UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Capacity Markets in Regions with Organized Electric Markets	Docket No. AD08-4-000

TECHNICAL CONFERENCE

COMMENTS OF DR. ROY SHANKER

On Behalf of

PJM POWER PROVIDERS GROUP

May 7, 2008

Introduction

1. I have been asked to provide comments and participate in this technical session by The PJM Power Providers Group, Inc. (P3).[1] In sum, it is too soon to make any conclusions as to the success or failure of PJM's capacity market design, and many of the concerns discussed today represent an effort to re-litigate issues already debated and rejected in the settlement agreement. The resulting regulatory and investment uncertainty threatens the ability of the capacity market to assure continued system reliability in PJM.

2. The stated objective of this technical conference is to discuss the operation of the forward capacity markets in New England and PJM, as well as proposals put forward by

[1] P3 is a non-profit organization that supports the development of properly designed and well functioning markets in the PJM region. Combined, P3 members own nearly 74,000 megawatts of power and over 51,000 miles of transmission lines in the PJM region, serving nearly 12.2 million customers. While the members of P3 have had the opportunity to review these comments, the content remains my own, and may not necessarily reflect the specific positions or opinions of any individual member of P3. While the members of P3 have had the opportunity to review these comments, the content remains my own, and may not necessarily reflect the specific positions or opinions of any individual member.

the American Forest & Paper Association and Portland Cement Association, et al. My comments today address both of these proposals, and in particular the Reliability Pricing Model (RPM) in PJM.

3. However prior to commenting on the status quo or potential changes to RPM, it is worth considering how we arrived at this point and the implications of the path that brought us here. In PJM, concerns began to arise regarding the functioning of the capacity market almost from the outset, and formal stakeholder deliberations began at least by 1999. The debate on how to modify the capacity market design to allow for reasonable recovery of costs, provide incentives for new investments and remove volatility went on for over five years. It was stalemated by a fundamental split in the stakeholder process between those who would be compensated for meeting the adequacy requirements of the system, and those who would be required to pay for these requirements.

4. It was years before there was even grudging acceptance of the need for capacity payments in markets where there were mandated reserve requirements, energy price caps and little or no reflection of scarcity in the energy markets. Similarly, after almost a decade of debate, many still oppose the use of clearing market mechanisms as the basis for uniform compensation and instead favor some form of pricing discrimination between existing and new capacity. This is despite numerous Commission decisions to the contrary.

5. In PJM, the buyer/seller stalemate led to a unilateral filing by PJM in August 2005 of its initial proposal of RPM. This was precipitated in part by PJM's belief that the continuing impasse was putting system reliability at risk. In April 2006 the Commission found that the existing PJM capacity market was unjust and unreasonable and directed a hearing process to resolve the market inadequacies. Finally, after extended negotiations, a settlement was filed in the fall of 2006 and approved by the Commission in December 2006, with transitional auctions commencing in 2007. The first "steady state" Base Residual Auction (BRA) is finally occurring May 5-9, 2008.

6. Under the existing RPM tariff provisions, capacity commitments are supposed to be determined based on a 3 year forward look at future capacity needs. Given the need to implement RPM effective with the 2008/2009 delivery year, a series of frequent “transitional” auctions commencing in 2007 were used to establish capacity commitments for the period less than 3 years out or through the 2010/11 delivery year. The Base Residual Auction (BRA) scheduled for May 5-9, 2008 is in fact the first non-transitional or “steady state” BRA under RPM. Thereafter, the BRAs will occur on an annual basis around the May timeframe.

7. The point of this short history is that even in the context of a market design that the Commission ultimately found unjust and unreasonable, it took nearly a decade to work through the competing interests in the stakeholders and regulatory processes. At this time, the PJM RPM is still in its infancy. Thus given the early stage of implementation of the RPM market, calls for potential changes and revisions are clearly premature and may simply represent efforts to re-litigate already decided issues, while simultaneously increasing the regulatory uncertainty surrounding the new capacity market.

8. With this background, the importance of capacity markets continues to be substantial, and can be seen from the basic motivations that drove us to the current solutions in PJM and New England. In both cases there was a recognition that capacity payments were a needed part of overall compensation, which could not be obtained from the existing energy market designs, and that in one form or another, a mechanism was needed to, *on average and over time*, result in a payment of the net cost of new entry to all generation providing capacity or adequacy services in order to assure system reliability.

