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

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to the notice issued June 17, 2013, as supplemented, and the technical conference in the above referenced proceeding convened September 25, 2013, Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submits these comments on how current centralized capacity market rules and structures in the regions served by ISO New England Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), and PJM Interconnection, L.L.C. (PJM) are supporting the procurement and retention of resources necessary to meet future reliability and operational needs.

I. COMMENTS

A. Role of Capacity Markets and Definition of the Capacity Product

The RPM capacity market design in PJM was created and defined as a result of revenue sufficiency issues in the energy market. The only purpose of defining capacity and creating a capacity market is to help make the energy market function effectively. Capacity is not used to power air conditioners or lights. The design of the capacity market reflects this tight integration between energy and capacity markets. The definition of capacity also reflects this tight integration. The definition of capacity is: the capacity must be physical; the energy from the capacity must be deliverable to all loads in PJM; the energy from the capacity must be offered into the day-ahead energy market every day; the energy from the capacity must be recallable in an emergency; capacity resources must meet minimum performance requirements; and owners of capacity resources must report outage data. In order for capacity to be sold in the capacity market, it must meet all elements of this definition.

Physical capacity is needed in order to provide the reliable delivery of energy under all system conditions. In practice that means, for example, that a firm liquidated damages contract is not physical and cannot be capacity. Payment of liquidated damages is not an acceptable substitute for the delivery of energy during a period when load approaches the capability of the generating capacity. Slice of system, which is not linked to specific units, is also not an acceptable substitute for capacity from specific units or resources.

Physical means that capacity resources must have an identified physical resource capable of providing capacity identified prior to the capacity market auction. For DR this means identifying customers and the measures to be taken. For imports this means having a pseudo tie to PJM. For planned generating resources this means having a queue position.

Physical should also be defined to mean that when a resource is offered into a Base Residual Auction (or an Incremental Auction) that it is committing to providing a physical resource in the delivery year. Thus, a DR resource could not make a speculative sale in a BRA and then buy out of the position in an IA.[1] The only exception to this requirement should be a force majeure event that makes it impossible to perform.

Deliverability means that the transmission system must be capable of delivering the energy output from the resource under peak conditions to load anywhere in PJM. Deliverability is enforced by requiring the builder of new capacity to pay for any transmission upgrades necessary to ensure that the energy is deliverable, according to

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1 *See*, *e.g.*, Monitoring Analytics, LLC, Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 (September 12, 2013), which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf*>.

transmission system analysis done by PJM and the transmission owners. This provides a strong incentive to locate where the transmission system is robust and also provides a market signal about the full cost of new capacity when transmission system upgrades are required.

In recognition of the tight integration between PJM energy and capacity markets to ensure reliability and revenue sufficiency, capacity resources are required to offer energy output equal to their full installed capacity value into the day-ahead energy market every day. This requirement reflects the fact that the purpose of the capacity market is to help ensure revenue sufficiency for units operating in PJM's energy markets rather than creating a standalone capacity product. The Market Monitor's view is that, as part of the definition of capacity, the offers into the day-ahead energy market should be competitive, meaning equal to short run marginal cost.

Energy from all capacity resources that clear in a capacity auction is recallable by PJM in an emergency. This ensures that even when such energy is being exported, PJM customers who paid for the capacity to ensure reliability, have a call on that energy at the PJM market clearing price if the energy is needed to meet load in PJM. Such recall can only work in an emergency if it is linked to specific units in specific locations with all the other attributes of capacity resources. Liquidated damages contracts do not work in these situations. Slice of system purchases do not work in these situations.

Capacity is fundamentally an economic concept in the PJM market design, although in order to implement the economic concept, capacity resources must be physical resources. The capacity market exists in its current form because revenues from the PJM market design, which included an energy market and a daily capacity market, were not adequate to provide an incentive to build and maintain the generating resources required to meet defined reliability requirements so that energy could be supplied reliably.

In the PJM market design, capacity markets and energy markets are inextricably intertwined. Generating units do not have capacity components and energy components. A unit is viable based on its total revenues without regard to whether they come from the capacity market or the energy market.

Capacity market revenues are not payments for one type of output from a unit and energy market revenues are not payments for another type of output from the same unit. The energy market requires energy in all 8,760 hours in the year. Not all units have to produce energy in all hours of the year but many base load units do so and all units have to be available to do so. Mid merit units produce energy for fewer hours than base load units and peaking units produce energy for fewer hours than mid merit units. But the capacity payments to each type of unit are not to reserve access to energy from those units for only a few on peak hours of the year and the capacity payments are not to reserve capacity only from peaking units. The capacity payments to each type of unit are an essential contribution to the viability of each unit type so that they can provide energy when needed. In return for capacity market revenues, each unit type must be available at any time during the year that they are needed to meet the demand for energy from PJM customers.

Generating units that are capacity resources, as part of the obligations they take on in return for capacity payments, are required to provide a call on their energy at any time during the year, at the market price. The capacity market is designed to ensure that generating units cover their fixed and variable costs from a combination of energy and ancillary market net revenues and capacity market revenues so that they can continue to provide energy economically. The capacity market is an annual construct. Generation owners sell capacity for a year and customers pay for capacity for a year. Net revenues and costs are evaluated for a year. The obligations of capacity resources are for a year. The relevant year in the capacity market is termed the Delivery Year, which is three years forward from the date of the capacity market base auctions.

1. Performance Standards.

> *When procuring a single capacity product, as under current market designs, are there certain fundamental performance standards that capacity resources should be required to meet in the delivery year to ensure resource adequacy? Should any such*

requirement change depending on the type of resource (traditional generation, new resources vs. existing resources, demand response, energy efficiency, distributed generation, etc.)?

