PJM Interconnection
2750 Monroe Blvd
Audubon, PA 19403

Jennifer Tribulski
Senior Counsel
610.666.4363 | fax 610.666.8211
jennifer.tribulski@pjm.com

April 10, 2015

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER15-623-___

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to the Commission's March 31, 2015 letter requesting additional information in this proceeding ("March 31 Letter"), encloses its written responses to the questions listed in the letter. These responses concern PJM's December 12, 2014 filing ("Capacity Performance Filing")[1] of revisions under section 205 of the Federal Power Act, 16 U.S.C. § 824d, to the PJM Open Access Transmission Tariff ("Tariff") and the Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA") to establish a new capacity product, to be known as a Capacity Performance Resource, on a phased-in basis, to ensure that PJM's capacity market provides adequate incentives for resource performance.[2]

Before providing our specific responses, PJM believes it helpful to provide context around the specific issues raised by the Commission in its deficiency letter. The Commission has long recognized the benefit of capacity markets. Indeed, when the Commission approved PJM as an Independent System Operator in 1997, it found PJM's capacity rules "generated significant reliability and cost-savings benefits for the PJM members over the years."[3] Since its implementation in 2007, PJM's forward capacity

[1] PJM Interconnection, L.L.C., Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA"), Docket No. ER15-623-000, filed December 12, 2014 ("Capacity Performance Filing").
[2] The March 31 Letter directed PJM to submit these information response using eTariff Filing Code 180, Deficiency Filing, which requires at least one eTariff record, even if no tariff changes are otherwise required. In compliance with this requirement, PJM encloses, as an .rtf file, the same revisions to OATT Attachment Q that were included in the Capacity Performance Filing. The changes to the relevant portions of Attachment Q are identical to those submitted with the Capacity Performance Filing. Because there are no changes in the Tariff revisions or their effective date from the Capacity Performance Filing, this submittal does not include PDF versions of the Tariff or RAA changes (which were already transmitted with the Capacity Performance Filing). The enclosed Attachment Q revisions retain the effective date requested in the December 12 Filing, i.e., April 1, 2015.
[3] *Pa.-N.J.-Md. Interconnection*, 81 FERC ¶ 61,257 at 62,275 (1997) ("PJM ISO Order").

market – the Reliability Pricing Model ("RPM")[4] – has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. During that time, the PJM Region has been buffeted by the impacts of a number of state and federal environmental initiatives affecting the generation fleet as well as rapidly changing economic conditions. Nevertheless, PJM's RPM capacity market design has worked effectively to spur new investment to replace the nearly 26,000 megawatts ("MWs") of retiring generation since 2008, and projecting forward to 2019 and ensure forward reliability in a period of unprecedented turnover of a large portion of the generation fleet. In the 2017/2018 BRA alone, PJM procured nearly 6,000 MWs of new generation resources. Approximately 35,000 MWs of total new generation have been procured since RPM was implemented in PJM's markets.

Capacity procurement is only a part of the reliability equation. The other part of the equation is generator performance. The Commission has most recently found that a resource adequacy construct that "fails to provide adequate incentives for resource performance, [can] threaten[] reliable operation of the system and forc[e] consumers to pay for capacity without receiving commensurate reliability benefits."[5] The Commission recently required each jurisdictional centralized market operator to identify actions it is taking to improve fuel assurance, which is a key pre-requisite to better generation performance.[6] PJM responded to the Commission's request in part by pointing out the reforms it seeks to implement through its Capacity Performance proposal. [7]

Despite its success in retaining and attracting sufficient capacity to ensure resource adequacy requirements are met, the capacity markets are failing to incentivize adequate generator performance. Resources in PJM have not performed as expected. As PJM fully explained in its Capacity Performance Filing, this is due to several key factors:

- RPM's current charges for sub-par performance are inadequate;
- RPM's current sell-offer pricing rules do not clearly allow for recovery of some fuel assurance costs
- resource mix in the PJM Region is changing rapidly, raising new performance challenges; and
- generator equivalent forced outage rates have gradually deteriorated over the same time period that RPM has been in effect.[8]

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[4] Unless otherwise defined in this filing, capitalized terms used in the enclosed responses have the meanings provided in the December 12 Filing, Tariff, or RAA, as applicable.

[5] *ISO New England Inc.*, 147 FERC ¶ 61,172, at P 23 (2014) ("*ISO-NE Pay for Performance*"), *reh'g pending*.

[6] *Centralized Capacity Markets in Reg'l Transmission Orgs. and Indep. Sys. Operators/Winter 2013-2014 Operations and Market Performance in Reg'l Transmission Orgs. and Indep. Sys. Operators,* 149 FERC ¶ 61,145, at P 20 (2014).

[7] *Centralized Capacity Markets in Reg'l Transmission Orgs. and Indep. Sys. Operators/Winter 2013-2014 Operations and Market Performance in Reg'l Transmission Orgs. and Indep. Sys. Operators,* PJM Interconnection, L.L.C. Report On Fuel Assurance Activities at 3-5, Docket Nos. AD13-7-000 and AD14-8-000 (filed Feb 18, 2015).

[8] Capacity Performance Filing at 6-16.

Simply, RPM's current capacity market performance incentives and requirements are weak, and therefore require immediate reform. Because RPM secures capacity commitments on a three-year forward basis, RPM reforms, for the most part, can only take full effect on a three-year-forward basis. The next RPM BRA is scheduled for May 2015, and will secure capacity commitments for the Delivery Year that starts on June 1, 2018. If PJM deferred these changes to the following BRA, held in May 2016 for the Delivery Year that starts on June 1, 2019, it would mean that the PJM Region would let *five more* winters pass after 2014 without implementing a full remedy to the manifestly deficient performance requirements in the current rules.

Many of the Commission's questions contained in the deficiency notice raised issues with PJM's proposed market power mitigation rules and the associated competitiveness of offers. Although PJM addresses the specifics in its response below, it is worth noting that the proposed offer cap set forth in the filing (as modified in this response after additional work with the Independent Market Monitor for PJM ("IMM")), represents but one component of a series of design features that PJM has in place to address market power mitigation. These features, which include a must offer requirement, advanced notice and review of retirement decisions, the Minimum Offer Pricing Rule and others, all work together to ensure that the capacity auction results are mitigated to guard against the exercise of market power and ensure competitive behavior and outcomes. Indeed, although the IMM has continually found the capacity market as structurally non-competitive, it has found the RPM results, competitive.[9] As a result, as the Commission approaches the issue of whether the proposed offer cap is reasonable, it should keep in mind that PJM does not depend on this feature alone to address market power mitigation. Rather the proposal is merely one aspect of a larger set of mitigation tools which the IMM has found have produced competitive results. This does not mean that the Commission need not satisfy itself as to the merits of this design component; but it does argue for recognition that there are a host of design features which work to mitigate any market power that otherwise could influence capacity market results. As explained in detail below, the modified offer cap proposal that PJM has developed in cooperation with the IMM is the same as the approach the Commission approved for ISO-New England, Inc. and will yield the same results as a detailed cost-based unit-specific offer cap approach.

While PJM has sought approval for a limited delay in the May BRA,[10] PJM did not take that step lightly. Any delay in the auction causes market uncertainty. PJM recognizes that any delay of the auction may affect financing decisions of potential new entrants as well retirement and new investment decisions for existing resources. PJM also

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[9] *2014 State of the Market Report*, Monitoring Analytics, LLC, Vol. 1, p. 7 (Mar, 12, 2015) ("Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules."). The report can be accessed at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume1.pdf

[10] *PJM Interconnection, L.L.C.*, Request of PJM Interconnection, L.L.C. For Expedited Grant Of Tariff Waiver, Docket No. ER15-1470-000 (filed Apr. 7, 2015) ("Waiver Request")

recognizes that a minimal delay is warranted in order to achieve the reliability benefits of implementing Capacity Performance. Given (i) the Capacity Performance Filing has been pending for nearly four months; (ii) an extensive record has already been developed in that proceeding; and (iii) the March 31 Deficiency Letter narrowly focused on a short list of elements of the Capacity Performance Filing, PJM respectfully urges the Commission to act on the merits of the Capacity Performance Filing without taking the full sixty days allotted by the FPA.

Accordingly, PJM asks that the Commission accept the Tariff changes in the Capacity Performance Filing effective April 1, 2015 as proposed, so that PJM can implement these changes for the 2018/2019 BRA.

Respectfully submitted,

/s/ *Jennifer Tribulski*

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743 (phone)
(202) 393-7741 (fax)
Craig.Glazer@pjm.com

Jennifer Tribulski
Senior Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-4363 (phone)
(610) 666-8211 (fax)
Jennifer.Tribulski@pjm.com

Barry S. Spector
Paul M. Flynn
Ryan J. Collins
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200 (phone)
(202) 393-1240 (fax)
spector@wrightlaw.com
flynn@wrightlaw.com
collins@wrightlaw.com

CC (via e-mail): Kris FitzPatrick, FERC OEMR

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.

Additionally, PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[11] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[12] alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp, in accordance with the Commission's regulations and Order No. 714.

Dated at Audubon, PA this 10th day of April, 2015.

/s/ Jennifer Tribulski
Jennifer Tribulski

Counsel for
PJM Interconnection, L.L.C.

