UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	Docket Nos. ER05-1410-000 and EL05-148-000

RESPONSE OF JOSEPH E. BOWRING

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JUNE 30, 2008

At the request of PJM, I am responding to issues 3, 5 and 7 identified in the April Order.[1]

Mitigation Rules

Issue 3 identified in the April Order is: "whether the avoidable cost offer mitigation mechanisms and other administrative mechanisms have been effective in preventing withholding, and what modifications to those mechanisms may be needed."

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate the competitive market offers.

Market power may be exercised by withholding. Withholding can take two forms, physical withholding and economic withholding. Physical withholding in the capacity market would be implemented by failing to offer available capacity into the auctions. Economic withholding in the capacity market would be implemented by offering capacity at a price greater than a competitive offer.

The market design for capacity leads, almost unavoidably, to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the RPM tariff. This represents a significant advance over the prior capacity market design. Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules will mean that market participants will not be able to rely on the competitiveness of the market outcomes. Ongoing review of those rules to ensure their efficacy is appropriate.

With regard to physical withholding, the RPM tariff has a must offer requirement that obligates the owners of capacity to offer capacity into the RPM auctions. The Market Monitoring Unit (MMU) checked every MW of capacity in the PJM footprint and validated that the capacity was offered into each auction or that there was a valid reason for not offering.[2] There was no physical withholding in any RPM auction to date.

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1 123 FERC ¶ 61,037 (2008) at P 5.

2 See "Analysis of the 2007 – 2008 RPM Auction" and "Analysis of the 2008 – 2009 RPM Auction" at http://www.pjm.com/markets/market-monitor/reports-2007.html and "Analysis

Nonetheless, the must offer rules could be modified in several areas to ensure that all relevant capacity is offered into the RPM auctions. In particular, the rules governing the participation of FRR resources should be modified to require that all available FRR resources are offered into the RPM auctions, without any cap on the total amount. The current rules provide for a cap on the excess FRR resources that may be offered into the RPM auctions and do not provide a must offer requirement. In order to be consistent and to ensure that FRR participants cannot exercise market power by increasing or decreasing auction prices, both modifications are required.

While it has not been a significant level of MW, another source of capacity not offered into the RPM auctions is associated with units for which ownership ends during a delivery year. An owner faces disincentives to offer into an auction if the owner is taking on a delivery obligation for part of a delivery year when there is no longer ownership. Most of such issues have been resolved bilaterally. A requirement to resolve such issues bilaterally could be created to ensure that all such capacity is offered into the auctions. Although it has not occurred to date, leaving this issue unaddressed could create a mechanism for physical withholding.

With regard to economic withholding, the RPM tariff has clear market power mitigation rules governing the offers of existing units. The RPM tariff rules also provide for a broad review of the offers of new units.[3] The RPM tariff provides for a market power test. If an owner fails the market power test, the owner's units are subject to offer capping in order to ensure that competitive offers are made, i.e. that there is no economic withholding. To date, the MMU has had responsibility for calculating default offer caps, offer caps based on ACR levels and offer caps based on a combination of ACR and APIR levels including detailed discussions with unit owners and the review of supporting data and documentation. It is unclear what the MMU's responsibility will be going forward.[4]

Only those participants that fail the market power test are subject to offer capping. All participants in the total PJM market as well as all LDA RPM markets failed the three pivotal supplier (TPS) market structure test in each base residual auction, but not all participants failed the TPS test in the 2008 - 2009 Incremental Auction.[5] The result was

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of the 2009 – 2010 RPM Auction" and "Analysis of the 2010 – 2011 RPM Auction" at http://www.pjm.com/markets/market-monitor/reports.html.

3 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 607 (Effective April 1, 2008) and Second Revised Sheet No. 608 (Effective April 8, 2008), section 6.5 (a)(ii).

4 122 FERC¶ 61,264 (2008).

5 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," and Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed discussion of market structure tests.

that offer caps were applied to all sell offers in the base residual auctions, except sell offers for new units. The offer caps are designed to reflect the marginal cost of capacity. The marginal cost of capacity is termed the avoidable cost rate (ACR).