The goal of the capacity market performance incentives should be to match the incentives that would result from a competitive energy only market.[2] The performance incentives in the PJM capacity market fall well short of that objective. The most basic market incentive is that sellers are not paid when they do not provide a product. That is only partly true in the PJM capacity market. There are two areas where the performance incentives are inadequate, overpayment for underperformance and incorrect outage rate definition.[3]

In RPM, a capacity resource will be paid 50 percent of its full capacity market revenues even in the case of complete nonperformance in the first year of such nonperformance. For example, a resource that sold 500 MW of unforced capacity at $150 per MW-day would be paid $75 per MW-day even if the resource did not produce energy when called during any of the PJM-defined approximately 500 RPM critical hours. That decreases to 25 percent in year two of sub 50 percent performance and to zero in year three, but returns to 50 percent after three years of better performance. Under some extreme circumstances, total nonperformance would result in total nonpayment as a result of penalties.

Not all unit types are subject to RPM performance incentives. Wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules.

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2 *See* Market Monitor, IMM White Paper: Selected RPM Issues (August 20, 2012) ("IMM White Paper"), which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf*>.

3 *Id*. at 25–32.

Hydro generation and intermittent generation capacity resources are not subject to peak season maintenance compliance rules.[4] Given that all generation is counted on for comparable contributions to system reliability, it would be efficient for all generation types to face the same performance incentives.[5]

In the PJM capacity market, the forced outage rate is a performance incentive. Resource owners sell unforced capacity in the capacity market, which is installed capacity times one minus the forced outage rate for the resource. The higher the forced outage rate, the less capacity can be sold from a generating unit in the capacity market and the lower are the capacity market revenues for that unit. The capacity market creates an incentive to have low forced outage rates in this direct way. The forced outage rate also affects the level of payment actually received for the level of capacity sold in the RPM Auctions. The issue in the PJM capacity market is that the forced outage rates used to provide these incentives do not correctly measure actual forced outage performance because they exclude some forced outages.[6] There is no reason not to reflect all outages in the economic fundamentals of the capacity market and the capacity market outcomes, exactly as they are reflected in PJM system planning. The current incentive design is not consistent with an efficient outcome. One of the most significant weaknesses of the RPM capacity market design is the attenuated nature of performance incentives compared to an energy only market. In an energy only market, a resource is paid only when it performs. If the unit does not perform when prices are high, in the summer, in the winter or in the shoulder months, the unit does not get paid. There is a simple and powerful incentive to perform in an energy only market.

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4 PJM Manual 18 (PJM Capacity Market) at 119. The rationale for this treatment of hydro, wind and solar capacity is unclear.

5 The installed capacity of wind and solar resources is derated when offered in RPM because, even if not on outage, such resources may not be available at times of peak demand.

6 For a more complete discussion of this issue, see the IMM White Paper.

Although the RPM capacity market design provides that there are only about 500 critical hours on which the performance incentives of capacity resources are based, it is essential that capacity resources be available to produce energy for all 8,760 hours per year in order to provide reliable service. During the shoulder period, when as much as a third or more of the PJM generation fleet may be on planned outage, it is just as critical that the remaining units be available to provide energy as during higher demand periods when PJM does not permit units to be on planned outages. The position that the capacity market is associated with peak hours only is not consistent with the basic design of the capacity market or the reasons for creating the capacity market.[7]

One test of whether the capacity market is working is whether the incentives are adequate to support continued investment in existing capacity and investment in new capacity such that reliability targets are met. A second and equally important test of whether the capacity market is working is whether customers, who must pay for capacity, are getting what they pay for.

The least cost market design would ensure that customers pay only for the most cost effective set of generating units, and demand resources, that provide a combination of energy and ancillary services when they are needed to meet demand. In order to achieve the least cost design, generating units that receive capacity payments must meet correctly defined obligations, including making competitive offers every day in the energy market, correctly measuring their available capacity and receiving payment only when available to provide energy when needed to meet customers' demand.

The Market Monitor concludes the current market design is not the least cost way to meet the design objective. The Market Monitor's recommendations are intended to ensure that the capacity market design is the least cost way to meet the design objective of

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7 This is the case regardless of the definition of peak hours used, including peak load, all on peak hours, high load hours or emergency hours.

reliability. While it is possible to maintain a reliable system with a capacity market design that overpays as a result of the incorrect definition of capacity, of the mismeasurement of capacity and of the payment of capacity revenues even when units do not meet performance standards, that is not in customers' best interests, is not in the interests of competitive generation suppliers and is not in the interests of a competitive market design. Customers, who pay $7 billion per year on average for capacity, should be assured that they receive full value for that payment.

2. Additional/Multiple Capacity Products.

Should existing capacity products be modified to reflect various operational characteristics needed to meet system needs? If there is a need for additional capacity products, how should those products be defined and procured in light of the current one day in ten year resource adequacy approach?

Alternatively, if it is more appropriate to rely on energy and ancillary services markets to obtain needed operational characteristics, how can market participants and regulators be confident that resources capable of providing such ancillary services will be available in future periods? To what extent are the existing categories of ancillary services adequate to meet current and future operational needs without a forward market?

Markets work best when the product is clearly defined, when it is as homogenous a product as possible, and all supply has the same basic features. This does not mean there are no variations in product. There are lots of different types of generation and lots of different types of demand side resources. But this does mean that all of the capacity resources must have the same core attributes.

As a result, it does not make sense to subdivide the capacity market by operational characteristics or other attributes. Such characterics are best dealt with in the energy markets and the ancillary services markets. Subdividing the capacity market into multiple submarkets would add exponential complexity to an already complex market and would be likely to exacerbate existing market power issues as there are more dominant positions in the smaller submarkets. The engineering/regulatory temptation is to predefine all the characteristics of new generation. But the temptation should be resisted in favor of designing markets with appropriate incentives to permit multiple, dynamic market solutions. A forward looking capacity market in combination with scarcity pricing will provide the appropriate incentives.

In PJM, the limited DR and the unlimited DR products do not meet the product definition tests. These DR products do not share key core attributes with basic capacity products. These DR products are inferior in that they only have a very limited obligation to respond and only a very limited obligation to provide energy. DR products do not have to make competitive energy offers in the day-ahead energy market, do not have to make cost-based energy offers and do not have to be available to produce energy whenever needed.

A result of letting those products replace capacity resources that do have an obligation to generation in 8,760 hours per year is that the capacity market price is suppressed, compared to an efficient price.

