128 FERC ¶ 61,157
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

PJM Interconnection, L.L.C.

Docket Nos. ER05-1410-013
EL05-148-013
ER09-412-002

ER05-1410-014
EL05-148-014
ER09-412-004

ER09-412-003

ER09-412-005

ORDER ON CLARIFICATION AND REHEARING AND ON COMPLIANCE FILINGS

(Issued August 14, 2009)

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1. In this order, the Commission grants in part and denies in part requests for clarification and rehearing of two earlier orders[1] regarding PJM Interconnection, L.L.C. (PJM)'s Reliability Pricing Model (RPM) capacity market. The Commission also accepts two related compliance filings.

I. Background

A. March 26 Order on RPM and May 1 Order on Clarification

2. As discussed in the March 26 Order, PJM has implemented RPM, a capacity market under which PJM purchases capacity on a multi-year forward basis through an auction mechanism. The prices for capacity are determined by these forward auctions. To date, PJM has conducted six Base Residual Auctions, which have determined the level of capacity and prices for Delivery Years 2007-

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[1] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275 (2009) (March 26 Order) and *PJM Interconnection, L.L.C.*, 127 FERC ¶ 61,104 (2009) (May 1 Order).

2013. PJM's most recent Base Residual Auction was conducted in May 2009 to procure capacity for the 2012-2013 Delivery Year.

3. As discussed in the March 26 Order, on December 12, 2008, PJM made a filing under section 205 of the Federal Power Act (FPA) in which it proposed significantly to revise the RPM capacity market. PJM subsequently amended that filing on February 9, 2009.

4. PJM sought to revise its calculation of the gross Cost of New Entry (CONE) parameter, which is designed to represent the cost of constructing a new generation resource. PJM also considered whether to continue using a combustion turbine unit as the reference resource for determining CONE, and concluded that this was the most appropriate action. PJM further proposed, in its February 9 amendment, to engage in a stakeholder process aimed at developing an automatic adjustment procedure for CONE (also known as "empirical CONE"). The Commission accepted PJM's revisions making these changes.[2]

5. PJM sought to alter the design of the auctions which it uses to obtain capacity. Under RPM, PJM conducts a Base Residual Auction three years ahead of each Delivery Year, but also conducts three incremental auctions during that three-year period. In the December 12 filing, PJM proposed to alter the design of these incremental auctions in various ways. First, PJM's revisions addressed its ability to procure additional capacity in the event of under-procurement or sell capacity in the event of over-procurement. Second, it proposed to revise the provisions governing capacity provided by Interruptible Load for Reliability (ILR) resources, a type of demand resource. Under its prior tariff, a portion of the capacity needed by PJM was set aside to be served by ILR resources. PJM proposed to eliminate the provision setting aside a portion of the capacity requirement specifically for ILR resources, and instead to "hold back" 2.5 percent of the capacity requirement so as to permit a substantial amount of short lead-time resources to have a reasonable opportunity to be procured in the final incremental auction. The Commission accepted PJM's revisions making these changes, subject to conditions.[3]

6. PJM also proposed to revise its process for determining the amount of capacity it needs to purchase in the auctions. Under its tariff, PJM must consider the possibility that planned upgrades to the transmission system (which would,

[2] March 26 Order, 126 FERC ¶ 61,275 at P 36-39.

[3] *Id.* P 83-90.

when completed, provide some of the system's capacity needs) may not be completed on schedule. In its December 12 filing, PJM proposed a set of bright line metrics to be used to determine the likelihood of such non-completion. The Commission accepted PJM's revisions making these changes.

7. PJM filed a request for expedited clarification or rehearing as to one aspect of the March 26 Order – whether the Commission intended to accept the Multi-Year Pricing Option (MYPO) pricing program for parties building upgrades to existing generating units. On May 1, 2009, the Commission issued an order on clarification, confirming that it intended to accept the new MYPO pricing program.

B. <u>Requests for Rehearing and Clarification and Compliance Filings</u>

8. In response to the March 26 Order, requests for rehearing were filed by the Illinois Commerce Commission (Illinois Commission), the Maryland People's Counsel (MPC), CPower, the PSEG Companies (PSEG), CPV Maryland, *et al.* (CPV Maryland),[4] the RPM Load Group and Indicated State Commissions (RPM Load Group) and Interruptible Intervenors, and timely requests for clarification or in the alternative rehearing of the March 26 Order were filed by the Mirant Parties (Mirant), PJM and the PJM Industrial Customer Coalition (PJMICC). PJM, Duke Energy, and Mirant filed answers relating to the rehearing requests.[5] NRG filed a request for rehearing of the May 1, 2009 Order.

9. In response to the Commission's directives in the March 26 Order, PJM made compliance filings on April 27, 2009 and June 1, 2009. Notice of the April 27, 2009 filing was published in the Federal Register, with motions to intervene, notices of intervention, comments and protests due on or before May 18, 2009.[6] No interventions or comments were filed regarding the April 27 filing, other than Mirant's May 18, 2009 filing discussed *supra* at footnote 5. Notice of the June 1, 2009 filing was published in the Federal Register, with

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[4] This group includes CPV Maryland, LS Power Associates, the NRG Companies (NRG) and Tenaska, Inc.

[5] Mirant's May 18, 2009 filing constituted both an answer to PJM's answer, and also a protest to PJM's April 27 compliance filing, discussed immediately below.

[6] 74 Fed. Reg. 22,536 (2009).

motions to intervene, notices of intervention, comments and protests due on or before January 2, 2009.[7] No interventions or comments were filed regarding the June 1 filing.

II. Procedural Issues

10. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2008), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept the answers filed by PJM and Duke Energy filed in response to the petitions for rehearing of the March 26 Order, and Mirant's answer to PJM's answer, because they have provided information that has assisted us in our decision-making process.

III. Discussion of Requests for Clarification or Rehearing of March 26 Order and Request for Clarification of May 1 Order

A. Issues Related to Determination of CONE

1. Establishment of Net CONE for the Rest-of-PJM Region as Equal to the Lowest Net CONE in PJM's Three CONE Areas

a. March 26 Order

11. Under the pre-existing tariff, prior to the December 12 filing, PJM determined the Net CONE for each CONE Area[8] by estimating the Gross CONE (the cost to build a combustion turbine plant – i.e., the Reference Resource) within each CONE Area and then subtracting from that Gross CONE the EAS offset (an estimate of the energy and ancillary services revenues such a unit would be expected to receive, based on energy prices from that zone).

12. Although PJM carried forward the pre-existing method of estimating the EAS offset for each CONE Area, the December 12 filing proposed substantial

[7] 74 Fed. Reg. 31,020 (2009).

[8] CONE Areas are the three regions within PJM. Broadly speaking, CONE Area 1 consists of the New Jersey/Delaware area, CONE Area 2 consists of the Maryland and Washington D.C. area, and CONE Area 3 consists of the western and southern parts of PJM in Ohio, Illinois and Virginia (*see* PJM Tariff, Attachment DD, section 5.10(a)(iv)(A)).

changes to the method of determining the Net CONE for the unconstrained portion of the PJM region. Prior to the December 12 Filing, the PJM tariff had included a stated level for the "RTO CONE," i.e., the gross CONE used for the unconstrained rest-of-market region,[9] offset by an EAS revenue estimate based on average energy prices for the full region. The RTO CONE capacity price is intended to establish the base price of capacity. In the December 12 filing, PJM proposed to eliminate the separately stated gross CONE for the rest-of-market region, from where capacity is exported to the constrained regions. Instead, to determine the Net CONE for the rest-of-market region, PJM proposed a two-step process: 1) it would calculate a Net CONE for each CONE Area using average energy prices for the entire CONE Area; and 2) it would use the lowest of those values for use as the rest-of-market Net CONE.

13. In the March 26 Order, the Commission rejected PJM's proposed methodology for determining the Net CONE for the unconstrained rest-of-market region, finding that PJM had not sufficiently justified the proposal. We stated that the purpose of the capacity market is to ensure that generators receive sufficient total revenue (capacity market payments plus energy and ancillary service revenue) to cover the actual cost of entering the unconstrained region in order to create the proper incentive for new entry. The PJM proposal, in our view, did not take into account the possibility that the energy and ancillary services in the RTO CONE could well be lower than in one of the other CONE areas, so that utilizing a lower Net CONE for the unconstrained area would not provide sufficient revenue to incent new entry there. We provided the following example:

> Suppose the Gross CONE (cost of building a peaking unit) is \$500/MW in both the constrained and unconstrained areas, but the energy and ancillary service revenue in the constrained area is \$200, while being only \$100 in the unconstrained area. Thus, the actual net cost of entry would be \$300 (i.e., \$500-\$200) in the constrained area and \$400 (i.e., \$500-\$100) in the unconstrained area. Under PJM's proposal, the Net CONE in the unconstrained area

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[9] "Rest-of-PJM" or "rest-of-market" is the portion of the PJM Regional Transmission Organization (RTO) other than those LDAs that are sufficiently constrained to cause capacity prices within those areas to be higher than the rest-of-market region.

> would be set at the lowest Net CONE of any area – $300 in this example – even though the actual net cost of entry in the unconstrained area would be higher, i.e., $400. Thus, under PJM's proposal, a generating unit being built in the unconstrained area would not recover its $500 cost of construction when the amount of capacity cleared equaled the target level.[10]

14. We therefore rejected PJM's proposal without prejudice to a future filing that adequately justifies its proposal.

b. Requests for Rehearing and Answers

15. The Illinois Commission argues that the Commission erred in rejecting PJM's proposal. It states that by rejecting the PJM proposal, the Commission permits the continuation of a method of calculating Net CONE in the unconstrained region that unnecessarily raises capacity costs for electricity consumers in unconstrained areas and will mute the relative price signals across the various PJM zones that should be incenting resource development where it is most needed. The Illinois Commission argues that since, under PJM's current method, the Net CONE for the unconstrained region could potentially be higher than the Net CONE for a constrained area, new entry would be incented to locate in the unconstrained region rather than in areas that contain constrained zones, and that, by making this clear, PJM did, in fact, sufficiently explain its proposal. The Illinois Commission further argues that, contrary to the Commission's view, PJM's proposal does not stifle price signals, but rather sends a signal for new entry into areas that contain constrained zones which signal is greater than or equal to the price signal that is sent for new entry into the unconstrained area. The Illinois Commission argues that a new entrant should expect to receive at least as much, if not more, total revenue by locating in a constrained area than by locating in the unconstrained area of PJM, and PJM's proposal produces that result. The Illinois Commission argues that the opposite result – attracting new capacity into areas that are already capacity-adequate, rather than incenting new development in areas with insufficient capacity – is perverse, compared to the goals of RPM.

16. The Illinois Commission also argues that the Commission's preferred method for calculating Net CONE in the unconstrained region would cause capacity prices throughout PJM to increase unnecessarily, with proportionately

[10] March 26 Order, 126 FERC ¶ 61,275 at P 54 n.32.

greater increases in the unconstrained region, and that the net effect of such a practice would be to increase costs to ratepayers and increase the profitability of existing resource providers within the unconstrained regions of PJM. The Illinois Commission argues that our March 26 Order signals (without explicitly ordering) that the Net CONE for the unconstrained region should be derived by subtracting the energy and ancillary services revenues that can be expected to be earned in the unconstrained region from the Gross CONE in the unconstrained region. The Illinois Commission argues that this would actually increase the Net CONE in the unconstrained region, exacerbating the problem identified by PJM.