9. The key element in the design of both capacity markets was the Commission objective to find market-based tools or mechanisms fulfilling an adequacy or capacity function that attracts new generation capacity and retains existing capacity as needed while providing this long run average net cost of new entry. A direct corollary of that

objective, when considered in the context of extraordinarily expensive and long-lived assets, is the need of potential investors and suppliers for a high degree of regulatory certainty and associated confidence in those market rules and mechanisms—and their stability—to allow recovery of significant investment over the *long run*. Basically, participants need to believe that the process will be stable if it requires a long-term business cycle to allow it to work.

10. The important point is that these have to be solutions for the *long run*, and mechanisms that can be sustainable in the long run without interference. This is not to say that the market designs should not be reviewed, analyzed and modified if needed. However, we should cease re-litigating the basic decisions that led us to these capacity market settlements and allow the capacity markets the opportunity to work and mature. Continued regulatory uncertainty adds to perceived investment risks and associated costs, and undermines one of the predicates of the solution: regulatory and business stability. This is particularly true with respect to repeated efforts to find some form of discriminatory pricing between existing and new generation despite the repeated rejections of this proposition as inefficient and unworkable.[2]

11. As recognized, there is no rational basis for the distinction between "old" and "new" megawatts of unforced capacity, and the distinction is only an artifice for trying to effectively expropriate existing property that is "sunk" and not pay the appropriate clearing price. While such expropriation may succeed in the short run, it is doomed to failure (or a return to fully regulated prices) as all new entrants will recognize that the day after they start operations they too become "old" and subject to the same treatment. Over time, this vulnerability becomes manifest with an absence of private new entry and the

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[2] As the Commission has stated:

> In a competitive market, prices do not differ for new and old plants or for efficient and inefficient plants; commodity markets clear at prices based on location and timing of delivery, not the vintage of the production plants used to produce the commodity.

PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 at P 141 (2006), order on reh'g, *PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,173 (2007). Past experience with vintage pricing in the context of natural gas ratemaking ultimately led to a national shortage in natural gas and prompted the passage of the Natural Gas Policy Act which deregulated natural gas supply.

need for the entire market to be subject to some sort of out-of-market procurement. The Commission itself has repeatedly recognized the inappropriateness of such discriminatory pricing in its various forms (e.g. RMR contracts), and dismissed various efforts to obtain such pricing.

Discussion Issues

12. In the context of the above, there are several specific points that I would like to address concerning the existing RPM design and potential areas of concern or modification as RPM implementation goes forward. Also, I have attached as an appendix at the end of these comments some remarks specifically related to the American Forest & Paper Association and Portland Cement Association, et al. proposals that were included in the specific items identified for discussion today.

Has RPM Performed As Intended? - Net Revenues

13. So is RPM performing as intended? The fairest analytic answer right now is that it is probably just too early to tell, but most indications seem positive. There were two primary objectives that can be linked to the basic RPM mandate: i) the need for a level of adequate compensation to retain existing and attract new generation; and ii) the ability to properly reflect the locational nature of a capacity or adequacy product within the RTO. In the next few paragraphs I discuss three elements that relate to RPM's success in addressing these needs.

14. Probably the most important change under RPM is the apparent reversal of the disturbing pattern of under collection of net revenues by generators. Net revenues reflect the money remaining after operations and maintenance expenses available to support the return on and return of capital investment. PJM tracks this metric as a basic indicator of the ability of market revenues to support new entry. If net revenues are less than the long-term levelized cost of new entry, such a unit would "fail to make the mortgage". This is a clear signal that the sum of energy and capacity payments is not adequate to support new

entry. As shown in the last MMU State of the Market report (Table 1-3), net revenues, on average, have only supported new entry in one of the last nine years for each type of technology considered (combustion turbine, combined cycle and coal). Further, on average, for the nine-year period, the net revenue recovery as a percent of 20-year levelized cost was only 43% for combustion turbines, 61% for combined cycles and 71% for a coal plant. This means that for nine years a new entrant would have not met the mortgage by a considerable amount. That is the bad news, and it sets a trend of expectations for new investment that is not trivial to reverse.[3]

15. The good news is that despite the continuing poor average results, the existence of locational capacity payments that pay premiums to resources located within constrained areas have resulted in positive net revenues for 2007 in several of the constrained locational delivery areas (LDAs). For example, the net revenue for a combustion turbine was significantly improved, and an overall positive value for the PEPCO zone, and similarly net revenues were much higher than average in this LDA for coal and combined cycle plants. The MMU attributed much of the increase to not only higher energy prices, but the "much higher locational capacity prices".[4] However, the real test will be whether prices can be sustained to support a reasonable expectation that, on average, net revenues will be positive. Simply being able to meet debt and equity payments ("pay the mortgage") once or twice every nine years is not sufficient for anyone to consider the levels of compensation to be adequate.