Demand side resources are cleared in the capacity market like other capacity and should therefore be treated as an economic resource. DR is not an emergency resource any more than a peaking unit is an emergency resource. DR is an economic resource, just like all the other capacity resources sold in the capacity market. The market design does not yet treat demand side resources as the economic resources they are.

Ancillary service markets need to continue to be refined but the current set of ancillary markets is working fairly well in PJM.[8] The recent FERC mandated changes to the regulation market have improved price signals, although the design needs refinement. The spinning reserve market also needs to continue to be improved.

3. Qualifications for Capacity Resources.

What improvements are needed in how centralized capacity markets determine qualification as a capacity resource? Do the requirements to participate in the

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8 See the *2012 State of the Market Report for PJM* (March 14, 2013) at 265–292; *2013Quarterly State of the Market Report for PJM: January through September* (November 14, 2013) at 251–283.

centralized capacity markets accommodate all resources (whether supply-side, demand-side, or imports) that are technically capable of providing the traditional forward capacity product?

The PJM RPM capacity market design can and does accommodate all resources that are capable of providing capacity. A resource can provide capacity if it can provide all the required core attributes of a capacity resource.

Unfortunately, the RPM design in its current form also accommodates resources that are not capable of providing capacity. Limited and extended summer DR are examples. But the capacity market has become a magnet for other resource types that are seeking an additional revenue stream. Storage devices that are even more limited than limited DR are proposing to be capacity resources when they cannot meet the definition of capacity. Imports from distant locations into PJM want to sell capacity in the PJM market when they are clearly not comparable to nor substitutes for capacity resources internal to PJM.

The reasons for the existence of the capacity market and the definition of the capacity product should be kept clearly in mind when evaluating proposals to participate in the capacity market. The fundamental reason for the existence of the capacity market is to make the energy market work effectively by ensuring adequate revenues for the resources that generate energy to cover their costs. But the concept of capacity as a separate product leads to attempts to define products as capacity that are not capacity as defined consistent with PJM markets. The only purpose for attempting to define such products as capacity is to receive the substantial revenue stream associated with capacity market prices. For example, DR receives more than 95 percent of total revenues from the capacity market. But the greater the participation by such resources that are not actually capacity resources, the greater the price suppression and the less likely the capacity market is to meet its design objective.

4. Resource Adequacy Requirements.

As changes in technology and markets drive new system needs, are modifications needed to existing methods for determining resource adequacy requirements (i.e., the reserve margins centralized capacity markets are designed to procure)?

It would be appropriate to review existing methods for determining resource adequacy requirements in order to determine whether any changes are necessary. This should include a review of forecasting methods to ensure that forecasts are reasonable and are consistent with forecasts used throughout the ISO/RTO.

5. Centralized or Residual Market.

> *What is the role(s) of centralized capacity markets? Should the centralized capacity markets function as a mandatory market for procuring capacity or a residual market that entities only need to use to meet their resource adequacy obligations that they cannot otherwise meet through self-supply?*

Capacity markets were created to address the net revenue issue or the missing money issue in the energy market. The net revenue issue can be addressed using a number of mechanisms. The net revenue issue is currently in some areas and was historically addressed using cost of service regulation. The net revenue issue is currently and was historically addressed in some areas through bilateral contracts. The net revenue issue can be addressed through simply letting market participants exercise market power. The net revenue issue can be addressed through administrative scarcity pricing. And finally, the net revenue issue is and can be addressed through capacity markets and a combination of scarcity pricing and capacity markets.

A combination of scarcity pricing and capacity markets is optimal. Scarcity pricing will improve performance incentives and will reduce the net revenue shortfall that must be recovered through capacity markets. But inclusion of a capacity market means that scarcity does not need to be defined arbitrarily or rely on a very small number of extraordinarily high prices in order to result in adequate revenues. Relying to the maximum extent possible on markets, whether through scarcity pricing or capacity markets, provides incentives to investors and shifts the risks to investors. Investors respond creatively and in unanticipated ways to market signals, which makes reliance on markets to solve the net revenue problem preferable to more regulatory solutions.

All of these approaches are defined administratively and require rules to implement. But that does not mean that they all rely on market mechanisms to an equal extent. The goal within these administrative structures is to rely on market mechanisms and market signals as much as possible.

The PJM capacity market has a must buy requirement and a must sell requirement. These markets cannot work without both a must buy requirement and a must sell requirement. All demand must be in the market and all supply must be in the market if the market price is to be based on the economic fundamentals. If demand is withheld from the market, the price will be suppressed compared to the competitive price. If supply is withheld from the market, the price will be inflated compared to the competitive price. A partial capacity market will not work to solve the net revenue issue in the energy market.

A residual market by definition relies on other mechanisms to acquire capacity. If the other mechanism is cost of service regulation, then the residual market will not result in a price that reflects the fundamentals of supply and demand conditions. Such a residual market is very unlikely to result in incentives adequate for a merchant generator to profitably build new generation. Cost of service regulation is one form of MOPR pricing. Cost of service regulation effectively provides a guaranteed long term bilateral contract to the capacity seller and shifts risks to customers.

A single central capacity market is clearly preferable to a series of bilateral contracts, whether based on cost of service regulation or not. The capacity market is transparent and market outcomes reflect supply and demand fundamentals. A bilateral market is opaque to market participants and provides opportunities to exercise market power in the presence of very little information about market fundamentals and likely significant asymmetries in access to information.

The most important point about all the approaches to the net revenue problem is that they are mutually exclusive. If a market chooses the cost of service paradigm based on state regulated cost of service revenue guarantees, it makes it impossible to have a competitive capacity market. It is not possible for a competitive merchant generation developer to compete with such revenue guarantees. The only form of competition will be competition to receive revenue guarantees.

6. Accommodating state policies and self-supply by load serving entities

As discussed at the technical conference, States have policies to maintain resource adequacy and procure specific resources to meet environmental objectives. In addition, load serving entities are often interested in supplying their own resource adequacy requirements; some load serving entities (LSEs) have suggested that current centralized capacity market designs do not allow them to do so effectively. Incorporating States' policies and LSE preferences in the design of capacity markets has raised challenges for the Commission in ensuring the integrity of its wholesale markets.

