Centralized Capacity Market Design Elements

Commission Staff Report
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On September 25, 2013, the Federal Energy Regulatory Commission (Commission) will hold a technical conference on centralized capacity markets in regional transmission organizations and independent system operators (RTOs/ISOs). The purpose of this technical conference is to consider how current centralized capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The technical conference will focus on the goals and objectives of existing centralized capacity markets and examine how specific design elements are accomplishing existing and emerging goals and objectives.

To that end, staff has examined a set of design elements present in the centralized capacity markets operated by the three eastern RTOs/ISOs: PJM Interconnection, L.L.C. (PJM), ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO). Below staff summarizes the approaches taken by the eastern RTOs/ISOs with respect to these design elements and discusses the impact particular market design choices can have on the procurement of capacity resources. Staff provides this review of the mechanics of current market operations to establish a common foundation from which to engage in broader discussions regarding the operation of the eastern RTO/ISO centralized capacity markets.

Background

To maintain reliable operations, electric systems must maintain sufficient capacity resources to meet peak load requirements plus a planning reserve margin (referred to as "resource adequacy" or the "planning reserves"). Under traditional utility regulation, resource adequacy is met by load-serving entities obtaining regulatory approval to hold a portfolio of resources, the costs of which (including a reasonable return on investment) are recovered from captive customers. In areas of the country that have restructured their electricity markets, many load-serving entities compete for retail customers with other suppliers, creating financial risk for long-term resource commitments, and in many cases have divested generation to new owners that compete for sales and thus have no guarantee of cost recovery. The capacity markets of the eastern RTOs/ISOs were implemented against this backdrop of restructuring in the retail electric markets of each region.

Early on, the eastern RTOs/ISOs, like the power pools that preceded them, employed rules requiring load-serving entities to maintain adequate capacity resources to meet the planning reserve margin, coupled with a deficiency charge assessed to members who failed to meet their capacity requirements. The original capacity market designs were voluntary balancing markets intended to provide transparent market-based mechanisms to assist load-serving entities in meeting their installed capacity obligations. These market constructs generally procured capacity on a daily or monthly basis with a short lead time and relied on deficiency charges to set market prices.

Over time, concerns grew that these early market-based capacity constructs were inadequate to ensure long-term resource adequacy. In response, centralized capacity markets were implemented by the eastern RTOs/ISOs to provide more lead time and certainty for investment in new capacity resources, including an adequate opportunity for all resources to recover both their variable and fixed costs over time.[1] The Commission has provided each region with flexibility as to market design and has not required a "one-size fits all" approach. However, the primary goal of each of these markets is the same: ensure resource adequacy at just and reasonable rates through a market-based mechanism that is not unduly discriminatory or preferential as to the procurement of resources.

The particular market design choices of each region have been different, with each market arriving at its specific approach through stakeholder processes and settlement agreements, evolving over time to address emerging issues. In recent years, refinements have been pursued or discussed to address the impact that broader industry changes have had on the markets, including an evolution in the mix of available resources driven by low natural gas prices, state and federal policies encouraging the entry of renewable resources and other technologies, state policies supporting the development of resources in particular areas or with particular characteristics, the retirement of aging generation resources, and the need to retain certain resources. Because the Commission has considered these variables on a case-by-case basis, there has been limited opportunity for the Commission to consider more broadly how the centralized capacity markets are accomplishing their intended goals and objectives through a competitive, market-based process.

While each market has made its own individual specific market design choices, at a high level there are similarities in the three eastern RTO/ISO centralized capacity markets. Each requires load-serving entities to secure, either through self-supply[2] or participation in the capacity auction, sufficient resources to meet their capacity obligation at a future time. All three centralized capacity markets allow participation by any resource that is technically qualified to provide the capacity product being procured and each includes locational constraints to a certain degree. Each conducts a capacity auction where eligible offers to sell capacity are compared to the demand for capacity resources, which is established through an administratively-determined demand curve. The market clears at the price where supply equals, or in some cases is slightly below or slightly exceeds, the planning reserve margin. When the market does not clear, price is set at an administratively-determined price. All cleared resources receive the market clearing

[1] Ensuring an opportunity to recover both fixed and variable costs over time should avoid the so-called "missing money" problem.

[2] While the specific rules vary by RTO/ISO, load-serving entities can own or construct resources or contract bilaterally for resources.

price for capacity regardless of resource type and participating load-serving entities pay their proportionate share of the costs. Figure 1 illustrates the capacity clearing prices in each RTO and select sub-regions for commitment periods between 2006 and 2017.

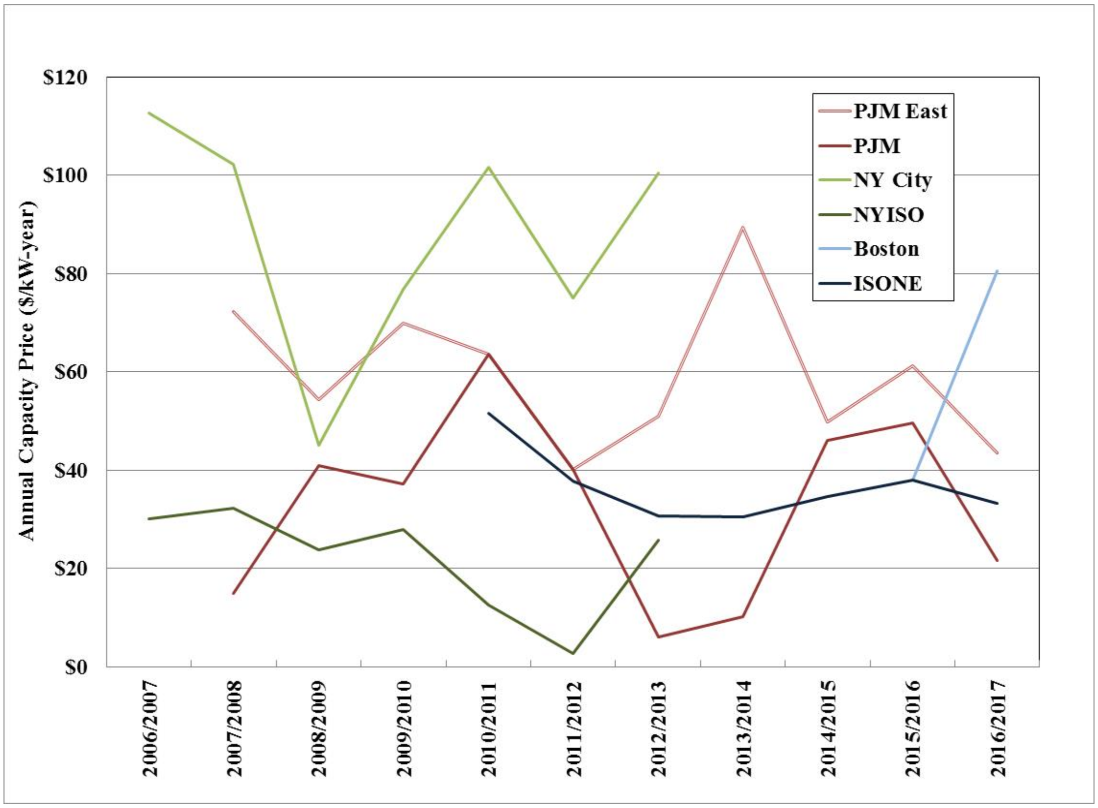

Figure 1: Capacity Clearing Prices in Each RTO and Select Sub-Regions for Commitment Periods between 2006 – 2017.[3]

To facilitate a discussion of these markets, staff has identified some key features of each market design – reflected in the five design elements discussed below – and

[3] PJM, 2016/2017 RPM Base Residual Auction Results, *available at* http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx; NYISO, ICAP Data & Information, *available at* http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp; ISO-NE, FCM Auction Results, *available at* http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html.

reviews how the particular choices of each region can influence the procurement of future capacity resources. These design elements are:

- Demand Curves
- Forward and Commitment Periods
- Definition of the Capacity Product
- Performance Requirements
- Market Power Mitigation

Some of the design elements discussed concern emerging issues affecting centralized capacity market operations. As the mix of available resources changes in response to market conditions and state and federal policy changes, centralized capacity markets face new challenges in meeting their goals and objectives. In deciding how to address these challenges, multiple and sometimes competing policy objectives will need to be weighed.

Staff focuses on this set of design elements in part because they involve issues common across the markets, allowing for comparisons in approaches taken across the regions. This review is, however, limited in that it does not capture every feature of the eastern RTO/ISO centralized capacity markets, some of which are specific to a particular market. Moreover, although each design element is addressed separately in this paper, they often interact with each other in the operation of the capacity market. For example, the cost of new entry used to establish the demand curve is based, at least in part, on the cost of the marginal unit that can be built within the forward period in PJM. Similarly, how the capacity product is defined implicates the performance requirements for capacity resources. Certain policy goals, such as meeting a state renewable portfolio standard (RPS) or other resource planning objectives, can impact multiple aspects of capacity market design, including the forward and commitment periods, performance requirements and market power mitigation.