[11] *See* 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).
[12] PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

Response of PJM Interconnection, L.L.C. to
Commission's March 31, 2015 Information Request
Docket No. ER15-623-000
Dated April 10, 2015

1) During periods when PJM does not need new capacity in a given Locational Deliverability Area (LDA), why would Net CONE be an appropriate competitive clearing price and appropriate competitive offer for the marginal resource?

Response:

The Commission's inquiry seems to draw a distinction between the appropriateness of the competitive offer in a constrained LDA needing new capacity versus an unconstrained LDA. However, such an offer is reasonable whether or not the resource is located in an LDA that needs new capacity, because as will be explained throughout PJM's responses herein, Capacity Performance Resources in every LDA are exposed to the proposed Non-Performance Charge rate whether or not the LDA requires new capacity.

As explained previously and in response to other questions, PJM and the IMM have collaborated to develop an alternative offer cap (the "PJM/IMM Agreed-to Offer Cap") instead of the Net CONE method proposed by PJM. As discussed in other responses in this filing and explained in Appendix 1, PJM and the IMM agree that the competitive offer for any resource in any LDA can be defined using the equation:

$$p = PPR \times H \times \bar{B} + max\{0, (ACR - PPR \times H \times \bar{A})\}$$

The derivation of this equation is explained in Appendix 1 (equation (1)). This methodology is consistent with the approach used in ISO-NE in their Forward Capacity Auctions, and approved by the Commission.

The competitive offer is a function of resource specific variables and system variables. The resource specific variables include resource specific marginal costs (ACR), resource specific performance (A) and the system variables include the non-performance charge rate (PPR), the expected value of balancing ratio ($\bar{B}$) and the performance assessment hours (H).

An appropriate competitive offer for a Capacity Resource properly includes all of the marginal costs faced by that resource. This principle is fundamental and provides the foundation for much of the Commission's policy on wholesale market design. Among other things, the Commission has found repeatedly that clearing prices based on the marginal costs of the marginal resource are just and reasonable. Consequently, as explained in more detail later in this document, a default Capacity Performance Resource offer cap, based on Net CONE times the balancing ratio is reasonable and appropriate under PJM's Capacity Performance proposal.

<u>Overview Regarding Questions 2-6:</u>

Commission Questions 2 through 6 address the details of establishing appropriate offer caps in the Capacity Performance design. The PJM/IMM Agreed-to Offer Cap, as discussed in those responses, is supported by a thorough analysis shown in Appendix 1 of the costs and revenues faced by sellers under various scenarios under the Capacity Performance paradigm of Non-Performance Charges and Bonus Performance Payments. The different scenarios shown in Appendix 1 consider whether a seller commits the resource as a Capacity Performance—or not; and the level of the seller's avoidable costs. The scenarios take into account the capacity payment a resource receives if it does commit as capacity, the Non-Performance Charge the seller faces it commits as capacity but underperforms, and the Bonus Performance Payments the seller can earn to the extent it does not commit as capacity and over-performs. The scenarios also take into account whether the seller expects its particular resource to over-perform or under-perform relative to the likely average performance levels. Tracking the same logic and analysis used by ISO-NE, this analysis concludes that the rational, profit-maximizing offer for a seller with avoidable costs below the expected capacity clearing price (i.e., below the standard capacity payment before accounting for performance charges/payments) is Net CONE times * B. PJM and the IMM are in agreement on this analysis. For reference, PJM includes that analysis in Appendix 1 to these responses. PJM's responses to questions 2 through 6 are supported by that analysis, and use terms that are defined in that analysis. PJM has drafted those responses, however, to be easily understandable without detailed knowledge of the formulaic analysis in Appendix 1.

2) In ISO-NE's Pay for Performance Filing in Docket No. ER14-1050-000, it proposed, and the Commission adopted, a default offer cap based on a formula consisting of going-forward costs (including non-performances penalties or bonus payments) and opportunity costs associated with accepting a capacity obligation.

a. **Would an offer cap in PJM based on the same components be consistent with PJM's expectations for resources offering competitively into PJM's capacity market?**

Response:

Yes. A PJM default offer cap based on a formula consisting of going-forward costs (including non-performances penalties or bonus payments) and opportunity costs associated with accepting a capacity obligation would be a competitive offer in PJM's Capacity Performance construct.

As detailed in Appendix 1, the formula for the PJM/IMM Agreed-to Offer Cap is identical to the formula proposed ISO-NE in its Pay for Performance Filing in Docket No. ER14-1050-000, and adopted by the Commission. As in the ISO-NE filing, for those resources that fall into the Low ACR category which have low going-forward costs and would expect to cover their costs even if they participate solely in PJM's energy market and did not earn a capacity revenue under the Capacity Performance construct, PJM believes that Net CONE * $\bar{B}$ will always represent each such resource's competitive offer. As in the ISO-NE filing, for those resources that fall into the High ACR category which have high going forward costs and would not expect to cover their costs unless they earn capacity revenues under the Capacity Performance construct, the formula provides for the inclusion of unit-specific ACR and unit-specific performance plus a risk premium for those with costs above the Net CONE * $\bar{B}$ default offer cap. Under the PJM/IMM Agreed-to Offer Cap, PJM will allow such resources to submit unit-specific offer caps which detail all ACR components including a quantifiable risk as proposed by PJM in its Capacity Performance filing.

2) In ISO-NE's Pay for Performance Filing in Docket No. ER14-1050-000, it proposed, and the Commission adopted, a default offer cap based on a formula consisting of going-forward costs (including non-performances penalties or bonus payments) and opportunity costs associated with accepting a capacity obligation.

b. Is the offer cap proposed by Monitoring Analytics, LLC, PJM's independent market monitor (Market Monitor) consistent with ISO-NE's offer cap methodology? If not, please explain the differences between the two methodologies and identify any modifications necessary to make the Market Monitor's proposed offer cap consistent with ISO-NE's methodology.

Response:

The PJM/IMM Agreed-to Offer Cap is fully consistent with ISO-NE's offer cap methodology and adopts the logic that was accepted by the Commission for ISO-NE's Pay for Performance proposal. The response to Question 2.a., above, and Appendix 1 show that the general offer cap formula proposed by the Market Monitor, the PJM/IMM Agreed-to Offer Cap and the ISO-NE approach are all identical.

2) In ISO-NE's Pay for Performance Filing in Docket No. ER14-1050-000, it proposed, and the Commission adopted, a default offer cap based on a formula consisting of going-forward costs (including non-performances penalties or bonus payments) and opportunity costs associated with accepting a capacity obligation.

c. What is the appropriate relationship between the Non-Performance Charge rate and a capacity offer cap?

Response:

The default offer cap proposed by the IMM and now accepted by PJM is exactly the same as adopted by the Commission in the ISO-NE Docket No. ER14-1050-000. That general equation captures the appropriate relationship between the Non-Performance Charge rate (PPR)[1] and the default capacity offer cap. The proposed default capacity offer cap is a direct function of PPR. The relationship is defined by the equation for a competitive offer, denoted by *p*, which is included in the Appendix.[2]

$$p = PPR \times H \times \bar{B} + max\{0, (ACR - PPR \times H \times \bar{A})\}$$

This general offer cap equation shows that the offer cap depends directly on PPR regardless of whether the default offer cap is used or whether going forward costs are also included in the case of high ACR units.

If the second term in the competitive offer equation is zero, meaning a resource could cover its net going forward costs through collection of Bonus Performance Payments, then the above equation demonstrates that the competitive offer and the default offer cap are both a direct function of the Non-Performance Charge Rate (PPR).

Because the version of PPR proposed by PJM is a function of Net CONE and H:

$$PPR = \frac{Net\ CONE}{H}$$

The default offer cap is expressed as either:

$$p = \ PPR \times H \times \bar{B}$$

or:

$$p = Net\ CONE \times \bar{B}$$

[1] PJM adopts the ISO-NE shorthand for the Performance Penalty Rate, PPR, which is identical in construction to PJM's proposed Non-Performance Charge Rate

[2] Variables are defined in the Appendix. H is the expected number of Performance Assessment Hours, $\bar{B}$ is the expected or average balancing ratio over all Performnace Assessment Hours, $\bar{A}$ is the expected or average resource performance over all Performance Assessment, and ACR is the net going forward cost of a resource defined as the avoidable costs less Expected Net Energy and Ancillary Service Market Revenues

In the case where the second term in the competitive offer equation is greater than zero, a resource cannot cover its net going forward costs through Bonus Performance Payments without a capacity payment, the unit specific competitive offer cap remains a function of PPR.

The competitive offer equation, or unit specific offer cap, simplifies to:

$$p = ACR + PPR \times H \times (\bar{B} - \bar{A})$$
$$p = ACR + Net\ CONE \times (\bar{B} - \bar{A})$$

3) The Market Monitor proposed a default offer cap of Net CONE times the Balancing Ratio (B). Some intervenors criticized this proposal on the grounds that B is too difficult to estimate in advance. If PJM's Capacity Performance proposal had been in place during the past three Delivery Years, what would the balancing ratio have been in the PJM RTO and in each of the LDAs that cleared separately.