Centralized capacity markets and RPM specifically are entirely consistent with bilateral contracting and self supply as are all markets. Market participants can and do enter into bilateral contracts to purchase capacity in PJM markets. Market participants can and do self supply.

But what the RPM does not permit is behavior which intentionally or unintentionally interferes with the efficient and competitive functioning of the market. The capacity markets can function only with a must buy and a must offer requirement, with the exception of the FRR option. A bilateral contract which guarantees payment of a fixed annual amount and requires an offer of zero in the capacity market is an example of behavior which is not consistent with the efficient and competitive functioning of the market. There is no reason for any competitive participant to engage in such behavior. A self supply option which is not procured through a competitive auction and which is guaranteed fixed annual payments and offers in the market at zero is another example of behavior which is not consistent with the efficient and competitive functioning of the market. There is no reason for any competitive participant to engage in such behavior.

The PJM tariff provides a good example of how state policies and responsibilities for reliability can be accommodated within a competitive capacity market, although additional modifications are required.[9] The MOPR tariff provisions provide four bases on which to obtain an exemption from the MOPR, which are a showing that a project: (i) is competitive; (ii) was selected in a competitive non-discriminatory process; (iii) is self supply based on ownership by a public power entity; or (iv) is self supply based on ownership by a vertically integrated utility. The MOPR collapses these four items into the competitive supply option which includes (i) and (ii) and the self supply option which includes (iii) and (iv).

With one exception, the two competitive supply exemptions (items (i) and (ii)) afford adequate protection for the markets from buyer-side market power, and better accommodate state procurement processes designed to meet state regulators' obligations to ensure local reliability than the current rule. The Market Monitor has repeatedly and publicly endorsed the competitive supply exemptions since the approval of the current MOPR last year, and welcomes these reforms.

The MOPR does not go as far as it should to protect state interests in addressing local reliability concerns while protecting competitive markets. The Market Monitor believes that state interests in maintaining local reliability would be enhanced with the addition of two special limited procurement processes while protecting competitive markets.[10] The first would apply in circumstances where PJM identifies an immediate, local reliability issue in a Locational Deliverability Area (LDA) that existing or imported capacity cannot solve. In these very limited circumstances, a MOPR compliant process should specify that only incremental resources in the LDA be included in a competitive and nondiscriminatory auction because existing resources and imports cannot resolve the issue. The second would apply in circumstances where a state identifies an immediate, local

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9 PJM OATT Attachment DD § 5.14(h).

10 *See* Comments of the Independent Market Monitor for PJM, ER13-535-000 (December 28, 2012) at 9–11.

reliability issue based on PJM information, but PJM does not agree with the state's assessment that the reliability need is immediate and local. In these very limited circumstances, resources selected in a competitive auction that includes only local resources would be MOPR compliant. Such resources could be included in RPM, under the state competitive exemption, only based on a unit-specific review of costs to ensure that the offer is competitive, provided that such review applies the same modeling assumptions used to establish the gross Cost of New Entry (CONE). These processes would apply only in extremely limited circumstances, but the Market Monitor believes that they meet the concerns raised by some of the state regulators about the potential impact of the MOPR on their ability to fulfill their obligations to maintain local system reliability.

7. Self Supply.

> *In what ways do the current centralized capacity market designs facilitate, or hinder, the ability of market participants to enter into arrangements to supply their own resource adequacy requirements? Should the Commission consider changes to the current capacity market designs to facilitate these arrangements? How would any potential changes impact capacity market prices paid by LSEs and the price signals provided to capacity resources?*

PJM has recently implemented a self supply exemption from the MOPR rules. The MOPR tariff provisions include an exemption for self supply which would exempt public power entities and vertically integrated utilities under certain, generally achievable criteria. A perfect MOPR would not include the self supply exemptions. The Market Monitor agrees, however, that the exemption for public power entities would resolve concerns raised by a segment of stakeholders without negative impacts on the markets.

The Market Monitor does not agree that vertically integrated utilities should be excluded from the MOPR because those entities have been responsible for significant investment historically, because this improperly discriminates against merchant competitors in the service territory and against utilities located in states where retail restructuring has occurred and because there are other alternatives in the RPM tariff to address the situation of vertically integrated utilities that do not want to fully participate in PJM capacity markets.

8. Resource Class Exemptions, Procurement Reductions and Other Policies Related to Self Supply.

Some panelists suggested other potential modifications to the existing centralized capacity markets to accommodate self-supply and/or state policies, including limited or resource class-specific exemptions from buyer-side mitigation rules, or offsetting reductions in the amount of capacity procured in the centralized capacity market. What are the advantages or disadvantages of such changes? Are there additional potential changes to particular design elements that should be considered to accommodate self-supply and/or state policies? How would any potential changes accommodate the long-term price signals that several panelists argued are necessary for capacity investment?

The various paradigms for addressing the net revenue problem cannot mutually coexist. Any significant modification to the underlying supply of and/or demand for capacity will change the market price and the market price will no longer reflect the supply and demand fundamentals.

It has not been demonstrated that cost of service based paradigms are cheaper than markets. In fact, the entire premise of regulation through competition is the reverse. Competition was introduced because cost of service regulation resulted in high priced units receiving revenue guarantees from customers. In PJM, the cost of capacity through RPM has been well below the actual cost of new capacity.

Changes to the market design which are inconsistent with the basic RPM market design and which would result in prices which do not reflect the supply and demand fundamentals should be rejected.