Capacity Market Design Elements

A. Demand Curves

To ensure that centralized capacity markets procure enough capacity to meet the planning reserve margin[4] at just and reasonable rates, the three eastern RTOs/ISOs have

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[4] A fundamental aspect of capacity markets is the targeted amount of capacity needed to satisfy resource adequacy. This target amount is based on an assessment of installed capacity requirements reflecting peak load and a planning reserve margin. *See, e.g.*, *Devon Power LLC*, 115 FERC ¶ 61,340, at P 4, *order on reh'g*, 117 FERC ¶ 61,133 (2006); *see also* NYISO, Manual 4: Installed Capacity Manual, § 2.1; PJM, Manual 18: PJM Capacity Market, Revision 19, § 2.

adopted market clearing processes that rely in part on an administratively-determined demand curve. Like any other market, the centralized capacity markets clear – and price and quantity are determined – at the intersection of supply and demand. The supply curve in these markets consists of actual offers from suppliers across a range of generating technologies and demand-side resources, with the highest-cost offers generally reflecting peaking generation technologies.[5] In contrast, the demand curve is established through an administrative mechanism that approximates customer demand for capacity resources, and the prices they are willing to pay for them, at various levels of supply. Demand curves can be either vertical or downward-sloping. Choosing between a vertical or downward-sloping demand curve involves several tradeoffs that have implications for the stability of capacity prices, the amount of capacity cleared, and how those prices signal new investment when needed.

1. Current Market Design

All three eastern RTOs/ISOs initially employed capacity market designs that secured a fixed amount of capacity equal to the planning reserve margin, and imposed deficiency charges on load serving entities who failed to meet their share of the planning reserve margin.[6] In practice, this resulted in a vertical demand curve. Concerns were raised in some regions that the prices resulting from the use of a vertical demand curve were too volatile, with prices at or near the deficiency charge when supply was not sufficient to meet the planning reserve margin, and prices near or at zero once the planning reserve margin was met. In response, NYISO and PJM adopted downward-sloping demand curves, while ISO-NE continues to use a vertical demand curve within the context of a descending clock auction.

Examples of the demand curves produced in PJM, NYISO and ISO-NE based on market data are demonstrated in Figure 2. Further, Appendix A illustrates in detail the features of a downward-sloping demand curve, and, using NYISO as an example,

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[5] The three markets use different auction processes through which they solicit supply offers. In PJM and NYISO, suppliers offer the amount of capacity they are willing to sell and the price at which they will sell that capacity. Typically, these offers can be one price/quantity pair or multiple price/quantity pairs that show an increasing cost. These offers, when stacked from least to greatest cost, define the supply curve. In ISO-NE, a descending-clock auction is used where suppliers choose to exit the market when the price offered by the market operator falls below the resource's approved de-list bid.

[6] A deficiency charge was assessed to a load-serving entity based on the amount of capacity that it was short of its capacity obligation in a given month and was generally expressed in dollars per kilowatt-month ($/kw-month).

describes the differences between NYISO's original vertical demand curve and the downward-sloping demand curve that it adopted in 2003 for use in its monthly spot deficiency auction. PJM employed a vertical demand curve until 2007, when it adopted its Variable Resources Requirement curve.[7] PJM's Variable Resources Requirement curve was the result of extensive settlement discussions, but reflects attributes similar to the NYISO downward-sloping demand curve described in Appendix A. Concern over volatility in capacity market prices under a vertical demand curve was a key reason that NYISO and PJM chose to move to the downward-sloping demand curve.[8]

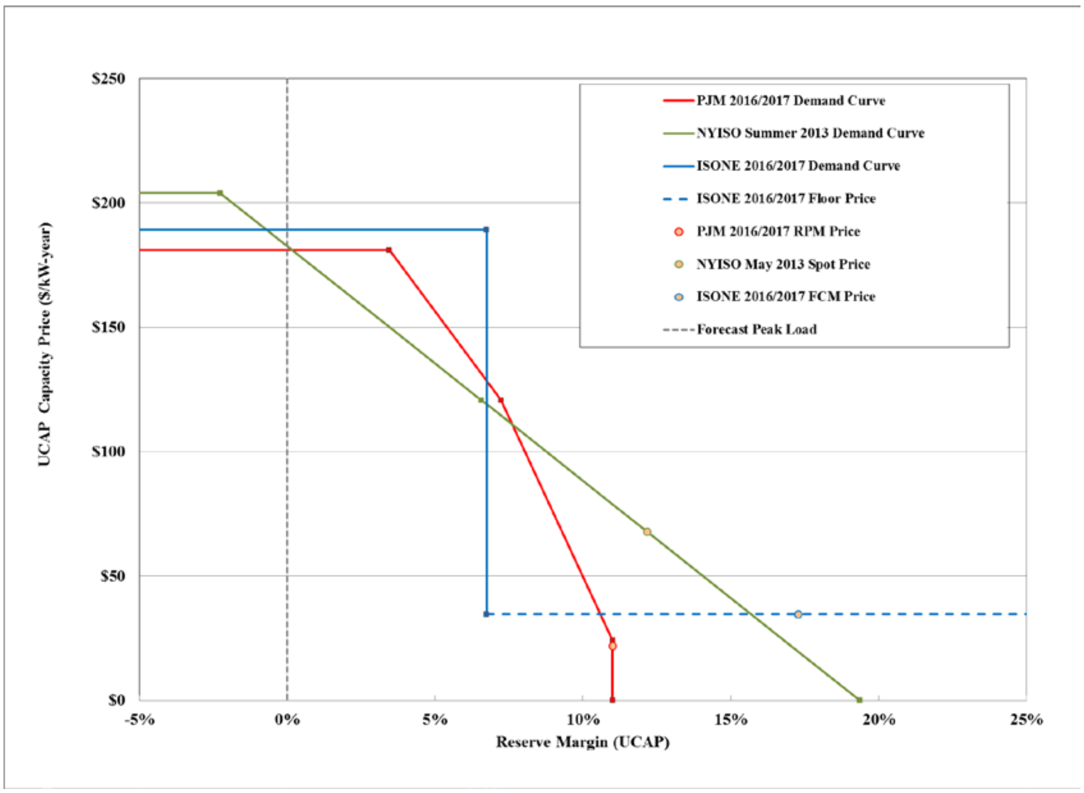

Figure 2: Example Demand Curves for PJM, NYISO, and ISO-NE[9]

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[7] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at PP 75-76 (2006).

[8] *See id.*; *New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, at PP 3-5, *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at P 92 (2006).

[9] PJM, 2016-2017 RPM Base Residual Auction Parameters, *available at* http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters.ashx; NYISO, Installed Capacity - View ICAP and UCAP Calculations, *available at*

An administratively-determined cost of new entry (CONE) can be a critical design parameter in constructing a downward-sloping demand curve.[10] The downward-sloping demand curves in place today are designed so that the market will procure, over time, an amount of capacity equal to the planning reserve margin at a price of net CONE.[11] Under PJM's and NYISO's current downward-sloping demand curves, CONE determines the exact slope and shape of the curve, as explained in Appendix A. In 2004, ISO-NE proposed a downward-sloping demand curve similar in concept to the NYISO and PJM curves described above. The Commission agreed with the overarching concept of the ISO-NE proposal, but required additional justification for the parameters and set several issues for hearing procedures.[12] In 2006, after lengthy settlement discussions with multiple stakeholders, the Commission approved a settlement establishing a basic auction structure that continues to utilize a vertical demand curve, albeit with several additional features not present in its earlier market design.[13]

Specifically, ISO-NE conducts an annual multiple-round descending clock auction, for delivery three years later, to procure its Installed Capacity Requirement for each capacity zone. ISO-NE establishes both a starting price, which is the maximum

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http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_detail.do, and ICAP/UCAP Translation of Demand Curve, *available at* http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2013/Summer_2013/Documents/Demand_Curve_Summer_2013_Revised.pdf; ISO-NE, FCM Auction Results, *available at* http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html, and *2016/17 ICR Values Report*, (January 2013), *available at* http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2013/icr_2016_2017_report_final.pdf.

[10] CONE is described in more detail in Appendix B. In the past, CONE was also used to establish the maximum price the market would pay for capacity under a vertical demand curve, although in ISO-NE it is no longer used for that purpose. *See ISO New England Inc.*, 131 FERC ¶ 61,065, at PP 140-141 (2010).

[11] Net CONE is equal to the Cost of New Entry minus the energy and ancillary services revenues the reference technology is estimated to earn for the hours that it operates.

[12] *Devon Power LLC*, 107 FERC ¶ 61,240, at PP 57-59, *order on reh'g*, 109 FERC ¶ 61,154 (2004), *order on reh'g*, 110 FERC ¶ 61,315 (2005).