Response:

Using data from the previous three Delivery Years, 2011/2012, 2012/2013 and 2013/2014, PJM calculated the RTO-wide balancing ratios during Performance Assessment Hours declared for the entire PJM Region. This analysis is contained in the supplemental Excel spreadsheet contained in Appendix 2 to this filing. During that period there were a total of 70 hours that would have been Performance Assessment Hours under the currently proposed rules for Capacity Performance. Of those 70 hours, 42 were RTO-wide emergencies while 28 were locational Performance Assessment Hours only.

If the Commission accepts the PJM/IMM Agreed-to Offer Cap, PJM proposes to use a historical weighted average of the balancing ratios (B) experienced in the previous three Delivery Years as the methodology to produce the balancing ratio ($\bar{B}$) used in determining the default offer cap for resources submitting offers into an auction to accept a Capacity Performance commitment. The weighted average balancing ratio for the PJM RTO considering the 42 Performance Assessment Hours in the most recent three Delivery Years is approximately 85%. A similar methodology would be used for LDA-specific $\bar{B}$, using the higher of the parent LDA or the LDA itself.

There is a marked difference between the balancing ratios during the winter Performance Assessment Hours and during the summer. In the winter of 2014, PJM experienced extraordinarily high forced outage rates and therefore had a significant number of hours that would have been considered Performance Assessment Hours. Capacity Performance provides extremely strong incentives for resource availability and therefore, over time, will eliminate occurrences like those seen in the winter of 2014. As a result the expected value of the balancing ratio $\bar{B}$ is anticipated to increase over time to a value that is more indicative of the summer Performance Assessment Hours which averaged around 93.5%.

4) Under PJM's proposal, Non-Performance Charges assessed to a capacity resource would be a function of the Non-Performance Charge rate, its performance relative to the balancing ratio, and the number of Performance Assessment Hours that arise in the resource's LDA.

a) In light of the Market Monitor's February 25, 2015, answer, which details historical Performance Assessment Hours,[3] is it appropriate to expect that the number of Performance Assessment Hours would vary predictably across different LDAs in PJM?

Response:

It is appropriate to expect that the number of Performance Assessment Hours could vary across different LDAs in the PJM Region. As shown in the spreadsheet in Appendix 2, of the 70 Performance Assessment Hours occurring over the 2011/2012 through 2013/2014 Delivery Years, such hours occurred either in the RTO LDA or in the eastern portion of the footprint (with 28 of such hours occurring in the east). This is true generally given the west-to-east constraint in the PJM Region as a whole. However, PJM cannot say with certainty that the number of Performance Assessment Hours will "vary predictably" given that the actual Performance Assessment Hours will be dependent on the number of Emergency Actions declared by PJM operators in each LDA, which are in turn dependent on such factors as load expectations, generator availability, and constraints on the transmission system (e.g., due to equipment failures or weather events).

[3] IMM February 25, 2015 answer at Appendix B, Table 1.

4) Under PJM's proposal, Non-Performance Charges assessed to a capacity resource would be a function of the Non-Performance Charge rate, its performance relative to the balancing ratio, and the number of Performance Assessment Hours that arise in the resource's LDA.

b) Would it be appropriate for offer caps to vary across different PJM LDAs to reflect any differences in expected Performance Assessment Hours?

Response:

Given that Performance Assessment Hours cannot be reliably predicted by LDA at this time, it would not be appropriate for offer caps to vary across PJM LDAs based on Performance Assessment Hours. As experience is gained with Capacity Performance and PJM transitions to a single Capacity Performance product market, this issue will be reevaluated.

5) Are there other appropriate approaches to developing offer caps for mitigation?

Response:

It is well-settled that under FPA section 205, there can be more than one just and reasonable alternative. Therefore, while PJM proposes here the use of a default offer cap equal to Net CONE * $\bar{B}$, other alternatives, depending on the circumstances, could be proposed and supported under section 205. For purposes of this response, PJM identifies and discusses two such alternatives, i.e., (1) use of a default offer cap of Net CONE, as originally proposed by PJM; and (2) elimination of a default offer cap and reliance instead solely on unit-specific review. Before discussing these alternatives, however, and to put this discussion in context, PJM will first review the purpose of offer-capping rules in an RTO bid-based market, RPM's current offer-capping rules and other market power mitigation rules, and PJM's current proposal, i.e., a default offer cap of Net CONE * $\bar{B}$, with a means for sellers to justify offers above that level on a unit-specific basis.

The Commission consistently has approved single-clearing price designs for RTO wholesale markets, in which all cleared offers receive the same price as the marginal offer that is needed to clear the market. This policy reflects the well-established principle that in a competitive, unregulated market, the market price will be set by the marginal supplier, based on that supplier's marginal costs of providing the marginal unit of supply. In Commission-regulated electricity markets (particularly capacity markets) which tend to be concentrated and implicate market power concerns, the Commission is able to maintain the single clearing price approach by limiting sellers to offering at their marginal costs. In this way, the Commission can continue to be assured that the clearing price paid to all sellers is indeed based on the costs of the marginal sell offer. Consequently, even in a market characterized by market power concerns, a Commission-regulated market can still mimic the operation of a competitive market and thereby promote market efficiency. Sellers in such a market are incented to reduce their costs and offer prices to a level below that of the expected marginal offer, so that they can clear and can receive a clearing price that is above their own individual marginal costs. Courts have repeatedly upheld this approach by the Commission, recognizing, for example, that setting a reasonable offer cap "require[s] striking a balance between, on the one hand, detecting and dampening exercises of market power and, on the other hand, allowing generators to charge prices that are high enough for them to recover their fixed costs."[4]

The relevant question, is how to ensure that seller offers will reasonably reflect seller marginal costs. The Commission has applied this basic pricing model in numerous markets across numerous RTOs, and so there is no single or exclusive just and reasonable approach to providing sufficient confidence that offers reflect costs. In practice, the Commission properly takes account of various relevant considerations and methodologies, including cost estimating uncertainties, administrative convenience and simplicity, the relative degree of market power

[4] *Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 262 (D.C. Cir. 2007).

concern, default "safe-harbor" levels for use on a generic basis, recognition of various types of legitimate costs (including opportunity costs and risk premiums), independent unit-specific offer review (by RTO or market monitor staff) as a back-stop to ensure that offers properly reflect costs, and formulaic guidance in a tariff to provide clarity to market participants and limit the exercise of discretion in offer reviews. But, regardless of the implementation details, the Commission has consistently supported the view that competitive offers in capacity markets reflect the marginal costs of providing capacity, and thus form the basis for just and reasonable clearing prices.

PJM's current capacity offer-capping rules reflect all of the above considerations. Under the current RPM rules, existing generation plants must limit their offers to a resource-specific calculation of Avoidable Cost Rate ("ACR"), i.e., the costs the resource could avoid by not committing as capacity, or the marginal cost of capacity. The Tariff describes the permitted elements of ACR, which sellers must estimate for their particular plants. The ACR rules allow sellers a ten percent adder to address cost estimating uncertainty. Sellers also are expressly permitted to include opportunity costs in their capped offer, when the seller can show that it is foregoing a firm sale of its power to loads outside the PJM Region. For sellers that prefer not to estimate their own unit-specific ACR, the Tariff includes default ACR levels for various resource categories. Sellers that choose to estimate ACR on a unit-specific basis must provide those estimates and supporting material to the IMM for review and verification. Offers from new-entry plants, which raise less market power concern because the resource does not yet exist, are not limited to ACR, and instead face a much higher offer cap that has rarely if ever been triggered. Moreover, the current rules set no offer cap on Demand Resource offers, recognizing that such resources are unlikely to have seller market power, that such resources cannot increase clearing prices above the level that would occur without any Demand Resource offers, and that the costs of demand reduction resources will vary widely with the differing types of demand reduction strategies, and present significant estimating challenges.

Notably, in RPM, offer caps are not the only means of protecting against the exercise of market power. RPM also includes must-offer requirements to protect against withholding, IMM market monitoring to protect against manipulative or anticompetitive conduct, and a Minimum Offer Price Rule to protect against certain types of offers that are below competitive levels. Offer caps therefore contribute to market power mitigation and are not the sole line of defense against market power.

In addition, PJM's experience under RPM has been that the single-clearing price market design itself provides significant incentives against non-competitive offers, indicating that absolute precision in tying offer levels to unit cost levels is not essential. As the Commission has recognized, the single-clearing-price design of markets like RPM "creates an incentive for resources to submit offers that accurately reflect their risks, rather than inflating them, in order to increase the likelihood that they will clear."[5] The incentive to clear has a powerful effect

[5] *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172, at P 198 (2014).

on offer behavior in RPM, notwithstanding the relatively concentrated market structure. A very large percentage of resources offer at zero or another price well below their avoided costs, in order to ensure the resource clears.[6] At the other end of the supply curve, offers at Net CONE are relatively infrequent, even among resources that presently can offer at or above Net CONE, i.e., planned generation resources and demand and Energy Efficiency Resources. Even without discussing individual sell offer prices from such resources, it is apparent that they often offer below Net CONE, because RPM Auctions frequently clear below Net CONE notwithstanding extensive offers from resources that are not offer-capped.[7] Therefore, sellers in RPM face a very real prospect that if they offer too high, they will not clear and will not realize any capacity revenues, even if the clearing price in the particular auction is set by new entry. Consequently, even aside from offer-capping rules, capacity sellers in PJM are incented to offer at or near their avoidable costs (i.e, the marginal cost of capacity), so that they can clear and realize a substantial contribution to fixed-cost recovery in the form of RPM capacity clearing prices.

