UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Power Providers Group	)	
	)	
v.	)	Docket No. EL11-20-001
	)	
PJM Interconnection, L.L.C.	)	
PJM Interconnection, L.L.C.	)	Docket No. ER11-2875-001 -002

STATEMENT OF WILLIAM W. HOGAN[i]

FERC Technical Conference

August 25, 2011

My name is William W. Hogan. I am a Professor at the John F. Kennedy School of Government, Harvard University. Further details of my affiliation are included in an endnote. I appreciate the opportunity to participate on this technical conference established by the Commission's June 13, 2011 order and July 22, 2011 supplemental notice in this case "to explore the applicability of PJM's Minimum Offer Price Rule (MOPR) to resources designated as 'self supply'" in PJM's Reliability Pricing Model (RPM) base residual auction. I was asked to prepare these comments and participate with support from PSEG. However, the views expressed here are my own and I do not speak on behalf of anyone else. These comments include my initial comments before the technical conference of July 28, 2011, and an appendix that addresses some of the issues raised at the technical conference.

The Commission has already found that the RPM market design as it stands would be vulnerable to buyer-side manipulation and the structure of RPM was such that a mitigation mechanism like the MOPR is necessary. I agree with this conclusion. For the present inquiry, the Commission delineated several further questions that will be addressed at the technical conference. These questions are important and I look forward to participating in the discussion. However, there are other matters that are also important in setting the context for this discussion. Here I would emphasize three issues that the Commission might consider as well as reviewing the particulars of the MOPR. The three issues include policies and practices contributing to the problem of the "missing money" that creates the need for the RPM; the larger context of reform of RPM that transcends the offered criticisms of the MOPR; and consideration of a different structure for dealing with buyer market power within the framework of the RPM.

As the Commission knows, a fundamental reason for the creation of RPM and similar capacity markets arises from the so-called "missing money" problem. The simple version of this story, captured now in regular reports by market monitors, is that energy and ancillary services revenues in organized electricity markets have not generally been adequate to support new investments.[1] This is not a new story. Despite the many successes of organized market design and the associated pricing mechanisms, it has long been clear that there are various design elements that contribute to depressed revenues, and this has always raised concern about the adequacy of generation and demand response investment going forward. In part this is a defect in the implementation of an efficient market design, and in part the missing money is a structural problem associated with the way that we set and enforce reliability standards.

From the early days of recognition of this problem, there has been a focus on using capacity markets to compensate for the implementation and structural problems. This process continues as the Regional Transmission Organizations and the Commission review and rethink the structure of capacity markets. While such review and reform of capacity markets is a good thing, it has long been my concern that the process has proceeded with too much weight placed on perfecting capacity markets and too little attention given to improving the implementation of electricity market design in order to reduce or eliminate the problem of the missing money.[2] Although the situation has progressed slowly over the years, there are still opportunities to improve designs for scarcity pricing, treatment of congestion prices, and related matters that have a material effect on energy prices and, therefore, the missing money. A review of the implementation of energy market design should be a high priority and not something ruled out or delayed by an exclusive focus on fixing the complementary capacity market.

However, reform of capacity markets is important and underway. For example, PJM now has an extensive study in process, being conducted by the Brattle Group, addressing the performance of RPM and foundational elements of its design. My understanding is that the process envisions reporting to PJM stakeholders in the early Fall and subsequent submissions to the Commission with any proposed changes in the RPM market design. This process is important for the present consideration of the MOPR. The structure of the MOPR, relying on prior mitigation of bids for new resources that receive out-of-market payments, is compatible with the design of the RPM. Most importantly, the principles for determining the mitigated bid to use in the single price auction are compatible with the methods for determining the net cost of new entry (net CONE) for the requirements curve in the design of the RPM. Without a mitigated offer, the single price auction would be subject to buyer-side manipulation. It is important that this calculation of the mitigated offer be internally consistent with the calculation of the net CONE.

As I explained in a previous filing with the Commission:

---

[1] *See* Monitoring Analytics, PJM Market Monitor, *State of Market Report*, 2010, Vol. 2, p. 176.

[2] See W. Hogan, "Resource Adequacy Mandates and Scarcity Pricing ("Belts and Suspenders")," Comments submitted to the Federal Energy Regulatory Commission, Docket Nos. ER05-1410-000 and EL05-148-000, February 23, 2006 (available at http://www.hks.harvard.edu/fs/whogan/Hogan_PJM_Energy_Market_022306.pdf).