9. Fixed Resource Requirement (FRR) Alternative.

PJM offers LSEs the alternative to opt out of its capacity auction by using the Fixed Resource Requirement (FRR) option. Should such an alternative be offered in other eastern Regional Transmission Organization (RTO)/Independent System Operator (ISO) centralized capacity markets? Given that the FRR option was originally developed to address a narrow set of circumstances facing the PJM region and its market participants at that time, would modifications to this alternative be *appropriate to meet the needs of regions and market participants today? For example, are there changes to the current FRR option that could be adopted to allow increased flexibility for entities looking to partially self-supply their capacity requirements while preventing adverse impacts on the competitiveness of the market?*

The FRR alternative was developed to permit a utility to meet its PJM defined capacity obligations and associated reliability targets while continuing to function in a cost of service environment. This demonstrates that other entities can also take similar steps to remain in the PJM markets while continuing with a cost of service approach to the cost of capacity. While this is not the preferred option, for any entity that does not want to participate in PJM capacity markets, the FRR approach is a defined way to meet that goal while minimizing the impact on the rest of the PJM market. All of the entity's demand and supply is removed from the PJM capacity market with the result that the capacity market price can continue to reflect supply and demand fundamentals for the remaining market participants. The FRR alternative is preferable to the self supply exemption from MOPR for vertically integrated utilities.

B. Market Design Elements

Throughout the technical conference, comparisons of the RTO/ISO capacity markets and market design elements were made, including whether there is a need for consistency in the approach to capacity markets across the eastern RTOs/ISOs and the interaction of the capacity market with other RTO/ISO markets. Panelists suggested that consistent approaches with respect to some design elements could improve the ability of market participants to participate in multiple markets.

Consistent elements of capacity market design could help the overall power market in the eastern interconnection. Key elements include the required elements of the PJM capacity market and some secondary characteristics of those required elements.

1. Slope of Demand Curve.

A number of panelists commented that a downward-sloping demand curve is preferable to a vertical demand curve. What are the advantages and disadvantages of a sloped demand curve versus a vertical demand curve? What are the key design criteria appropriate to consider in establishing the slope of the demand curve in each of the eastern RTO/ISO centralized capacity markets?

Having a must buy requirement is a critical element of capacity market design. The nature of the demand curve is a secondary characteristic of this design element but an important characteristic.

In the PJM capacity market, the sloped portion of the demand curve makes up a very small portion of all the MW of capacity demanded. The reason is that the downward-sloping part of the demand curve cannot begin at a MW point less than the minimum reliability requirement. The extent to which the demand curve can exceed the minimum reliability requirement is a matter of judgment, but the range is quite limited. The limit is defined by how much extra capacity customers should be required to purchase even when the price is low. While it is a positive to have a downward-sloped demand curve, the positive impacts it can have on market outcomes are limited.

All LSEs are required to purchase capacity equal to their forecast load plus a reserve margin. That requirement is enforced through the demand curve, the variable resource requirement (VRR) curve, in the RPM capacity market design. The demand curve for system capacity in the RPM capacity market design is downward sloping, replacing the vertical daily demand curve in the capacity credit market design. The shape and inflection points of the RPM demand curve are based on the reliability requirement and the net cost of new entry for a peaking unit, and have a significant impact on prices in the capacity market. The net cost of new entry includes the gross costs net of the net energy and ancillary services revenues offset. This offset reflects the total revenue sufficiency purpose of the capacity market and the integration of the capacity and energy markets. Figure 1 is the demand curve for the 2016/2017 RPM Base Residual Auction for the entire RTO.[11]

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11 This demand curve ignores the minimum annual and minimum extended summer requirements.

The highest price part of the demand curve is flat from the y or price axis at a price equal to 1.5 times the net cost of new entry, or the gross cost of new entry if that is higher.[12] The flat portion extends to point A, where the quantity equals the reliability requirement less approximately three percent.[13] The curve slopes downward to point B, where the price is the net cost of new entry. The quantity at point B is the reliability requirement plus approximately one percent. The curve slopes downward to point C where the price is 20 percent of the net cost of new entry. The quantity at point C is the reliability requirement plus approximately five percent. The demand curve drops to the x axis from point C. The quantity at each point is reduced by the 2.5 percent Short-Term Resource Procurement Target (STRPT). The demand curve shown in Figure 1 is for the entire RTO without accounting for locational differences. There are separate supply and demand curves for each LDA with a potentially binding transmission constraint.[14]

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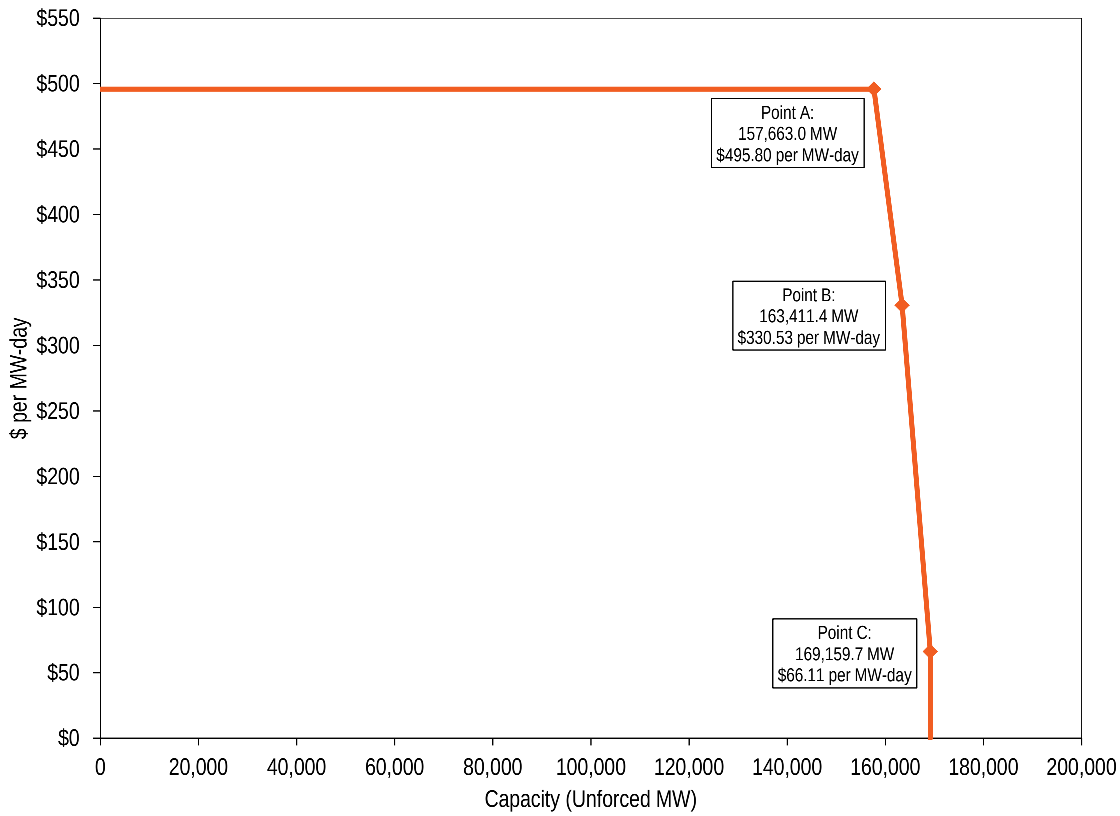
12 The prices are all adjusted to be on an unforced capacity basis. Unforced capacity is installed capacity or gross capacity adjusted for the relevant forced outage rate. See PJM Interconnection, L.L.C., "*Manual 18: PJM Capacity Markets,*" Revision 15 (June 28, 2012). p. 98.