In the Capacity Performance Filing, PJM proposed to increase the offer cap for Capacity Performance Resource offers to Net CONE. PJM now agrees, based on a careful review of seller incentives and costs under such a model, as highlighted by the IMM and reflected in the ISO-NE offer capping rules, that Net CONE * $\bar{B}$ is the better approach. In either case, however, whether the cap level is Net CONE or (Net CONE * $\bar{B}$), that cap acts as a generic default level, mooting additional review of a seller's unit-specific costs. The rationale behind such a default level, whether for Capacity Performance or for the current rules' resource-category default ACR levels, is that the default level represents the costs that all sellers face. Under the Capacity Performance Filing, the Net CONE offer cap levels would vary by LDA[, and PJM also is willing to permit the "$\bar{B}$" values to vary by LDA. PJM also proposed in the Capacity Performance Filing, and continues to propose, that a seller of a specific Capacity Performance Resource that has costs above the generic default level can offer based on those unit-specific costs if it can demonstrate those costs to the IMM in the unit-specific review process. PJM proposes no change to its offer-capping rules for resources that are not Capacity Performance Resources.

For purposes of this response, PJM refers to this offer-capping approach as the "PJM/IMM Agreed-to Offer Cap." Alternatives to that approach could include (1) Net CONE as originally proposed by PJM; or (2) unit-specific offer caps, without a generic default offer level of Net CONE or (Net CONE * $\bar{B}$). PJM briefly discusses the advantages and disadvantages of these approaches below.

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[6] *See* Comments and Limited Protest of the PJM Utilities Coalition, Affidavit of Dr. William Hieronymus and Dr. David Hunger ¶¶ 32-36 (filed January 20, 2015 in this proceeding).

[7] *See id.*

(1) Net CONE Default Offer Cap Level

PJM proposed a Net CONE default offer cap in the Capacity Performance Filing, and PJM anticipates that some parties will continue to advocate that approach. The arguments advanced in comments to date against the Net CONE * $\bar{B}$ approach have been, among others, that (i) "B" will vary but should always be relatively close to 1.0, so there is not much additional precision gained in the offer cap level as a result of multiplying by the "$\bar{B}$" factor; and (ii) "B" is difficult to estimate on a three-year forward basis, and so the resulting offer cap may not in fact be a good reflection of the actual "$\bar{B}$" factor during the relevant Delivery Year.

PJM initially shared these same concerns, upon first reviewing the IMM pleadings that advanced the Net CONE * $\bar{B}$ approach. However, upon closer review of the issue, the IMM analysis, and the specific approach taken by ISO-NE, PJM believes there are sufficient countervailing arguments to these criticisms. First, upon closer review of the IMM analysis with the IMM, PJM is satisfied that it is a comprehensive and reasonable analysis of the costs and revenues that would be expected by a rational seller considering a Capacity Performance Resource offer. Because that analysis convincingly results in a rational profit-maximizing offer (i.e., an appropriately competitive offer) of Net CONE * $\bar{B}$, an offer cap that includes that B factor will be more accurate than one that does not account for that factor. Second, PJM is comforted by the fact that ISO-NE employs the same logic to determine the offer cap for offers in its very similar pay for performance proposal. Therefore, ISO-NE has had to confront the same issue of estimating $\bar{B}$ and the Commission has accepted ISO-NE's approach. Third, RPM is a three-year forward auction and PJM therefore already has to estimate, before the auction, numerous parameters that are expected for the Delivery Year three years later. Consequently, the fact that PJM must make a reasonable estimate of this parameter should not prevent use of the parameter if the parameter is needed to help ensure just and reasonable auction results.

(2) Unit-Specific Offer Review without Net CONE * $\bar{B}$ Default Level.

Another alternative would be to eliminate the proposed default offer level of Net CONE * $\bar{B}$, and instead review all Capacity Performance Resource offers on a unit-specific basis to ensure that each offer properly reflects the costs reasonably expected for a Capacity Performance Resource. In PJM's view, this alternative should include specific references in the Tariff to the types of additional costs that are properly associated with a Capacity Performance Resource offer, given that the current ACR rules were not written with Capacity Performance in mind and therefore do not reflect those costs. To be clear, PJM views the IMM analysis as correctly identifying the additional types of costs that should be allowed for a Capacity Performance Resource offer.

The prime advantage of this approach is that it would provide greater assurance that the marginal resource offer that sets RPM clearing prices is in fact based on the costs of the marginal resource.

The prime disadvantage is the added administrative burden inherent in such an approach, compared to the proposed use of a default offer level.

The key question in such an approach, therefore, is whether the extra administrative burden outweighs the greater assurance that auction outcomes are just and reasonable. On that question, PJM would observe that for a Capacity Performance Resource offer, the results of these two approaches should be essentially the same. PJM already proposes a unit-specific review For any Capacity Performance Resource that seeks to offer above the default level, so there is no difference there. For a Capacity Performance Resource seeking to offer below Net CONE * $\bar{B}$, the unit-specific review properly should take into account the same costs identified by the IMM and ISO-NE, including the potential payment of penalties that are based on Net CONE * $\bar{B}$, and the foregone opportunity to obtain performance bonus payments, also calculated at up to Net CONE * $\bar{B}$, to the extent the resource is not committed as capacity, but still expects to perform during emergencies, so again the results should be essentially the same.

In making these observations, however, PJM does not discount the potential appeal of unit-specific review in providing an extra measure of security that auction results are just and reasonable. In that regard, it appears that ISO-NE uses a hybrid approach, with a version of one of the formulas used in the IMM's analysis (before solving it to reduce to the Net CONE * $\bar{B}$), and populates that formula with ISO-NE-determined default values. However, although the Commission could adopt this hybrid approach, PJM believes that the analysis would simply return the results back to Net CONE * $\bar{B}$. The unit-specific reviews in ISO-NE have not been without controversy and have added to disputes as to the need for certainty of market results vs. the administrative difficulties of full Commission adjudication of capacity market results after the fact. The consensus PJM-IMM approach outlined herein avoids that level of administrative uncertainty and potential litigation yet, as detailed above, provides the same results as would the more unit-specific kind of approach adopted for ISO-NE. As a result, PJM urges the Commission to adopt the PJM/IMM consensus approach in the instant filing especially given the panoply of additional market power mitigation measures already in place in the RPM construct.

Lastly, PJM would not include among the "appropriate" alternatives requested by this question any alternative that does not recognize the costs that are uniquely faced by Capacity Performance Resources (including lost opportunity costs), whether on a unit-specific or generic default basis. If a seller faces reasonably expected and legitimate costs of offering as a Capacity Performance Resource that are *not* reflected in the offer cap, then sellers will not offer Capacity Performance Resources, and the goal of creating incentives to improve Capacity Resource performance will be frustrated.

6) Provide any analysis PJM has completed that indicates the expected frequency with which a Capacity Performance resource would hit the monthly stop-loss limit of (0.5*Net CONE), or the annual stop loss of (1.5*Net CONE). Similarly, provide any analysis PJM has completed of expected performance charges and bonus payments for Capacity Performance resources under PJM's Capacity Performance proposal. Please provide supporting documentation in a machine-readable spreadsheet.

Response:

PJM has not performed any unit-specific analysis to determine when or the frequency with which a committed RPM resource would have hit the monthly or annual stop-losses. However, when PJM developed its stop-loss provisions, PJM paid careful attention to the number of full non-performance hours required for any cleared resource to reach either the monthly or annual stop-losses. PJM's Non-Performance Charge Rate is determined by converting Net CONE, stated in $/MW-day, into an equivalent $/MWh rate, incorporating the anticipated number of Performance Assessment Hours in an average year (30), that can be charged on an hourly basis for shortfalls on a capacity seller's obligation. The use of Net CONE as the anchor for the Non-Performance Charge Rate and 1.5*Net CONE for the stop-loss provisions establishes a ratio of 1.5:1 between the number of full non-performance hours needed to hit the annual stop-loss versus the expected numbers of Performance Assessment Hours in a year. Said a different way, in order for any resource to hit the annual stop-loss, it would have to have full non-performance in 50% more hours than PJM expects in an average year. Applying that principle to PJM's expectation of 30 Performance Hours in a year, a resource would have to fully not perform in 45 hours in the same year in order to hit the annual stop-loss.

In terms of the monthly stop-loss, PJM has proposed the annual stop-loss divided by three. It follows that in order to hit the monthly stop-loss a resource would have to fully fail to perform in 15 hours (45 / 3) within the same month in order to hit the monthly stop-loss. The example below illustrates the potential impact of the monthly stop- loss.

Using the data from Emergency Actions declared by PJM in the 2013/2014 Delivery Year that ran from June 1, 2013 through May 31, 2014, the IMM calculated the Non-Performance Charges that would have been paid by a non-performing resource. For this example, the resource is assumed to be in one of the zones where only RTO-wide Performance Assessment Hours apply. Any resource in the DEOK, DAY, EKPC and ComEd zones of the PJM service territory would be an example for the calculation. Assuming a resource with 500 MW ICAP, offered in the BRA with an EFORd of 0.05, the resource has a commitment of 475 MW UCAP. The RTO-wide emergency events that would qualify for Performance Assessment Hours are as shown in Table 1. There were 30 Performance Assessment Hours for RTO wide events in the 2013/2014 Delivery Year.