Has RPM Performed As Intended? - Level of Supply

16. PJM has estimated that there have been thousands of megawatts of new resources made available to the capacity market either from additions to the market via generation or demand management, or retained via reduced exports and delayed retirements. Again,

[3] In fact, the number of years historically that a unit had a positive net operating margin, and prospectively, the number of years that a unit would be expected to have positive net revenues were among the major determinants of the investment decision making process in the PJM-sponsored analyses by Dr. Hobbs in the RPM filings. Numbers such as those witnessed for the last nine years for PJM would have resulted in no new investment.

[4] PJM 2007 State of the Market Report, Volume 1, page 13.

it is early in the process and there hasn't been adequate opportunity for new site development and entry to have occurred totally in response to RPM price signals. In fact, as just discussed, there is a need to overcome the cumulative recent history in order to convince developers and lenders of the existence of a stable, remunerative market. Further, as discussed below, there is a significant understatement of the net cost of new entry values, which likely will inhibit any "pure" new entry. However, the early results do seem promising in terms of short-term response. As part of each BRA report, PJM prepares a summary of new elements of supply, provided as Table 4 of the report.[5] These results show net increases of 923 MW for the 2008/2009 BRA, 937 MW for the 2009/2010 BRA and 1503 for the 2010/2011 BRA.

17. PJM reports that a total of 1,373 MW of new Demand Resources were cleared in the first four auctions and that there were a total of 3,861 MW of net increases in Installed Capacity for these same auctions. In addition, PJM identifies in Table 5 of the same report that a total of 3,227 MW of capacity has been withdrawn from deactivation requests, postponed or cancelled retirement, or reactivated. Finally, there has been a significant change in net exports reflecting improving competitive conditions for existing supply. In this same report summarizing the 2010/2011 BRA results, PJM reported that in the planning year preceding the first RPM auction (2006/2007) there were net exports of 3,383 MW. For the 2010/2011 planning year net exports were 395 MW for a net shift of 2,987 MW. These early results are providing economically efficient capacity at far less cost than building new generation. This is how a market is supposed to work, by promoting innovation and finding the most cost-effective solutions. Creating a similar amount of capacity in the form of new build would impose multiple billions of dollars in additional consumer costs.[6]

18. Another indirect measure of the impact of RPM is the expansion of the new generation interconnection queue. This can be seen as a "leading" indicator of potential new generation resources. Over the last two years the queue volume and megawatts have

[5] See http://www.pjm.com/markets/rpm/rpm.html.
[6] For 2008/2009 PJM certified approximately 3600 MW of ILR versus the approximately 2100 MW estimated for the BRA. This also indicates a material price signal in terms of new supplies.

tripled versus the previous two years.[7] While there is no ability to link this change exclusively to the implementation or anticipated implementation of RPM, it is indicative of the perception of a change in the anticipated level of compensation, and associated ability to recover the necessary level of net revenues to support new entry. In fact, the level of new interconnection requests has become so large as to overtax the system, leading to both complaints in front of this Commission, and efforts at the stakeholder level, to address changes in methods to expedite interconnection studies.

Has RPM Performed As Intended? - Locational Pricing

19. Though poorly understood, RPM has responded as intended with respect to establishing locational differences based on constrained transfer limits within PJM. Further, as anticipated, as RPM takes account of PJM's transmission requirements and related planned projects, differentials between the LDAs are reduced, and prices appear to be approaching a relatively uniform value across the RTO. To the extent that locational differences may persist for some areas in which sufficient capacity resources are being acquired, paying the premium to the in-area resources is probably the most cost-effective way of meeting reliability standards. As I discuss below, however, these cases should be relatively rare.

20. Some apparent criticism has been raised because of perceptions that LDA prices should either not converge, or that in response to LDA price differentials, new generation should only be expected to locate within the constrained LDAs. These criticisms are invalid, and demonstrate a fundamental misunderstanding of the function of the locational elements of the RPM design.