17. Mirant asks the Commission to clarify that the March 26 Order requires a change in PJM's method of calculating the Net CONE for each of the three CONE Areas in the PJM region, even though the Commission did not address that topic in the March 26 Order. Specifically, Mirant asks that the Commission order PJM to base the EAS revenue offset (used to determine Net CONE) on prices for the entire CONE Area, rather than on prices for the transmission zone in which PJM has assumed that the generator used to estimate the CONE (i.e., the Reference Resource) will be built. Mirant states that PJM's interpretation is unreasonable. According to Mirant, the Commission rejected PJM's proposal to set Net CONE for Rest-of-PJM equal to the lowest Net CONE for a CONE Area because that procedure could result in capacity prices below the cost of new entry in Rest-of-PJM. Mirant argues that similarly, calculating the EAS offset based on the prices for a single transmission zone will produce an offset figure that is not representative of the prices across the entire CONE Area. If the Commission does not grant this clarification, Mirant seeks rehearing, and asks the Commission to require PJM to calculate the EAS offset based on average prices across the entire CONE Area, for all Base Residual Auctions beginning with the 2013/2014 Base Residual Auction. In the alternative, Mirant asks the Commission to require PJM to initiate a stakeholder process to re-examine its methodology for calculating the EAS offset, and to make a filing proposing a revised methodology to reflect the March 26 Order's reasoning in time for implementation for the 2013/2014 Base Residual Auction.

18. PJM, in its answer, urges the Commission to reject Mirant's request. It states that, as shown in its April 27 compliance filing, the original December 12, 2008 tariff filing retained the pre-existing method of determining Net CONE for the CONE Areas, based on the prices for the zone where the reference resource is assumed to be built. PJM further states that Mirant's argument regarding PJM's current method of determining the EAS offset is unconvincing. PJM states that the gross CONE for each CONE Area is estimated based on a specific location in that area and takes into account costs specific to that location, such as labor rates and property taxes; PJM therefore considers it reasonable also to offset that gross

cost estimate with an estimate of energy market revenues that is specific to that same location.

19. PJM also asks the Commission to reject Mirant's request for a stakeholder process, stating that stakeholders are free to propose changes to the Net CONE calculation method, but that the Commission should not require PJM to file changes to the Net CONE methodology for CONE Areas, because Mirant has not shown that the current method is unjust and unreasonable.

20. In Mirant's answer to PJM's answer, Mirant reiterates its earlier arguments, stating that calculating the EAS offset for each CONE Area based on the average hourly prices across that same CONE Area, rather than on the prices for a much smaller transmission zone within that CONE Area, is consistent with the Commission's concerns in the March 26 Order that an appropriate Net CONE calculation for Rest-of-PJM should be based on the EAS revenues that could be earned in Rest-of-PJM.

c. Commission Ruling

21. We deny the Illinois Commission’s request for rehearing regarding PJM’s proposal for establishing the Net CONE for the unconstrained area. On several occasions a constrained Locational Delivery Area (LDA), which must of necessity be an import area, had a deficit of capacity such that it cleared the capacity market at less than the target installed reserve margin. As a result of the shortage of capacity in the import area, its capacity price was high relative to other areas, as was the price for energy and ancillary services. Because of the higher projection of energy and ancillary services revenue in the import area, the Net CONE in subsequent auctions was reduced, leading to a lower demand curve. PJM thus noted that its RPM design could produce the contradictory result that at the same level of supply relative to the target capacity level, the Net CONE in the import area would be reduced with a consequent reduction in capacity price (due to the shift in the demand curve) and that, as a result, the Net CONE in the import area would be less than the Net CONE in an unconstrained (i.e., export) area. PJM thus proposed to remedy the situation by lowering the Net CONE in the export area so that it would not exceed that of each of the import areas.

22. As we found in the March 26 Order, PJM (and the Illinois Commission on rehearing) have failed to support the conclusion that reducing Net CONE in the export area is a just and reasonable solution to the problem identified by PJM. As we stated in the March 26 Order, under PJM’s proposal, due to the higher EAS offset, the Net CONE used for the demand curve in the unconstrained export area could be below the actual net cost of new entry in that area, and could thereby prevent entry into that area. Neither PJM nor the Illinois Commission explained

why Net CONE should be adjusted in an export area because of supply conditions in an import area, or why a supply shortage in an import area should be resolved by decreasing prices in another area.

23. A new entrant requires sufficient revenues from the combination of the capacity market and the energy and ancillary services market in order to cover its cost of entry. Net CONE for an area is designed to reflect the amount of money a new entrant will need from the capacity market in order to make up for potential shortfalls in energy and ancillary services revenues. Under PJM's proposal, an offset developed from the higher energy and ancillary service revenues from the import area would be applied to the export area in which presumably the EAS revenues will be lower, and as a result, the Net CONE in the export area will be depressed below the amount established under the current RPM tariff as necessary based on the energy and ancillary services for the unconstrained zone. Even if a problem exists between the relative demand curves between the import and export areas due to shortages of capacity in the import area, the Illinois Commission has not adequately justified setting the incorrect price for the export area.

24. The Illinois Commission appears to presume that new entry will never be needed in an export area. However, the purpose of RPM is to provide reasonable prices over time to retain existing efficient generation and to attract new entry when needed. Since energy and ancillary services revenues in an export area are not sufficient by themselves to support new entry, capacity payments are needed to provide the proper incentives for new efficient entry in that area and to retain existing efficient generators over the long term. The Illinois Commission has not explained why the need for new investment might not at times exist in *both* constrained and unconstrained areas or why, even if new entry is not needed in the export area, the value of capacity for existing resources should be set improperly in the unconstrained area.

25. The Illinois Commission repeats an argument made by PJM – that if the Net CONE underlying the demand curve in the unconstrained region were higher than that in the constrained region, then new entrants might have the incorrect incentive to locate solely in the unconstrained region rather than in both the constrained and unconstrained zones. However, while differences in the demand curve may have an effect on price, the price is determined through the auction clearing process. A shortage of supply in the import area still can lead to a higher capacity price in the import area even if its demand curve is shifted to the left relative to that of the export area. Moreover, even if the relative demand curves between the import and export areas are incorrect, we do not find that PJM’s proposal to reduce the Net CONE in the export area is just and reasonable, for the reason discussed above. PJM’s proposal merely introduces an arbitrary reduction

in the price for the target capacity level in the unconstrained area, without any consideration of the cost conditions in that area, and thus, a reduction of the price needed in the long run to support the target capacity level. As we stated in the March 26 Order, our rejection of PJM's proposal is without prejudice to a future filing that adequately justifies the proposal.[11]

26. We also deny Mirant's request for clarification or rehearing. Mirant is seeking a ruling that the March 26 Order requires a change in PJM's method of calculating the Net CONE for each CONE Area. However, PJM's filing in this docket did not propose to change its current method of determining Net CONE based on the prices for the zone where the Reference Resource is assumed to be built. By rejecting PJM's proposal, we maintained the existing just and reasonable tariff provision. Any changes to an existing just and reasonable tariff provision must occur through the PJM stakeholder process or through proper filings to the Commission.

2. Deadline for Proposing Additional CONE Areas

a. Request for Rehearing

27. PJM's February 9 Filing proposed to establish a stakeholder process to review the CONE Areas, and provided that PJM would submit a filing to the Commission no later than December 1, 2009 either proposing PJM Tariff amendments under Section 205 of the Federal Power Act to implement changes to the CONE Areas, or explaining why the CONE Areas should not be modified at the time. PJM states that in the March 26 Order, the Commission misstated this proposed deadline, and stated that PJM would make this filing on or before

[11] Other methods used by RTOs to calculate the energy and ancillary service revenue offset, and hence Net CONE, may achieve PJM's objective regarding relative capacity prices in different areas. For example, the March 26 Order noted the method currently used by the New York Independent System Operator (NYISO). *See* March 26 Order, 126 FERC ¶ 61,275 at P 54 n.33. Under the NYISO method, the energy and ancillary service revenue offset in any area is calculated by estimating the amount of revenue that the reference resource would receive when the area had the target level of capacity. (*See* NYISO Services Tariff, section 5.14.1 (b).) In that way, the demand curve in an import area is not necessarily lowered when a capacity shortage exists in that area driving up energy and ancillary service revenue above that which would obtain at the target level of capacity.

September 1, 2009. PJM asks the Commission to confirm that the deadline for a filing either proposing additional CONE Areas or explaining why no changes are required at such time, is December 1, 2009, as proposed.

b. Commission Ruling

28. The Commission grants the clarification requested by PJM, and states that this deadline is December 1, 2009, not September 1, 2009.

3. Timing of the Commission's Acceptance of the Scarcity Pricing Offset

a. March 26 Order

29. With regard to its calculation of the EAS offset, PJM also proposed to retain its current approach of basing that calculation on the average EAS revenues that would have been received by the Reference Resource for the three most recent calendar years, plus an estimate of reactive service revenues. PJM proposed additionally to adjust the EAS offset with a true-up for scarcity pricing revenues that reflect the reference resources that would have been in service for the Delivery Year in which scarcity revenues are paid. The first step of this process is to remove EAS revenues earned during periods of scarcity over the three-year historical period from the EAS offset. The second step, which is the true-up step, involves adding back the EAS revenues that would have been earned by the Reference Resource during the year immediately preceding the Base Residual Auction. For example, as PJM prepares for the auction to be held in May 2009, it proposes first to develop its EAS offset based on non-scarcity energy and ancillary services revenues for 2006, 2007 and 2008. Then, when PJM takes the true-up step, it will add to that amount the scarcity revenues solely for 2008. This sum will constitute the EAS offset. As a result, scarcity energy and ancillary services revenues earned in one year will be reflected in the demand curve for the auction to be held in the next year, which will procure capacity for a Delivery Year three years after the auction.

30. The Commission accepted PJM's proposal regarding the scarcity pricing true-up, on the basis that it was a reasonable method to be used for setting the Net CONE for the May 2009 auction. Additionally, however, the Commission directed PJM and its stakeholders to address and resolve the various concerns raised by stakeholders about how to calculate the scarcity pricing revenues in the EAS offset in its upcoming stakeholder process, and file revised tariff provisions, if necessary, in time for the May 2010 auction.

b. Request for Rehearing

31. The Illinois Commission asks the Commission to clarify that an improved method to calculate the scarcity pricing offset must be in place before the May 2010 base residual auction. The Illinois Commission also reiterates its concerns expressed in its protest to PJM's original filing: namely, that a capacity resource could earn double revenues in a particular year for both scarcity and capacity, and load in a zone could pay twice in a particular year – once in the form of scarcity payments and once in the form of capacity payments – but only receive the true-up four years later.

32. PJM, in its answer, states that (as it noted in its April 27 compliance filing) the language in the March 26 Order has precisely the opposite effect, accepting the scarcity pricing offset but deferring its effectiveness until after the May 2009 auction, and allowing, but not requiring, changes to this provision as a result of the scheduled stakeholder discussions. PJM argues that in the March 26 Order, the Commission accepted PJM's proposed scarcity true-up mechanism but noted concerns raised by parties. According to PJM, the Commission then found that it need not rule on those concerns now, because scarcity pricing is already on the agenda to be discussed by PJM stakeholders in the upcoming year, and the Commission therefore approved PJM's proposal with regard to calculating the EAS offset in order to set the Net CONE value for the May 2009 auction, and directed PJM and its stakeholders to address and resolve in the upcoming stakeholder process the concerns raised regarding the scarcity pricing calculation, and file tariff revisions "if necessary," in time to be implemented for the May 2010 auction.[12] Moreover, PJM asserts that the March 26 Order stated that PJM should file changes to this provision for next year only "if necessary," i.e., only if the stakeholder process results in changes.

c. Commission Ruling

33. We will provide clarification of our statements in the March 26 Order. We require only that PJM address the stakeholder concerns and file a report with us on its progress before the May 2010 auction and file tariff revisions, if necessary, in time to be implemented for the May 2010 auction. We have made no determination that the scarcity pricing mechanism in PJM's current tariff must be replaced for the 2010 auction.

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[12] PJM Answer at 13, *citing* March 26 Order, 126 FERC ¶ 61,275 at P 45.