13 The exact equations can be found in Manual 18.

14 For the detailed rules, see the *2012 State of the Market Report for PJM*, Volume II, Section 4- Capacity Market, Pg. 143.

Figure 1. Demand Curve for 2016/2017 RPM Base Residual Auction



The demand curve design incorporates a form of scarcity pricing. The price goes to the maximum level if the supply, at offer prices less than the maximum price, is less than approximately 97 percent of the reliability requirement. For example, if the reliability requirement were 100,000 MW, the price would be set to the maximum whenever the supply, at an offer price less than the maximum, is less than approximately 97,000 MW. The scarcity price also serves as a price cap.

The demand curve design conservatively sets the quantity associated with the expected equilibrium price at a level slightly higher than the reliability requirement. This means that the market clearing price will equal the net cost of new entry at a quantity approximately one percent greater than the reliability requirement (Point B). As a result, the demand curve sets the price for the reliability requirement at greater than the net cost of entry.

The downward slope requires the purchase of capacity greater than the reliability requirement if consistent with offer prices and requires the purchase of capacity less than the reliability requirement if consistent with offer prices. The downward sloping demand curve is also intended to add some elasticity compared to the vertical demand curve used in the capacity credit market that was replaced by the RPM.

2. Accurately Assessing Future Capacity Needs.

> *Whether using a sloped or vertical demand curve, RTOs/ISOs must attempt to accurately assess future capacity needs in order to ensure resource adequacy in the delivery year. Are there improvements to the derivation of an RTO/ISO's resource adequacy requirement that would improve the functioning of its capacity market? How do differences in the derivation of resource adequacy requirements across the RTOs/ISOs impact the markets? For RTOs/ISOs with three-year forward markets, should the RTO/ISO procure 100 percent of its resource adequacy requirement three years in advance of the delivery year, or is there a portion of the resource adequacy requirement that can be reliably procured closer to the delivery year? What are the advantages and disadvantages of procuring a portion of the resource adequacy requirement closer to the delivery year?*

It would be appropriate to review existing methods for determining resource adequacy requirements in order to determine whether any changes are necessary. This review should include a review of forecasting methods to ensure that forecasts are reasonable and are consistent with forecasts used throughout the ISO/RTO.

The market design must be the same for all sellers of capacity. A market needs a homogeneous product and a design and rules that apply identically to all participants. For the same reasons that the capacity market can only work with a must buy and a must sell requirement, there cannot be partial procurement by year. Removing a portion of demand affects market clearing prices at the margin, which is where the critical signal to the market is determined.

The Market Monitor has documented the significant impacts on clearing prices of moving just 2.5 percent of demand from the Base Residual Auctions into Incremental Auctions.[15]

3. Derivation of Net Cost of New Entry (CONE).

Panelists did not focus extensively on the derivation of Net CONE, although it was discussed in the staff white paper. Are there improvements to the derivation of Net CONE that would improve the functioning of capacity markets? How do differences in the derivation of Net CONE across the RTOs/ISOs impact the markets?

Net CONE is the annualized gross cost of new entry (CONE) net of the net revenues that the new entrant is expected to earn in the energy and ancillary services markets. The gross cost of new entry is appropriately based on units that can and do serve as peaking units in the market. Peaking units may be required for reserves but may seldom run if demand does not exceed forecasts. Peaking units, if always on the margin, would not receive adequate revenues to cover their total costs despite the fact that they are required in order to meet the target reserve margin. Gross CONE should be the cost of a new peaker based on the actual costs to build such a unit in the geographical market.

Net revenues are a critical part of the net CONE calculation and in the PJM market they are calculated so as to have no expected relationship to expected revenues for the new unit.

The E&AS revenues in the net CONE calculation do not correctly reflect market revenues. PJM's approach calculates the energy and ancillary services revenues to apply to a new unit for the delivery year three years in the future using average revenues earned in PJM over the past three calendar years. This approach will always, except by accident,

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15 *See*, *e.g.*, Monitoring Analytics, LLC, Analysis of the 2015/2016 RPM Base Residual Auction (September 24, 2013) at 32–38 <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf>

provide an incorrect forecast of net revenues for the delivery year three years in the future. The problem gets worse when changes in market conditions result in substantial differences between historical and expected market revenues. Recent changes in market conditions including lower gas costs and improvements in CC technology mean that expected market revenues are significantly higher than historical average market revenues. This means that the E&AS offset used by a competitive entrant will be higher than the E&AS offset calculated using the three year average. This, in turn, means that a competitive offer, even using PJM's gross CONE, will be lower than PJM's MOPR threshold.

A forward looking E&AS offset calculation method is needed in order to make the net CONE calculation reasonable.

Net CONE for the entire RTO should be calculated as the lowest net CONE which is deliverable to the entire RTO. Net CONE should not use an average net revenue because no actual unit ever receives PJM average LMP. Prices are locational and the net CONE for the entire RTO should reflect the cheapest way to meet the capacity requirements of the RTO. If that is a unit in New Jersey which by definition could meet reliability requirements anywhere in the RTO, that should be the net CONE for the RTO.