21. PJM establishes reliability and associated resource requirements for each LDA based on an analysis of the necessary transfer capability into an LDA from the rest of

[7] Interconnection Queuing Practices : Docket No. AD08-2-000 STATUS REPORT OF THE PJM QUEUE, April 21, 2008.

PJM. This is based on the level of generation resources within the LDA, and the required transfer capability needed to reach the desired reliability target (this transfer requirement is referred to as the Capacity Emergency Transfer Objective, or CETO). An LDA is required to maintain a target capacity of the sum of its internal generation and the CETO. If the actual Capacity Emergency Transfer Limit (CETL) is less than the CETO, then an LDA is incapable of meeting its reliability requirements (inclusive of imports from the rest of PJM), and in the context of the RPM clearing mechanism, under the variable resource requirement curve, prices will increase as total supply is less than the target. The price will either be set by the intersection of the supply curve and the demand curve, or by the demand curve level at the point at which existing resources are no longer available. Because the demand curve level is set at the net CONE for the LDA resource requirement (plus 1%), when the CETL is less than CETO, prices must rise above the net cost of new entry.

22. However, what must be realized is that the condition of CETL being less than CETO is a reliability violation under the Reliability First criteria for PJM. PJM must remedy this violation via appropriate transmission expansions to increase the CETL. Because of the nature of the transmission planning process, such “fixes” that appear in the Regional Transmission Expansion Plan (RTEP) will be committed to and underway to solve the CETL/CETO reliability violation prior to the BRA for any given year.[8] Thus for the most part, other than for the cost differences of building and maintaining resources between each LDA, the separations occur when the transmission “fixes” in the RTEP are delayed. When this occurs, and CETL approaches or goes below CETO, the constraints in the RPM auction come into play, and prices are greater than the net CONE, and in turn they create price incentives for additional new generation, delayed retirements or new demand resources to be made available until the transmission plan “catches up” to the reliability requirements.

[8] Inherent in the overall market design is this preference for transmission as a solution for locational reliability violations because of the fact that transmission violations are identified and resolved prior to the capacity auctions for any given year. The only way to remove this bias would be for the timing of the commitment for the “fix” of the transmission violation for any given year to occur at the same time as the Base Residual Auction for the same year. This would require BRAs to be on the order of five or more years in advance of any given delivery year. This type of lead time was rejected in the stakeholder and settlement processes.

23. Persistent price separation would be expected to occur only in a narrow set of circumstances in which the constrained zone passed the CETO/CETL test but only because excess CETL over the CETO depended upon one or more higher cost units located within the constrained area. If the resultant price differential were relatively small, the premiums could persist indefinitely because the incentives might not be large enough to justify the investment by market participants to make it "go away". Also, if new build and marginal "to go" costs were more expensive than outside of the LDA, a price difference could persist even if new generation were added. In these cases, however, the payment of the small premium to in-area capacity resources would probably be the most cost-effective solution.

24. Because there are both must offer obligations for generation and mitigation of supply offers in combination with these transmission design elements, it is both predictable and reasonable that: i) major locational differences will not persist; ii) prices will approach convergence across the RTO except for the relative difference in costs among existing facilities between LDAs; and iii) it is just as likely that resolution of new generation needs will occur either within or outside of a constrained LDA, as the necessary transmission into the LDA will be mandated in advance of any given Base Residual Auction by PJM's reliability requirements. Thus under RPM, price convergence is to be expected as price signals operate and as anticipated RTEP upgrades increase CETL into constrained LDAs. So far, this is exactly what appears to be happening.

RPM Limitations—The Need For An Accurate Estimate of the Cost of New Entry (CONE)

25. A key element to making RPM work is getting the prices right. One way of viewing the RPM mechanism is as a control or dampening tool to keep prices "in the vicinity" of the long run average net cost of new entry while maintaining system adequacy. If supplies get a little long, prices decrease and create incentives to retire or slow new entry; if supplies are short, prices increase and encourage delays in retirement and speed new entry. The slope of the Variable Resource Requirement curve (VRR or

demand curve) is one control element, and the level of the curve based on the net cost of new entry (net CONE) is another. Both elements need to work in concert for the RPM design to be successful. In particular, the net CONE has to reflect the actual “real” CONE that is associated with the cost of building new peaking capacity. A major concern right now is the fact that the CONE value being used in positioning the VRR curve is acknowledged to be much lower than actual costs.