Table 1 RTO wide Performance Assessment Hours in Delivery Year 2013/2014

Date	Performance Region	Emergency Procedure	Start Time (EPT)	End Time (EPT)	Number of Performance Assessment Hours
3/4/2014	PJM RTO	Emergency Load Management/Maximum Emergency Generation	4:30 AM	8:30 AM	5
1/30/2014	PJM RTO	Voltage Reduction Warning	6:50 AM	7:35 AM	2
1/8/2014	PJM RTO	Emergency Load Management/Maximum Emergency Generation	5:00 AM	8:00 AM	3
1/7/2014	PJM RTO	Emergency Load Management/Maximum Emergency Generation	3:00 PM	6:16 PM	4
1/7/2014	PJM RTO	Primary Reserve Warning	12:55 AM	12:14 PM	13
1/6/2014	PJM RTO	Voltage Reduction Warning/Maximum Emergency Generation	7:27 PM	9:23 PM	3
		Total			30

Using hourly total load and losses as a proxy for the sum of total generation and net imports, and adding back demand resource settlement MW and real time reserve requirement MW, the IMM estimated the expected performance of the example generation resource during each of the Performance Assessment Hours. The Non-Performance Charge and monthly stop loss is estimated using a Net CONE value of $297.92 per MW-day, which is reflective of the average Net CONE in the rest of RTO region for the Delivery Year 2013/2014.[8] If the resource clearing price were equal to the proposed offer cap of $Net\ CONE \times \bar{B}$, as proposed by the IMM and supported by PJM for use in the Capacity Performance construct, the IMM estimated the total Non-Performance Charges with and without the monthly stop loss provision and the net capacity revenue that the resource would have received in the 2013/2014 Delivery Year.

Table 2 shows the estimated Non-Performance Charges and capacity revenues that the resource would have received for the 2013/2014 Delivery Year under the PJM/IMM Agreed-to Offer Cap.

[8] PJM, spreadsheet entitled "Planning Period Parameters" (May 17, 2010), which can be accessed at: <*http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-planning-period-parameters.ashx*>.

Table 2 Estimated Non-Performance Charges and capacity revenues in Delivery Year 2013-14

Resource ICAP (MW)	500
Resource UCAP (MW)	475
Net CONE ($/MW-day)	297.92
Non-Performance Assessment Charge ($/MWh)	$3,625
Monthly Stop Loss	$25,825,940
Cumulative non-performance charges - January 2014	$32,298,170
Actual non-performance charges - January 2014	$25,825,940
Cumulative non-performance charges - March 2014	$6,031,302
Actual non-performance charges - March 2014	$6,031,302
Total non-performance charges DY 2013-14	$31,857,242
Total non-performance charges DY 2013-14, without monthly stop loss	$38,329,472
Total non-performance charges DY 2013-14 (per MW UCAP basis)	$67,067.88
Total non-performance charges DY 2013-14 without monthly stop loss (per MW UCAP basis)	$80,693.62
Initial Revenue assuming clearing price at (Net CONE*B)	$38,329,472
Net Capacity Revenue with stop loss	$6,472,230
Net Capacity Revenue without stop loss	$0

Table 2 shows that in the month of January 2014, the monthly stop loss would have limited the Non-Performance Charges to the resource at a value that is $6.5 million lower than it would have been without the monthly stop loss. On a per MW UCAP basis, the non-performance assessment charge is $13,626/MW lower with the stop-loss compared to what it would have been without the stop loss.

While the monthly stop-loss is beneficial from the capacity seller's perspective because it reduces the non-performance payments in a month like January of 2014, it dilutes the core incentives because it allows underperformance without consequence any time a resource has reached the monthly stop loss. Additionally, it decreases the total pool of over-performance dollars available to resources that exceed their commitments, because the total pool of under-performance dollars to be paid out is less than it otherwise would be had resources not hit the monthly stop-loss. The annual stop-loss is based on the premise that no resource should be penalized more than 1.5 * Net CONE times its capacity commitment because, based on the shape of the VRR curve, 1.5 Net CONE is set as the maximum price load will pay for capacity. It is logical, and consistent with the Capacity Performance design, to limit a seller's repayment for non-performance to this maximum price permitted under RPM.

PJM clarifies that it would not be opposed to the Commission requiring PJM to eliminate the monthly stop loss in this proceeding or requiring PJM to review the monthly stop loss and any impact on performance incentives at an appropriate time after implementing the Capacity Performance design.

7) In ISO-NE's Pay for Performance Filing in Docket No. ER14-1050-000, it proposed, and the Commission adopted, a phase-in for its Capacity Performance Payment Rate. Is it appropriate for PJM to phase-in its Non-Performance Charge by transitioning from its proposed rate, based on 30 expected Performance Assessment Hours, to a more stringent penalty assessment?

Response:

Given the transition PJM has already proposed in this proceeding, summarized below, there is no need for any further phase-in of the Non-Performance Charge Rate.

In its Pay for Performance proposal in Docket No. ER14-1050-000, ISO-NE proposed a phased-in approach to its Capacity Performance Payment Rate such that "for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh."[9] ISO-NE's rationale for this proposed phased-in approach is essentially to allow the ISO to gain experience with the Pay for Performance structure and gauge the impact of the Capacity Performance Payment Rate, so that adjustments could be made if necessary before the full, $5,455/MWh rate goes into effect in 2024.

PJM has proposed a Transitional Incremental Auction structure PJM which will provide for a transition to the Capacity Performance structure over two remaining Delivery Years before the 2018/2019 Delivery Year. Specifically, PJM has proposed to procure steadily increasing quantities of Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years (up to 60% of the requirement in the 2016/2017 Delivery Year and up to 70% in the 2017/2018 Delivery Year) at steadily increasing price caps (50% of Net CONE in the 2016/2017 Delivery Year and 60% of Net CONE in the 2017/2018 Delivery Year). To complement the reduced price caps PJM has proposed for Capacity Performance Resources in these two Delivery Years, PJM has also proposed reduced Non-Performance Charges for these years in the form of both a reduced, per MWh charge and also reduced monthly and annual stop-loss values. The result of these transitional components for these two, intervening Delivery Years will be to allow both PJM and Capacity Market Sellers to gain experience with the Capacity Performance structure while ensuring both reduced cost to Load Serving Entities and also reduced exposure to Non-Performance Charges for Capacity Performance Resources. From the 2018/2019 Delivery Year and subsequent Delivery Years, while PJM will apply the market power mitigation measures as described both in PJM's initial filing and

[9] Filings of Performance Incentives Market Rule Changes of ISO New England, Inc. and New England Power Pool, Docket No. ER14-1050-000, at 24 (Jan. 17, 2014).

this response as well as those that remain unchanged in PJM's current Tariff and continue to conduct the RPM BRAs utilizing the Variable Resource Requirement curve which sets the maximum price that can result from the auction, PJM will not impose the lower price caps on the Capacity Performance product proposed for the transition years. Market Sellers will begin receiving capacity revenues based upon the full implementation of the Capacity Performance rules beginning with the 2018/2019 Delivery Year. As such, PJM therefore believes that it is unnecessary to provide further transition into the Capacity Performance structure from the standpoint of the Non-Performance Charge, because load should be assured that Capacity Performance Resources have the full incentive to invest appropriately in their resources from the 2018/2019 Delivery Year forward. Phasing in the non-performance charge rate beyond what PJM has already proposed in its transition mechanism would inappropriately dilute this incentive.

For the PJM region, a stringent Non-Performance Charge is critical to ensure that sufficient incentive exists for Capacity Market Sellers to invest the increased capacity payments they will receive as a result of the Capacity Performance proposal in preparing their resources to be capable of providing energy to the system when they are most needed for reliability. A reduced Non-Performance Charge would dilute this incentive to make these needed investments, and instead encourage Market Sellers not to make such investment and take a chance that emergency conditions will not occur. Even with a Non-Performance Charge that is based on PJM's initial proposal of 30 expected Performance Assessment Hours, there would be the potential for Market Sellers to evaluate the incrementally increased probability of their resource being unavailable during PJM Performance Assessment Hours given the relatively small chance of actually having 30 Performance Assessment Hours in a single year and choose to reduce the amount of investment made in their resources. Therefore, PJM believes it is critical to implement a sufficiently high Non-Performance Charge to drive investment in Capacity Performance resources, and do so from the first, full Delivery Year of implementation of the Capacity Performance Proposal. Given PJM's experience with declining performance level of units (as exemplified by unit performance levels during the Polar Vortex) and given the increased pressure on the coal fleet as a result of the MATS rule and potential implementation of EPA's Clean Power Plan, these penalty levels are appropriate for the PJM region given the future challenges to the fleet notwithstanding the Commission approving a longer phase-in for ISO-New England.

8) Other than the proposed seller representations, what other mechanisms could be used to supplement the Non-Performance Charge to better incent resource performance?