4. Use of a Combustion Turbine Unit as the Basis for CONE

a. March 26 Order

34. In the March 26 Order, the Commission found that PJM's Tariff defines CONE as "the nominal levelized cost of a Reference Resource," and defines the Reference Resource as "a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/MWh."[13] In the original December 12 filing, in which PJM and its stakeholders sought to make a number of changes to RPM, PJM discussed its consideration of the question of whether a combustion turbine should remain the Reference Resource for RPM. The Commission accepted PJM's reasoning, stating:

> We will also accept PJM's proposal to continue to base CONE on a combustion turbine plant. As PJM pointed out in its December 12 filing, combined cycle units may in certain scenarios have a lower Net CONE. However, combined cycle plants have more variable EAS revenues, and therefore, present significant estimating uncertainties. Moreover, PJM and the stakeholders argue, and we agree, that shifting between a combined cycle and combustion turbine unit from year to year could prevent owners of combustion turbines from recovering their costs over time.[14]

b. Request for Rehearing

35. MPC argues that the Commission erred in concluding that the PJM Tariff defines CONE as the cost of a combustion turbine generating unit, and, on that basis, erred in approving an increase in CONE.

36. MPC first states that the Commission erred by basing its ruling on CONE on a misinterpretation of the PJM Tariff. It argues that the Tariff's provisions regarding CONE do not tie CONE to the cost of a new combustion turbine unit.

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[13] PJM Tariff, Attachment DD, section 2.58.

[14] March 26 Order, 126 FERC ¶ 61,275 at P 39.

MPC points to the statement that the "Cost of New Entry for the PJM Region shall be $112,868 per MW-year,"[15] and to other tariff provisions which do not link CONE to a particular type of resource. MPC concedes that the PJM Tariff does refer to combustion turbine units in the definition of "Reference Resource" and in the Minimum Offer Pricing Rules,[16] but argues that these provisions do not relate to the value or derivation of CONE. MPC further argues that in the provisions containing an empirical methodology for adjusting CONE, the PJM Tariff links CONE to previous results of the Base Residual Auctions.[17]

37. MPC asserts that in the March 26 Order, the Commission erroneously presumed that CONE, and thus the Variable Resource Requirement (VRR) curve, must be increased in response to increases in construction costs for a combustion turbine, and acted based on that presumption alone: in other words, the Commission assumed that only one type of new entrant should be considered in setting CONE. MPC states, however, that evidence shows that the most frequent new entrant into RPM at this point is not a combustion turbine,[18] and that the presumption that the most likely new entrant would be a combustion turbine may have been necessary at the initiation of RPM, but after years of experience it is no longer necessary, and in fact leads to a CONE value that is inaccurately high. MPC argues that the purpose of RPM is to ensure sufficient capacity in PJM, and not to ensure sufficient revenue for any specific type of resource.

38. MPC urges the Commission to reconsider its decision to increase CONE. It first points to an earlier case in which PJM sought an increase in CONE, which was rejected by the Commission.[19] MPC states that, similarly to that 2008 case,

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[15] PJM Tariff, Attachment DD, section 5.10(a)(iv).

[16] *Id*. at section 5.14(h).

[17] *Id.* at section 5.10(a)(iv)(2).

[18] MPC points to a report by a consultant, James Wilson, to the effect that in the 2011/12 RPM base auction there was more new entry from combined cycle plants (1,135MW), coal fired plants (705MW), new uprates (over 1,000 MWs) and new demand response (425MW) than from new combustion turbines (416MW). MPC Request for Rehearing at 9, citing an affidavit submitted by Mr. Wilson in support of the protest of the RPM Load (Wilson Initial Affidavit) at P 196.

[19] *PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,015 (2008) (increase in CONE rejected due to PJM's failure to adhere to requirements in its tariff).

PJM has not sufficiently demonstrated that reliability requires an increase in CONE. MPC further states that PJM's assertion in this case that it must increase CONE to maintain reliability is undermined by the results of the past two auctions, in which PJM achieved significantly higher reserve margins (i.e., was able to procure significantly more capacity) than it required while using the existing CONE numbers, as well as by PJM's own reduced load forecasts. MPC asserts that these results show that an increase in CONE is not necessary to maintain a sufficient level of capacity.

c. Commission Ruling

39. The Commission denies rehearing. We disagree with MPC's interpretation of PJM's tariff regarding the definition of CONE. The definition of CONE appears in the Definitions section at the beginning of Attachment DD, which is the Attachment containing the provisions of the Reliability Pricing Model. At section 2.16, the tariff states: "'Cost of New Entry' or 'CONE' shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5." At section 2.58 of the Definitions section, the tariff states: "'Reference Resource' shall mean a combustion turbine generation station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/MWh." When the tariff is read consistently, we find that it is properly interpreted as defining CONE as the cost of a combustion turbine.

40. MPC's other arguments against PJM's adjustments to CONE were addressed in the March 26 Order. For example, MPC argues that the Commission erroneously presumed that CONE should be calculated based on the cost of a combustion turbine, when the most frequent new entrant into RPM at this point is not a combustion turbine. MPC has not explained why the most frequent new entrant should be chosen as the reference technology. Different technologies can efficiently exist within the market and are needed to meet different types of demand. For example, technologies with higher capital costs and lower variable costs typically can meet baseload demand at the lowest cost, while technologies with lower capital costs and higher variable costs can meet peak load at the lowest cost. The most frequent type of entrant is likely to vary over time, in part, because plants of different technologies are likely to retire and need to be replaced at different times and because of the lumpiness in the size of investments. Units meeting peak demand efficiently should have an opportunity to recover their costs over time, even if mid-merit or baseload investments are the most frequent new entrant during some years. As the March 26 Order pointed out, shifting the CONE calculation between a peaking unit and another technology from year to

year could prevent owners of efficient peaking units from recovering their costs over time.[20]

41. MPC also argues that the results of the past two auctions show that a CONE increase is not needed, since higher reserve margins were achieved in recent auctions than were required. But this argument mis-states the function of the CONE parameter, which is part of the derivation of an appropriate demand curve reflecting the value of capacity. As the March 26 Order stated, with a sloped demand curve, it is to be expected that the amount of capacity cleared in any individual auction will often differ from the target installed reserve margin. Cleared capacity can exceed the target in some periods and fall short of it at other times.[21] But in order for the RPM auction mechanism to achieve its reliability objectives, the demand curve needs to be properly set to reflect the actual costs of a new entrant.

5. Elimination of PJM's Triennial Review of CONE

a. March 26 Order

42. The RPM program originally provided for a review of CONE every three years.[22] In its February 9 amendment to its original filing, PJM proposed to convene a stakeholder process to develop an automated Net CONE adjustment procedure, and proposed that this adjustment procedure would supersede the existing provisions regarding formulaic changes to CONE and on triennial review of the shape and parameters of the Variable Resource Requirement curve. PJM further committed to file an automated Net CONE adjustment procedure with the Commission no later than September 1, 2009.

43. The Commission endorsed the principle of an automated adjustment procedure for CONE, stating:

> [B]ecause of the need for certainty in the RPM auction, the normal section 205 process of suspending the filing, subject to refund, while a hearing is

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[20] March 26 Order, 126 FERC ¶ 61,275 at P 39.

[21] *See id.* P 37.

[22] PJM Tariff, Attachment DD, sections 5.10(a)(iii), 5.10(a)(vi)(C) and 5.10(a)(vi)(D).

> conducted is often not available. When a utility makes its filing on short notice (as in this case), hearing procedures for such cost data become even more impractical. Once an automated process is approved, we anticipate that the process of adjusting CONE will become smoother and less contentious, and the stability of the capacity market will benefit thereby.[23]

The Commission further stated that "[w]e . . . agree with PJM that this process will serve as an acceptable substitute for, and should render unnecessary, the triennial CONE review process."[24]

b. Requests for Rehearing and Answer

44. Mirant and PSEG ask the Commission to clarify that it did not predetermine the issue of whether PJM's proposed automatic adjustment procedure will remove the need for, or justify the elimination of, the triennial review process, and that parties will have the opportunity to address this issue when PJM files a proposed mechanism. If such clarification is not granted, Mirant and PSEG seek rehearing on this issue, on the basis that because PJM has not yet filed an automatic mechanism, there is no basis to determine whether it will negate the need for the triennial review process. Mirant and PSEG state that the Commission should clarify that this question will be revisited at the time when the Commission reviews the actual mechanism that PJM proposes.

45. Mirant points out that in the March 26 Order, the Commission stated that an automatic mechanism "will serve as an acceptable substitute for, and *should* render unnecessary, the triennial CONE review process."[25] Mirant believes, however, that it is likely to be difficult, if not impossible, to design and implement a robust and reliable automatic adjustment mechanism, so that there will be a continuing need for periodic administrative review. Mirant states that "[i]f the [automatic adjustment] process fails to keep CONE in line with observed trends in actual construction costs, the triennial review process provides a valuable cross-check to ensure both that consumers are not paying more than a

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[23] March 26 Order, 126 FERC ¶ 61,275 at P 63.

[24] *Id*. P 65.

[25] *Id.* P 65, emphasis added by Mirant.

reasonable price and that the VRR curve is set to support new entry when new resources are needed."[26] Mirant stated that the Commission has not yet had the opportunity to gauge the justness and reasonableness of any automatic adjustment mechanism that will be proposed by PJM in the future, or to review how such provisions would interact with other RPM rules, including the triennial review process. PSEG asserts that the review mechanism was originally approved by the Commission as a necessary adjunct to an automatic CONE adjustment process to assure that deficiencies in the VRR curve or CONE could be addressed, and as such serves as an important check on the accuracy of any automatic CONE-setting mechanism.

46. PJM, in its answer, asks the Commission to deny Mirant's requested clarification. It states that the March 26 Order accepts an amended section 205 tariff filing that prescribes that the triennial review process shall be eliminated by a filing that the Commission has directed PJM to submit, and the Commission has unambiguously directed PJM to submit a new CONE adjustment process by September 1, 2009 to replace the current process. PJM further states that, while there is some discretion allowed to PJM and the stakeholders to develop the new process, the February 9 Filing is explicit that the new process will supersede the existing formulaic adjustment and triennial review provisions, and PJM's September 1, 2009 filing eliminating those provisions will thus be a compliance filing. PJM argues that if Mirant objects to that compliance directive in the March 26 Order, its proper recourse is a request for rehearing of that order, rather than a future protest to PJM's implementation of that compliance directive.

c. <u>Commission Ruling</u>

47. We grant clarification regarding elimination of the triennial review. As noted above, PJM proposed it convene a stakeholder process to review and propose an automatic adjustment procedure to supersede the current provision for triennial review of CONE. In our March 26 Order, we discussed the difficulties associated with the current method of hypothetical cost projections,[27] and strongly encouraged the development of an automatic adjustment mechanism.

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[26] Mirant Request for Rehearing at 18 n.63, *citing* Affidavit of Robert B. Stoddard in Support of the Mirant Parties (Attachment A to Mirant February 23, 2009 Comments) at ¶¶ 35-39.

[27] March 26 Order, 126 FERC ¶ 61,275 at P 63-64.

We stated that we expect PJM to include such a proposal in a filing that it intends to make on September 1, 2009.

48. However, we clarify that until a change to the tariff is accepted, the triennial review remains a part of the PJM tariff, and we have not prejudged the justness and reasonableness of any proposed revision. After PJM makes its filing, all parties retain full rights to comment on such a proposal.

B. Issues Related to Incremental Auctions

1. PJM's Redesign of Scheduled Incremental Auctions

a. March 26 Order

49. Under the tariff prior to March 26, PJM procured capacity for each Delivery Year through a Base Residual Auction conducted three years before the Delivery Year, and then a series of three scheduled incremental auctions conducted at varying points during that three-year forward period. The incremental auctions provided a means for PJM to procure additional capacity if it underestimated loads in the Base Residual Auction. Specifically, PJM would conduct a second incremental auction if PJM's revised load forecast completed fifteen months before the Delivery Year showed that the region's reliability requirement exceeded by 100 MW or more the amount of capacity procured in the base residual auction. However, RPM had no mechanism to respond to a decrease in the load forecast or other circumstance which indicates that the Base Residual Auction procured more capacity than is needed.