26. Ultimately the CONE value sets quantity of supply, not the price, in the market, absent third party intervention. This is because regardless of how you administratively “set” CONE, there is a “real” price to actually construct new capacity in the market, and capacity will only be added if the “real” value can be obtained. If the VRR curve is set using a value that is too low, the “real” CONE doesn’t change, there is simply less new entry until the overall quantity in the market gets low enough, and prices in turn rise along the VRR curve, to result in payments equal the “real” CONE.

27 Thus using a CONE value that is known to be too low works against the basic intent of the RPM design. It simply depresses the level of supply, and in turn adversely impacts reliability. The effect likely “trickles down” and will spur out-of-market intervention. Such intervention in and of itself reflects a form of price discrimination, which further erodes market confidence, and reinforces the perceived risks of new entry, encouraging the need for more out of market intervention, i.e. it all plays into a destructive and reinforcing cycle.

28. Further, until supply is sufficiently depressed to result in prices equal to the “real” CONE, the use of an artificially low value simply results in higher prices for load without the prospect of new entry. Further, because of artificially low prices, units may retire resulting in higher prices until new out-of-market interventions occur. These conditions result in the worst possible outcome, as prices increase reflecting transfers among existing supply and demand without the desired new entry and support of reliability. Said another way, the temptation to try and suppress prices via artificially low CONE does nothing more than destroy the market feedback mechanism.

29. These observations are very important today given the recent Commission decision to disallow implementation of proposed revisions to CONE because PJM failed to adhere to its tariff requirements. Because the current adjustment process within RPM that is referred to as the "empirical CONE" mechanism is grossly inadequate to address cost increases, these revisions reflected a very significant increase of the CONE values, from an average of about $73,400 per MW-year to an average of about $105,500 per MW-year.[9] Regardless of the merit of the regulatory decision, it must be understood that in the presence of this type of discrepancy between what is believed to be the right estimate of CONE and the values used in the actual auction, i.e. about 44%, there is simply no way that the market results will support new entry absent a huge level of unit retirements, load growth or some other mechanisms that will cause the market to go very "short" and effectively price out at or near the cap, which happens to be near the values that PJM thinks are the right base prices.

[9] These values are taken from the Affidavit of Raymond Pasteris, Docket ER08-516-000 PJM develops the CONE values for three aggregations of LDA's, and the values cited are the simple averages.

Appendix A to Comments of Roy Shanker

Brief Comments Regarding The Portland Cement Association Proposal and the American Forest & Paper Association Proposal

Section 1 - Portland Cement Association Proposal

The documentation for the Portland Cement Association (PCA) proposal is quite limited, only a five-page document, with two pages of abbreviated comments on a "framework."[10] However, even from this short summary a number of fundamental flaws are evident. First, the framework directly incorporates an explicitly discriminatory pricing structure designed to undervalue existing generation and attempt to only pay market prices to new entry. Second, the use of pay-as-bid mechanisms for both energy and apparently capacity virtually assures an inefficient solution to the auction results, and the false expectation of cost savings (ignoring the discrimination), while in actuality costs would be expected to be higher. Third, the use of pay-as-bid mechanisms also creates an almost insurmountable barrier to rational market monitoring by making it impossible to distinguish between: i) legitimate bids attempting to capture legitimate market-based margins for capacity sales; and ii) artificially "high" bids reflecting attempts at economic withholding. Finally, there are a number of simply missing or unexplained properties that would need to be developed in order to judge any further problems with the overall proposal, e.g. the relevant criteria and portion of capacity subject to longer term procurement commitments, and how such procurements are reflected in any single-year auction.

In the following paragraphs I briefly address each of the three major flaws identified above.

As discussed in the main comments above, price discrimination is a pernicious element in any design that attempts to introduce efficiency via market-based tools.

