capacity markets in your region? How is each RTO/ISO going about addressing those challenges?

In New England, there are three key challenges we are seeking to address, in two stages. The challenges are product definition, resource performance, and setting the capacity price. The first stage of addressing these challenges is underway. Over the past year, we have engaged in a major stakeholder process that seeks to clearly define the capacity product and how its payment will be affected by performance. Our plan is to complete the stakeholder process on ISO-NE's Pay-for-Performance design in December and file tariff changes by year-end. This would allow

a Commission decision on the proposed changes by May 2014, so that they can be in place for the ninth capacity auction, to be run in early 2015. We need the Commission's decision by May in order to allow resources to comply with rules and deadlines regarding resource qualification that occur in June 2014.

In the second stage, we will review the capacity price setting mechanism. As we have explained to stakeholders, we plan to discuss a downward sloping demand curve and potential exemptions from the minimum price offer rules for certain state-sponsored renewable projects. We expect these to be another potential set of market changes that will require significant stakeholder discussion before any submission to the Commission. Therefore, we are targeting this discussion with NEPOOL during the first half of 2014, with any filing to occur later in the year and implementation for the tenth auction in early 2016. Because we have not yet completed our internal evaluation or begun the stakeholder process on this issue, I do not have any specific information on either the parameters of any demand curve or considerations for renewable exemptions.

a. Overview of the Pay-for-Performance Approach

To appropriately define the capacity product and compensate all capacity resources for their performance, ISO-NE is proposing amendments to the FCM rules under the label of "Pay-for-Performance." We are continuing to work through the stakeholder process, so the complete parameters of the proposal are not yet final. That said, the core design is complete and is being actively discussed by stakeholders.

Under Pay-for-Performance, each resource's FCM revenue will be contingent, in part, upon its actual performance during periods when aggregate performance does not enable ISO-NE to satisfy system reserve requirements. The new design will result in transfers from under-performing to over-performing resources, providing strong incentives for each resource to perform as needed and for resources that can meet the system's needs by exceeding their obligation to benefit by doing so. These incentives will place performance risk on all FCM resources, and this risk will need to be priced in each resource's bid in future capacity auctions.

The proposal structures the transfers among suppliers so that consumers continue to pay the forward capacity auction clearing price. This will continue to provide consumers with a predictable capacity price three years out, after the close of each forward capacity auction. In addition, the performance incentives should eliminate any need to specify explicit product requirements in the FCM.

Under today's FCM rules, the capacity product lacks specificity and the performance obligations of capacity resources have a variety of exceptions. The definition of the capacity product in Pay-for-Performance is very straightforward – it is the obligation to provide a share of the system's requirements, as energy or reserves, when the system is experiencing scarcity conditions. There are three fundamental reasons why the single capacity product is being defined in this way under Pay-for-Performance:

- Markets pay for performance. In other words, based upon the fact that capacity markets are paying the "missing money," money which in theory goes missing when prices are insufficiently high during shortage conditions, it is logical that the product be defined as performance when the system experiences these shortage conditions.
- Markets are blind to fault. If a supplier is not producing – for any reason – at the time demand reaches short-run capacity, it misses out on the opportunity to receive the market's (equivalent of the) missing money. It does not matter why the supplier is not producing, or whether the reason(s) are within, or beyond, the supplier's control. Those are business risks that suppliers must manage, and their entry and exit decisions – and expected market prices – should reflect that operational risk.
- Markets are resource neutral. In competitive markets, two suppliers that provide the same good or service receive the same price. Their compensation is not dependent upon whether they use the same means of production.

Under Pay-for-Performance, a capacity supplier's FCM revenue will comprise two parts: A *base payment*, and a *performance payment*. The base payment is determined by the forward capacity auction result. The performance payment is determined by a resource's performance whenever scarcity conditions occur during the capacity commitment period. A resource's performance

payment may be a positive or negative adjustment to its base payment, reflecting superior or inferior performance during scarcity conditions. This Pay-for-Performance design is based on the two-settlement logic of forward markets. This entails two key elements:

1. Forward position. The forward capacity auction determines a resource's base capacity payment, and creates a physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during a reserve deficiency event.

2. Settlement for deviations. The performance payment during a reserve deficiency event is based on the deviation between a resource's actual performance and its forward financial position. These deviations are credited or charged at a pre-determined "Performance Payment Rate." It is important to note that the deviation charges are not penalties, instead they are reductions in what are effectively forward energy market payments when resources do not provide the product they have committed to provide.