50. In its December 12 filing, PJM proposed to revise the framework of its incremental auctions so that it can also sell capacity. If PJM's updated reliability requirement differs by a specific amount from PJM's prior reliability requirement, in either direction, PJM will either purchase more capacity in the next incremental auction, or else allow sellers to buy out of their prior capacity commitments (i.e., PJM will sell back capacity).

51. The Commission conditionally accepted this proposal. We stated, however, that:

> PJM does not clearly explain the procedures for determining whether and how it would secure additional commitments of capacity, or allow sellers to buy out of their prior capacity commitments, based on an update of the regional and LDA reliability requirements, and capacity held back from the Base

> Residual Auction for short-lead-time resources, before each of the three scheduled incremental auctions.[28]

52. For this reason, the Commission stated, "[w]e will . . . accept PJM's proposal, conditioned on its filing revisions to sections 5.4, 5.10, and 5.12 to clarify and render consistent those procedures and include the revisions in the filing to be made by September 1, 2009."[29]

b. Request for Rehearing and Answer

53. The tariff provisions approved by the Commission at section 5.4(c) trigger PJM's participation in incremental auctions to buy or sell capacity if there is a difference between PJM's prior reliability requirement and its updated reliability requirement. The Illinois Commission states that the Commission erred by not limiting PJM's participation in the incremental auctions solely to situations in which there is a difference between the actual amount of capacity procured by PJM, and PJM's updated reliability requirement. The Illinois Commission asserts that omitting this limitation may result in non-compliance with PJM's actual reliability needs, in that either (a) PJM may buy additional capacity, when its updated reliability requirement is already satisfied by the amount previously procured, or (b) PJM may sell capacity, when the updated reliability requirement has not been satisfied by the actual capacity previously procured.

54. Thus, the Illinois Commission asks the Commission to ensure that proposed section 5.4(c)(2) should use what it terms the "absolute value" (i.e., the difference between the updated reliability requirement and actual capacity procured) to trigger PJM participation in incremental auctions,[30] rather than allowing such participation to be triggered by differences between the updated and the previous reliability requirements. The Illinois Commission alleges that this requirement would provide for the reciprocal treatment of over-procurement and for under-procurement. The Illinois Commission acknowledges that the Commission has directed PJM to revise the tariff with respect to incremental

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[28] *Id*. P 87.

[29] *Id*.

[30] The Illinois Commission further asserts that in our March 26 Order, we inaccurately stated that section 5.4(c)(2) already provides for use of this "absolute value" figure in determining when PJM's participation in incremental auctions to buy or sell capacity is triggered.

auction design to clarify and render consistent those sections. The Illinois Commission seeks clarification, however, that by this statement, the Commission intended to require PJM to address these specific concerns, as raised by the Illinois Commission in its prior comments and in this request for rehearing.

55. PJM states in its answer that in its September 1, 2009 compliance filing, it will explain and clarify, as necessary, the incremental auction provisions. PJM states that it does not, however, read the March 26 Order as directing PJM to depart from use of the VRR Curve to determine the level of capacity committed to serve the PJM region, which would be the effect of the relief the Illinois Commission seeks. PJM points out that the VRR Curve can, in fact, result in commitment of capacity in excess of the target reliability requirement when that is the least-cost overall solution. PJM notes that the Commission has expressly approved the VRR Curve for PJM and similar demand curves for other capacity markets based on evidence that they should result in greater reliability at lower cost over time. It asserts that if all capacity procured in excess of the reliability requirement in the base auction was sold back in the incremental auction, an essential attribute of the VRR Curve would be eliminated: capacity above the original target reliability requirement would be devalued, the former approach of using a vertical demand curve would effectively be reinstated, and reliability and cost would both likely be adversely affected.

c. **Commission Ruling**

56. In the March 26 Order, while we accepted PJM's revised incremental auctions framework, we also agreed with the Illinois Commission and Joint Protestors[31] that PJM needs to clarify and ensure consistency of the provisions of sections 5.4, 5.10, and 5.12 of the tariff, and therefore conditionally accepted the filing while requiring PJM to provide a better explanation of these provisions in its September 1, 2009 filing. For instance, the precise conditions that would trigger procurement or sale of capacity by PJM in relation to updates of the reliability requirement and capacity already procured were not clearly described. We expect that PJM's revisions to the tariff provisions in its compliance filing will remedy this lack of clarity, and PJM has already committed, in its answer, that it will do so.

[31] The Joint Protesters are Mirant Parties, FPL Energy, and IPA Central, LLC.

57. For this reason, we will defer ruling on the Illinois Commission's request for clarification or rehearing until after PJM makes its compliance filing on September 1, 2009. When PJM makes that filing, the Commission will rule on whether PJM's new tariff provisions have sufficiently clarified and explained PJM's procedures to enable us to determine whether they are just and reasonable. In the September 1 filing, we anticipate that PJM will respond to the Illinois Commission's contentions in the rehearing request that PJM's provisions are not just and reasonable because they discriminate between purchasing and selling capacity in the situation in which the actual amount of capacity procured deviates from an updated reliability estimate. After the September 1 compliance filing, the Illinois Commission may either choose to file comments to PJM's compliance filing, or to renew this pending request for clarification or rehearing.

2. PJM's Proposed Conditional Auction

a. March 26 Order

58. PJM also proposed to allow for additional "conditional" incremental auctions. PJM proposed that, if, for example, a planned transmission upgrade was modeled in the Base Residual Auction (to enable delivery of capacity from an unconstrained area to a constrained one), but it became clear prior to the Delivery Year that that transmission upgrade would not be completed in time, PJM would conduct an additional "conditional" incremental auction to secure commitments of additional capacity to address reliability criteria violations.

59. The Commission accepted PJM's proposal.

b. Request for Rehearing and Answer

60. The Illinois Commission argues that the Commission erred in accepting this conditional auction design proposal without directing PJM to incorporate a mechanism to address over-procurement of capacity in the unconstrained portion of PJM. According to the Illinois Commission, PJM's conditional incremental auction design addresses the harm caused by inaccurate modeling of new transmission lines to customers in the constrained PJM zones, because it provides for the purchasing of additional capacity in the constrained zones, but does not address the harm caused by inaccurate modeling of new transmission lines on the unconstrained region of PJM. The Illinois Commission asserts that PJM's proposal is not just and reasonable because it does not provide similar relief for customers in unconstrained zones by providing for the sell-back of excess capacity procured in the unconstrained region.

61. PJM states in its answer that in its view, the March 26 Order expressly considered and rejected the Illinois Commission's requested changes to the

Conditional Incremental Auction, so there is no reason to readdress those concerns.

c. **Commission Ruling**

62. We will grant rehearing, and require PJM to provide a further explanation of its tariff with respect to the possibility of selling back capacity in the event that previously committed capacity can no longer be delivered to a constrained area due to the failure of a planned transmission line to be placed into service. The Illinois Commission is concerned about the harm that may accrue to customers in an unconstrained area when the capacity from that area that was modeled to be sold to customers in a constrained area and transported over the new planned transmission line cannot be used to satisfy the reliability requirements in the constrained area due to the non-completion of a transmission upgrade.[32] The Illinois Commission argues that if a transmission line that was modeled in the Base Residual Auctions fails to come online, this will have implications both for the area which was importing capacity through that line, as well as the areas exporting capacity out of the unconstrained region of PJM. The Illinois Commission argues that PJM's proposal addressed the issue of under procurement in the import area, but failed to address the issue of over procurement.

63. In its comments to the December 12 filing by PJM, the Illinois Commission proposed a solution to this problem that would require re-running the capacity market to arrive at what it considers an equitable price for the unconstrained area customers.[33] In our March 26 Order we stated that:

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[32] Illinois Commission Request for Rehearing at 17 ("The failure of a planned transmission line to come into service by the beginning of the delivery year will also mean that the base residual auction will likely have cleared at a price higher in the unconstrained zones than would have cleared if the line had not been modeled in the base residual auction parameters. The result is that the capacity costs imposed on electricity consumers in the unconstrained region would be higher than they should be had the transmission line modeling been accurate.").

[33] *See* Illinois Commission's January 9, 2009 comments at 22-23:

> To minimize the harm to the customers in the unconstrained portions of PJM under such circumstances, PJM should be required to re-run the

(continued…)

> We disagree with the Illinois Commission's proposal to rerun the markets every time there is a conditional auction. A fundamental element of RPM is that it is intended to provide significant forward certainty on capacity procurement and capacity pricing.[34]

As we have found in other orders, the results of the base residual auction commit PJM to paying the generators the prices determined in that auction.[35] Therefore, no basis exists to re-run the auctions.

64. However, the Illinois Commission alternatively argues on rehearing that PJM is failing to provide relief to customers in an unconstrained zone, because its conditional auction tariff does not contain a provision authorizing PJM to sell back unneeded capacity when the failure of a large transmission project renders previously purchased capacity unusable. The Illinois Commission argues that

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> underlying auctions and determine what the capacity clearing price would have been if the system had been modeled properly. PJM should then calculate what total cost of capacity would have been under that scenario and compare it to the actual result. Revenues from the disposition of the excess capacity should be used to offset the difference between those two calculations. The remaining amount should be uplifted and recovered from all market participants in PJM, including both load and generation.

[34] *Id*. P 88.

[35] *Maryland Public Service Commission, et al. v. PJM Interconnection, LLC*, 124 FERC ¶ 61,276, at P 26 (2008) ("[c]hanging a rate and quantity already determined in accordance with existing tariff provisions on which parties have relied would defeat the purpose of the forward binding commitment, and undo the incentives for new capacity resources"), *aff'd on reh'g*, 127 FERC ¶ 61,274, at P 24-26 (2009). *See also Duquesne Light Company*, 122 FERC ¶ 61,039 at P 92, footnotes omitted (2008) (in evaluating Duquesne's request to leave PJM and enter another RTO, the Commission "conclude[s] that Duquesne's RPM liability extends to all auctions in which its load forecasts are included [and] these obligations are set at the time that PJM establishes its RPM auction parameters").

conditional auctions "should be designed as dual-purpose," similarly to PJM’s regular incremental auctions.[36]

65. The Commission finds that PJM needs to provide further information to justify its proposed exclusion of a sellback provision for the conditional auction when it includes such a provision for all other incremental auctions. We recognize that when a transmission line is not constructed, PJM by definition will be unable to use the additional capacity procured in the unconstrained area to satisfy demand in the constrained area. However, because the transmission line is not built, PJM has purchased excess generation in the unconstrained area and it may be able to sell back some of that generation, albeit at a cost that often will likely be lower than what it is committed to pay the generator, thus lowering its total cost for capacity.[37] We therefore will require PJM to include in its September 1 filing, or to make a compliance filing within 30 days of this order, either providing for a sellback provision to be added to the conditional auction or explaining why it is not reasonable not to include a sellback provision as part of the conditional auction. If PJM determines to include a sellback provision in the rules for the conditional auction, it must also explain how it proposes to allocate any savings resulting from such sellback of capacity.

3. <u>Elimination of ILR Provisions and Implementation of the 2.5 Percent Holdback from the Base Residual Auction and in Constrained LDAs</u>

a. <u>March 26 Order</u>

66. Under the RPM mechanism prior to the March 26 Order, a portion of the reliability requirement target was not procured in the Base Residual Auction, but rather was explicitly reserved to be served by ILR resources, which are certified no later than three months prior to the Delivery Year. PJM proposed to eliminate the specific ILR provisions of its tariff, effective for the 2012-13 Delivery Year, on the basis that it raised costs through over-procurement:

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[36] *Id*. at 16.

[37] For example, if a generator has a more profitable opportunity outside of PJM, it might be willing to buy back its capacity obligation from PJM at a price less than what PJM is obligated to pay. Or, if new construction is involved, the generator may be concerned about its ability to meet its delivery deadline and would be willing to buy back its capacity obligation.