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[6] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource (APIR). Avoidable costs are defined to be net of net revenues from all other PJM markets and unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using permitted combinations of these options. The default ACR values were calculated by the MMU based on available unit data and posted to the PJM Web site in order to provide an alternative for owners that did not wish to calculate unit-specific ACR values or who believed that the default ACR values exceeded their unit-specific ACR values. The opportunity cost option allows resource owners to input a documented export opportunity cost as the offer for the unit. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export.

In general, unit-specific offer caps were calculated for less than 20 percent of all units. As an example, 1,104 generating units submitted offers in the 2010 - 2011 RPM auction. Unit-specific offer caps were calculated for 154 units (13.9 percent) including 134 units (12.1 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 20 units (1.8 percent) without an APIR component. Owners submitted unit-specific cost data and net revenue data for these units and the MMU calculated the unit-specific offer caps based on that data. Offer caps of all kinds were used by 532 units (48.1 percent), of which 370 (33.5 percent) were the default ("proxy") offer caps calculated and posted by the MMU. Of the 1,104 generating units, 15 new units had uncapped offers while the remaining 557 units were price takers, of which the offers for 546 units were zero and the offers for 11 units were set to zero because no data were submitted.

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[6] See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.8 (b).

The MMU verified the reasonableness of offer data and calculated the derived offer caps based on submitted data, calculated unit net revenues, verified capacity exports, verified the reasons for MW not offered, verified the maximum EFORd rates used, verified EFORd offer segments, verified clearing prices based on the demand curves and verified that the market structure tests were applied correctly. All participants in the RPM auction failed the market structure tests with the result that offer caps were applied to all sellers. Based on these facts, the MMU has concluded that the results of the RPM auctions to date were competitive.

The affidavit of James Wilson (Attachment A, dated May 30, 2008) makes various assertions regarding market power in the RPM auctions.[7] After a discussion of incentives, Mr. Wilson describes the "evidence" supporting his statement that sellers were able to "significantly raise RPM prices above the levels that would have been obtained under reasonably competitive circumstances."[8] Mr. Wilson's claims of physical and economic withholding are limited to three areas: offer behavior in the SWMAAC LDA in the 2009 BRA; offer behavior in the EMAAC LDA in the 2008 BRA; and offer behavior associated with capacity in the interconnection queues. In no case does the evidence support Mr. Wilson's claim that market power was exercised in the RPM auctions.

The evidence about behavior in the SWMAAC LDA in the 2009 BRA consists of a brief statement about forced outage rates and a discussion of offer prices. In support of his first point, Mr. Wilson provides a recitation of facts about the relevant supply offers and the statement that increased forced outage rates and a reduction of offered MW are "consistent with the incentives" to withhold. This does not constitute a claim of market power and it does not constitute evidence. The deratings of units were consistent with the physical facts at the units. The forced outage rates of units were based on the actual forced outage rates. Such mechanisms were not used to physically withhold. The MMU Report on the 2009-2010 base residual auction explains the exact reasons for the 431.9 MW reduction in unforced capacity in SWMAAC for this auction:[9]

> Total internal SWMAAC unforced capacity, which includes all generating units and demand resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to

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7 Maryland Public Utility Commission, et al. v. PJM Interconnection, L.L.C., Complaint of RPM Buyers, Docket No. EL08-67-000 (May 30, 2008), "Affidavit Of James F. Wilson in Support of Complaint of The RPM Buyers."

8 *Id* at P 84.

9 See "Analysis of the 2009 – 2010 RPM Auction" at http://www.pjm.com/markets/market-monitor/reports.html, pp 25-26.

> ICAP ratings (Table 6), decreased 431.9 MW from 10,777.1 MW in the 2008-2009 auction to 10,345.2 MW. This decrease was due to upgrades to existing generation and increases in demand resources, net of derations to existing generation and demand capacity resources. Multiple owners submitted both positive and negative capacity modifications, which resulted in a net decrease of 420.0 MW of ICAP and 255.9 MW of UCAP in SWMAAC. Of the 431.9 MW decrease in total internal SWMAAC unforced capacity, 176.0 MW were due to higher sell offer EFORds in the 2009-2010 auction resulting from updated EFORds.[45] Of the remaining 255.9 MW decrease in unforced capacity, 298.2 MW (116.5 percent) were generation capmods and -42.3 MW (-16.5 percent) were DR capmods. Since there were no imports from outside PJM into SWMAAC, RPM capacity was 10,345.2 MW. This amount was reduced by 33.5 MW which were excused from the RPM must-offer requirement as a result of planned reductions due to environmental regulations, resulting in 10,311.7 MW that were available to be offered into the auction, a decrease of 314.4 MW. After accounting for the above exception, all capacity resources were offered into the RPM auction, with offered volumes decreasing by 314.4 MW from 10,626.1 MW to 10,311.7 MW.