> Within the framework of RPM, . . . there is a simple consistency test that should guide FERC decisions on the appropriate mitigation policy. The consistency test is that the mitigation rule applied to the Reference Resource should yield a mitigated offer of the net CONE for the Reference Resource. Within the RPM framework, the net CONE is intended to be the best estimate of the appropriate price for capacity like the Reference Resource. If an offer for capacity like the Reference Resource is to be mitigated because the actual offer arises with some form of subsidy, then the result of the mitigation should be the net CONE. Otherwise, the mitigation policy would put itself at odds with the design of the RPM capacity market. Any argument that the appropriate mitigation level for the Reference Resource differs from the net CONE for the Reference Resource would inherently be a criticism of the RPM design, not a justification for an internally consistent mitigation policy.[3]

This observation from the discussion of the then proposed MOPR carries over to the subsequent criticisms of the MOPR design and the entreaties for a self-supply exemption or special treatment. Many of the criticisms of the MOPR, such as the critique of the levelized net CONE as a "complete economic fiction" are not apt within the context of the RPM design.[4] They are better understood as general criticisms of RPM and could be taken up as part of the broader Brattle Group study process. Some mitigation is necessary to address the problem of buyer market power manipulation. Within the framework of RPM and the single clearing price auction design currently employed, the existing MOPR procedures are appropriate and internally consistent.

The choice of preserving a single price clearing auction is critical in this observation. Although the Commission chose otherwise, it would be useful to reconsider the merits of a version of the Alternative Capacity Price Rule ("APR") reform that had been developed in New England.[5] The distinction here from the comment above is that this approach would require a simple change in the RPM design to apply mitigation only in determining the price to be paid to existing resources. The RPM without mitigation would apply to all new resources, and these would receive the market clearing price determined in the normal way.

Admittedly, the APR approach would present complications: first, it would deviate from the usual single-price rule, and second, it might result in an increase in the total locational capacity procured through the RPM. These may be difficult pills to swallow, which was my own reaction when I first encountered the proposal. But the APR approach was carefully designed to strike at the exercise of buyer market power, not by precluding

---

3 W. Hogan, "Minimum Offer Price Mitigation for the PJM Reliability Pricing Model," Affidavit included in PJM Power Providers Group, *Answer To Motions To Dismiss And Other Pleadings*, FERC Docket Nos. EL11-20-000 and. ER11-2875-000, March 18, 2011, pp. 12-13.

4 National Rural Electric Cooperative Association, "Request for Rehearing and/or Clarification," FERC Docket Nos. El11-20-000 and ER11-2875-000, May 12, 2011, p. 9.

5 *See ISO New England*, FERC Docket Nos. ER10-787-000, EL10-50-000 and EL10-57-000, First Brief of ISO New England Inc., July 1, 2010, pp. 12-17.

market-clearing by some investments but by eliminating the incentive and ability to manipulate price for the bulk of the resources. Within this framework, the current MOPR mitigation calculation would apply for new resources receiving out-of-market payments, but would be used only in determining the price for existing units. An attractive feature of this approach is that it would obviate virtually all of the current complaints about the MOPR. There would be no need for special treatment of self supply, nor any need for exemptions for renewables or demand side resources. And as for the expressed concern that there is not enough new construction to meet reliability and other objectives, the incremental procurement of capacity that might result under the APR could be seen as a solution rather than a problem.

There are possible variants of these other reforms. The details under each of these headings would require attention by the Commission. But the import for today is clear. The Commission is correct in concluding that an unmitigated RPM would be vulnerable to buyer-side manipulation that would undermine the intent and relevance of capacity markets. The current MOPR is consistent with the current RPM, and a special modification of the MOPR for self-supply would undermine the fundamental policy. Any changes in the MOPR should be considered as part of the larger review of RPM, and appropriate mitigation policy designed consistent with changes in the design of RPM. One such change that the Commission should revisit is the New England APR approach that would deal with most if not all of the criticisms of the MOPR. And all this should be done with as part of a larger process that would reform energy market design and pricing to reduce the missing money problem and lessen the importance of RPM and similar capacity markets.