[13] *Devon Power LLC*, 115 FERC ¶ 61,340 at PP 150-51.

price it is willing to pay for capacity, and a minimum price below which it will not allow the price to fall.[14] To establish a market price, ISO-NE announces the opening price it will pay for capacity and suppliers submit offers to sell at that price. If the total amount of MWs offered exceeds the Installed Capacity Requirement, ISO-NE lowers the price and conducts another auction round. Once again, suppliers offer the amount of capacity they are willing to supply at that new, lower price. ISO-NE repeats this process until the amount of capacity willing to remain in the auction at a given price equals or falls below the Installed Capacity Requirement.[15] Since the quantity procured does not vary with price, this implicitly establishes a vertical demand curve with the quantity procured equal to the ICR. For the first seven auctions, price floors were established to provide some price stability and ensure that capacity prices would not drop to near zero with excess supply, although the price floor has since been removed.[16] The ISO-NE capacity market has experienced significant excess supply, with prices in all but the most recent auction for a single capacity zone clearing at the price floor.[17]

Finally, use of a demand curve to approximate customer demand for capacity resources has implications for the ability of load serving entities to self-supply capacity, including specific kinds of capacity resources they build or acquire to meet policy goals such as state renewable portfolio standards. Some customers may prefer to supply their own capacity outside of the centralized capacity market based on factors such as their view of market risk, desire for long-term arrangements, or business models. Whether to allow customers to self-supply, and if so, how the self-supply is reflected in the demand and supply curves, can impact the price signals sent by capacity markets. Therefore, whether and to what extent load serving entities can opt to self-supply their capacity needs outside of the centralized capacity market varies among the three eastern RTOs/ISOs. In PJM, load serving entities have the option to opt-out of the Reliability Pricing Model (RPM) market and self-supply through the Fixed Resource Requirement program, or procure all, or part, of their resource requirement through the Variable

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[14] *Id.* PP 17, 19, 125-26, 130.

[15] ISO-NE Internal Market Monitor, *2011 Annual Markets Report*, at 62 (May 15, 2012), *available at* http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf.

[16] The last Forward Capacity Auction employing a price floor was the seventh Forward Capacity Auction, in 2013. *See ISO New England Inc.*, 138 FERC ¶ 61,238, at P 27 (2012). The Commission approved the removal of the price floor beginning with the eighth Forward Capacity Auction. *See id.* PP 127-28.

[17] Individual results of all Forward Capacity Auctions to-date are available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html.

Resource Requirement program of the RPM. Participating in the Fixed Resource Requirement program, however, requires the load serving entity to use its resources to serve its entire capacity requirement for at least five years; in other words, load serving entities may not secure some of their capacity obligation through the centralized capacity market and some through self-supply. In NYISO, a load serving entity can meet its capacity obligation, in whole or in part, through self-supply or bilateral contracts, but is still required to participate in the centralized capacity spot market. In ISO-NE, self-supplied capacity must participate in the centralized capacity market auction regardless of whether it is an existing capacity or new capacity resource. If the self-supplied resource clears the market, it obtains revenue that will offset a portion of the costs the load serving entity must pay for capacity; however, if the self-supplied resource does not clear in the auction, the load serving entity receives no capacity revenue and alternative capacity is procured in the auction.

2. Discussion

The selection of a downward-sloping or vertical demand curve has implications for the stability of capacity prices, whether those prices provide appropriate price signals for new investment, and how much capacity the centralized capacity market procures.

As discussed above, PJM and NYISO no longer use a vertical demand curve due to concerns about volatile capacity prices. A vertical demand curve can create volatile – or even binary – prices from one commitment period to the next. Clearing prices can swing dramatically from near zero (or at the administrative price floor, if one is established) when there is excess supply to near the maximum when supply is insufficient.[18] Capacity additions are often large and can be far larger than a current shortfall in installed capacity. Therefore, when a new resource enters the market, prices have the potential to drop significantly. For example, adding a 100 MW capacity resource when 50 MW are needed to meet the planning reserve margin target could result in capacity prices dropping from at or near the maximum price to at or near zero. This can inhibit efficient entry of new capacity resources even when supplies are below the planning reserve margin. While this "lumpiness" problem exists when using a downward-sloping demand curve, it is particularly acute with a vertical demand curve.

Implementing a downward-sloping demand curve moderates the impact on prices as supply and demand conditions change, addressing price volatility.[19] However, the

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[18] This may be a particular concern in capacity markets that are short-term in nature, e.g., NYISO, where the longest forward period is six months, because in those cases supply options are relatively limited.

[19] In the years following implementation of the downward-sloping demand curve, the NYISO Independent Market Monitor explained that the downward-sloping demand

choice of a downward-sloping demand curve has implications for the value the market places on capacity resources at various levels of supply, including above and below the planning reserve margin. In particular, a downward-sloping demand curve allows for procurement of capacity in individual auctions that can be more or less than the level needed to meet the planning reserve margin. Some stakeholders object to market outcomes that procure an amount of capacity that is less than what is needed to meet the planning reserve margin (which could result in decreased reliability) or, on the other hand, that procure capacity in excess of what is needed to meet the planning reserve margin (which could result in increased costs). One way these objections can be addressed is by changing the slope of the demand curve. For example, the slope of the demand curve in excess of the planning reserve margin can be made steeper to assign less value to increasing amounts of capacity beyond that target amount, and similarly, the slope of the demand curve can be made steeper below the target amount to assign a higher value when capacity supplies are short. A vertical demand curve can also address these concerns, since it is designed to procure in each auction the exact amount of capacity that is needed to meet the planning reserve margin (assuming that there is sufficient supply offered in the market). ISO-NE and its stakeholders chose to retain a vertical demand curve in response to similar concerns.[20]

Using a downward-sloping demand curve also means that market outcomes are more heavily influenced by the administratively-determined CONE value. As Appendix B explains, calculating a value for CONE requires a number of estimations and assumptions that can be contentious. The choices made in these estimations and assumptions, and any errors in them, will impact the shape of the demand curve and the corresponding market clearing prices. Moreover, CONE (and the estimations and assumptions underlying it) must be updated at regular intervals (such as every three years as in NYISO), requiring sometimes lengthy and contentious stakeholder proceedings and litigation at the Commission. In addition, choosing the reference technology whose typical costs and revenues will form the basis for CONE could have a significant impact on the types of technologies that, in the long run, will be likely to recover their fixed costs, since the downward-sloping demand curve is ultimately designed to procure an amount of capacity equal to the planning reserve margin at a price of CONE over the long term.[21] Basing CONE on a reference technology may present some risk that market

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curve appeared to have addressed volatility in capacity prices. *See* Potomac Economics, Ltd. – Independent Market Advisor to NYISO, *2004 State of the Market Report New York ISO*, at 61-63 (July 2005), *available at* http://www.hks.harvard.edu/hepg/Papers/NYISO_2004_state_of_the_market_report.pdf.

[20] *Devon Power LLC*, 115 FERC ¶ 61,340 at PP 20, 45.

[21] The choice of a reference unit and its physical characteristics can impact CONE by as much as 25 percent. The Brattle Group, *Second Performance Assessment of PJM's*

prices will not encourage investment in any technology other than the reference technology (assuming it has the lowest fixed cost), potentially losing the value of a diverse resource base. As the mix of available resources changes in response to market conditions and state and federal policies, the assumptions used to determine the CONE value may become more critical considerations for ensuring that centralized capacity markets provide appropriate price signals for capacity resource investment when needed.

Finally, as noted above, an administratively determined demand curve (either vertical or downward-sloping) has implications for the ability of load serving entities to self-supply capacity resources, including specific kinds of resources they acquire to satisfy energy policy goals such as a state renewable portfolio standard. As discussed above, the eastern RTOs/ISOs have taken different approaches to accounting for self-supplied capacity resources in their centralized capacity markets. Allowing individual load serving entities to meet some or all of their share of the region's capacity requirements through self-supplied resources, without accounting for that self-supply in the capacity market and the demand curve, can potentially distort the market. Whether and to what extent self-supply creates a risk of market distortion can vary greatly depending on such things as the degree to which a customer is allowed to self-supply (in whole or in part), whether a vertical or downward-sloped demand curve is used, and whether or not self-supplied capacity resources are offered into the auction. For example, allowing a customer the ability to choose to self-supply in a market with a vertical demand curve could cause market prices to fluctuate significantly as customers opt in or out of the market. These adverse impacts can be addressed by requiring the self-supplying customer to offer its contracted capacity into the market at its true cost. The effect of such a requirement, however, could be that relatively higher cost self-supplied new resources may not clear in the auction.

B. Forward and Commitment Periods

The eastern RTO/ISO centralized capacity markets include both a forward period, which is the amount of time an auction takes place ahead of when capacity is needed, and a commitment period, which is the length of time that a capacity resource is required to provide capacity to the RTO/ISO. The length and duration of the forward and commitment periods have implications for encouraging competitive entry of new resources and efficient market exit of existing resources, balancing risk between suppliers and customers, and the stability of prices.