In support of his second point about the SWMAAC LDA, Mr. Wilson states that the fact that the supply curve shifted to the left shows that "suppliers had flexibility within the RPM rules to substantially vary their offer prices from year to year, and to offer prices well in excess of avoidable cost."[10] The data do not support this claim. The MMU reviewed the offers in detail and the offers were not above avoidable costs.

The MMU Analysis of the 2009-2010 RPM Auction stated:

> A combination of factors led to the increase in the clearing price. A 781.0 MW increase in CETL from 5,610.0 MW to 6,391.0 MW, which would normally lower LDA prices due to the import of more lower priced generation, was partially offset by a corresponding 220.0 MW increase in CETO from 5,940.0 MW to 6,160.0 MW. Unit derations, 144.3 MW of which were for environmental regulations, resulted in less available capacity, which when combined with increased offer prices due to higher APIR to meet environmental regulations and the higher CETO resulted in the higher clearing price.

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[10] Maryland Public Utility Commission, et al. v. PJM Interconnection, L.L.C., Complaint of RPM Buyers, Docket No. EL08-67-000 (May 30, 2008), "Affidavit Of James F. Wilson in Support of Complaint of The RPM Buyers," at P 86.

Mr. Wilson focuses on the definition of APIR in the RPM tariff. Mr. Wilson asserts that the APIR provisions "deviate from the concept of avoidable cost." Mr. Wilson also states that "the fact that for a large quantity of capacity, offer prices were raised significantly one year and lowered significantly the next, suggests that RPM's mitigation is not successfully containing offer prices to the avoidable cost." Mr. Wilson's logic is flawed. The essence of Mr. Wilson's argument is that the APIR provisions of the RPM tariff "allow suppliers to raise RPM clearing prices and costs by enormous amounts."[11]

The APIR provisions of the tariff permit owners to add to offer caps an amount based on investments required to maintain units as capacity resources and a capital recovery factor which translates the total investment into an annual recoverable amount. This is equivalent to the treatment of the costs of new entry for a new unit and provides the ability for older units to make required investments and reflect the associated costs in RPM offers. The APIR provisions of the tariff permit this recovery over relatively short periods of time when the investment is at units above specific age thresholds and when other specific criteria are met. The shorter the time period, the higher the adder to the offer caps.

If the treatment of APIR investments were identical to the treatment of new entry, the ability to add the associated investment recovery would be limited to one year. The tariff reflects the explicit decision to permit such recovery over a defined number of years in order to reduce the uncertainty associated with such recovery and to increase the incentives to make such investments. This is consistent with the tariff provisions that permit such treatment for new investments under defined circumstances and is in fact consistent with Mr. Wilson's recommendation regarding new entry pricing. The tariff reflects policy decisions regarding the appropriate way to provide incentives to investments in existing generation and in new entry. While it is perfectly appropriate to revisit those decisions, it is not accurate to state that they permit the exercise of market power.

In fact, the behavior described by Mr. Wilson is entirely consistent with his own description of the appropriate underlying economic logic.[12] Mr. Wilson states that a competitive supplier would include the costs of new investments for an existing unit in one year and after that treat the costs as sunk. Mr. Wilson's description of the behavior in which he asserts that APIR was added in one year and not included in the next year is entirely consistent with his own description of competitive behavior and, if true, does not mean that market power was exercised.[13]

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11 *Id* at P 96.

12 *Id* at P 90.

13 *Id* at P 92.

With regard to behavior in the EMAAC LDA in the 2008-2009 BRA Mr. Wilson discusses offer prices and compares offer behavior in the 2008-2009 BRA to what Mr. Wilson assumes is the offer behavior for the same units in the incremental auction for 2008-2009.[14] Mr. Wilson's claim is: "The fact that so much EMAAC capacity was offered at prices well above its apparent avoidable cost calls into question whether RPM's mitigation is effective in holding capacity offers to the avoidable cost levels at which resources would be offered under competitive circumstances." [15] Mr. Wilson bases the statement that offers were above competitive offers entirely on his assumption that owners reduced offers in subsequent auctions.