> PJM currently adjusts the demand curve [which determines the total amount of capacity procured through RPM] to take into account anticipated ILR, but the existing rules do not place limits on how much, or in what locations, ILR may be certified. Thus, when the amount of certified ILR exceeds the amount by which the demand curve was reduced, PJM procures (and buyers pay for) more resources than are needed. Since the excess ILR does not displace higher-cost generation, but merely adds more total capacity, this translates into higher total cost for load serving entities.[38]

67. However, to accommodate short lead-time resources, PJM proposed to set aside a "holdback" of a percentage of the total capacity requirement, one-third of which will be procured in each of the three incremental auctions. In its February filing, PJM proposed that the holdback for the Base Residual Auction for the 2012-2013 Delivery Year would be 2.5 percent, and that no later than three months following the second and third incremental auctions for the 2012-2013 Delivery Year, PJM must provide stakeholders a recommendation as to whether that holdback should be modified.

68. The Commission accepted PJM's proposal to eliminate the ILR provisions, and to create a holdback provision, subject to conditions. It agreed that "the current ILR framework unnecessarily leads to over-procurement of capacity in the Base Residual Auction and needlessly imposes additional costs on load [and that] it is more efficient for those demand response resources that are able to offer their resource three years forward in the Base Residual Auction to do so, rather than wait to certify as ILR three months prior to the Delivery Year."[39] However, the Commission conditioned its acceptance on PJM revising the structure of the incremental auctions in order to allow greater participation of all types of short lead-time resources as close as possible to the Delivery Year and to permit a substantial amount of short lead-time resources a reasonable opportunity to be procured in the final incremental auction.

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[38] March 26 Order, 126 FERC ¶ 61,275 at P 66.

[39] *Id*. P 84.

b. <u>Requests for Rehearing</u>

69. Interruptible Intervenors argue that the Commission's decision to eliminate the ILR provisions is unsupported by evidence, and will expose customers to unjust and unreasonable rates by introducing significant uncertainty to those rates. Interruptible Intervenors argue that the problem is not that the ILR framework leads to over-procurement of capacity, but rather, that PJM consistently under-estimates the amount of ILR that it will procure close to the Delivery Year. According to Interruptible Intervenors, absent such bias in estimation, errors arising out of estimates of such ILR amounts should average out to zero: in some years PJM would over-estimate the amount of ILR and under-procure capacity in the Base Residual Auction, and in other years it would under-estimate the amount of ILR and over-procure capacity in the Base Residual Auction. Interruptible Intervenors suggest that the solution to the problem of over-procurement would be, as they stated in their protest, to require ILR certification ahead of the last incremental auction of the Delivery Year, so that PJM could conduct the last incremental auction with full knowledge of the quantity of ILR available for that Delivery Year.

70. PSEG states that it does not disagree with the elimination of the current ILR mechanism. However, it argues that holding back 2.5 percent of the reserve requirement from the Base Residual Auction modifies the intended operation of the RPM design, and the VRR curve must therefore also be modified to assure that RPM operates as originally intended. According to PSEG, acquiring less than the full reliability target in the Base Residual Auction will understate demand and suppress prices for most capacity resources, which in turn will result in greater price volatility and lower reliability. PSEG states that "[a]s originally designed by PJM . . . , the ability of RPM's price-clearing mechanism to set valid prices over the long-term is premised on the expectation that procurement shortages occurring in a [Base Residual Auction] will be addressed mainly in subsequent [Base Residual Auction]s,"[40] and that the March 26 Order fails to refute those assertions.

71. PSEG argues that the 2.5 percent holdback would not be expected to affect the need for new entry resources in the Base Residual Auction during the years when the level of load growth and retirements exceeds 2.5 percent; however, in other years, prices in the Base Residual Auction will not accurately reflect the need for new entry even though, according to PSEG, new entry is actually

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[40] PSEG Request for Rehearing at 8.

required to clear the market. PSEG urges the Commission to order PJM to conduct additional studies to confirm whether the RPM model, with the addition of the holdback, will continue to yield comparable projected results to those relied on by the Commission in approving RPM originally.

72. Finally, PSEG urges the Commission to apply the holdback solely to the rest-of-PJM region. According to PSEG, the risks of under-procurement are particularly dangerous for constrained areas because they may face risks not applicable to the unconstrained region, such as the delay in the in-service date for a transmission upgrade. PSEG argues that the larger rest-of-PJM market is more able to absorb the quantity and price volatility associated with the holdback than smaller constrained areas.

73. PJMICC argues that because the March 26 Order eliminated ILR opportunities, demand side resources that previously participated through ILR now participate in the Base Residual Auctions. PJMICC argues that the requirements for Base Residual Auctions are more stringent than those for ILR participation, and that PJM and its stakeholders should consider changing them. PJMICC also argues that the Commission requested PJM stakeholders to review certain aspects of RPM design related to elimination of ILR, and seeks clarification that the Commission did not intend to exclude from ongoing PJM stakeholder discussions the rules regarding demand resource participation in the Base Residual Auction and that PJM should file any necessary tariff modifications prior to the May 2010 Base Residual Auction. In particular, PJMICC is concerned about (1) the existing creditworthiness requirements and (2) the mismatch between the peak load contribution (PLC) used for bidding purposes and the PLC used for performance purposes.

74. PJM, in its answer, states that it intends to address PJMICC's concerns in its stakeholder process, but asks the Commission not to impose a deadline on this process or mandate a tariff change filing, arguing that PJMICC has not provided any basis for such a requirement. PJM commits to working with its stakeholders to see if any changes in this area are appropriate.

c. <u>Commission Ruling</u>

75. We deny Interruptible Intervenors' request for rehearing on the elimination of the ILR option. As discussed in the March 26 Order, we found that PJM's proposal to eliminate the ILR option was just and reasonable, on the basis that it is more efficient to require those demand response resources that are able to offer their resource three years forward in the Base Residual Auction to do so rather than wait to certify as ILR three months prior to the Delivery Year.

76. Interruptible Intervenors contend that PJM's proposed provision is unjust and unreasonable because it is necessary to retain ILR to provide participants with price certainty, and that the ability of demand response to participate in incremental auctions will not provide a suitable replacement for ILR. However, we cannot find PJM's proposal that treats short lead-time resources the same as other resources unjust and unreasonable. As we stated in the March 26 Order, holding back capacity for such resources creates an incentive for those resources to stay out of the base residual auction, and thus they are assured the auction clearing price without taking any actions that might reduce that price. We continue to find that PJM's proposal creates a reasonable balance between treating all resources comparably while recognizing some of the specific needs of short lead-time resources. PJM's tariff still provides for the hold-back of a limited amount of capacity, in recognition that some short lead-time as well as other resources may have difficulty committing three years in advance. All market participants bid their capacity into the Base Residual Auction or into the incremental auctions, as they choose, and take the risk that their capacity will not be taken, or (if they bid in as price takers) that they will receive a less desirable price than they might wish. Moreover, bidders into the auctions always have the certainty that, if taken, they will receive at least as high a price as they bid. Short lead-time resources are being given comparable opportunities.

77. Interruptible Intervenors argue some of the reasons PJM advanced for changing the ILR provision, such as over-procurement of capacity, is due to PJM's "consistent bias in estimation,"[41] and propose, as a solution, that ILR capacity be determined prior to the third incremental auction so that this last auction would adjust total capacity procured such that PJM ultimately procured the targeted amount of capacity. This argument, however, does not go to the question of whether PJM's proposal in this case is just and reasonable. It is true that there may be more than one just and reasonable means of accommodating short lead-time resources in PJM's auctions,[42] and in determining whether to accept PJM's filing, the Commission must only determine that PJM's proposed

[41] Interruptible Intervenors Request for Rehearing at 2-3.

[42] *See, e.g.*, *Midwest Independent Transmission System Operator, Inc.*, 127 FERC ¶ 61,109, at P 20 (2009) ("It is well established that there can be more than one just and reasonable rate") and *New York Indep. Sys. Operator*, 126 FERC ¶ 61,320, at P 40 (2009) ("there can be more than one just and reasonable planning process and RTOs and ISOs [Independent System Operators] are not required to have identical planning processes").

solution is just and reasonable, not that it is superior to other possible solutions.[43] Interruptible Intervenors have not demonstrated that PJM's proposal is unjust and unreasonable, and we therefore reject their request for rehearing.

78. Interruptible Intervenors also argue that the 2.5 percent holdback allocation is not large enough and that the relatively small size of the auctions will reduce the potential depth and liquidity of the market. We deny this request for rehearing. In the March 26 Order, we found acceptable PJM's determination of this holdback amount based on past data with the additional consideration of ensuring that reliability is not compromised. We encourage Interruptible Intervenors to participate in stakeholder deliberations as to whether 2.5 percent is an appropriate amount for the holdback. PJM is, in fact, continuing stakeholder processes with respect to adjustments to that figure. We consider this approach appropriate and encourage PJM and its stakeholders to undertake such a reevaluation based on an analysis of actual auctions data.

79. We deny PSEG's requests for rehearing with respect to the holdback provision, the associated adjustments to the VRR curve, and application of the holdback provision to individual LDAs. We continue to find the holdback provision reasonable because of the need to recognize that some short lead-time resources may not be available until after the Base Residual Auction to commit capacity closer to the Delivery Year. Such a hold-back therefore will help to ensure that all short-term resources are given a fair and reasonable opportunity to compete in the auction process.[44] PJM stated that it had no objection to

[43] *ISO New England*, 114 FERC ¶ 61,315, at P 33 (2006) ("Under the FPA, if we find that ISO-NE has successfully supported the justness and reasonableness of its [filing], we must approve it. We cannot, under those circumstances, consider alternatives to what is proposed by ISO-NE"), *citing Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir.) ("FERC has interpreted its authority to review rates under [the Federal Power Act] as limited to an inquiry into whether the rates proposed by a utility are reasonable -- and not to extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs"), *cert. denied*, 469 U.S. 917 (1984).

[44] As PJM argued, the capacity procurement targets for the Base Residual Auctions prior to May 2009 were already reduced to reflect forecast ILR and therefore any concerns about adverse consequences due to the holdback provision would already exist as a result of the holdback for ILR, but the problems that protesters feared had not arisen. According to PJM, the forecast ILR adjustments had not prevented the RPM auctions from committing sufficient capacity

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reviewing the provision in the future, "to assess what effects the holdback may have on reliability and the conduct of the auctions."[45] As noted above, proposals for revising the frameworks for incremental auctions (including possible elimination of the holdback provision) and the participation of demand response resources in RPM are already being discussed in the stakeholder process, with the possibility of implementing some changes in time for the May 2010 Base Residual Auction,[46] and PSEG may present its position in that process.

80. With respect to PJMICC's request for clarification, we grant clarification that the Commission did not intend to exclude from ongoing PJM stakeholder discussions the rules regarding demand resource participation in the Base Residual Auction and that PJM should file any necessary tariff modifications prior to the May 2010 Base Residual Auction.

B. Market Power Issues

1. Rejection of Economic Scheduling

a. March 26 Order

81. In its February 9 filing, PJM proposed to require capacity resources to offer their output in the day-ahead energy market on "economic schedule," if not on forced maintenance outage, absent a Maximum Generation Emergency. PJM argued that this provision simply made explicit the rules and practices already implied in the PJM tariff, namely, that all capacity resources committed through RPM must offer their output in the day-ahead energy market on economic schedule, if either (a) the units are not on forced or maintenance outage, or (b) the

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resources to assure reliability. PJM also noted that it had deliberately taken a conservative approach with regard to this issue in order to ensure that reliability is not jeopardized. PJM Answer, February 2, 2009, at 39-41.

[45] *Id.* at 42.