Appendix

Alternative Capacity Price Rule for RPM

The Alternative Capacity Price Rule ("APR") suggested here follows the conceptual outline of the New England proposal. The focus is on the impact of out of market (OOM) generation resources offering into a capacity market. "OOM resources typically hold contracts that ensure full payment for the resource or otherwise receive particularized subsidies regardless of the capacity price that they could receive through their participation in the FCA [capacity auction]. Because OOM resources receive 'out-of-market' revenue, these resources can be offered into the FCA at very low prices that do not reflect a market-based or competitive cost of entry. OOM resources clear in the FCA on the basis of these low offers, and in so doing take the place of new or existing resources that offer in the FCA at competitive but higher prices. As a result, the FCA clears at a price (the 'Capacity Clearing Price') that is too low to retain or attract the displaced new or existing resources."[6] The lower clearing price for all resources presented an incentive for the exercise of buyer market power. The proposed New England approach offered a "way to correct for the effect of OOM resources is to establish the price that would have prevailed if the OOM resources had submitted competitive offers into the FCA – that is, the price that would have prevailed if these resources did not receive OOM revenues and had offered into the FCA at prices reflecting their full cost of entry. In this 'but-for' world, the FCA would clear based on the competitive but higher offers of the resources that were displaced by the OOM resources. This higher price, the Alternative Capacity Price, is established on the basis of resource bids that fully reflect their cost of entry. The Alternative Capacity Price thus fully corrects for the price-suppressing effect of some resources being OOM."[7]

As applied to the context of the PJM RPM, the analogous approach would include two related auctions. In the first auction, the offers of all prospective generation, both existing and new, would be accepted and an auction conducted with the standard offer caps and other RPM rules but no minimum offer price mitigation. All the generation that cleared in the market would receive an equivalent of the New England Capacity Supply Obligation (CSO), meaning they would receive a capacity payment through the RPM mechanism. Associated with this auction would be the Capacity Clearing Price (CCP). The offers at this stage would be unmitigated. Hence, the CCP would be affected by any OOM offers. This first auction CCP price would apply to all new generation that cleared and received a CSO in this first stage.

The second stage would utilize the same offers and information, but the market monitor would replace any OOM related offers for new or existing generation with mitigated offers using the procedure of the current PJM MOPR. Therefore, the second auction would correspond to the current PJM mitigated auction. The second auction determines the Alternative Capacity Price (ACP). At this stage, the rule discriminates between

---

6 *ISO New England*, p. 10.

7 *ISO New England*, p. 11.

existing competitive generation and any new generation. All existing generation that cleared in the second or mitigated auction would receive a CSO. Any new generation that clears in the second auction but not in the first auction, would not receive a CSO. And, of course, new generation that did not clear in either the first or second auction would not receive a CSO.

The prices paid would distinguish between new and existing resources. All new resources with a CSO would receive the (possibly lower) CCP from the first auction. All existing resources with a CSO would receive the (possibly higher) ACP from the second auction.

There would have to be a rule to determine when new competitive resources would be converted and subsequently be treated like other existing resources. Presumably this would be connected to the competitiveness of the offer as revealed by clearing in the second or mitigated auction. There will be some price variability from year to year that does not reflect long-run competitive conditions. The intent of the APR is to mitigate the effect of long-run uncompetitive offers. Therefore, clearing once in the mitigated auction would not be sufficient to demonstrate a competitive offer. For purposes of the present discussion, therefore, assume this conversion follows after the new resource that has received a CSO has also cleared at least two or more times in the second auction.

This is the basic summary following the design of the New England proposal adapted to the PJM RPM. Besides its complexity, the two most distinctive features are that this discriminatory auction involves two prices and the total capacity purchased could be more than would otherwise be purchased in the RPM mitigated auction under the current PJM MOPR.

In analyzing the incentives and effects of this proposal, two simplifying assumptions help in avoiding a distracting critique of the larger RPM design. First, assume that the offers based on the net CONE provide a workable competitive approximation of the intended long term incentives for the capacity market. In other words, we are assuming that absent the OOM offers the RPM auction would work as intended. Second, assume that the market monitor can appropriately calculate the proper competitive mitigated offer to apply to OOM offers. This includes the ability to estimate the independent value of non-market objectives such as promoting renewable resources, local economic development, and so on. But this adjustment does not count as a benefit any reduction in RPM price.

If there are no OOM offers, the auction reduces to the standard single-price, market-clearing RPM design. The CCP is the same as the ACP, so there is no effect on the price or the total quantity purchased.

Suppose that there are OOM offers but these offers do not reflect any attempt to manipulate the market price. Then the offer prices would correctly reflect the out-of-market benefits but not any additional offer price reductions intended to capture lower capacity prices through the exercise of buyer market power. Under these conditions, the mitigated offers would be the same as the unmitigated offer prices. Again the auction reduces to the standard single-price, market-clearing RPM design. The CCP is the same as the ACP, so there is no effect on the price or the total quantity purchased.