In addition to the Non-Performance Charge, PJM proposes an increased market seller default offer cap precisely so that sellers can include in their offers the added operating and capital costs that are needed to improve resource performance. As explained in the initial filing, this allowance for higher offers, coupled with the incentive to offer at levels likely to clear, will promote competition among sellers that choose differing strategies to improve resource performance, which should help ensure that only the most efficient approaches to improved performance will clear. The prospect of obtaining performance bonus payments further reinforces these incentives, because the resources that prove most effective at delivering better performance stand to receive higher performance payments. The Non-Performance Charge, bonus Performance Payments, and increased offer cap are therefore designed to work together to incent the most effective performance enhancements at the lowest cost. The PJM Capacity Performance proposal also includes strong rules related to the use of unit offer parameters in Docket No. EL15-29-000, which effectively prevent units from using inflexible parameters to avoid responding when the energy from their resources is needed by PJM. The parameter rules are another mechanism to better incent actual unit performance when it is needed and although filed in a separate docket, are integral to ensure the appropriate incentives toward enhanced unit performance. The PJM Capacity Performance proposal includes a combination of market features that include price formation which reflects supply and demand fundamentals and rules which prevent units from avoiding the obligation to provide energy when it is needed and which result in strong price incentives to provide that energy.

9) In Docket No. ER14-1461-000, PJM proposed moving from three incremental auctions to one incremental auction. Would modifying PJM's proposal to include this change reduce the incentive to make speculative offers, and thereby improve price formation in the capacity market?

Response: Modifying PJM's proposal to move from three incremental auctions to one incremental auction would further reduce the incentive to make speculative offers and improve price formation in RPM. Therefore, PJM remains committed to its proposal to reduce the number of scheduled Incremental Auctions from three to one as proposed in its filing in Docket No. ER14-1461-000. PJM indicated in its August 18, 2014 letter in that proceeding and the related FPA section 206 proceeding in Docket No. EL14-48-000, that PJM would, in response to the Commission's section 206 action, address any needed changes to address the speculative offer problem following Commission action on the anticipated Capacity Performance Filing. Thus, the Commission could note this Incremental Auction issue in its order on this deficiency response and direct that the issue be addressed in Docket No. EL14-48-000 (or, if so inclined, the Commission could order a compliance filing in this docket for PJM to address this issue).

Capacity Market Sellers with RPM capacity commitments for a Delivery Year are currently provided an opportunity in each of three Incremental Auctions to buy out of their capacity commitment. In Docket No. ER14-1461-000, PJM proposed moving from three Incremental Auctions to one Incremental Auction for the following reasons, all related to speculative offers impacts on price formation:

- The current rules allow the demand for replacement capacity to be spread among three auctions, but require the supply of replacement capacity to offer into every one of the three auctions (unless cleared or excused). This dilution of demand across three auctions tends to reduce the Incremental Auction clearing prices, because there are fewer Buy Bids in any given Incremental Auction to match with Sell Offers.

- Providing sell-back opportunities in three Incremental Auctions also multiplies the chances that a BRA seller will be able to buy out of its BRA commitment at a profit. A prospective BRA seller will know when it submits its offer that it will have three separate chances to successfully "shop" its BRA commitment at a low price in the Incremental Auctions. Therefore, this rule can undermine the seller's incentive to only submit offers for resources that it is reasonably certain will result in physical delivery.

- The current three-Incremental Auction structure even permits a seller to engage in repeated capacity sales and buy-backs over the course of the four auctions for a Delivery Year, and reap multiple profits on the same MWs for a single Delivery Year. Clearly, that is not behavior concerned with meeting the region's resource adequacy needs.

As PJM explained, the essential purpose of allowing parties to buy out of their commitment to avoid deficiency charges during the Delivery Year is served so long as they have at least one opportunity to buy replacement capacity in an Incremental Auction before the Delivery Year.[10] This would be true under PJM's Capacity Performance proposal as well. Moving from three Incremental Auctions to one Incremental Auction would assure Capacity Market Sellers the ability to buy out of their commitment prior to the Delivery Year but would reduce: the incentive for submitting speculative offers; the ability for Capacity Market Sellers to suppress prices, and the ability to reap profits on the same MWs without incremental benefit to the region's resource adequacy needs. These objectives clearly are in line with the objectives of PJM's Capacity Performance structure to ensure generator performance and fuel security.

Just as PJM proposed in Docket No. ER14-1461-000, the Incremental Auction known as the Third Incremental Auction held three months prior to the start of the Delivery Year after generation resource forced outage rates (known as EFORd) have been determined for the upcoming Delivery Year, would be the appropriate time for such Incremental Auction under the Capacity Performance structure.[11] If the Commission were to issue an order requiring PJM include this proposal as part of its Capacity Performance structure, this would be the only Incremental Auction PJM would conduct, unconditionally, for every Delivery Year, and it would call it the "Scheduled Incremental Auction, " just as it proposed to do in Docket No. ER14-1461-000.[12]

Just as PJM proposed in ER14-1461-000, PJM would want to include in its Capacity Performance structure the ability to hold up to two "conditional" Incremental Auctions to procure additional capacity if an updated load forecast calls for upward revisions to the Reliability Requirement.

For these reasons, PJM seeks an indication from the Commission that this issue should be further pursued either in a compliance filing in this docket or in the pending 206 complaint proceeding ER 14-1461-000.

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[10] *PJM Interconnection, L.L.C.*, Docket No. ER14-1461-000, Transmittal Letter at 36-37 (filed Mar. 10, 2014).
[11] *Id.*
[12] *Id.*

10) Please describe how PJM evaluates the performance of external resources that are not pseudo-tied to PJM. Specifically, how and when does PJM receive the data necessary to perform this evaluation?

Response:

External resources that are not dynamically transferred into PJM through either a pseudo-tie or dynamic schedule, are required to schedule their energy delivery into PJM via external interchange transactions. These transactions are identified using the NERC transaction tagging process and entered into the PJM ExSchedules internet application. Interchange schedules implemented via the ExSchedule application are not resource specific. Rather, they are identified by customer account and the external Balancing Authority from which the energy being scheduled into PJM is sourced. Capacity resource commitments by contrast are unit-specific.

PJM performs an external unit capacity verification process following any day on which a capacity emergency event occurs. The purpose of this process is to ensure that external capacity resources fulfilled their commitment to deliver energy into PJM by virtue of their commitment as a PJM Capacity Resource. For each external capacity resource owner, PJM determines the external capacity resource owner's hourly MWh of interchange scheduled via the ExSchedules application. PJM also determines whether the capacity resource owner had submitted an outage tickets for their external resources via the eDART reporting system. If the sum of the hourly MWh of interchange scheduled into PJM by the external capacity resource owner plus the sum of the outage tickets submitted by the resource owner for its external units is greater than or equal to the external capacity resource owner committed ICAP or FRR MW, then the external capacity resource owner is not deficient with respect to its capacity resource commitment. However, if the sum of the hourly MWh of interchange scheduled into PJM and the eDART outage tickets submitted by the external capacity resource owner is less than the sum of the ICAP or FRR MW, then the resource owner is determined to be deficient and must submit additional eDART outage tickets in at least the amount of the difference.

The information required to perform this evaluation is as follows:

- Committed External Capacity resource and FRR Committed ICAP MWs – this information is stored in the PJM eRPM database and is available prior to the Delivery Year for resources committed via RPM auctions or in FRR plans, and updated up until the operating day via bilateral and replacement transactions.

- Resource owner scheduled imports to PJM – this information is submitted to PJM via the ExSchedules internet application prior to the transactions flowing in real time, and is therefore available immediately following the operating day.

- Resource owner submitted outage tickets - resource outage information is submitted via the PJM eDART internet application. Outage information may be submitted to PJM after-the-fact, and there is therefore no definitive timeline for when the final information becomes available to PJM.

The fact that external interchange schedules submitted via the PJM ExSchedules internet application are not unit specific and therefore cannot be tied to any specific external resource is one of the reasons underlying the PJM proposal to require that external units must be pseudo-tied into PJM in order to qualify as Capacity Performance Resources. Without the benefit of the pseudo-tie, PJM cannot accurately determine whether an external capacity resource owner met its commitment to delivery energy to PJM from the resource(s) committed to PJM as Capacity Performance resources. This information is critical to ensure that the performance assessment evaluations are completed accurately and any Non-Performance Charges are applied correctly.

APPENDIX 1

OVERVIEW OF
CAPACITY PERFORMANCE OFFER CAP LOGIC

Capacity Performance Offer Cap Logic

Definitions

R^c – net revenue for a resource with a capacity commitment. ($)

R^{nc} – net revenue for a resource without a capacity commitment that sells energy and ancillary services. ($)

PPR – non-performance charge rate. ($/MWh) PPR equals Net CONE (in installed capacity (ICAP) MW terms) ($/MW-year) divided by H, for the delivery year for a particular Net CONE area)

$CPBR_i$ – capacity performance bonus rate for hour i, varies with the hour. ($/MWh) CPBR depends on the level of non-performance charges collected from underperforming resources during each performance assessment hour. The maximum value of CPBR is the non-performance charge rate, PPR, which occurs when no resource is exempted for under performance. If resources are exempted for under performance, the CPBR would decrease.

ACR – Net ACR (net going forward costs) for the resource on a per MW UCAP basis. ($/MW-year)

A_i - availability during performance assessment hour i ($A_i = MWh_i/UCAP$)

$\bar{A}$ – expected value of availability across all performance assessment hours. ($\bar{A} = \sum_{i=1}^{H} MWh_i/(H \times UCAP)$)

B_i – balancing ratio during performance assessment hour i, ratio of total load and reserve requirement during the hour to total committed UCAP.