There are three fundamental principles underlying this Pay-for-Performance approach:

1. Creating strong economic incentives for all capacity suppliers, without exception, to perform during scarcity conditions. This first principle involves changing the FCM market design so that resources with superior performance during scarcity conditions are able to earn a greater share of the missing money revenue stream determined by the FCA. Resources with inferior performance during scarcity conditions earn a smaller share of the missing money revenue stream. This is consistent with the central tenets of how an efficient, properly functioning market remunerates (the equivalent of) the missing money to suppliers. In effect, it ensures that suppliers face risk and reward for their performance at the right times – when the energy market alone provides performance incentives that are too low and, simultaneously, system reliability needs are high.

2. Implementing these incentives through transfers from resources that under-perform to resources that over-perform during scarcity conditions. This second principle balances

the twin objectives of a sound risk and reward structure for FCM suppliers and a relatively predictable total capacity cost for New England consumers three years hence. It ensures that consumers do not bear the financial risk of unexpectedly high incentive payments earned by high-performing suppliers during the FCM delivery year. Instead, it is the low-performing resources that bear the financial risk. This allocation of risk provides sound economic incentives for suppliers not to under-perform during scarcity conditions.

3. Defining scarcity conditions as any time in which ISO-NE is unable to satisfy the combined energy demand and operating reserve requirements of the power system. This third principle reflects the central observation that the periods when the energy market provides insufficient performance incentives to suppliers are precisely the times when the power system is deficient of operating reserves.

As I have noted, the supply curve under Pay-for-Performance will need to account for both the costs of providing the no exceptions capacity product and the risk of non-performance. At the bottom of the supply stack will be resources that perform very well and have low costs of providing capacity. As we move up the supply stack, we expect resources that have either higher costs to perform or resources that face higher risks of non-performance. At the top of the supply stack, we expect resources that rarely perform, which makes their risk very high. In other words, the poorest of performers that would cost the most to have perform effectively will be the most likely to be priced out of the market. Interestingly, we expect that demand response and other alternative technologies that can respond very quickly to system needs, or are likely to be operating during a shortage event, will be financially successful under Pay-for-Performance. The resources which we expect to retire first are the oldest steam units that rarely operate because of their high prices and long start times.

There are two important areas where some stakeholders have expressed potential alternatives to, or concerns about, the Pay for Performance design – they argue for a tranched market and/or for exceptions to the loss of revenue for nonperformance. I will address each of these below.

b. Problems with the "Tranches" Approach

Some stakeholders have encouraged ISO-NE to develop a market with capacity "tranches." These tranches are described as focused on either acquiring more resources with specific operational characteristics, such as more fast-start units, or focused on acquiring capacity with an increased level of obligations to incent increased levels of reliability. Tranches are discussed as a way to address the general resource performance problems experienced in New England and as a (less expensive) alternative to increased performance incentives for all resources, achieved by paying more to some "preferred" capacity resources and less to others through some form of pricing that would likely fail as unduly discriminatory.

ISO-NE does not believe that applying performance incentives to only a subset of all capacity resources – that is, a "pay-for-performance tranche" – would be a workable market design or an alternative to applying Pay-for-Performance incentives to the entire portfolio of capacity resources. Likewise, ISO-NE does not view an increased level of fast-start resources as a substitute for broader improvements in resource performance. ISO-NE does not support these approaches for a variety of reasons, including:

- Reliable operations require improved resource performance, not specific operational characteristics. ISO-NE's Pay-for-Performance design is intended to provide strong economic incentives for resource owners to perform to their stated physical capabilities during stressed system conditions. It is not intended to procure specific quantities of resources with specific operating characteristics, such as additional fast-start resources. In general, New England's power system could be operated reliably with the existing fleet if all resources consistently performed according to their stated physical characteristics. Likewise, buying more fast-start resources that perform poorly will not ensure reliability.