Reliability Pricing Model, at 80-81 (Aug. 26, 2011), *available at* http://www.pjm.com/~/media/committees-groups/committees/mrc/20110818/20110826-brattle-report-second-performance-assessment-of-pjm-reliability-pricing-model.ashx.

1. Current Market Design

Forward periods differ in the three eastern RTO/ISO markets. NYISO's installed capacity market is short-term in nature, with the longest forward period being at least 30 days prior to its Capability Period Auction, sometimes called the six-month strip auction.[22] Although NYISO and its stakeholders recently considered whether to alter the structure and timing of its auctions, it ultimately decided not to do so.[23] PJM and ISO-NE use a three-year forward period. PJM and ISO-NE also conduct realignment auctions to adjust capacity procurement based on updated load forecasts and system conditions, and provide a secondary market for participants to offer in new capacity or buy out of their previous capacity supply obligation. PJM conducts up to three realignment auctions held twenty, ten, and three months prior to delivery.[24] As needed, PJM may also conduct a Conditional Incremental Auction in response to delays in large transmission projects.[25] ISO-NE conducts annual and monthly reconfiguration auctions prior to the delivery year.[26]

Commitment periods also differ in each market. NYISO's longest commitment period is six months for those participating in its Capability Period Auction, whereas PJM and ISO-NE primarily acquire capacity for a one-year commitment period. Both PJM and ISO-NE also offer a multi-year commitment period option, allowing certain new capacity resources to commit to provide capacity and "lock-in" the capacity price they will receive over a longer term: three years in PJM or five years in ISO-NE. PJM makes a three-year commitment period available to planned generation resources where the size of the resource relative to the Local Deliverability Area has the potential to drop the

[22] NYISO, Manual 4: Installed Capacity Manual, § 5.2.

[23] NYISO has commissioned two independent studies over the past five years to analyze its capacity market and both studies concluded that a longer-term forward capacity market does not appear warranted. FTI Consulting, *Evaluation of the New York Capacity Market*, at xi-xiii (Mar. 5, 2013), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Final_New_York_Capacity_Report_3-13-2013.pdf; The Brattle Group, *Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market*, at 3 (June 15, 2009), *available at* http://www.brattle.com/_documents/uploadlibrary/upload789.pdf.

[24] PJM, PJM Manual 18: PJM Capacity Market, § 5.7.

[25] *Id.*

[26] ISO-NE, Market Rule 1, Standard Market Design, § III.13.4.

clearing price. This three-year commitment is subject to multiple conditions.[27] The five-year commitment option in ISO-NE is available only to a new resource awarded a capacity obligation for the first time in the auction.[28]

2. Discussion

a. Forward Period

A longer forward period (such as the three years currently utilized in PJM and ISO-NE) provides more lead time to allow new resources that can be constructed or activated within that period to compete with existing capacity resources, thus increasing competition among different capacity supply options. If the forward period is not sufficiently long enough to develop capacity resources that need relatively longer lead times, then market participants may have to commit to developing these resources and incur significant costs prior to participating in the auction and without the benefit of auction results. Thus, a forward period that is not sufficiently long may discourage entry or encourage bids that do not reflect the full cost of new entry. For example, the three year forward period adopted by PJM and ISO-NE is based on the average lead-time for a new gas-fired combustion turbine or a gas-fired combined cycle generator, and is viewed as providing sufficient time for those resources to arrange for financing and complete construction. Similarly, a longer forward period provides more time for an existing resource considering whether to exit a market to make decisions to either retrofit or retire if it does not clear in the auction.

However, a longer forward period can result in increased risk for customers when compared to a shorter forward period. Forecasts of planning reserve margins are generally more accurate closer to the period in which capacity resources are needed, when market conditions are better known. More accurate forecasts lead to more accurate procurements of capacity, helping to mitigate economic and resource adequacy risk for customers.[29] PJM and ISO-NE's use of realignment auctions closer to the commitment period is intended, in part, to address this concern. In addition, using a longer forward period that accommodates the construction of longer lead-time resources can be problematic for resources with shorter lead times, like demand response, which may face difficulties in securing customer commitments so far in advance.

[27] PJM, PJM Manual 18: PJM Capacity Market, § 5.3.3.

[28] ISO-NE, Market Rule 1, Standard Market Design, § III.13.1.1.2.2.4.

[29] *See* James. F. Wilson, *Forward Capacity Market CONEfusion*, at 22-24 (June 2010), *available at* http://wilsonenec.com/Forward-Capacity-Market-CONEfusion.pdf.

b. Commitment Period

Like the choice of the forward period, the length of the commitment period also affects the entry of new capacity resources, the balance of risk between suppliers and customers, and the stability of prices.

A longer commitment period may help promote market entry and increase competition. Some suppliers claim that a one-year commitment period provides an insufficient incentive to take on the risk of building a new power plant.[30] They have expressed a strong interest in longer commitment periods, similar to long-term purchase power agreements, arguing that the lack of certainty regarding long-term fixed cost recovery can present an obstacle for new entry and obtaining non-recourse project financing. A one-year commitment period, by itself, may present challenges to obtaining financing on attractive terms for newly-constructed capacity resources, as there may be too much uncertainty in future revenue streams once the commitment term expires. PJM and ISO-NE have attempted to address this concern by offering optional multi-year commitment periods to certain resources: three years in PJM and five years in ISO-NE.

A longer commitment period can also address short-term volatility in capacity market prices by locking-in the price for capacity for a longer time horizon, thus providing certainty to suppliers for the revenue streams needed to contribute to the recovery of fixed costs. However, a longer commitment period places greater reliance on the accuracy of long-term forecasts of energy prices, demand, and the economy and thus can transfer price risk, or the uncertainty in such long-term forecasts, from suppliers to customers. Thus, a commitment period that is too long might encourage investment in capacity resources to meet or exceed targeted resource adequacy needs, but at the risk to customers that the investment becomes uneconomic either before or during the commitment period. In addition, locking-in capacity arrangements for a longer period necessarily results in fewer opportunities for customers to change those arrangements in response to changing market conditions, since they are committed to those capacity resources for a longer amount of time.

Finally, regulatory certainty can play a role in the choice of commitment periods. When a market is allowed to function without significant changes over multiple years,

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[30] *See, e.g.*, *In the Matter of the Investigation of the Process and Criteria for use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149 (Public Service Commission of Maryland), at 5-6 (2008), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9100-9199\9149\Item_049\&CaseN=9149\Item_049.

resulting price trends can inform rational bidding and investment strategies by market participants. This can lessen the need for the price certainty provided by longer-term commitment periods and, with them, a shifting of risk from suppliers to customers.

C. Definition of the Capacity Product

In the eastern RTO/ISO centralized capacity markets, the capacity product that each market procures has been defined in a generic way. Resources available to generate energy or reduce load when needed can generally be designated as a capacity resource and receive a capacity payment. To procure sufficient capacity to meet the planning reserve margin at just and reasonable rates, the existing centralized capacity markets in ISO-NE, NYISO, and PJM acquire capacity from a range of resources with varying capabilities. As the electric industry and wholesale markets evolve, an emerging issue is whether the capacity product should be redefined to take into account operational characteristics needed by system operators.

1. Current Market Design

As noted above, all three eastern RTO/ISO centralized capacity markets define the capacity product in a generic way, generally allowing resources available to generate energy or reduce load when needed to compete solely on price to become a capacity resource.[31]

The generic capacity product definition used in the eastern RTO/ISO centralized capacity markets allows for little differentiation between the operational capabilities of the capacity resources that each market procures; every MW of capacity is generally treated the same. The primary differentiation that exists is with regard to location. Each of the eastern RTOs/ISOs includes locational components in its capacity market to account for transmission constraints that may prevent the output of certain capacity resources from being deliverable throughout the RTO/ISO region. Where these constraints bind, each market generally requires that a certain amount of capacity be procured from resources within the particular local area or zone. Separate market clearing processes are conducted in these areas, and different prices may be produced as a result.[32]

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[31] ISO-NE Market Rule 1, Standard Market Design, § III.13.1.1; PJM, Manual 18 PJM Capacity Market, § 1.2.2; NYISO, Manual 4: Installed Capacity Manual, § 4.2.2.

[32] Because these zones are defined by the existence of transmission constraints, they do not conform necessarily to traditional utility footprints; rather the RTOs/ISOs carry out studies to determine if transmission constraints impact the deliverability of

The generic definition of the capacity product, and the capacity and energy markets' participation rules, were originally developed to accommodate the traditional generation resources that were primarily the marginal resources being constructed at the time. As the resource mix has changed, the eastern RTOs/ISOs have implemented market rule changes, e.g., rules for calculating capacity factors for variable resources, to incorporate additional technologies and non-traditional resources. Eligible resources now include traditional generation, renewable and variable resources, demand response, and energy efficiency.[33] The ways in which these resources can participate vary across the eastern RTOs/ISOs.[34]

2. Discussion

An emerging issue is whether the basic definition of the capacity product should account for specific operational attributes needed to address system needs. While the centralized capacity markets include a locational component to account for transmission constraints and ensure that capacity is available and deliverable to load, other operational considerations are generally not considered when defining what types of capacity the market will procure. As the electric industry and wholesale markets evolve, the capacity market may need to take additional operational needs into account.[35] The characteristics of potential capacity resources also must be considered. While the eastern RTO/ISO

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capacity resources in the region, requiring the creation of separate pricing/deliverability zones.