$\bar{B}$ – expected value of balancing ratio across all performance assessment hours in a delivery year.

H – Expected value of total number of performance assessment hours in a delivery year. (Hours/year)

p – Offer price in RPM on a UCAP basis. ($/MW-year)

PAH – Performance Assessment Hour - each whole or partial clock-hour for which an Emergency Action has been declared by PJM[1]

[1] "Emergency Action" shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action. See PJM proposed Tariff, Attachment DD, section 2.23A' Emergency Action'

Expected net revenues

If a resource is expected to underperform i.e., when expected $A_i < B_i$ for all PAH:[2]

The total cash flow for a resource that has a capacity commitment, R^c, can be calculated as:

$$R^c = UCAP \times [p + \ PPR \times H \times (\bar{A} - \bar{B})] - UCAP \times ACR \qquad (1)$$

The total cash flow for that same resource that does not have a capacity commitment but participates in the energy and ancillary services markets and earns capacity bonus performance payments, R^{nc}, can be calculated as:

$$R^{nc} = UCAP \times [\ \sum_{i=1}^{H} (CPBR_i \times A_i)] - UCAP \times ACR$$

If CPBR = PPR,

$$R^{nc} = UCAP \times PPR \times H \times \bar{A} - UCAP \times ACR \qquad (2)$$

In equation (2) since the resource does not have a capacity performance obligation, the resource earns capacity bonus performance payments for all of its energy and reserves during performance assessment hours. Equation 2 assumes, to make the presentation more direct, that there are no exemptions from under performance penalties and that therefore CPBR = PPR. In fact, PJM has exemptions, which will result in CPBR < PPR. The proposed monthly stop loss could also result in CPBR being less than PPR because smaller non-performance charges mean smaller bonus payments. To the extent that CPBR is less than PPR, the competitive offer will be lower. CPBR will not exceed PPR.

Low ACR case

If $R^{nc} \geq 0$, a resource is expected to make enough revenues to cover net going forward costs (ACR) without a capacity commitment and has the opportunity to be profitable as an Energy Resource in the Capacity Performance design. The revenues for such a resource equal the performance rate times the number of performance assessment hours (H) times the performance of the unit during those hours (A).

$$i.e. \quad if\ ACR \leq PPR \times H \times \bar{A}$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the Capacity Performance design, the additional expected revenue from being a capacity resource must be greater than or equal to the expected revenue as an Energy Resource, or $R^c \geq R^{nc}$.

[2] If a resource is expected to over-perform, the competitive offer is lower in each case.

In other words, if taking on a capacity obligation is to be profitable and competitive:
$R^c - R^{nc} \geq 0$

Thus, the competitive offer and therefore the expected equilibrium clearing price in RPM equals equation (1) (revenues from being a capacity resource) minus equation (2) (revenues from not being a capacity resource):

$$p \geq PPR \times H \times \bar{A} - PPR \times H \times (\bar{A} - \bar{B})$$
$$or, \quad p = PPR \times H \times \bar{B} \qquad (3)$$

Using PJM's proposed formula for the non-performance charge rate (PPR):

$$PPR = \frac{Net\ CONE}{H}$$

The result is:

$$p = Net\ CONE \times \bar{B}$$

High ACR case

If $R^{nc} < 0$, a resource is not expected to make enough revenues to cover net going forward costs without a capacity payment.

$$i.e. \quad if\ ACR > PPR \times H \times \bar{A}$$

In order for such a resource to have an incentive to take on the obligation to be a capacity resource under the Capacity Performance design, the expected revenue from selling capacity would have to be enough to cover the difference between ACR and capacity bonus performance payments.
If taking on a capacity obligation is to be profitable and competitive: $R^c \geq 0$.
From equation (1):

$$UCAP \times [p + PPR \times H \times (\bar{A} - \bar{B})] - UCAP \times ACR \geq 0$$
$$or, \quad p \geq ACR + PPR \times H \times (\bar{B} - \bar{A})$$

The competitive offer is:

$$p = ACR + PPR \times H \times (\bar{B} - \bar{A}) \qquad (5)$$

From equation (5), for a resource that is expected to perform poorly ($\bar{A} < \bar{B}$), capacity revenue needs to cover the net going forward costs (ACR) plus any non-performance charges. The competitive offer for such a resource is greater than its net going forward costs by the amount of its non-performance charges.

For a resource that is expected to perform well ($\bar{A} > \bar{B}$), bonus performance payments cover part of the net going forward costs, and capacity revenue needs to cover the rest. The competitive offer for such a resource is less than its net going forward costs but not less than $Net\ CONE \times \bar{B}$.

Equation (5) can also be re-written as:

$$p = PPR \times H \times \bar{B} + (ACR - PPR \times H \times \bar{A}) \qquad (6)$$

Combining the competitive offer equations in both the low ACR (equation (3)) and high ACR cases (equation (6)), a general definition of a competitive offer can defined is:

$$p = PPR \times H \times \bar{B} + max\{0,\ (ACR - PPR \times H \times \bar{A})\} \qquad (7)$$

This is the same equation as the ISO-NE competitive offer equation. For a resource with low ACR, the second term in equation (7) is zero. For a resource with high ACR, the second term is a positive value.

ISO-NE used equation (7) to calculate the de-list bid threshold value for their Forward Capacity Auction with certain assumptions, as described in the testimony of ISO-NE witnesses Dr. LaPlante and Dr. Gheblealivand.[3] The de-list bid threshold in ISO-NE is the offer below which the ISO-NE Internal Market Monitor does not review the unit specific cost components of the resource. It is analogous to the Market Seller Offer Cap in RPM.
The PPR in ISO-NE is a phased in rate that starts at $2,000/MWh for the first three forward capacity auctions. This rate is approximately one third of the PPR derived using Net CONE for ISO-NE.

ISO-NE calculated a specific numerical offer cap (de-list bid threshold) of $3.94/kW-month or $129.53/MW-day based on specific assumptions about the expected marginal resource in the capacity auction (fossil steam unit), the average net going forward costs of the expected marginal resource from a prior auction and the average availability (A) of a resource.[4] Instead of calculating a specific numerical value based on assumptions about the marginal clearing resource type and the expected availability of resources in the Capacity Performance framework, PJM proposes to use the formula in equation (7) to calculate unit-specific offer caps.

In PJM, the PPR is set at the full rate using Net CONE (in $ per MW of ICAP) divided by the expected number of performance assessment hours (H).

$$PPR = \frac{Net\ CONE}{H}$$

[3] *See* ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes, Docket No. ER14-1050-000 (January 17, 2014), Attachment I-1e (Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand) at 59-61.
[4] *Id.* at 60-61.

Using this equation for PPR, and the expected number of performance assessment hours (H), the competitive offer in PJM from equation (7) is:

$$p = \left(\frac{Net\ CONE}{H}\right) \times H \times \bar{B} + max\left\{0, \quad \left(ACR - \left(\frac{Net\ CONE}{H}\right) \times H \times \bar{A}\right)\right\}$$
$$or, \quad p = Net\ CONE \times \bar{B} + max\{0, \quad (ACR - Net\ CONE \times \bar{A})\}$$

For low ACR units, the second term in the above equation is zero because capacity market revenues exceed ACR, and the competitive offer is:

$$p = Net\ CONE \times \bar{B}$$

Note that the competitive offer of a low ACR unit is only dependent on the system variables of net CONE and balancing ratio. The offer cap is only dependent on the LDA/Net CONE area where the resource is located.

For high ACR units, the competitive offer also depends on unit specific ACR and expected resource performance compared to B:

$$p = Net\ CONE \times \bar{B} + ACR - Net\ CONE \times \bar{A}$$
$$p = ACR + Net\ CONE \times (\bar{B} - \bar{A})$$

Instead of assuming values for ACR and average expected performance (A) to calculate a fixed value for the offer cap, PJM proposes to calculate a unit specific offer cap for high ACR units.

The detailed review shows that for units that could profitably provide energy under the Capacity Performance design even without a capacity payment because their Capacity Performance bonus payments exceed their net ACR, based on expected unit specific performance, expected balancing ratio and expected PAH, the competitive, profit maximizing offer is (net CONE * B), where B is the expected average balancing ratio. This is the appropriate offer cap for such units.

As a result of the fact that B is always expected to be less than or equal to 1.0, the default offer cap is less than or equal to Net CONE. This result is consistent with the actual obligation to provide energy during each Performance Assessment Hour (PAH), which is (UCAP * B). Under the Capacity Performance design, units are required to provide their share of the peak load and reserve requirement in every PAH. Units are not required to provide full ICAP or full UCAP. The balancing ratio, B, is defined to be the ratio of load plus reserves to total UCAP cleared in the capacity market.

For those units that could not profitably provide energy under the Capacity Performance design without a capacity payment because their net ACR exceeds their Capacity Performance bonus payments based on expected unit specific performance, expected balancing ratio and expected PAH, and the units are expected to perform poorly, the competitive, profit maximizing offer is equal to net ACR, plus expected non-performance charges, plus any appropriate risk premium. This is the appropriate offer cap for such units. Unit offers made subject to this offer cap will require unit specific review because they depend on unit specific ACR information and unit specific risk premium.