- Improved incentives applied to fast-start units alone will not resolve the problem. The existing fleet's performance is not an "insufficient operating reserves" problem that can, or should, be addressed by applying performance incentives to fast-start

> resources alone or by buying more fast-start resources. Rather, the problem requires applying performance incentives to the resources that ISO-NE expects, and relies upon, to supply energy to meet the full range of loads. Even if fast-start and other resources providing operating reserves serve the system reliably during some tight system conditions, these resources are there to handle contingencies. The system must still have reliable performance by the region's fleet to meet load. For example, during the tight system conditions experienced the week of July 14-19th, 2013, many of the operating challenges ISO-NE experienced were due to poorly performing larger units that were unavailable to supply energy, or that failed to start – not a performance problem with fast-start resources operating as reserves.

Ultimately, the Commission Staff Report effectively summarized the problems inherent in procuring capacity tranches, stating:

> redefining the capacity product to procure needed operational attributes, defining the specific attributes to be procured, and determining how much of the overall capacity requirement should be met by capacity resources with such attributes would be a complex undertaking. Co-optimizing the procurement of different capacity products to ensure an overall least-cost result for customers also would add significant complexity for system operators and market participants.[12]

ISO-NE's Pay-for-Performance design is an elegant solution that avoids these problems.

c. Problems with Allowing Exceptions to Pay-for-Performance

Some stakeholders have objected to ISO-NE's proposal to eliminate exemptions from penalties for poor performance by resources in the capacity market. The current capacity market rules have a variety of exceptions that excuse or mask poor performance by capacity resources, or evaluate different resources using different metrics. These include exemptions for units with long start times, special ratings rules for intermittent resources, and more complicated (and some

[12] Centralized Capacity Market Design Elements, Commission Staff Report, Docket No. AD13-7-000 (August 23, 2013) at 18.

would argue, more severe) penalty structures for demand resources; it is in part our experience with exemptions in the current market design that have led us to propose the elimination of exemptions going forward. ISO-NE's Pay-for-Performance approach would eliminate all exceptions and exceptional treatment and compensate all resources based on the same performance standard: provision of energy or reserves during periods of reserve (and/or energy) shortage.

This approach mirrors the compensation that would be provided by an energy-only market. Resources earn money when providing a service, whether it is energy or reserves, and do not earn money when they are offline and unavailable. This compensation structure provides clear signals to resources about when their performance is valuable, and how valuable it is. And like an energy-only market, it does not matter why you did not perform when needed – if you perform you get paid, otherwise you get nothing.

Stakeholders have proposed a range of exemptions to the performance requirements under the Pay-for-Performance proposal. In each case the underlying rationale is that it would be "unfair" to penalize a resource that did not perform for a particular reason. ISO-NE has continued to reject such proposals. Exemptions are inconsistent with the Pay-for-Performance construct under which you get paid for only what is delivered; deviating from this approach would bias the performance incentives away from desirable performance toward excepted performance. It would also negatively affect price formation as resources which are granted exemptions for non-performance under certain conditions would be able to offer at lower prices in the capacity auction, advantaging them relative to resources not granted exemptions. But ISO-NE has also maintained its opposition to any exemptions because opening the door to any exceptions quickly unwinds the logic for opposing the next set of exemptions.

Every resource has its list of unfair or "out of my control" excuses. The oil didn't get delivered, the production line wasn't running, the wind didn't blow, the pipelines were at capacity – each resource type will have its own list of appropriate exemptions. And where is the line drawn between reasons that are within or outside the resource owners' control – could the gas unit have put in dual-fuel capability, could the slow-to-start unit have installed a package boiler to shorten

start times? In sum, properly designed markets do not include performance exceptions and there is no good economic reason to create exemptions for poor performance in the case of capacity markets. Moreover, doing so raises issues of fairness and comparability across resources.

This concludes my general comments. Again, I very much appreciate the opportunity to comment on these important and evolving issues. As I mentioned previously, the remainder of these written comments provides a brief history of the capacity market in New England.

History of the Capacity Market in New England

In the mid to late 1990s, the region's state legislatures and regulators directed their vertically integrated utilities to divest their generating assets while continuing to provide transmission and distribution service to their customers. There were several goals of these actions, including:

- Bringing competition into the provision of generation service to allow all resources to compete;
- providing choice to customers;
- placing risk for investment decisions on resource owners, not captive utility customers; and
- using markets, not regulation, to achieve an efficiently priced mix of resources to provide energy to customers.