[33] *See, e.g.*, FERC Commission Staff, National Action Plan on Demand Response, Docket No. AD09-10, at Appendix B Table 3 (2010) *available at* http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf.

[34] PJM, for example, includes three different categories of demand response: Limited, Extended, and Annual. The Limited demand response product can be dispatched up to a maximum of ten times during the summer months. The Extended product can be dispatched an unlimited number of times during the May through October period. The Annual product can also be dispatched an unlimited number of times throughout the entire delivery year (June through May). *See* http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/demand-response-fact-sheet.ashx.

[35] For example, the eastern RTOs/ISOs have, at times, found the need to enter into arrangements outside of the centralized capacity market, such as Reliability Must Run contracts, to retain resources needed to meet system needs. Defining the capacity product (or products) to more accurately reflect the needs of the system could allow for the market to reflect these needs in clearing prices.

centralized capacity markets have incorporated certain non-traditional resources, some rules and requirements may still present barriers to new technologies that could otherwise meet the definition of the capacity product, and thus impair the ability of the markets to procure resources best suited to meeting future operational needs.

Some power system operators are considering whether capacity products should be defined more granularly to address emerging challenges or accommodate certain policy goals.[36] For example, changes in the electric industry have created additional operational and system requirements, including an increased need for more responsive and flexible resources, e.g., quick start and fast ramp capability, responsiveness in providing regulation or load following, etc. In particular, the rapid growth in variable energy resource integration creates a greater need for flexible resources to balance load instantaneously and to smooth fluctuations in output during the operating day. Other emerging challenges include the increasing reliance on natural gas-fired generation in some regions where gas-fired resources rely upon a "just in time" fuel delivery system, which can create an additional need for access to a diverse set of resources. Additionally, in some control areas older units that are relied upon for peaking, ramping, or reserves may not be performing within their offered parameters, potentially requiring a new product definition that accounts for resource performance. Environmental regulations may also limit the operation of some generation resources that could consequently result in resource adequacy concerns in local areas. Finally, some state policymakers and other stakeholders are asking if the current capacity markets accommodate state policy goals like renewable portfolio standards or integrated resource planning requirements. The capacity product procured by the current capacity markets generally does not reflect such goals.

To address these emerging needs and challenges, new product definitions could be developed that specify offer parameters such as start-up time, minimum run time, minimum down time, or other operational parameters that would address specific system needs such as quick start and fast ramping capability, or load following ability. For instance, a single "dispatchability" product could be based on ramp rates and the ability to maintain output for a certain minimum number of hours that would meet the emerging system needs such as those described above. Alternatively, multiple capacity products could be defined and procured through a co-optimized market clearing mechanism analogous to the operation of RTO/ISO energy and ancillary services markets. Creating more granular product definitions, and acquiring them through the centralized capacity market, could create financial incentives to encourage the development of new resources

[36] *See* ISO-NE Strategic Planning Initiative, *Using the Forward Capacity Market to Meet Strategic Challenges*, (May 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_whitepaper_final_may_11_2012.pdf.

with specific operational attributes needed by system operators. As system needs change over time, system operators could adjust the amount of each granular product they purchase, and the market response would send price signals as to the need for investment in capacity resources that can provide such products. These new product definitions might also specify performance standards (discussed in more detail below) for capacity resources in a manner such that flexible and more reliable resources would be rewarded for the value they provide, creating an additional incentive for the market to bring new capacity resources with these attributes onto the system. However, 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.

Alternatively, system operators could continue to rely on the existing ancillary services markets to satisfy these emerging system needs, and allow the capacity market to continue to procure a more basic product intended simply to meet the planning reserve margin. Order No. 755 is an example of this approach, in that it requires RTOs/ISOs to compensate regulation resources based on the speed and accuracy of the regulation service they provide.[37] If more resources respond to these types of price signals in the ancillary service market, the need for specialized requirements in the centralized capacity markets could decline. However, this could require reforms to the existing ancillary service markets to meet operational needs. An example of this could be a ramping product that procures resources based on their ability to ramp up and down at a certain rate. Whether ancillary services markets can provide sufficient revenues to allow resources with desired system attributes to recover their fixed costs also should be considered. To address such concerns, system operators could look to forward reserve market constructs such as the one used in ISO-NE to give them more certainty that operational needs will be met in future time periods.

As alternative approaches are considered, the growth and impact of distributed resources should be taken into account. Procuring capacity to meet specific operating characteristics could lead to new market opportunities for resources that may not currently be able to participate in the centralized capacity markets. Distributed generation, storage resources, or demand response may not meet minimum size requirements (absent aggregation) or minimum discharge time requirements. Current

[37] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 (2011), *reh'g denied*, 138 FERC ¶ 61,123 (2012).

rules governing capacity resource qualification may need to be reviewed for their necessity or appropriateness.

D. Performance Requirements

Each of the three eastern RTOs/ISOs imposes performance requirements on resources with a capacity supply obligation (*i.e.*, resources that cleared the auction and received a capacity payment). These requirements are meant to ensure that resources are made available during the operating day and that they perform when needed. Capacity resource requirements vary in their details but generally are of two types: a requirement to offer into the energy market and a requirement to meet performance standards. Recently, concerns have been raised in the eastern RTOs/ISOs about the ability of procured capacity resources to perform when needed, and discussions are ongoing to develop new market rules with more rigorous performance incentives for capacity resources.

1. Current Market Design

The eastern RTOs/ISOs impose two kinds of performance-related requirements on resources with a capacity obligation. The first is a requirement to make the resource available in the energy market. Often called a "must-offer" requirement, this requirement is meant to ensure that a capacity resource is made available to provide energy when called upon. Second, once the operating day has passed, the system operator evaluates the resource's performance to ensure that it meets a minimum standard. While the markets all impose these two generic requirements, they differ in their specific details.

In ISO-NE, resources with a capacity supply obligation are generally required to offer into both day-ahead and real-time energy markets during all hours, at a MW amount equal to or greater than their capacity supply obligation amount, whenever the resources are physically available.[38] NYISO also requires capacity resources to offer or schedule into the day-ahead energy market or to declare resources as unavailable.[39] Generation capacity resources in PJM are also subject to a must-offer requirement in the day-ahead energy market; however, demand response capacity resources are considered "emergency only," are not subject to the must-offer requirements, and are not economically dispatched unless they similarly offer into the energy markets as an economic resource.[40]

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[38] ISO-NE, Market Rule 1, Standard Market Design, § III.13.6.1.1.1.

[39] NYISO, Manual 4: Installed Capacity Manual, § 4.8.

[40] Depending on the relative levels of Annual, Extended Summer, and Limited demand response, there may be different capacity clearing prices for each product. *PJM*

If capacity resources clear in the day-ahead or real-time energy markets, their performance is evaluated to ensure that minimum standards are met. One measure adopted early in the evolution of capacity markets to encourage performance is still in place: the translation of the amount of installed capacity of a capacity resource into an unforced capacity rating. Under this mechanism, the capability of a capacity resource is de-rated to reflect actual outage experience, effectively penalizing resources with more outages by reducing the amount of capacity they can offer in subsequent auctions.[41]

More specifically, NYISO retrospectively imposes a deficiency charge (1.5 times the clearing price that NYISO pays in the spot deficiency auction) on any capacity resource found at any point during a capability period to have a capacity short-fall. NYISO defines a capacity shortfall as any time during a capability period when the amount of unforced capacity is less than the amount committed to supply.[42] In PJM, the exact performance requirement varies by resource type. While the individual requirements vary, every non-renewable capacity resource inside PJM is required to demonstrate, either by responding to dispatch during peak hours or through a test, that it could have performed at or above its capacity obligation if called upon. Resources which underperform on these tests are subject to penalties proportional to their performance shortfall.[43] ISO-NE measures the performance of capacity resources in periods of reserve deficiency (called a Shortage Event), and adjusts capacity payments downward when resources are fully or partially unavailable during such periods.[44]

Exceptions for non-performance, where the outage is deemed outside control of management, vary across the eastern RTOs/ISOs. For example, in PJM a capacity resource's lack of fuel can qualify as outside of control of management, and thus such an outage may not count in determining the de-rated value of capacity that the resource is

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Interconnection, L.L.C., 138 FERC ¶ 61,062, at PP 119-25, *reh'g denied*, 139 FERC ¶ 61,031 (2012).