Mr. Wilson's claim that market power was exercised by offers greater than avoided cost is not supported by the evidence. The MMU reviewed the offers in detail and the offers were not above avoidable costs.

While Mr. Wilson asserts that PJM did not explain the nature of the supply curve, the MMU report on the auction did describe the supply curve in some detail.

The MMU Analysis of the 2008-2009 Auction stated:

> Of the 30,231.3 MW cleared in EMAAC, which was a decrease of 566.5 MW from the 2007-2008 auction, 28,829.9 MW were cleared in the RTO before EMAAC became constrained. Once the constraint was binding, based on the 7,930.0 MW capacity emergency transfer limit (CETL) value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 1,549.5 MW of incremental supply, 401.4 MW cleared, which resulted in a resource clearing price of $148.80 per MW-day, as shown in Figure 6. The price was determined by the intersection of the incremental supply and demand curves. On the horizontal section of the supply curve, 1,098.3 MW were offered at the net CONE price of $148.80 per MW-day. Of this amount, 660.6 MW were base offers with APIR from existing generation and 437.7 MW were EFORd offer segments.

Again, even if Mr. Wilson's assertion were correct that APIR investment explains all the higher offers in the BRA, his own logic implies that competitive behavior would dictate the offer of the same capacity in subsequent auctions at levels excluding APIR, which has not been demonstrated to have occurred.

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[14] *Id* at P 93-96.

[15] *Id* at P 96.

Finally, Mr. Wilson offers as evidence of market power the unsupported assertion that it is possible that some generation in the PJM interconnection queues was not offered in order to affect the price in the auction. Mr. Wilson's statement is: "It is quite possible that a significant amount of this capacity that was not offered will in fact be built for the upcoming delivery year, but its owner declined to offer the capacity into the BRA in order to not depress RPM prices."[16] Mr. Wilson's claim is unsupported speculation about the intent of potential sellers that are owners of existing generation. Mr. Wilson does not address the incentives of new entrants that do not have substantial portfolios of existing generation. Mr. Wilson does not address any of the factors that govern actual offers of units in the interconnection queues.

VRR Curves

Issue 5 identified in the April Order is: "whether the slopes of the Variable Resource Requirement (VRR) demand curves to determine capacity prices provide inappropriate incentives to withhold capacity."

The MMU has previously reached conclusions about the basic structure of the capacity markets. The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in other markets or does not have value as a hedge, may be expected to retire. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The level of elasticity built into the RPM demand curve (VRR) is not adequate to modify this conclusion. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is pivotal and therefore has structural market power.[17]

The existence of structural market power and the associated incentives to exercise market power are part of the basic facts about capacity markets. While the shape of the VRR curve adds some elasticity compared to the vertical demand curve of the prior capacity market construct, it is not adequate to mitigate the existing structural market power. The inclusion of some elasticity is an improvement over the vertical demand curve but there are identifiable costs and benefits associated with the inclusion of

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16 *Id* at P 98.

17 See "Analysis of the 2010 – 2011 RPM Auction" at http://www.pjm.com/markets/market-monitor/reports.html.

elasticity. In some cases, the introduction of elasticity resulted in a higher clearing price than would have occurred with a vertical demand curve.

However, the shape of the VRR curve does not provide "inappropriate incentives to withhold capacity." The demand curve for capacity is established by the reliability requirement that must be met by PJM. That reliability requirement is a target number and a demand curve based on that target would be a vertical demand curve. The goal of the VRR design was to add some elasticity around the reliability target while attempting to ensure that market outcomes would result in the required level of reliability. Given the constraints imposed by the requirement to reach a defined reliability objective, it is not possible to introduce enough elasticity in the VRR curve to offset the structural market power that characterizes the capacity market. Given that the reliability requirement provides a lower limit on the demand for capacity, the only way to introduce more elasticity would be to require the purchase of more capacity at lower prices. This approach has both costs and benefits but the result would not achieve the desired objective of offsetting the structural market power in the capacity market.