[46] "RPM Issues List" at: http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/cmec/20090630/20090630-item-02-rpm-issues-list.ashx. Allegheny Energy Supply, "Proposed Enhancements to RPM" at: http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/cmec/20090608/20090608-item-07c-allegheny-dr-presentation.ashx.

criteria for a Maximum Emergency schedule as defined in the Operating Agreement are met. PJM states that a capacity resource may only designate its output as emergency output to the extent permitted by the tariff, but that this provision adds no new limit on the price level that can be included in such an offer. PJM also noted, however, that because its stakeholders had not reached consensus on this issue, economic scheduling could also be a matter for future stakeholder discussions.

82. The Commission found that PJM and the commenters had divergent views of what this proposal was intended to accomplish, and rejected it on the basis that it was unclear what the new tariff provision would require. We stated:

> The term economic schedule is not defined and it can, and obviously has, led to different conclusions. . . . [S]ome parties seem to find that "economic scheduling" means "to offer at the default bid level" . . . while others . . . believe that "economic scheduling" eliminates the ability to offer capacity on an emergency basis when the $1000/MWh [payment] is not adequate whereas PJM seems to suggest that an "economic schedule" only subjects day-ahead bids to the $1000/MWh bid cap. . . .
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> This rejection, however, is without prejudice to PJM and its stakeholders, or PJM, refiling this request for relief, with a clearer explanation of what this provision is intended to accomplish.[47]

b. <u>Requests for Rehearing and Answer</u>

83. The Illinois Commission seeks rehearing of this ruling, stating that the lack of an economic scheduling requirement would leave open the possibility that suppliers could employ a "high-offer" strategy such as that employed by Edison Mission in a recent complaint case.[48]

84. The RPM Load Group also seeks rehearing, arguing that an economic scheduling requirement would prevent economic withholding, and asserts that the

[47] March 26 Order, 126 FERC ¶ 61,275 at P 118-119.

[48] *See In re Edison Mission*, 123 FERC ¶ 61,170 (2008).

intent of the new tariff provision is, in fact, clear. It states that, because the present tariff allows an asset owner to choose to offer capacity into the day-ahead market solely on an emergency basis, there is a risk that resources will use this current provision as a strategy to engage in economic withholding. The RPM Load Group argues that the different points of view that caused the Commission to reject the tariff proposal are not different points of view regarding what is intended by "economic scheduling" but differences over whether the current $1000/MWh cap for offers that do occur on "economic schedule" should continue.

85. Duke Energy, in its answer, urges the Commission to reject the requests that it implement economic scheduling, stating that it is, in effect, a proposal to take the existing "must offer" requirement and transform it into a "must offer at a specific price" requirement. Duke Energy states that this is a type of automatic mitigation program, which has previously been rejected by courts.[49]

c. Commission Ruling

86. The Commission denies rehearing because it continues to find that the proposal that PJM made to require economic scheduling is unclear. We understand the RPM Load Group to be claiming that the tariff currently allows capacity resources to circumvent their obligation to offer their output into the energy market by declaring that all or some portion of their energy is available on an emergency basis only, and that PJM's proposed revisions will remedy this problem. However, as set forth above, PJM's view of what the "economic scheduling" language is intended to accomplish is quite different from what the RPM Load Group or the Illinois Commission believe.[50] We agree that the market

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[49] Duke Energy answer at 5 n.23, *citing Edison Mission Energy, Inc. v. FERC*, 394 F.3d 964, 969 (D.C. Cir. 2005).

[50] The proposed revision . . . simply makes clear that, in the offers a Capacity Resource is required to submit in the Day-ahead [M]arket, it may only designate its output as emergency output to the extent permitted by section 6A.1.3. Any other output must be designated as "economic schedule," which simply means that it is not emergency output. This provision adds no new limit on the price level that can be included in such an offer.

PJM's February 9, 2009 amendment to its December 12, 2008 filing, Explanatory Statement at 14.

rules should not allow capacity resource owners to circumvent the must-offer requirement in such a way as to constitute withholding. But until PJM and/or stakeholders explain clearly how the current tariff permits this practice, and how the proposed changes would prevent it, we deny rehearing. We note again, as we did in the March 26 Order, that this denial is without prejudice to PJM refiling this provision in a manner that makes it clearly understandable, either under section 205 or section 206.

2. Retention of the Minimum Offer Price Rule

a. March 26 Order

87. If an entity is both a seller and a buyer of capacity, and is ultimately a net buyer, it may have the incentive and the ability to depress market clearing capacity prices below the competitive level (i.e., the entity will sell a small amount of capacity into the market at a price below its own costs, so as to depress the price of the larger amount of capacity that it then purchases). To prevent this type of market manipulation, RPM currently includes a Minimum Offer Price Rule (MOPR) providing for review, rejection, and substitution of new entry offers from market participants that are net capacity buyers when such offers are deemed to be too low.[51] PJM proposed to eliminate the MOPR provisions of its tariff, and replace them with a provision giving responsibility to the Market Monitor to determine whether a seller's new generation resource offer constitutes an exercise of market power in this manner, and requiring PJM to apply to the Commission for appropriate relief.

88. In the March 26 Order, the Commission rejected the provision in the February 9 filing to eliminate the MOPR provisions. We stated:

> The Commission rejects the [proposal] to eliminate the MOPR provisions, because PJM provides no justification for providing the [Market Monitor] with

[51] If bids fall below 80 percent of CONE of the applicable asset class (or if there is no applicable asset-class cost, 70 percent of the cost of new entry), the Market Monitor first gives the seller an opportunity to cost-justify its bid. If, in the Market Monitor's judgment, the seller does not provide satisfactory justification, the Market Monitor replaces the bid with a price equal to 90 percent of the estimated asset class cost, or if there is no asset-class estimate, 80 percent of the cost for the generally applicable net cost of new entry. *See PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,264, at P 11 (2008).

> unfettered discretion to determine whether an offer violates the MOPR. As we stated in previous RPM orders, to provide needed certainty to all participants, PJM must provide objective tariff provisions that will determine when mitigation measures will be applied, including application of the MOPR rule.[52]

b. Requests for Rehearing

89. MPC asks the Commission to grant rehearing of its decision not to eliminate the MOPR. It states that if a Load Serving Entity (LSE) decides it is economical to serve a portion of its own load through self-supply with a new unit and makes the rational business decision to bid that supply into the auction as a price taker, that action will trigger the MOPR rule and result in an artificially high price for all of the LSE's remaining load. MPC argues that punishing load for making economically rational decisions in the market is antithetical to the Commission's stated goal of developing a competitive market, which requires the interaction of supply and demand in equal terms. MPC further argues that the Commission has supported the inclusion of demand response in RPM in other contexts, but punishes it with the MOPR, and that entities making economically rational decisions on behalf of load is exactly the demand response the Commission should be seeking, not punishing.

c. Commission Ruling

90. We deny rehearing. A capacity market will not be able to produce the needed investment to serve load and reliability if a subset of suppliers is allowed to bid non-competitively to suppress market clearing prices. According to MPC, a new unit supported by an LSE's captive customers should be allowed to offer capacity at a level that does not necessarily reflect its actual costs, because those costs are recovered elsewhere from captive customers.

91. The lower prices that would result under MPC's proposal would undermine the market's ability to attract needed investment over time. Although capacity prices might be lower in the short run, in the long run, such a strategy will not attract sufficient private investment to maintain reliability. The MOPR is the mechanism that restricts the ability of an LSE from using its position as dominant buyer in the market to suppress market clearing prices for at-risk investors, and is analogous to the way market power mitigation rules restrict dominant at-risk

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[52] March 26 Order, 126 FERC ¶ 61,275 at P 190.

investors from using their market position to raise market clearing prices by creating an artificial scarcity. The MOPR does not punish load, but maintains a role for private investment so that investment risk will not be shifted to captive customers over time.

C. Issues related to New Entry Price Adjustment (NEPA) and MYPO

1. Rejection of Proposed Modifications to NEPA in March 26 Order

a. March 26 Order

92. RPM's NEPA provision allows a new capacity resource within a congested LDA to lock-in a "new entry price" for three years if it meets certain conditions.[53] Such a resource is then required to offer its capacity in the two subsequent Base Residual Auctions at a price that is either equal to the first year's sell offer or equal to 90 percent of the then-current Net CONE.

93. In the December 12 filing, PJM proposed to (1) increase the commitment period to five years (later extended in the February amended filing to seven years); and (2) require capacity sellers to offer their resources into the RPM

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[53] One of the conditions is that entry of the new resource would increase the total unforced capacity in the LDA from a quantity below the LDA's reliability requirement to a quantity "corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable net CONE." *See* Section 5.14(c)(b). Our March 26 Order mistakenly stated that in order for NEPA treatment to be triggered, new entry needed reduce the LDA's capacity price from a level higher than 112.5 percent of Net CONE to less than 40 percent of Net CONE. However, Section 5.14(c)(b) speaks only to the quantity of capacity that must be offered by the new entrant relative to the LDA's reliability requirement in order to enable the resource to qualify for NEPA treatment. This section does not require the entry of the NEPA resource to bring about any particular reduction in price. Indeed, Sections 5.14(b) and 5.14(c)(c) provide that the LDA's clearing price could be set at the level of the new resource's bid for each of the years in which it is eligible for NEPA treatment, and thus, be significantly higher than 40 percent of Net CONE. The price will, therefore, not automatically drop to 40 percent of Net CONE. In addition, the new resource's quantities in excess of the amount needed to clear the market at that price can be paid an amount equivalent to the clearing price via make-whole payments.

auctions for subsequent years of the commitment period (i.e., years two through seven) at either zero or the unit's avoidable cost rate (less the projected energy and ancillary revenues).[54] Under PJM's proposal, if a new resource meets the pre-conditions to qualify for NEPA treatment and clears in the subsequent auctions during a selected commitment period (up to seven years), and the seller would be paid its original offer price in each of the subsequent years. PJM proposed that, if that price was lower than the clearing price in those subsequent years, the difference would be credited to LSEs, and if that price was higher than the subsequent-year clearing price, LSEs would also supply the difference. PJM argued that the prior NEPA provisions did not provide sufficient incentives for new entry. Multiple generators, including CPV Maryland, supported the proposed PJM revisions, and urged the Commission to extend the NEPA lock-in period even longer, to ten years.

94. In the March 26 Order, the Commission found this proposal unjust and unreasonable:

> The proposed relaxation of the pre-conditions and the extension of the lock-in period go beyond the intent of the original provision, intended only to address the issue of lumpy investments in a small LDA. PJM's proposal would further bifurcate capacity markets by giving new suppliers longer payments and assurances unavailable to existing suppliers providing the same service. Thus, it would result in further price discrimination between existing resources, including demand response, and new generation suppliers. . . .
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> We also recognize that a longer commitment period may aid the developer in financing a project. However, as PJM notes, RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers, and we must therefore balance the

[54] Additionally, PJM proposed that NEPA treatment be available to resources under less stringent pre-conditions, so that the NEPA provision would be available to any entrant in an LDA that has a separate VRR Curve if the LDA clears with a locational price adder or if the LDA would have had a locational price adder had the new entrant not cleared.

> benefits of the longer commitment period (to the extent it fosters new entry by making project financing easier or cheaper) against the possible uplift payments in excess of auction clearing prices that loads may have to bear due an extension of the NEPA term. In our view, no party has made the case that extending the NEPA term to five or seven years strikes a superior balance to the existing provisions.[55]

b. Request for Rehearing of March 26 Order

95. CPV Maryland seeks rehearing and argues that the Commission should permit the longer ten-year lock-in period for prices for new generation. CPV Maryland argues that the Commission's decision applied the incorrect legal standard of review by failing to consider whether PJM's NEPA proposal is just and reasonable, and not unduly discriminatory or preferential, in its own right, and instead rejecting it because no party had shown that its proposal is superior to the existing NEPA provision. CPV Maryland argues that in fact, a utility need only show that its proposal is just and reasonable, and that any other view is an infringement on utilities' section 205 filing rights.