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[10] Wholesale Competition in Regions With Organized Electric Markets, RM07-19, AD07-7-000 Consumers' Supplemental Comments and Proposed Alternative Market, January 10, 2008 Model

Pricing existing capacity differently from new capacity leads to a host of problems, and ultimately destroys the ability of a competitive process to work. Inherent in the PCA proposal is very likely such a discriminatory process. The proposal calls for a most-offer obligation for all existing capacity.[11] The proposal also calls for a first Base Residual Auction to procure less than the full reserve requirement. The full requirement would be procured over time by a final Incremental Residual Auction.[12]

The purported logic for less-than-complete procurement is "due to the inherent uncertainty of load forecasts and the pricing implications of procuring more than is needed".[13] In combination, a mandatory must-offer requirement coupled with less than the procurement of full requirements will typically result in price discrimination in a clearing auction. This is not a surprising result as it has been a major element of the negotiation and stakeholder agenda for many of these parties throughout the last decade of debate. The nature of this discriminatory result can be illustrated by a simple example. Assume that the auction is four years forward as suggested in the PCA proposal. Assume that load growth is averaging about 2% a year. In that case, even if 90% of the capacity requirement was procured in the first BRA, all capacity requirements could be met by existing generation. If an efficient single clearing auction mechanism were in place, sellers would have an incentive to offer at marginal "to go" costs, knowing that they would get the clearing price for the auction. However, if there is a must offer requirement and supply is thus assured to exceed demand (e.g. through procurement of only 90% of the capacity requirements) then marginal offers would be expected to reflect the lower marginal costs of existing units, and never the marginal costs of a new entrant. The marginal costs of the new entrant would only set the clearing price in the Incremental Residual Auctions where supply exceeds demand. The resulting clearing price in that auction will be paid to a small number of suppliers (i.e., those providing the remaining 10% of the capacity requirement) with the result that, by design, suppliers of the same product will likely be paid two different prices. The mandated surplus/staged

[11] Forward Capacity and Energy Market Framework; item 2 (d).
[12] Id , item 2 (c)
[13] Id, item 2 (c)

procurement creates a lower clearing price, and de facto discrimination, exactly the result rejected repeatedly by the Commission.

Presumably, the PCA response to this criticism is that while the must-offer obligation exists, there is no limitation on the market-based bids for capacity in their initial BRA.[14] While it isn't clear what limits will be placed on such "market-based bids," it might be true that part of the discriminatory effect might be eliminated by the unrestricted pay-as-bid offers into their partial requirements Base Residual Auction. However, allowing open pay-as-bid offers in the context of a mandatory must-offer environment coupled with excess supply will still result in discrimination, as the surplus supply will force existing generation to price levels below the desired average of the net cost of new entry. In these circumstances, assuming that "new units" become "existing units" after some time interval, there would appear to be insufficient economic incentives for new entry through the auction process with the likely result, ultimately, being the failure to achieve generation adequacy.

The structure of this market design, moreover, would appear to create an erratic and destructive investment cycle for upgrades and major maintenance of existing generation. Thus, initially, because of a surplus in the partial procurement auction, prices for existing generation would clear at relatively low levels dependent on the level of surplus supply mandated (or demand not procured). The rational economic response of the owners of aging or inefficient units receiving such prices would then be to defer investments in upgrades and major maintenance activities. Over time, however, the condition of these units would deteriorate, eventually requiring large expenditures (that would need to be reflected in bids) or forced retirement of these units in the face of the price discrimination. Similarly, units faced with large capital expenditures for major upgrades associated with more stringent environmental requirements may be reluctant to make those commitments. Under these conditions, prices in the partial procurement auction could fluctuate widely depending on the condition of the generation fleet (or its size) in a particular delivery year, and units that may be able to provide a material

[14] Id, item 2 (d)

reliability benefit, will be forced to retire because of their inability to obtain reasonable "to go" costs under the discriminatory pricing. Such fluctuations, moreover, would tend to reinforce the inherently erratic investment cycle associated with this construct by making the owners of existing generation, as well as new entry, seek additional premiums before investing their capital.

PCA proposed to combine these discriminatory pricing design elements with the pay-as-bid clearing mechanisms, which then leads to the next problem, an inefficient procurement driven by pay-as-bid incentives for those who offer.