Regardless of the exact elasticity of the demand curve, the incentive to withhold is also a function of the elasticity of supply. The supply curves in the base residual auctions have been characterized by a flat portion reflecting substantial amounts of capacity offered at zero or very low prices and a tail with a steep slope reflecting the high incremental costs associated with some units. The characteristics of the tail of the supply curve were determined by the tariff rules governing the definition of avoidable costs, including both ACR and APIR. These issues were addressed in the prior response regarding mitigation rules. A steep supply curve tail is to be expected in a market where total supply exceeds total demand by a relatively small margin. The incremental cost of capacity for some units is high as a result of requirements for ongoing annual expenditures as well as requirements for additional investment to permit the units to remain in operation as capacity resources. The ultimate discipline on such offers is new entry. When the cost of keeping older units in the market is less than the cost of new entry, the efficient solution is to keep those units in the market. When the cost of new entry is less than the cost of keeping older units in the market, the cost of new entry will set the price at the margin and the older units will no longer clear.

CONE and Net Revenues

Issue 7 identified in the April Order is: "whether RPM's mechanism for determining the net Cost of New Entry (CONE), which uses historical energy and ancillary service revenues, produces prices that accurately reflect the need for new capacity, and whether there are more accurate ways to set capacity prices."

The net CONE consists of a gross CONE level and an offset based on the net revenues from energy and ancillary services markets. The net CONE level represents the revenues that would have to be earned from the capacity market if the full amount of gross CONE is to be covered from all markets, including energy, ancillary and capacity markets.

The energy and ancillary services revenue offset is currently based on a three year historical average of revenues for the CONE technology, determined prior to the relevant Base Residual Auction, which is itself three years prior to the actual delivery year.

Clearly, the results of the historical offset calculation bear no defined relationship to the level of actual energy and ancillary services revenues that will be achieved in the delivery year. In addition, the results of the historical approach bear no clear relationship to the expectations of investors who are deciding whether to offer new units into the RPM auction. While investors' expectations are undoubtedly based in part on historical data, there are also other factors considered which weaken any relationship between the historical data and expectations.

While the most accurate way to set capacity prices would be to link them to actual net revenues in the delivery year, it is not possible to set CONE for a BRA three years prior to the auction using actual net revenues. The demand curve must be established using data available at the time. However, a true up provision could be used to adjust the historical average after the fact.

While there is no single right way to calculate the offset using actual data, the use of a three year historical average is a reasonable compromise between using one or two years which could be affected more significantly by unusual results in a single year and using a longer period which would include increasingly stale data reflecting irrelevant market conditions. Data from available forward price curves could also be used as a way to project the offset, but use of the less granular forward data would require the interpolation of all hourly data for the period, as the calculation of the energy and ancillary services offset is based on hourly data. Information from the forward curves could be used to scale the results from historical data, but this becomes less critical with a true up.

Getting the energy and ancillary services offset right is important because it has a significant impact on the demand curve and thus the clearing price for capacity. If the offset is too low, prices are greater than necessary to attract investment. If the offset is too high, prices are lower than necessary to attract investment. In addition, getting the true up right ensures market participants that, if scarcity pricing is implemented in a way that results in increased scarcity revenues, the scarcity revenues will serve to offset capacity market prices in a well defined and predictable way.

A reasonable way to true up the offset would be to set it based on the three year average for the BRA, with or without scaling based on forward prices, and then to do a true up after the delivery year based on actual results in the delivery year. Such a true up approach would have the advantage of ensuring an accurate link to the energy and ancillary services markets results for the delivery year, while minimizing the associated uncertainty experienced by market participants. The true up could be done by calculating the energy and ancillary services offset for the delivery year based on actual market prices, recalculating the net CONE, recalculating the demand curve based on the revised net CONE and recalculating the clearing price using the revised demand curve. If sellers in the BRA received more than the revised clearing price, they would refund that amount. If the sellers in the BRA received less than the revised clearing price, they would receive that amount.

The use of a true up to recalculate net CONE, to recalculate the VRR curve and to recalculate the clearing price addresses the demand side of the market but it does not address the supply side. The offer of each unit is based on a unit-specific calculation of actual, historical net revenues. The calculation of the unit-specific offer caps has the same issues as the calculation of the net revenue offset for net CONE.