[41] For example, NYISO proposed to replace its installed capacity methodology with the unforced capacity methodology to provide an incentive for generators to increase their efficiency and to improve reliability. *See New York Indep. Sys. Operator, Inc.*, 96 FERC ¶ 61,251, at 61,990 (2001). ISO-NE operates as an installed capacity market rather than an unforced capacity market, and does not translate the installed capacity of a resource into an unforced capacity rating.

[42] NYISO, Market Administration and Control Area Services Tariff, § 5.14.2.

[43] PJM, Manual 18: PJM Capacity Market, § 8.

[44] ISO-NE, Market Rule 1, Standard Market Design, § III.13.7.1.1.1.

eligible to sell into the market. However, in NYISO, only outages caused on the high voltage side of the network are classified as outside of control of management.

2. Discussion

Effective performance requirements for capacity resources can help ensure that centralized capacity markets achieve their resource adequacy goals and customers receive the benefit of the capacity for which they paid. As noted above, performance requirements in the eastern RTO/ISO markets today fall into two general categories: must-offer obligations and performance standards.

Implementing generic must-offer requirements helps to ensure that the capacity set aside to meet resource adequacy needs is deliverable to the market when called upon. Expanding the must-offer requirement to ensure capacity resource availability for other system needs, for example, requiring offers into the ancillary services market, could be considered. However, such broader must-offer requirements could limit the pool of available resources to provide capacity if certain resource types cannot provide the ancillary services. Such a requirement could also raise capacity costs, and potentially create indirect barriers to participation in the capacity market. Resources that are not able to qualify to offer into the ancillary service markets would also not qualify, therefore, as capacity resources. On the other hand, a requirement to bid into the ancillary service markets could be necessary if capacity market procurement were to be expanded to take operational characteristics into account, as discussed in Section C above. This requirement might be needed to ensure that the operational characteristics procured in the capacity market are available during real-time operations. Further, capacity suppliers may raise their offer prices to account for any additional costs to meet these broader requirements thereby sending price signals to potential market entrants regarding the need for capacity resources.

With respect to performance standards, existing requirements tend to be general in nature, penalizing capacity resources for outages after-the-fact by reducing the amount of capacity they can offer in future auctions. However, ineffective performance incentives (or a lack of consequences for failure to meet the standards) have the potential to adversely affect the ability of centralized capacity markets to deliver on the goal of ensuring resource adequacy in real time. In addition, if capacity resource owners face little or no consequences if they fail to perform, they may not make appropriate investments in needed upgrades or maintenance.[45] To the extent capacity with particular operational characteristics are needed to address changing market conditions, e.g.,

[45] While performance standards typically extend beyond just periods of energy or operating reserve shortages, it is these periods when capacity resources are most needed.

penetration of variable energy resources increases, aging generation retires, etc., there may be a need for performance standards to become more granular by tailoring performance measures to desired operational characteristics.

While more stringent performance standards and consequences for failure to perform could better align resource adequacy capacity, (i.e., planning requirements) with operational needs, there is a risk that unnecessary barriers to participation could be created. Overly onerous performance obligations may chill interest in new resources participating in the capacity market, if a capacity resource perceives that the risk of non-performance outweighs the benefit of participation in the capacity market.

E. Market Power Mitigation

Each of the eastern RTOs/ISOs has market rules in place to mitigate potential market power of both capacity suppliers and capacity buyers. Supply-side market power most commonly results from limited competition inside a constrained delivery area. Delivery constraints can prevent competitors from providing supply to a particular area, thus providing resources within that area the incentive and ability to enter a bid above their costs, which can result in capacity prices above efficient levels. Buyer-side market power is typically the result of a net-buyer with the incentive and ability to suppress prices below a competitive level by offering its capacity at a price below its cost, or by subsidizing the entry of another capacity supplier.[46] If the net-buyer is able to suppress the market-clearing price enough, the cost savings to its load will more than offset any costs it incurs by bidding its capacity below cost or providing a subsidy to another supplier. Constraining the ability of sellers and buyers with the incentive and ability to exercise market power is critical to ensuring that centralized capacity markets achieve resource adequacy at just and reasonable rate.

1. Current Market Design

    a. Supply-Side Mitigation

With respect to supply-side market power, each of the eastern RTOs/ISOs has taken somewhat different approaches to mitigation. PJM uses a “three pivotal supplier” test to determine if a particular capacity resource has the potential to exercise market power; if the demand in the market cannot be met without the participation of a particular seller plus the two largest sellers in the market, those sellers are deemed to be pivotal and therefore have market power. Under this construct, the PJM market monitor conducts a

[46] A net-buyer is a load serving entity which does not have sufficient resources to meet its own capacity obligation, or self-supply, and must therefore buy capacity from the capacity market.

market concentration test for each constrained area (and for the PJM region as a whole) to determine if the regions are structurally competitive. This test analyzes whether the three largest suppliers (including affiliates) in the market constrained area are jointly pivotal, i.e., whether market demand can be met without those three largest suppliers; if they are not, then no seller is considered to have market power. Any suppliers found failing the market power test are subject to an automatic offer cap based on submitted going-forward cost data. All participants may submit additional information to the market monitor to request a unit-specific avoidable cost determination.[47]

NYISO uses a different pivotal supplier test. Any entity, in combination with its affiliates, controlling 500 MW or more of unforced capacity necessary to meet New York City's capacity requirement is deemed a pivotal supplier and is therefore subject to mitigation.[48] Mitigated resources offering into NYISO's spot-market are mitigated to the higher of the projected clearing price for the capacity suppliers into New York City or the going forward costs of the supplier, calculated by NYISO based on cost data submitted by the supplier. NYISO does not apply this supply-side mitigation outside of New York City.

ISO-NE uses a different market power mitigation approach. In ISO-NE, existing capacity resources that have cleared in a previous capacity auction and do not wish to participate in a subsequent auction are required to submit a specific bid to withdraw, called a de-list bid.[49] Resources seeking to de-list at or above $1/kW-month, however, must submit data to be reviewed by the Internal Market Monitor. If the bid is judged to be inconsistent with the net risk-adjusted going-forward costs of the unit, it will be excluded from the auction or the unit may use an alternative price derived by the Internal Market Monitor.[50] If the capacity clearing price is below the delist bid, the resource is permitted to withdraw from the capacity market in that delivery year.

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[47] PJM, Manual 18: PJM Capacity Market, § 5.3.4.

[48] Mitigation only applies to resources bidding into the New York City zone in the spot market. NYISO, Market Administration and Control Area Services Tariff, Att. H – ISO Market Power Mitigation Measures.

[49] De-list bids can be submitted either for a specific capacity auction (and associated delivery year), to permanently leave the capacity market, or to retire. ISO-NE, Market Rule 1, Standard Market Design§ III.13.1.2.3.1.

[50] *Id.*

In assessing going-forward costs in the context of market power mitigation, unit-specific or generic costs may be used for specific resource types, with assumptions that the unit will retire, mothball, or continue providing energy and ancillary services if it fails to clear in the capacity market. ISO-NE, for example, does not assume a resource will retire and that it may continue to participate in the energy market even if it fails to clear in the capacity market; PJM, on the other hand, calculates going-forward costs assuming a unit that does not clear the capacity market will be mothballed.[51]

The use of a downward-sloping demand curve by PJM and NYISO also serves to mitigate the exercise of supply-side market power by limiting how large a price increase can result from a decrease in supply. A capacity market that employs a vertical demand curve, such as ISO-NE, also can employ design parameters that provide safeguards against the exercise of market power. Safeguards used by ISO-NE include a maximum capacity price (price cap or starting price), and rules addressing peak energy rents, where revenues above a high threshold price in energy markets are deducted from capacity payments.[52] In addition, a must-offer requirement is employed that eliminates the possibility of physically withholding from the capacity market.

b. Buyer-Side Mitigation

To mitigate potential buyer-side market power, all three eastern RTOs/ISOs use some form of a Minimum Offer Price Rule (MOPR). A MOPR is designed to limit the ability of buyers to suppress capacity prices by subsidizing relatively higher-cost new capacity to replace lower cost existing capacity. Such price suppression can occur, for example, when a buyer pays a new capacity resource out-of-market, and then offers that capacity as a price-taker in the capacity market. A buyer has the incentive and ability to take such an action if the savings it will achieve from reduced capacity prices are greater than the costs of any out-of-market payments it must make. MOPR rules generally establish offer floors, requiring that new capacity resources submit bids that are above a predefined value representing the going-forward costs of a benchmark resource. The markets differ with respect to what types of capacity resources are subject to the MOPR,

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[51] ISO-NE, Market Rule 1, Standard Market Design, § III.13.1.2.3.2.1.2; PJM OATT Attachment DD § 6.7.

[52] ISO-NE Internal Market Monitor, *2012 Annual Markets Report*, at 78 (May 15, 2013), *available at* http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2012/amr12_final_051513.pdf. Minimum price floors also can be used to mitigate potential buyer market power. As discussed earlier in this paper, ISO-NE has removed its minimum price floor for future auctions.

how the offer floors are calculated, and the mitigation that is applied to a capacity resource bidding below the offer floor.