96. CPV Maryland further argues that the Commission erred in rejecting PJM's proposal based on the determination that PJM's proposed revisions "go beyond the intent of the original provision" of promoting investment in constrained LDAs. According to CPV Maryland, PJM did seek to go beyond the original provision, because the NEPA provision as it exists today is not succeeding in bringing new entry into constrained areas. CPV Maryland emphasizes the enormous challenges to obtaining financing for new investment and how the longer period of price guarantees could overcome that obstacle and encourage new investment. CPV Maryland also argues that the Commission did not meaningfully address the arguments and evidence in favor of the ten-year proposal.[56]

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[55] March 26 Order, 126 FERC ¶ 61,275 at P 149-50.

[56] CPV Maryland also makes arguments in favor of the Multi-Year Price Option (MYPO) proposal for upgrades to existing generators; as noted above, however, subsequently to CPV Maryland's filing of its request for rehearing, on May 1, 2009, the Commission accepted the MYPO proposal for upgrades, on similar terms to new planned generation resources.

97. CPV Maryland further asserts that the Commission failed to properly balance the costs and benefits of enlarging the NEPA period, as it overestimated the costs and underestimated the benefits. CPV Maryland states that changes to NEPA would not necessarily result in any net increase in uplift costs:

> The new entrant would not receive any uplift costs in the initial year, and in subsequent years, the new entrant would receive its original offer price, which may or may not be higher than the market-clearing price. As PJM explains, if the new entrant's offer price is lower than the subsequent-year clearing price, "the difference will be credited to load serving entities," and if its offer price "is higher than the subsequent-year clearing price, then LSEs shall bear a charge to recoup the differences." The Commission's conclusory statement that the NEPA proposal will increase uplift costs appears to be based on the implicit and unsupported assumption that the offer price will always be higher than the market-clearing price.[57]

98. CPV Maryland similarly argues that a new entrant's offer price would not set the market-clearing price in subsequent years, but would actually lower the market-clearing price paid by all buyers in subsequent years. CPV Maryland suggests that "[t]he reduction in costs due to such new entry would likely more than offset the amount paid to an individual new entrant to cover the difference between the market-clearing price and its original offer price."[58]

99. CPV Maryland also states that the Commission erroneously found that PJM's NEPA proposal discriminates against existing generators: it points to the fact that extending the price lock-in period would also apply to existing generation making new investment. CPV Maryland additionally asserts that new entrants and existing entrants investing in upgrades are not similarly situated to existing generators that are not investing in new upgrades, as they are not in danger that by entering the market, a new entrant or new upgrade may depress prices in subsequent years so that it may not be able to recover its costs going forward.

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[57] CPV Maryland Request for Rehearing at 21-22, footnotes omitted.

[58] *Id*. at 23.

100. CPV Maryland further states, with regard to the MYPO provision for upgrades to existing generators, that if the Commission responds to PJM's request for clarification of the March 26 Order regarding the MYPO provision, the Commission should require PJM to allow upgrades to elect the MYPO option for the May 2009 Base Residual Auction.[59]

c. Commission Ruling on Request for Rehearing of March 26 Order

101. We deny rehearing, continuing to find that PJM has not sufficiently shown that its proposal is just and reasonable and not unduly discriminatory. As we stated in our March 26 Order, we originally approved a three-year NEPA to address the limited concern that investment in a small LDA that would have the effect of lowering market clearing prices significantly could deter entry that was needed. A three-year lock-in price period was intended to provide support to the new entrant until sufficient load growth would be expected to support the new entry by reducing the surplus attributable to such lumpy investment. This problem is not anticipated in large LDAs, where load growth is likely to be sufficient to accommodate entry without the extreme price suppressing effect.

102. However, by proposing to extend NEPA to seven years, PJM has created a discriminatory pricing regime that goes beyond the justifiable need to protect against lumpy investment. The new entrants are guaranteed higher prices and assurances that are not available to existing suppliers. Moreover, while the new entrant is guaranteed its price, the extra capacity it introduces into the market will reduce the prices to existing suppliers. In order to assure reliability, PJM needs to attract new entry when needed, but also to assure that prices are sufficient to retain existing efficient capacity. Both new entry and retention of existing efficient capacity are necessary to ensure reliability and both should receive the same price so that the price signals are not skewed in favor of new entry.[60]

103. CPV Maryland argues that, in some cases, customers will benefit from lower prices brought about through NEPA. But this may occur only in the short run, because the proposed revision to NEPA creates price discrimination by

[59] The Commission's ruling with regard to the MYPO issue in its May 1 Order on Clarification is discussed *infra*.

[60] *See Southeastern Mich. Gas Co. v. FERC*, 133 F.3d 34, 41 (D.C. Cir. 1998) ; 1 Alfred E. Kahn, The Economics of Regulation 140 (1970) (prices for new and existing customers should be the same).

treating new entrants differently from all other suppliers. The new entrant is guaranteed its price while the extra capacity introduced by the new entrant reduces the market prices that can be earned by all other suppliers. A market should be designed correctly so that the contribution to reliability from both new entrants and existing suppliers is compensated comparably.[61]

104. We agree with CPV Maryland that the only issue in this proceeding is whether PJM's proposal is just and reasonable. For the reasons provided in the March 26 order, and summarized above, however, we find PJM's proposal creates price discrimination and is unjust and unreasonable.

2. Issues Relating to MYPO in May 1 Order

a. May 1 Order

105. As discussed above, PJM's current rules for new entry pricing provide certain pricing guarantees to new entrants to deal with "lumpy investments," investments in new plant where the efficient size of the investment is greater than the amount of capacity needed so that the investment will have the effect of decreasing prices. In its filings leading to the March 26 Order, PJM had also proposed a Multi-Year Pricing Option (MYPO) program, which would, in effect, grant similar treatment to generators investing in large upgrades to existing plants as NEPA provides to developers of new plants that qualify for NEPA treatment under the existing rules. Most significantly, if the developer of an upgrade elected MYPO, that new capacity would also be able to elect to lock in prices for a 3-year period, similarly to new projects under NEPA.

106. This proposal was contained in a portion of PJM's proposed changes to the NEPA rules, some of which, as discussed earlier, the Commission rejected. Because the disposition of the MYPO was not clear in the Commission's March 26 Order, PJM filed a request for expedited clarification of the Commission's disposition of the MYPO issue. In response, the Commission issued the May 1 Order granting that clarification,[62] agreeing that we had accepted the MYPO:

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[61] If retention of existing capacity is less costly than new entry, in the long run, extending NEPA could lead to higher overall costs if existing capacity exits and has to be replaced by new entry.

[62] Because the Commission issued this order on May 1, 2009, PJM was able to permit generators constructing upgrades to elect the MYPO option, if they chose, in the May 2009 Base Residual Auction.

> We agree with PJM's proposal to extend the price assurances available to new generation investment to investment in energy efficiency and major generation upgrades. Extending the tariff provisions to . . . generation upgrades is reasonable because it provides for these types of investments to receive price assurances that are comparable to new generation resources. Therefore, we clarify our prior order to provide for such comparable treatment.[63]

b. Request for Rehearing of May 1 Order

107. The NRG Companies (NRG) filed a request for rehearing of the May 1 Order.

108. NRG states that the current NEPA and MYPO pricing mechanism provides that a new unit would only receive capacity payments in the second and third years of its three-year lock-in period if the unit bids into and clears in those two auctions. NRG states that RPM also requires the new entrant to bid into the auction in the second and third years at the lesser of either (i) 0.90 times the then-applicable Net CONE, or (ii) the unit's first-year bid price. NRG argues that these bidding restrictions on NEPA and MYPO resources "effectively require[] a unit to risk pricing itself out of the market in years two and three of the [lock-in period], if it wishes to receive the benefits of the price lock-in beyond the first year." [64] NRG argues that the situation creates a perverse disincentive to elect either NEPA or MYPO, because the existing Tariff requires that a qualified capacity seller decrease prices in the LDA below the reference price defined by the Tariff in order to qualify for the program. Specifically, NRG argues that the Tariff requires both that a qualified capacity seller decrease prices to less than 40 percent of Net CONE and that the unit place a bid of 90 percent of CONE in subsequent auctions, making it highly unlikely that the unit will clear in years two and three of the commitment period.

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[63] May 1 Order at P 13. The Commission evaluated the tariff sheets filed by PJM with respect the MYPO and accepted these sheets subject to the condition that Third Revised Sheet No. 616, dealing with large capital investments in generation upgrades, would be appropriately revised to reflect the MYPO provision.

[64] NRG Request for Rehearing at 5.

109. NRG states that the Commission did not rule on the issues NRG has raised in this rehearing petition (i.e., whether it is just and reasonable to require units electing the MYPO provision to risk pricing themselves out of the market in the second and third years of their lock-in period) in either the March 26 Order or the May 1 Order, and that the relief sought here is consistent with the intent of the original NEPA program to address the problem of lumpy investment in a small LDA.

c. Commission Ruling on Request for Rehearing of May 1 Order

110. We deny the request for rehearing. First, the request for rehearing of the May 1 Order is a complaint against an unchanged provision of PJM's tariff that is beyond the scope of this proceeding and a late-filed rehearing of the March 26 Order. In the March 26 Order, the Commission rejected the proposed changes to NEPA relating to bid limitations, and the identical provisions relative to MYPO. By rejecting these provisions, the Commission continued the existing tariff provisions with respect to NEPA that included the pricing provisions to which NRG now objects.

111. In the May 1 Order, the Commission clarified that it was accepting the MYPO provisions under the same conditions as the existing NEPA provisions. NRG's request for rehearing of the May 1 Order is unrelated to the Commission's determination in the May 1 Order. Rather, it is a request that the Commission change PJM's existing tariff provisions relating to both NEPA and MYPO. Moreover, any request to change the Commission's determination to reject PJM's NEPA and MYPO proposal with respect to the bidding limitations should have been filed as a request for rehearing of the March 26 Order. Although NRG (as part of the CPV Maryland group) filed a request for rehearing of the dismissal of both the NEPA and MYPO provisions, the CPV rehearing request did not address the question of bid limitations.

112. Second, we affirm our finding that PJM's proposed changes to the bidding limitations for NEPA and MYPO are not just and reasonable and are unduly discriminatory. The original purpose of including the bidding limitations was to ensure that a new entrant in a small LDA will not reduce price to the existing resources by submitting a $0 bid in Years 2 and 3, knowing that it is guaranteed to be paid its first year bid price no matter what it bids. We continue to find that PJM and NRG have not explained why a bid floor is not necessary to protect against such bidding behavior and the resulting discriminatory pricing. That is, the new resource would receive its first-year price for all of the years in which it receives NEPA treatment, while existing resources in the LDA would receive a lower price (reflecting the LDA's surplus of capacity).

113. NRG states that it is concerned that under the existing bidding restrictions, NEPA resources are effectively required to price themselves out of the market, because the market price (which it assumes is at or below 40 percent of Net CONE) would be below its required bid (at 90 percent of Net CONE). But, as noted above, the existing market rules do not require that a new resource's entry cause the capacity price to fall below 40 percent of Net CONE (or below any other specific price level) in order to trigger NEPA treatment. Rather, Section 5.14(c)(c) specifies a trigger based on the new resource's quantity of capacity relative to the LDA's reliability requirement. That is, this section requires that the new resource increase the total unforced capacity in the LDA from an amount below the LDA's reliability requirement to an amount substantially above that requirement. When the NEPA/MYPO conditions are triggered, the new resource would receive its bid price, and would set the clearing price, in its first delivery year. In the following two years, if the LDA continued to experience price separation from the rest-of-RTO region,[65] it is not clear why an efficiently built and sized new resource would not expect to continue to set the clearing price under the current bidding requirements. That is because as long as the LDA's load does not decrease over time and as long as no significant other entry were to occur,[66] the new resource would continue to be needed to meet the LDA's reliability requirement.

[65] If no congestion (and thus, no price separation) were to occur into the LDA after the first year, resources in the LDA would receive the same price as the rest-of-RTO region. Thus, in this case, the rest-of-RTO price would provide a price floor for resources in the LDA, which typically would be significantly higher than 40 percent of the LDA's Net CONE. RPM has been designed so that the average price in the rest-of-RTO region is expected to approximate Net CONE over time. The LDA's new resource would have a much smaller effect on the price in the rest-of-RTO region than in the LDA because the rest-of-RTO region is much larger.