As a result of these decisions, roughly 90% of the region's generation fleet was sold to companies that were not traditional New England utilities. These assets were primarily nuclear generators, hydro-electric projects and oil- and coal- fired steam generators. Customers received two large and immediate benefits from these actions. First, many of the resources were sold at prices well in excess of book value and the profits received from the sales were returned to customers to reduce rates or eliminate stranded costs. Second, the risk of ownership of these facilities was shifted from ratepayers to investors, which is particularly significant in the case of nuclear assets where the risks of both operational efficiency and decommissioning had been major concerns when the utilities owned the assets.

Simultaneous with these changes, the region implemented wholesale markets for the provision of energy. These markets went live on May 1, 1999. In anticipation of the wholesale markets, significant new gas infrastructure was planned and built, including roughly 10,000 megawatts of new, efficient combined cycle gas plants.

In May of 2000, an early heat wave gripped the region and energy prices spiked to over $6,000 per megawatt hour. This resulted in the implementation of a $1,000 offer cap in the energy market, effectively limiting the revenue available to resources during tight system conditions. Over the next few years, and due to a number of factors, a wave of bankruptcies swept the companies that owned generation. In New England, numerous units that were needed for reliability were given RMR contracts and other alternative means were attempted to provide for cost recovery, particularly for generators in constrained areas. The combination of price caps, bankruptcies, and RMR contracts pushed capacity market reform to the top of the region's agenda.

In two significant orders in 2002 and 2003,[13] the Commission directed the region to develop a locational capacity market. On March 1, 2004, ISO-NE filed its proposal in accordance with these orders. The proposal, known as the Locational Installed Capacity Market ("LICAP"), contained a downward sloping demand curve and the provision for separate zones in New England. On June 2, 2004, the Commission accepted in part and rejected in part the proposal and set certain issues (most significantly the parameters of the demand curve) for hearing.

After a year of litigation, the Administrative Law Judge issued an initial decision in the case.[14] This decision contained three key determinations:

- It affirmed the parameters of the downward sloping demand curve proposed by ISO-NE;

[13] *New England Power Pool and ISO New England Inc.*, 100 FERC ¶ 61,287 (2002); *Devon Power LLC*, 103 FERC ¶ 61,082 (2003).

[14] *Devon Power LLC*, 111 FERC ¶ 63,063 (2005).

- it upheld the Peak Energy Rent deduction ("PER"); and
- it rejected a shortage hours metric in favor of the EFORd approach for determining how a resource should be paid or penalized for performance.

This decision was highly controversial and led to several important events. First, in the Energy Policy Act of 2005, Congress included a "Sense of Congress" that the Commission "should carefully consider the States' objections" to LICAP.[15] In turn, the Commission held oral argument on whether the Administrative Law Judge's initial decision or any other proposal would provide just and reasonable wholesale power prices to maintain reliability and encourage needed generation additions, and whether a capacity market would be preferable to continuing the proliferation of RMR agreements. Following argument, the Commission provided an opportunity for the parties to settle on an alternative proposal to LICAP.[16]

On March 6, 2006, a significant cross-section of the parties in the LICAP proceeding, including ISO-NE and NEPOOL, filed a settlement proposal, which was accepted by the Commission in a June 16 order.[17] This settlement established New England's current FCM. The settlement agreement and the tariff provisions initially implementing it contain the following key features:

- A three year forward auction to procure resources;
- an extensive qualification process to assure that resources bidding into the auction can actually provide capacity;
- predetermined zones that would only have price separation if they are short of capacity prior to the auctions;
- a pre-approval process administered by the Internal Market Monitor for bids from resources that wish to delist from the market above a specified price;
- a vertical demand curve that sets the amount of capacity to be acquired equal to the region's installed capacity requirement;

[15] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1236, 119 Stat. 961 (2005).

[16] *Devon Power LLC*, 113 FERC ¶ 61,075 (2005).

[17] *Devon Power LLC*, 115 FERC ¶ 61,340 (2006).

- a price collar initially set such that prices could not fall below $4.50/kW-month (0.6 times the Cost of New Entry) or exceed $10.50/kW-month (1.4 times the Cost of New Entry), adjusted for subsequent auctions, and set to expire after three successful auctions;
- a shortage hours penalty, which reduces a resources capacity payment, with significant exceptions and potential losses capped at the FCM price, for failure to perform when the system is short of operating reserves; and
- participation for demand-side resources as well as supply-side resources.

These features, the details of which have been revised in numerous Section 205 filings, are currently in effect. The upcoming auction, the eighth forward capacity auction, will be held in February 2014 for the capacity commitment period beginning on June 1, 2017.