PJM applies its MOPR only to three specific types of capacity resources: combustion turbines, combined cycle units, and integrated gasification combined cycle units. The offer floor is established at the applicable net CONE value for the particular type of resource. Capacity resources that bid below the offer floor are mitigated to the net CONE for their resource type. PJM allows for three potential exemptions from MOPR: (1) a self-supply exemption, through which a load serving entity can offer new capacity without being subject to an offer floor if its supply portfolio is within certain net-short or net-long thresholds;[53] (2) a competitive entry exemption, which can apply where the seller can demonstrate that it will not receive contracts or payments from government entities on a non-competitive basis and that it will not recover costs from customers through a non-bypassable charge; and (3) a unit-specific exemption, which is approved after review of cost information by the Independent Market Monitor.[54]

In NYISO, buyer-side market power mitigation is applied only to resources bidding into the New York City zone's capacity spot market and in new capacity zones.[55] Offers from capacity resources in these areas are subject to an offer floor set at the lower of the net CONE for the seller's unit, or 75 percent of the CONE used in the demand curve. Mitigation is applied until a resource clears in 12 monthly spot auctions. There are several exemptions from mitigation. For example, resources that went into service before November 1, 2008 and resources that have cleared the capacity auction in 12 previous months (but not necessarily consecutive months) are exempt from mitigation.

ISO-NE also relies on a MOPR-type construct, but establishes offer floors (termed "trigger values") separately for each potential type of capacity resource. The offer floors are calculated to represent a low end competitive offer for the particular type of capacity resource. Unlike the other two markets, there are no specific exemptions to the offer floors. Offers to provide capacity from new resources that are below the offer floors are subject to review by the market monitor. If an offer is found to be below the resource's

[53] PJM defines self-supply load serving entities to include as vertically integrated utilities, municipals/cooperative utilities, and single customer load serving entities. A net-short load serving entity is a net-buyer and a net-long load serving entity is a net-seller. *PJM Interconnection. L.L.C,* Tariff Amendment, Docket No. ER13-535-000, at 18 (filed Dec. 7, 2012).

[54] *See PJM Interconnection,* L.L.C. 143 FERC ¶ 61,090, at PP 27-144 (2013).

[55] *See New York Indep. Sys. Operator, Inc.*, 143 FERC ¶ 61,217, at PP 21-22, 39-40 (2013).

benchmark costs, the market monitor will calculate a new offer by replacing all out-of-market compensation with the market monitor's estimate of the energy revenues.[56] Resources that have cleared in one auction are no longer subject to mitigation.

2. Discussion

Ideally, the prices resulting from the capacity markets would reflect offers to sell and bids to purchase from many competing buyers and sellers in an environment with low barriers to entry and no glut or extreme deficit of supply. When these conditions do not exist, there must be measures in place to prevent the actions of sellers and buyers from interfering with the ability of the capacity market construct to produce competitive outcomes and, in turn, just and reasonable rates.

While the mechanisms currently applied to mitigate the potential for exercise of supply-side market power are relatively stable and the tradeoffs well understood, the existing buyer-side market power mechanisms have continued to present difficult issues. As a general matter, any market power mitigation construct should be designed to constrain actions that will alter competitive market outcomes, while avoiding over-mitigation that can deter from the formation of accurate market price signals for investment in capacity resources. In short, their goal is to preserve the integrity of the prices produced by the capacity markets. In achieving this goal, however, market power mitigation constructs could capture conduct that is not intended to artificially impact market prices. As discussed below, this can result in tension with other goals, such as satisfying a state renewable portfolio standard, where conduct intended to meet those other goals can fall under the market power mitigation construct.

a. Supply-Side Mitigation

In instances of supply deficit (economic or physical), supply-side market power mitigation prevents market sellers from withholding capacity or increasing offers with the intent to increase prices above a competitive level. The eastern RTOs/ISOs have chosen somewhat different approaches to supply-side market power mitigation, employing constraints that differ in how and when mitigation is applied to a potential capacity supplier.[57] Regardless of the choice of mitigation construct, the specific features of supply-side market power mitigation can have implications for achieving centralized

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[56] Out-of-market compensation refers to revenues paid to a resource outside of ISO-NE's capacity, energy, and ancillary service markets; *e.g.*, bilateral payments or subsidies from government entities.

[57] For example, in PJM mitigation is applied automatically; a capacity resource failing a screen is subject to an automatic offer cap based on submitted cost data. Mitigation can also be applied based on an *ex post* assessment of unit-specific costs.

capacity market goals, including the ability to attract and retain investment. For example, if supply-side market power mitigation mechanisms are not carefully designed to focus on suppliers with both the intent and the ability to raise market prices above competitive levels, there is a risk of excessive mitigation that could artificially dampen market clearing prices and detract from the ability of the market to attract and retain resources and ensure just and reasonable rates. In addition, the precise determination of going forward costs is difficult (whether done prospectively for automatic mitigation approaches or after-the-fact) and can impact market clearing prices. Lower offer caps will tend to drive capacity prices down, while higher caps will tend to drive capacity prices up. Moreover, determining going forward costs may become more challenging as the resource mix continues to change, especially if the usual mechanisms used to determine such costs were developed based on the typical costs structures of more traditional resources.

b. Buyer-Side Mitigation

In instances of new entry when such entry is not necessarily needed to meet resource adequacy needs, buyer-side market power can become an issue. At present, buyer-side market power mitigation in each of the eastern RTOs/ISOs takes the form of a MOPR, which sets a minimum price at which resources must bid (typically the net CONE of a target resource). The markets generally differ in the types of resources to which they apply the MOPR, where in the region the MOPR applies, and whether exemptions are available.

MOPR-type mitigation generally focuses solely on the impact that a capacity supply bid will have on market clearing prices. In general, with use of a MOPR, mitigation is applied automatically to offers below the bid floor without regard to the intent of the entity offering the resource into the capacity auction. As a result, mitigation could be applied regardless of an intent to impact market clearing prices. The issue of whether intent is relevant has come up in applying MOPR-type mitigation to certain types of new capacity resources of interest to state policymakers to achieve energy policy goals, such as the procurement of new renewable resources under a renewable portfolio standard or the procurement of local capacity resources with particular attributes. As noted above, the capacity product procured by the current capacity markets generally does not reflect such goals.

Specifically, the use of offer floors – whether resource-specific (as in ISO-NE) or based on the net CONE of a target resource (as in PJM) – present the risk that a resource built to satisfy a state renewable portfolio standard or other energy policy goal will not clear the capacity market at the applicable minimum offer floor. If that resource does not clear the market, it will not receive a capacity payment, and, in some cases, it may not be counted toward satisfying the load-serving entity's capacity obligation, requiring that the load-serving entity procure and (pay for) additional capacity resources to meet its capacity obligation. Pointing to this risk, state policymakers and other stakeholders have raised concerns that application of MOPR-type mitigation to resources procured to satisfy a state renewable portfolio standard will result in the purchase of excess capacity and additional costs to customers. Similar concerns have been raised regarding the application of MOPR-type mitigation to a resource that is self-supplied by a load-serving entity. As specific types of resources continue to be constructed to meet increasing renewable portfolio standards or other policy goals, the tension between the goal of promoting competitive new entry through buyer-side market power mitigation measures and accommodating state energy policy goals is likely to continue.

While exemptions to a MOPR can be crafted to address these concerns (as PJM has done with its self-supply exemption), they can be difficult to implement and administer and present their own challenges with respect to meaningfully distinguishing between offers made with the intent to impact prices, offers reflecting legitimate cost advantages, and offers made without intent to impact prices. A more particularized, unit-specific review of offers can address these concerns, but raises additional issues regarding transparency, the potential erosion of market participant confidence, regulatory uncertainty, and the need to guard against undue discrimination or preference. In addition, MOPR exemptions could have different impacts on market clearing prices depending on whether a vertical or downward-sloping demand curve is employed. In several individual proceedings addressing specific buyer-side mitigation proposals, the Commission has addressed these difficult trade-offs.[58]

To date, few alternatives to a MOPR have been presented. ISO-NE proposed a possible alternative, called "two-tiered pricing." Under this proposal, whenever new capacity offered at prices deemed uncompetitive cleared the market, two prices would result. New resources would have received a capacity clearing price based on all sellers' actual offers, while existing resources would have received a higher price based on the capacity clearing price that would have resulted if all new resources had offered their capacity at competitive levels (based on a benchmark estimate of their actual costs). In its order rejecting this proposal and instead requiring ISO-NE to develop a MOPR-type construct, the Commission identified some of the trade-offs associated with choosing two-tiered pricing. For example, two-tiered pricing ensures that uncompetitive prices are mitigated while also accommodating state energy policies. However, a downside to choosing this approach is that the capacity market would purchase capacity in excess of that needed to meet the planning reserve margin whenever two-tiered pricing is invoked. The Commission ultimately concluded that, under ISO-NE's existing capacity market

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[58] *See, e.g., ISO New England Inc.*, 142 FERC ¶ 61,107 at P 65-71; *ISO New England Inc.*, 135 FERC ¶ 61,029, at PP 17-20 (2011); *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at PP 163-72 (2007).

design, requiring purchases in excess of the capacity target in order to permit all offered capacity resources to clear regardless of the competitiveness of their offer was not just and reasonable.[59]

Conclusion

While there are similarities in the specific design elements present in the three eastern RTO/ISO centralized capacity markets, the particular market designs of each region diverge, with each market evolving over time to address emerging issues. This broad review of certain design elements and the mechanics of their operation is intended to provide a common foundation to consider how current centralized capacity market rules and structures are supporting the procurement and retention of resources necessary to meet future reliability and operational needs. The technical conference will focus on the goals and objectives of existing centralized capacity markets, and examine how specific design elements are accomplishing existing and emerging goals and objectives.