In both these cases, new resources may expand the available capacity and reduce the RPM price, for both new and existing resources, but the mitigation rule does not cause any deviation from the RPM design. Furthermore, the reduced price does not arise from the exercise of buyer market power.

Now suppose that some of the OOM offers are below the competitive mitigated offer. If this were to occur, it would reduce the CCP below the ACP, and increase the total purchased capacity. However, it would not reduce the ACP below the intended RPM price. The whole purpose of APR design is to create this disconnect for the simple reason that it removes the buyer's incentive to offer OOM capacity that depresses the RPM price for existing capacity. Any buyer that followed this strategy would face the higher cost of making the higher OOM payments for the new capacity it offered. The same buyer would have to pay its pro-rata share of any incremental capacity purchased through the RPM. And the only added benefit it would receive through the RPM would be in any reduction of the first auction CCP which applied only to the (probably small) volume of new generation that received a CSO. The conditions where this would produce any benefit worth the cost of the added OOM payments would require an unusual combination of many other OOM offers. An assumption of the APR approach is that this would be so unlikely that it would not overcome the deterrent effect that would prevent buyers from making offers that otherwise would depend on benefitting from lower RPM prices. In effect, the APR would make buyers act as price takers, as intended.

If this deterrent effect works, then the result of the APR structure would restore the outcome (but not the design) to a single-price market-clearing RPM for competitive offers.

The incentive for generation then reduces to the usual approximately incentive compatible conditions of a first-price auction where the participants don't know exactly who is on the margin and act as price takers. The optimal offer for new OOM generation is the mitigated offer. Offering the generation for less, they may end up with a CSO at the CCP that is less than they need net of the out-of-market benefits they expect. And if they offer more than their mitigated price they may miss a chance to get a CSO at a price that would be beneficial to them. For the competitive new offers, the same logic applies and they should make a competitive offer.[8] And for existing generation, the same argument applies for the incentive to make the competitive offer going forward.

Apparently, with agreement on the value of OOM benefits and calculation of the competitive mitigated offers, the APR approach result, if not its design, would be close to or exactly equal to the single-price market-clearing RPM structure. Furthermore, this conclusion applies without requiring any exemptions in treatment in the first unmitigated auction. Hence, the APR logic covers everything from gas plants to renewables and demand resource investments. All resources would be allowed to make their own offers and receive the CCP if they clear in the first auction. Mitigation would not affect new

[8] Note this is one reason for paying both the OOM offers and the competitive new offers the CCP rather than the ACP, which would otherwise change their incentives. Hence, this is not the same rule or incentives as including all the market-clearing offers in the first auction the same price as determined in the second auction.

resources, it would only affect the ACP paid to existing resources. All new resources would have an incentive to offer at their competitive price that reflects the minimum they would accept to go forward with the generation. For new resources, therefore, it would not usually be wise to offer in at zero, unless the non-market benefits outweighed the cost of the plant, in which case participation in RPM would not be necessary to go forward.

Note that the RPM incentives would also apply to retirements of existing generation. There would be no problem with existing generation that should otherwise retire being kept in the market to "clip coupons" at a higher ACP that was much greater than the competitive RPM price.

What then could cause a significant divergence between the CCP and the ACP? Absent mitigation, there would be a strong buyer incentive to drive down the RPM price, but this incentive is removed under the APR approach. This could not be the explanation.

Another possible circumstance would be a difference in view about the OOM value of the generation and, therefore, a disagreement between the market monitor and the generation owner about the proper mitigated competitive offer. Presumably this assumes that the generation owner prefers a greater valuation for the renewable or job creation benefits, and a lower "competitive" offer than could be supported by the market monitor. This could be a legitimate difference of opinion. In this case, the generation could win a CSO and would receive a CCP payment that was at least what it wanted, even if it is not what the market monitor estimated. The total capacity purchased would be higher than the RPM would otherwise anticipate, but the cause of this increased procurement would be the OOM offers being low because the other benefits were perceived to be greater. If this occurs because of state polices and actions, this may be as much a solution as a problem. But the difference would not arise because of the exercise of buyer market power.

Endnote

---

[i] William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This paper draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. These comments were prepared on behalf of PSEG. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, Australian Gas Light Company, Avista Energy, Barclays, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, Calpine Corporation, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Duquesne Light Company, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Exelon, FTI Consulting, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GWF Energy, Independent Energy Producers Assn, ISO New England, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, JP

Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, PPL Corporation, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Corporation, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, Transcanada, TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).