For those units that could not profitably provide energy under the Capacity Performance design without a capacity payment because their net ACR exceeds their Capacity Performance bonus payments based on expected unit specific performance, expected balancing ratio and expected PAH, and the units are expected to perform well, the competitive, profit maximizing offer is equal to net ACR minus expected bonus payments, plus any appropriate risk premium. This is the appropriate offer cap for such units. Unit offers made subject to this offer cap will require unit specific review because they depend on unit specific ACR information and unit specific risk premium.

APPENDIX 2

Delivery Year	Date	Performance Region	Summer or Winter	Timestamp (Local Time)	Balancing Ratio Numerator	Total Gen Capacity Obligation	Balancing Ratio
2013/2014	Mar 4, 2014	PJM RTO	Winter	3/4/2014 5:00	119,752.4	167,526.5	**71.5%**
2013/2014	Mar 4, 2014	PJM RTO	Winter	3/4/2014 6:00	125,652.0	167,526.5	**75.0%**
2013/2014	Mar 4, 2014	PJM RTO	Winter	3/4/2014 7:00	128,534.6	167,526.5	**76.7%**
2013/2014	Mar 4, 2014	PJM RTO	Winter	3/4/2014 8:00	127,558.1	167,526.5	**76.1%**
2013/2014	Jan 30, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/30/2014 5:00	56,521.9	83,398.2	**67.8%**
2013/2014	Jan 30, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/30/2014 8:00	62,711.7	83,398.2	**75.2%**
2013/2014	Jan 30, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/30/2014 9:00	60,192.8	83,398.2	**72.2%**
2013/2014	Jan 30, 2014	PJM RTO	Winter	1/30/2014 6:00	134,668.2	168,069.7	**80.1%**
2013/2014	Jan 30, 2014	PJM RTO	Winter	1/30/2014 7:00	139,048.9	168,069.7	**82.7%**
2013/2014	Jan 24, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/24/2014 5:00	59,177.1	83,398.2	**71.0%**
2013/2014	Jan 24, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/24/2014 6:00	65,210.0	83,398.2	**78.2%**
2013/2014	Jan 24, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/24/2014 7:00	68,095.8	83,398.2	**81.7%**
2013/2014	Jan 24, 2014	Mid-Atlantic Dominion (MAD)	Winter	1/24/2014 8:00	66,121.6	83,398.2	**79.3%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 15:00	58,403.4	92,146.4	**63.4%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 16:00	60,695.9	92,146.4	**65.9%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 17:00	65,588.8	92,146.4	**71.2%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 18:00	68,798.0	92,146.4	**74.7%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 5:00	60,880.5	92,146.4	**66.1%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 6:00	65,989.2	92,146.4	**71.6%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 7:00	69,237.7	92,146.4	**75.1%**
2013/2014	Jan 23, 2014	Mid-Atlantic Dominion (MAD) + AP	Winter	1/23/2014 8:00	68,739.3	92,146.4	**74.6%**
2013/2014	Jan 8, 2014	PJM RTO	Winter	1/8/2014 6:00	131,519.0	168,930.1	**77.9%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 16:00	133,293.4	168,930.1	**78.9%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 17:00	140,327.4	168,930.1	**83.1%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 18:00	143,362.8	168,930.1	**84.9%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 0:00	122,602.3	168,930.1	**72.6%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 1:00	121,927.3	168,930.1	**72.2%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 2:00	121,947.9	168,930.1	**72.2%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 3:00	122,826.7	168,930.1	**72.7%**

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Delivery Year	Date	Performance Region	Summer or Winter	Timestamp (Local Time)	Balancing Ratio Numerator	Total Gen Capacity Obligation	Balancing Ratio
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 4:00	125,049.9	168,930.1	**74.0%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 5:00	129,809.7	168,930.1	**76.8%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 6:00	136,483.4	168,930.1	**80.8%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 7:00	140,614.3	168,930.1	**83.2%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 8:00	140,451.8	168,930.1	**83.1%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 9:00	139,497.0	168,930.1	**82.6%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 10:00	138,389.2	168,930.1	**81.9%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 11:00	137,190.4	168,930.1	**81.2%**
2013/2014	Jan 7, 2014	PJM RTO	Winter	1/7/2014 12:00	135,476.9	168,930.1	**80.2%**
2013/2014	Jan 6, 2014	PJM RTO	Winter	1/6/2014 19:00	133,803.6	168,930.1	**79.2%**
2013/2014	Jan 6, 2014	PJM RTO	Winter	1/6/2014 20:00	133,238.5	168,930.1	**78.9%**
2013/2014	Jan 6, 2014	PJM RTO	Winter	1/6/2014 21:00	131,688.8	168,930.1	**78.0%**
2013/2014	Sep 11, 2013	Mid-Atlantic Dominion (MAD)	Summer	9/11/2013 14:00	70,878.7	83,345.2	**85.0%**
2013/2014	Sep 11, 2013	Mid-Atlantic Dominion (MAD)	Summer	9/11/2013 15:00	70,169.7	83,345.2	**84.2%**
2013/2014	Sep 11, 2013	Mid-Atlantic Dominion (MAD)	Summer	9/11/2013 16:00	70,007.0	83,345.2	**84.0%**
2013/2014	Sep 11, 2013	Mid-Atlantic Dominion (MAD)	Summer	9/11/2013 17:00	68,384.5	83,345.2	**82.0%**
2013/2014	Sep 11, 2013	Mid-Atlantic Dominion (MAD)	Summer	9/11/2013 18:00	66,281.8	83,345.2	**79.5%**
2013/2014	Jul 18, 2013	PJM RTO	Summer	7/18/2013 14:00	159,517.6	169,629.1	**94.0%**
2013/2014	Jul 18, 2013	PJM RTO	Summer	7/18/2013 15:00	160,148.2	169,629.1	**94.4%**
2013/2014	Jul 18, 2013	PJM RTO	Summer	7/18/2013 16:00	160,970.4	169,629.1	**94.9%**
2013/2014	Jul 18, 2013	PJM RTO	Summer	7/18/2013 17:00	160,511.6	169,629.1	**94.6%**
2012/2013	Jul 18, 2012	Mid-Atlantic	Summer	7/18/2012 14:00	54,844.5	60,586.6	**90.5%**
2012/2013	Jul 18, 2012	Mid-Atlantic	Summer	7/18/2012 15:00	54,900.0	60,586.6	**90.6%**
2012/2013	Jul 18, 2012	Mid-Atlantic	Summer	7/18/2012 16:00	51,684.0	60,586.6	**85.3%**
2012/2013	Jul 18, 2012	Mid-Atlantic	Summer	7/18/2012 17:00	49,434.8	60,586.6	**81.6%**
2012/2013	Jul 17, 2012	PJM RTO	Summer	7/17/2012 15:00	157,053.6	166,198.0	**94.5%**
2012/2013	Jul 17, 2012	PJM RTO	Summer	7/17/2012 16:00	158,038.3	166,198.0	**95.1%**
2012/2013	Jul 17, 2012	PJM RTO	Summer	7/17/2012 17:00	157,895.0	166,198.0	**95.0%**
2012/2013	Jul 17, 2012	PJM RTO	Summer	7/17/2012 18:00	156,185.0	166,198.0	**94.0%**

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Delivery Year	Date	Performance Region	Summer or Winter	Timestamp (Local Time)	Balancing Ratio Numerator	Total Gen Capacity Obligation	Balancing Ratio
2012/2013	Jul 17, 2012	PJM RTO	Summer	7/17/2012 19:00	152,654.0	166,198.0	**91.9%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 13:00	154,545.6	163,626.2	**94.5%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 14:00	154,995.2	163,626.2	**94.7%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 15:00	154,466.7	163,626.2	**94.4%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 16:00	153,099.3	163,626.2	**93.6%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 17:00	151,036.1	163,626.2	**92.3%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 18:00	147,398.2	163,626.2	**90.1%**
2011/2012	Jul 22, 2011	PJM RTO	Summer	7/22/2011 19:00	143,542.3	163,626.2	**87.7%**
2011/2012	Jun 9, 2011	Mid-Atlantic	Summer	6/9/2011 15:00	54,124.6	60,662.9	**89.2%**
2011/2012	Jun 9, 2011	Mid-Atlantic	Summer	6/9/2011 16:00	54,653.7	60,662.9	**90.1%**
2011/2012	Jun 9, 2011	Mid-Atlantic	Summer	6/9/2011 17:00	54,287.3	60,662.9	**89.5%**
2011/2012	Jun 9, 2011	Mid-Atlantic	Summer	6/9/2011 18:00	52,612.8	60,662.9	**86.7%**

Delivery Year	Constrained LDAs in RPM			
2011/2012	None			
2012/2013	MAAC	EMAAC	PSEG-North	DPL-South
2013/2014	MAAC	EMAAC	SWMAAC	PEPCO

(1) Constrained LDAs in RPM listed above are those LDAs that cleared separately in any RPM auction conducted for the specified Delivery Year.
(2) A single balancing ratio is determined for each performance assessment hour and for the entire region defined by the emergency action. The constrained LDAs listed above are wholly contained in each of the performance regions for which PJM has calculated balancing ratios, therefore, the calculated hourly balancing ratios are applicable to each resource located in these constrained LDAs.