[66] Additional new resources contemplating whether to enter the LDA in following two years would face significant hurdles, because they would not be eligible for NEPA treatment since the LDA's capacity now exceeded its reliability requirement.

D. <u>Additional Issues</u>

1. <u>Credit Deposit Requirements for Demand Response</u>

a. <u>March 26 Order</u>

114. Neither PJM’s December 12 filing nor the Commission’s March 26 Order made any changes to the credit deposit requirements for demand response. However, as part of its restructuring of RPM, PJM proposed changes to its existing structure for penalties for resources that failed to provide capacity, including demand resources. The Commission accepted this proposal, stating that "PJM’s proposed changes improve the comparability between demand response and generation resources."[67]

b. <u>Requests for Rehearing</u>

115. CPower argues that the Commission erred by not requiring corresponding changes to PJM's credit deposit requirements at the time that it accepted changes to PJM's penalty provisions. According to CPower, given the reduction in the penalty amounts that a deficient seller could possibly owe, the RPM credit requirement is now inconsistent with the seller’s possible obligation to PJM, because it exceeds the maximum possible penalties imposed on a seller who completely fails to deliver.[68] Therefore, in CPower's view, PJM's reduction in the

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[67] March 26 Order, 126 FERC ¶ 61,275 at P 180.

[68] Sellers of Planned Demand Response capacity are required to post a pre-auction credit requirement: a deposit equal to the Auction Credit Rate for each megawatt of planned capacity they seek to provide. CPower states that PJM has posted the pre-auction credit requirement for the upcoming 2012 auction as $27,273/MW. A seller in the RPM market who does not deliver is now subject to deficiency penalties which are a net 20 percent of the clearing price of the relevant capacity. Thus, CPower asserts, the liability of a completely deficient seller who provides none of the capacity it bid into the auction could only be equal to that seller's required pre-auction credit requirement if the auction cleared at $373.60/MW-days, which is higher than the maximum possible clearing price in six of the seven LDAs defined for the 2012 auction.

possible penalty amount that a resource could owe should require a corresponding reduction in the credit requirement that that resource must meet.[69]

116. CPower further asserts that PJM's Auction Credit Requirement (1) requires market participants place funds on deposit with PJM that PJM otherwise has no possible claim on; (2) requires market participants to place funds on deposit with PJM that will be returned under all possible circumstances; (3) is unjust and unreasonable in that it requires a credit deposit greater than any possible liability owed to PJM; (4) creates discriminatory barriers to entry by artificially raising capital requirements to participate in PJM markets; (5) unjustly privileges existing assets by artificially raising the cost of capital for new market entrants; and (6) unnecessarily imposes costs that will ultimately fall on the ratepayers. To address this problem, CPower asks the Commission to direct PJM to cap the Pre-Clearing Base Residual Auction credit rate for each LDA at 20 percent of the maximum possible clearing price in that LDA, and further, that the Commission direct PJM to cap the Post-Clearing credit rate for each LDA at 20 percent of the actual clearing price in that LDA.

117. PJM states in its answer that CPower has not demonstrated that these existing requirements are unjust and unreasonable, but that it supports adding the concern raised by CPower – namely, whether the tariff's previously approved credit requirements for planned demand resources are still just and reasonable – to the ongoing RPM stakeholder process.

c. <u>Commission Ruling</u>

118. We will deny CPower's request for rehearing. The only issue before the Commission was PJM's proposal to revise penalty levels. We found that this proposal is just and reasonable and CPower has not argued that the proposed change in penalty levels should be found unjust and unreasonable because PJM did not include a change in credit requirements. CPower's request therefore goes beyond the scope of the section 205 filing made by PJM and is a request for the

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[69] PJMICC, in its request for rehearing, similarly notes that PJM's creditworthiness requirements are onerous for demand resources and may discourage demand resources from seeking to participate in RPM (particularly because new demand resources are subject to creditworthiness requirements while existing demand resources are not). However, PJMICC does not seek rehearing or clarification specifically on this issue.

Commission to find PJM's existing tariff with respect to credit requirements unjust and unreasonable.

119. CPower has not made a sufficient case for the Commission to establish a section 206 hearing on this issue. CPower's argument is based on the premise that the purpose of the credit requirement and the penalty are identical, which it has not established. The deposit that a resource is required to provide to meet the credit requirement is designed to ensure that PJM is made whole if a resource fails to honor its contract. It is based on PJM's assessment of the amount of funds it will need to procure new capacity, possibly on very short notice, if a resource fails to honor its capacity commitment. Should the resource fulfill its commitments, the collateral will be returned to the resource. The penalty, on the other hand, is designed to motivate resources to honor their commitments while recognizing that sometimes resources may have good reasons for not honoring their commitments. While these purposes are clearly related, they are not identical, and we do not see a sufficient basis at this point for instituting a section 206 proceeding to examine this issue, particularly since PJM is considering this issue as part of its ongoing discussions regarding demand resource participation in the Base Residual Auction.

2. PJM's Changes to the Modeling of Transmission Projects

a. March 26 Order

120. Prior to the March 26 Order, PJM included all planned Regional Transmission Expansion Plan (RTEP) projects in the RPM modeling as of the specified in-service date thus assuming that transmission projects will never be delayed. Once included in the Base Residual Auction's system model, however, proposed transmission projects increase transfer capability to the load zones. If transmission projects failed to enter service by the start of the Delivery Year, PJM would have under-procured capacity. PJM therefore proposed a set of project development milestones for including RTEP upgrades in the system models used for the RPM auctions, including submission of a project development schedule, certification that the schedule is reasonably achievable, and identification of all states in which the project must obtain a permit or regulatory approval and the current status of such permit proceedings.[70]

121. The Commission accepted PJM's proposal, stating that "it is critical to accurately reflect these projections in the assumptions and modeling used for the

[70] *See generally* March 26 Order, 126 FERC ¶ 61,275 at P 91-94.

RPM auctions, so as to ensure that PJM procures the necessary amount of capacity through the RPM process."[71] We noted that, while currently PJM included all planned RTEP projects in the RPM modeling and assumed that the transmission project will be in service without delays, this may not always be an accurate assumption, and we found reasonable PJM's proposal to provide greater certainty to ensure that the transmission upgrade would be able to meet the in-service date.

b. <u>Request for Rehearing</u>

122. PSEG argues that the revisions approved in the March 26 Order will perpetuate the flaws of the existing mechanism that assumed the achievement of all in-service dates. According to PSEG, the requirement that major permits must be sought does not address the main causes of delay in the permitting process, which are (a) opposition directed to the application and (b) the time required for governmental agency action. It argues that the requirement to obtain specified levels of rights of way, for the many projects that follow existing transmission routes, is meaningless, and that the obligation imposed on transmission owners to supply construction schedules and a certification will not add much additional certainty. PSEG argues that, due to factors beyond the control of the applicant, it will be difficult for transmission owners to determine the point when the delay in the receipt of a permit renders the in-service date unachievable. PSEG states that, once permits are received, delays during the construction phase of transmission projects typically are not the reason for failure to achieve a projected in-service date.

123. PSEG suggests the adoption of a "bright line" test such that, when PJM performs modeling for RPM and determines the level of import capability into a given LDA, PJM should model only transmission projects that are already in-service or for which construction of the project has actually commenced.[72] PSEG states that this will send the appropriate price signals to generators and demand response and minimize the risk that transmission project delays will compromise system reliability and distort price signaling. PSEG further notes that, if adequate

[71] *Id*. P 99.

[72] PSEG notes that its witness Napoli estimated that there is a 90 percent chance of achieving the in-service date projected when construction has commenced. *See* PSEG Request for Rehearing, *citing* PSEG Protest, Napoli Affidavit, ¶ 13.

generation and demand response do respond to the RPM signal so that the transmission upgrade is not needed, PJM's RTEP process can reassess the need for the planned transmission project. PSEG also states that, if a planned transmission project does meet its planned in-service date, the impact of not including the project in RPM modeling on RPM will be limited to a single year.

c. Commission Ruling

124. We deny PSEG’s request for rehearing. We find that PJM’s proposal is just and reasonable because it helps to ensure that these projects will be available to meet the in-service date. In contrast to the existing tariff, under which PJM assumes all projects will meet their in-service dates, PJM’s proposal has established some reasonable milestones for measuring whether this may occur. PSEG argues that even these proposed methods will not assure that projects will meet in-service dates and that therefore the Commission should reject PJM’s proposal. However, rejecting PJM’s proposal would simply return to the existing tariff under which no metrics are applied to evaluate whether projects are likely to meet their in-service dates. We find that PJM’s metrics strike a reasonable balance for determining when transmission projects should be included.

125. PSEG is arguing that we should find that PJM’s proposal and existing tariff are unjust and unreasonable because they permit the consideration of any project that is not in-service or for which construction has not commenced. As we stated in our March 26 Order, excluding all RTEP projects that are not in service or under construction, as PSEG suggests, would be overly cautious[73] considering the fact that the Base Residual Auctions are conducted three years ahead of the Delivery Year. The purpose of holding RPM three years in advance of the Delivery Year is to ensure that both new generation and transmission can be considered in determining reliability, and PSEG’s proposal would be directly at odds with that goal.

II. PJM's April 27 and June 1 Compliance Filings

A. April 27 Compliance Filing

126. On April 27, 2009, PJM made a compliance filing as directed by the Commission's May 26 Order. PJM’s filing made tariff changes to: (1) revise values for minimum offer price rule; (2) eliminate the sliding-scale payment

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[73] March 26 Order, 126 FERC ¶ 61,275 at P 102.

option for energy efficiency resources; (3) make minor ministerial changes to the tariff to reflect other provisions rejected by the March 26 Order.

127. Mirant filed the only protest of that filing, in which it presented the same arguments as in its request for rehearing on the CONE Area issue. As discussed above, Mirant argued that the Commission should order PJM to base the EAS revenue offset in each CONE Area on prices for the entire CONE Area, rather than on prices for the transmission zone in which PJM has assumed that the generator used to estimate the CONE (i.e., the Reference Resource) will be built. Mirant states that the Commission should reject PJM's compliance filing, and direct PJM to calculate the EAS offset using prices across the entirety of the CONE Area.

128. As we stated above in our discussion of Mirant's request for rehearing of the March 26 Order, PJM's method of calculating the Net CONE for each of the three CONE Areas was not addressed in the March 26 Order, and is therefore outside the scope of this filing. We thus reject Mirant's protest. We find that PJM's filing is in compliance with our directive in the May 1 Order, and therefore accept the compliance filing. We note, however, that in its April 27, 2009, filing, PJM states at Substitute Second Revised Sheet No. 621, section 9(d) that "the unforced value of a positive shortfall calculated for the committed --, for each day. . ." We assume PJM meant "the unforced value of a positive shortfall calculated for the committed capacity for each day. . . ." We will therefore require PJM to file a correction of this minor error, filling in whatever term is appropriate, in its September 1, 2009 compliance filing.

B. <u>June 1 Compliance Filing</u>

129. On June 1, 2009, PJM made a compliance filing as directed by the Commission's May 1 Order. No party protested that filing. We find that PJM's filing is in compliance with our directive in the May 1 Order, and therefore accept the compliance filing.

<u>The Commission orders</u>:

(A) The Commission grants in part and denies in part rehearing and clarification of our March 26 and May 1 Orders, as discussed above.

(B) The Commission defers the request for rehearing of the Illinois Commission with regard to incremental auction redesign, as discussed above, until after PJM files its September 1, 2009 compliance filing.

(C) The Commission accepts PJM's April 27 and June 1 compliance filings.

(D) The Commission requires PJM to file a correction of the error discussed above in its Substitute Second Revised Sheet No. 621, section 9(d), in its September 1, 2009 compliance filing.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.