[59] *ISO New England Inc.*, 135 FERC ¶ 61,029 at P 19, n.24.

APPENDIX A – Demand Curves

Conceptually, three things define a vertical demand curve: (i) a vertical segment set at the forecasted level of peak demand plus targeted reserves; (ii) an administratively-determined maximum price that the market operator is willing to pay for quantities of capacity less than the needed reserve margin that reflects a multiple of CONE; and (iii) a maximum price the system operator is willing to pay for quantities beyond the reserve margin (sometimes set at $0). As an example, Figure A1 illustrates the generic vertical demand curve originally employed in NYISO.[60] At the time, NYISO had a state-wide reserve margin of 118 percent of peak load, and the maximum price NYISO was willing to pay for quantities below that was $255/MW (or three times CONE), and quantities above 118 percent received $0/MW. By placing a maximum value of $255/kW-year, NYISO implied that customers would pay no more than that for reliability. This serves as a proxy for the value of lost load that customers would choose on their own were they to bid directly into the market. Figure A1 also illustrates one of the challenges of using a vertical demand curve. Specifically, it can be seen that small deviations in quantity supplied to the right or left of 118 percent can result in extreme swings in capacity prices.

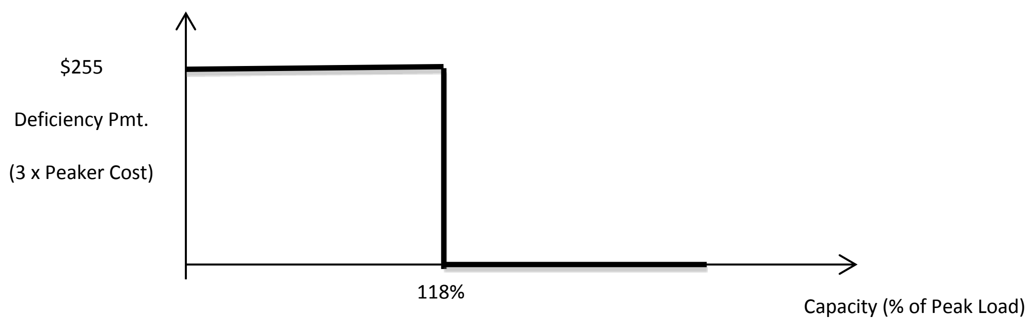

Figure A1: NYISO Installed Capacity Demand Curve

A downward-sloping demand curve is usually determined by connecting multiple straight lines, with the simplest approach utilizing two straight lines, as illustrated in Figure A2, which is a generic illustration of the current NYISO demand curve.

[60] *See New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 at P 3.

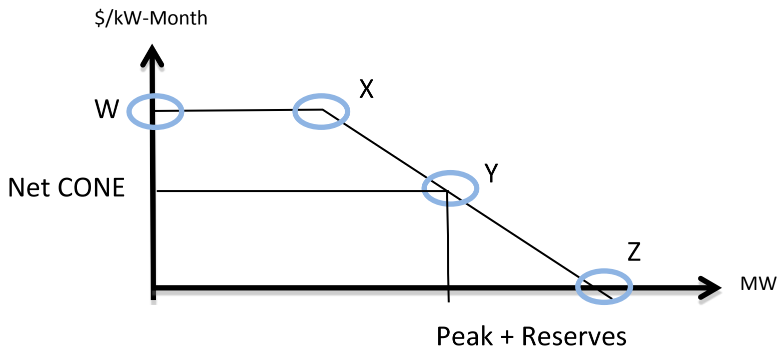

Figure A2: Generic Downward-Sloping Demand Curve

The first section is a downward-sloping line, XYZ in Figure A2, that is determined by establishing a reference point, Y, where the levelized cost of a peaking unit, net of energy and ancillary services revenues (net CONE), discussed below, intersects with the unforced capacity requirement (peak load plus reserve margin). The second reference point, Z, identifies the level of excess capacity above unforced capacity as the point at which customers would be unwilling to buy additional capacity unless the price was zero.[61] The third reference point, X, is at the point where the straight line defined by YZ intersects with a horizontal line equal to 1.5 times net CONE, shown as point W in Figure A2. At this point, the demand curve continues horizontally to the Y-axis at point W.[62] Line WX, like the horizontal portion of Figure A1 at $255/kW-year, indicates that customers have a maximum price they are willing to pay for reliability. Line segment YZ reflects that reserve margins greater than the target (at point Y in Figure A2) still have some positive, though decreasing value. The result of this demand curve construct is to send a price signal indicating that, when the reserve margin drops below the minimum, investment in the reference technology can be profitable, encouraging new entry. Likewise, when supply exceeds the minimum reserve margin, prices drop, indicating that any new investment will not receive the necessary revenues to be profitable and that some current market participants will also not receive sufficient compensation, and should exit the market.

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[61] For example, currently the point where capacity has zero value, Z, equals 112 percent of requirement for the New York Control Area, and 118 percent for New York City and Long Island.

[62] NYISO, Manual 4: Installed Capacity Manual, § 5.5.

APPENDIX B –CONE

Each of the eastern RTOs/ISOs establishes either gross or net CONE as an administrative parameter in its capacity market in establishing the demand curve. Because CONE is calculated based on a certain type of resource, it represents a set of assumptions about the marginal capacity resource likely to clear the market.[63] The type of resource used to define CONE has historically been an artifact of the type of unit that could be built in a reasonable amount of time, and would be financially viable, at the time parties developed the current capacity markets, i.e., a gas-fired combustion turbine or a gas-fired combined cycle unit. The use of CONE, which reflects the levelized cost of the reference technology over multiple years of service, is intended to provide a reasonable price signal, or target, for competitive supply offers. CONE can also be used as a basis to establish offer floors in the event that market power mitigation is necessary.[64]

Calculation of CONE requires a variety of assumptions, including the choice of technology for the currently financially viable unit that can be built in a reasonable amount of time, the cost of building and operating that unit, and the offsetting revenues the unit is expected to earn in the energy and ancillary services markets. In some instances, these estimates have locational characteristics.[65]

PJM currently sets CONE for five regions, based on the levelized capital costs and annual fixed operation and maintenance costs for a hypothetical gas-fired combustion turbine or a gas-fired combined cycle unit in the delivery year. Components of the calculation include the costs of the project excluding financing costs, net summer installed capacity, annual ongoing fixed operations and maintenance costs, and an after-tax weighted average cost-of-capital. In NYISO, CONE is updated on a triennial basis and is based on the levelized embedded cost of a peaking plant located in each of the capacity zones, *i.e.*, a separate CONE for each zone. The tariff specifies that the peaking plant reflect the technology that results in the lowest fixed costs and highest variable

[63] Note that this administratively determined control is limited to only the cost of entry and does not limit entry by other physical characteristics. That is, any resource that has a cost of new entry equal to or less than the target level is a potential entrant. Physical product differentiation is discussed in section C.

[64] A more complete discussion of market power mitigation is presented in section E.

[65] Currently the eastern RTO/ISO capacity markets only differentiate between zones strictly according to the deliverability of the capacity in a given zone to serve load in other zones. When there are transmission constraints that limit deliverability, zonal prices can diverge.

costs among economically viable technologies.[66] To date, this requirement has resulted in the selection of simple cycle combustion turbines as proxy units in developing the demand curves. Like in PJM, various costs are included in the CONE calculation. The specific proxy unit and technology may be different in each capacity zone due to factors that include environmental restrictions, fuel or other operating and interconnection constraints, and permitting requirements. ISO-NE, in its most recent Forward Capacity Auction, based the starting point on its descending clock auction on net CONE,[67] but beginning in its February 2014 Forward Capacity Auction, will no longer use net CONE. The internal market monitor will establish the auction starting price. In addition, the price floor will be removed.

[66] NYISO, Market Administration and Control Area Services Tariff, § 5.14.1.2.

[67] *ISO New England Inc.*, 135 FERC ¶ 61,029, at P 342.