4. Length of Forward Period.

> *Panelists debated the merits of a longer or shorter forward period in centralized capacity markets. Some argued that a longer forward period can aid in managing retirements; others argued that a shorter forward period facilitates bilateral contracting. What are the advantages, disadvantages and related considerations that may support longer or shorter forward periods? Should the length of the forward period vary for different categories of resources (traditional generation, new resources vs. existing resources, demand response, energy efficiency, distributed generation, etc.)?*

The RPM design reflects supply and demand three years in the future; RPM is a forward market. The goal of the three year forward requirement is to provide for competition from new entry, to provide an opportunity to market test decisions to invest in existing units, to provide for advance decisions about unit retirements and to provide for a window to resolve reliability issues revealed in market outcomes before they occur. In each case, the three year forward requirement provides for more competition in a market for long lived assets that require years to build or modify. The three year forward procurement allows the market to react to external factors like changes in environmental regulations and provides an incentive to make retirement decisions prior to the capacity auction. For these reasons, a three year forward period is strongly preferred to a short term market for capacity.

There is no reason to believe that a short term market facilitates bilateral contracting. Bilateral arrangements depend on market price signals and the increase in market information associated with a three year forward period provides more market information than a short term market.

The market design must be the same for all sellers of capacity. A market needs a homogeneous product and a design and rules that apply identically to all participants. For the same reasons that the capacity market can only work with a must buy and a must sell requirement, there cannot be different lead times for resources of different types. If that were the case, there would no longer be direct competition among all suppliers of capacity.

There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects market clearing prices at the margin, which is where the critical signal to the market is determined.

5. Length of Commitment Period.

Commitment periods also vary by RTO/ISO and by resource-type. Is there an ideal length of the commitment period? Should the length of commitment period vary for different categories of resources (traditional generation, new resources vs. existing resources, demand response, energy efficiency, distributed generation, etc.)? Does the length of the commitment period impact the ability and willingness of buyers and sellers to enter into bilateral contracts? How do differences in commitment periods across the RTOs/ISOs impact the markets?

In the RPM capacity market, the product sold is a one year commitment, three years forward. The market is repeated each year. This one year commitment provides appropriate incentives for building new capacity and maintaining existing capacity. This conclusion depends on the confidence of market participants that the capacity market will continue to exist for the forseeable future and that capacity market prices will reflect the underlying supply and demand fundamentals.

Some argue that the commitment must be for a longer period, perhaps from three to as long as seven or even ten years. The argument is that a one year clearing price, three years forward, is not an adequate basis on which to build a new capacity resource. While that is true in a narrow sense, it does not mean that a longer term contract is the solution. A three year contract is also not an adequate basis on which to build a new capacity resource. The solution is a market that continues to reflect market fundamentals. This argument ignores the fact that long term market based contracts are available, including the sale of energy market price hedges and tolling agreements, which reflect market participants' views of future market conditions.

A change in the commitment period changes the definition of the capacity product and would have significant unintended consequences. If the capacity product becomes a five year product, that product definition would apply to all capacity traded in the capacity market. The product in the market must be homogeneous. It is not possible to have a rational market design with one year products competing against five year products and with one year and five year prices resulting. A five year product would impose substantial risks on existing resources. If a generating unit faces the possibility of significant environmental expenditures in three years, the sale of a five year product commits the unit owner to making those expenditures or replacing the capacity in three years. If DR suppliers were required to commit to providing the offered MW for five years instead of one year, it would impose substantial new risks on DR providers.

6. Zones.

Some panelists at the technical conference asserted that capacity market zones are not sufficiently granular and do not change often enough to reflect important market and system changes. Are there advantages or disadvantages associated with increasing *the granularity of capacity zones? If so, what are they? What are the challenges, advantages or disadvantages of a dynamic approach to establishing capacity zones?*

The RPM design includes the potential for locational price separation to reflect locational differences in supply and demand conditions. The demand curves in individual Locational Deliverability Areas (LDA) are defined in exactly the same way as the system demand curve except that the locational reliability requirements are used in place of the system reliability requirements and locational net cost of new entry values are used for the price points.

There is locational price separation when the demand for capacity in an LDA cannot be met by the supply taken in merit order over the entire system including capacity within the LDA and capacity imported into the LDA, but must be met by higher cost supply located in the LDA. This is analogous to locational marginal pricing in the energy market.

The PJM capacity market has cleared with significant locational price differences in all but one Base Residual Auction since 2007, with prices in the transmission constrained eastern parts of PJM generally exceeding prices in the western part of PJM.

The RPM market in PJM is appropriately locational. The capacity market prices must reflect the underlying realities of the transmission system. When RPM was implemented, the market conditions in the east were very tight and the market conditions in the west were not. A single price over the entire RTO would undervalue capacity in constrained areas and overvalue capacity in unconstrained areas.

The PJM RPM market needs to use a more sophisticated approach to location pricing that it uses now. LDAs reflect the traditional transmission zones. While these were a good place to start, the traditional transmission zones to not always reflect the reality of the underlying transmission system. PJM should run the capacity market nodally and define LDAs on the basis of appropriately aggregated nodes such that LDAs reflect the transmission system constraints but are sufficiently broad to permit entry and competitive outcomes.

7. Coordination of Transmission Planning and the Capacity Market.

Price signals in the capacity markets also provide information to transmission planners to the extent that transmission may substitute for capacity resources. How can investment in capacity and transmission planning be better coordinated? Should the capacity market planning process and transmission planning process use common assumptions and common planning horizons?

The lack of direct competition between capacity and transmission is an ongoing gap in wholesale power market design. If transmission planning uses a longer term horizon it is possible that reliability issues will be identified and solved with transmission upgrades before there is a capacity market run for the relevant year. In addition, there is a disincentive to build new generation if potential developers of new generation capacity face the risk that a transmission upgrade may be subsequently built which will remove locational price separation and reduce capacity prices for the new generation.

The transmission planning horizon is a function of the long and uncertain time lags associated with many transmission upgrades as well as PJM's need to look farther forward for reliability purposes. The RPM market could be four years forward rather than three, but that would not resolve the issue. The option to identify a reliability issue in the transmission planning process and to determine if it is reasonable to leave the issue to be resolved by the capacity market should be considered.

It is important to use the same planning assumptions for transmission planning and capacity markets. PJM's use of a 2.5 percent offset to demand in the capacity market (Short-Term Resource Procurement Target) is an example of an inappropriate disconnect between transmission planning and the capacity market in addition to being an inappropriate intervention the capacity market.

PJM has suggested that the 2.5 percent demand reduction is a correction for forecast error.[16] Apart from the implausibility of forecast error being the same 2.5 percent every year and always in the same direction, it would make more sense to fix the forecast method directly if that were really the issue. But forecast accuracy does not appear to be the real issue. The PJM manuals do not indicate that the Short-Term Resource Procurement Target is related to forecast accuracy. The same forecast, which is adjusted down in the capacity market, is used without adjustment for PJM's reliability analysis to determine whether PJM needs to mandate the construction of transmission facilities to ensure reliability. It does not make sense to use different forecasts for reliability purposes depending on the nature of the reliability fix which could result.

If the transmission related forecast is always higher than the capacity related forecast, then transmission fixes for reliability issues will be identified when no reliability issue is identified in the capacity market. This creates a bias towards relying on transmission rather than generation to resolve reliability issues. This creates additional risk for potential investors in generation who could see the value of their investment undercut by a subsequent investment in transmission facilities. Given the difference in load forecasts, the need for a transmission upgrade could still be identified even when the full amount of capacity required to resolve the reliability problem as measured in the capacity market has been procured.

8. Retirement notice.

What role do retirement and mothballing decisions and notification play in the operation of the eastern RTO/ISO centralized capacity markets? Is there an ideal approach to retirement or mothballing notification? What is the impact of different

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16 *See* PJM Interconnection, LLC, "PJM Response to the 2012 State of the Market Report," (May 10, 2013) <http://www.pjm.com/~/media/documents/reports/20130510-pjm-response-to-the-2012-state-of-the-market-report.ashx>

retirement or mothballing notice procedures across the eastern RTOs/ISOs on the market, resource adequacy and reliability?

The purpose of RPM's three-year forward design is to allow competition from new entry to help establish competitive and efficient prices.[17] Notice should be required for deactivations prior to the deadline for new entrants to enter the planning queue. New entrants cannot participate in the RPM Auction if they have not entered the planning queue. A later deadline, one which is after the deadline for new entrants to enter the planning queus, is required in order to ensure that there is no anticompetitive barrier to entry in the PJM capacity markets.

The PJM rules require a generation owner to provide only 90 days notice of a deactivation (including a retirement or mothball) to PJM and the Market Monitor. This notice is inadequate and should be at least 12 months. But the forward looking nature of the capacity market creates strong incentives for generation owners to provide notice prior to the BRA for the first delivery year in which the unit would be retired.

The RPM design permits owners of an existing generating unit to make offers into the BRA that fully reflect the costs of complying with all the investment requirements for the unit. If the unit fails to clear the BRA, the owner has the option to provide notice of deactivation at that point. The time period from December 1 prior to a BRA to the actual Delivery Year is slightly less than three and a half years, not four years, and it is approximately one month longer than the current notification period.

Any potential entrant must have entered the planning queue by October 31 of the year preceding the BRA in order to qualify to offer in the BRA. In order to determine whether there is an opportunity to compete to replace a retiring generating unit, potential entrants must know where such retirements will take place. It is impossible to offer in the

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17 *See* Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, ER13-2140-000 (August 13, 2013).

BRA to compete to replace the retiring unit without this information and without entering the planning queue based on this information.

If the incumbent generators had no deadline, they could postpone notifying the market until it is too late for potential entrants to compete, including waiting until the end of the auction week. In fact, generation owners have engaged in exactly such behaviors, which is one of the reasons for the current deadlines in the tariff. It is also a reason to have a deadline which permits potential entrants to compete, meaning at least two months prior to the October 31 planning queue deadline.

C. Regulatory certainty

1. Stability of the Rules.

How should the Commission strike a reasonable balance in adopting market rule changes when necessary without creating undue regulatory uncertainty?

The markets are constantly evolving and new lessons are learned from new experience. The rules should not be frozen in their current status because the markets still need improvement. Recent examples in PJM include lessons learned from the dramatic increase in DR clearing in the capacity market and lessons learned from the dramatic increase in capacity imports clearing in the capacity market.

The best way to strike the appropriate balance is to be sure that market changes are thoroughly thought through, that appropriate supporting analysis is done and shared and that the changes are completely discussed in the membership process to ensure that changes represent improvements to the market design that are likely to persist. This thoughtful evolution process will lead both to a better and more stable market design.

2. Updating Design Elements.

What are the advantages and disadvantages of an RTO/ISO regularly revisiting certain market design elements, such as NYISO's triennial reset of its capacity demand curve?

Regularly revisiting market parameters on a prescheduled basis, like gross and net CONE, is essential. But it is not clear that revisiting core elements of the market design on a prescheduled basis makes sense. The expectation of related changes can create unnecessary uncertainty for market participants.

D. Next steps

Conference panelists indicated that further direction from the Commission could help to inform the development of appropriate eastern RTO/ISO centralized capacity market design elements in the future.

1. Next Steps.

What Commission action would be an appropriate next step with respect to those markets?

The Market Monitor recommends that the Commission consider whether it makes sense to require that all capacity markets have certain core elements. As with the evolution of individual market designs, such requirements should be implemented only after careful consideration and the opportunity for all market participants to comment.

2. Other Issues Appropriate for This Proceeding.

Are there outstanding issues or questions raised by, but not fully discussed at, the conference that should be considered in this proceeding?

The Market Monitor may address this question at a later stage in this proceeding.

3. Other Issues Appropriate for Another Proceeding.

Are there other issues that, if addressed, would help the centralized capacity markets ensure resource adequacy in a just and reasonable and not unduly discriminatory manner (e.g., enhancements to the energy and ancillary services markets) that should be considered by the Commission in another forum?

The Market Monitor may address this question at a later stage in this proceeding.

II. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to this pleading as the Commission resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: January 8, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 8th day of January, 2012.

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