In a pay-as-bid auction, those making offers have an incentive not to bid their true costs, but to bid "guesses" at the level of prices they can offer and still clear in the auction. In the proposed PCA design, while capacity offers are market-based (with unspecified if any mitigation), energy offers must be supplied with the capacity, and such energy offers are cost-based and effectively constitute a call on the output of the unit at production costs (indexed for energy costs) for the period during which capacity is sold (i.e. the energy is sold as bid and at cost).[15] The objective function of the procurement is to minimize the combined energy and capacity costs of meeting load requirements based on the market-based capacity bids coupled with the cost-based energy bids.[16]

This creates an incentive for the capacity offers to reflect some "guess" at the value their energy supplies contribute to overall costs, or said another way, the infra-marginal rents that would have been collected in an efficient energy clearing market had one existed for the sale of their energy, and include these estimated lost energy rents in their "market-based" capacity bids. This type of structure, even in the face of a surplus, still creates the incentive for capacity suppliers to estimate and include the lost energy rents, but the level of lost rents now changes and becomes a function of the artificial surplus created by procuring less than 100% of load requirements. Further, it has its own perverse impacts. Now, rather than having an incentive to offer at marginal costs for both

[15] Id item 2 (d)
[16] Id item 3 (a)

energy and capacity, the sellers of capacity have to simulate the entire market-clearing process to guess at the relative value of their units' energy, and tack that guess onto the marginal cost of their capacity. Further, in doing this they have to estimate the gaming impact of other suppliers doing the same thing in an artificially "surplus" market.[17]

Interestingly, in a perfect world (and without the artificial surplus or underbidding of load requirements), this proposal would result in exactly the same expected costs (at equilibrium) as simply allowing for single clearing-market bids for energy and capacity with appropriate mitigation of offers. However, the world isn't perfect, and forced to make such guesses, the typical supplier is likely to tack on a premium for the uncertainty, and raise total overall costs of supply. Thus, even in the face of the artificial surplus, some inefficiency is built into the discriminatory discount resulting in a combination of contradictory impacts.

This creates something of a Catch 22. Either the mandated must-offer requirement coupled with less-than-full requirements procurements creates a surplus environment that supports discriminatory pricing, or the use of pay-as-bid market-based offers for capacity coupled with cost-based pay-as-bid energy supplies creates an incentive for inefficient bids at a premium. Or, in the PCA case, you get the adverse impacts of both elements. This is something of a lose/lose proposition, with the actual results and the cost to consumers and level of discrimination against suppliers "to be determined".

Finally, the above interactions create a virtually impossible environment for monitoring highly concentrated markets for the exercise of market power. The introduction of pay-as-bid elements for market-based bids requires the bidder to tack on an adder to some portion of its bid in order to properly reflect the market risks and incentives that the supplier faces. However, who is to say where such risk-based premiums stop and the exercise of market power via economic withholding begins? As

[17] It isn't clear what the final impact would be, as the level of "guessing" on the lost energy rents would be a function of the level of surplus supply of capacity created by procuring only part of the full load requirements. That is the level of guessed lost energy rents would be different if 100% of existing capacity were forced to offer in against the procurement of 50% of forecasted load versus 75% of forecasted load.

mentioned above, the way in which the premium is established is via the simulation of the overall value of lost energy margins, with some form of adjustment for the surplus of the supply of capacity over the load demand in the auction structure. This is a very complex simulation, and driven by all sorts of assumptions about load shape, transmission topology and changes, generation outages etc. It effectively forces each bidder to replicate PJM's procurement optimization. Obviously, bidders will incorporate their own differences of opinion and data regarding this complicated optimization result. In turn, to "challenge" any bid, the market monitor would have to refute every element of the supplier's simulation process and data to even attempt to establish economic withholding. This is simply an untenable obligation and creates a huge barrier for anyone to distinguish in the inefficient environment between legitimate bids or economic withholding.

The limited detail of the proposal also raises a number of other questions. For example, how will the portion of forecast load to be met in the first auction be supplied? The proposal suggests that some long-term contracts will be awarded, but how many, for how long a duration, and why? How will buyer mitigation be triggered and implemented?

While many details of the PCA proposal remain to be fleshed out, the elements that are contained in PCA's submission appear to be specifically designed to result in price discrimination, a concept the Commission has soundly rejected many times in the past based on solid economic considerations.

Section Two - American Forest and Paper Association Proposal

The American Forest & Paper Association (AF&PA) proposal calls for the establishment of an energy call, at a strike price associated with the production cost of a new generation entrant. This call is created as part of the sale of physical capacity within the existing market designs. It is characterized simply—and incorrectly—as just modifying the energy and ancillary services pricing adjustment in the calculation of net

CONE. In the following comments I address this proposal from the perspective of the RPM design.

It is worth noting the fact that this type of arrangement, in one form or another, was already considered during the development process for RPM and, as I understand it, for FCM as well. It was rejected for a number of reasons, and the rest of the market design reflected in the settlement was constructed around that rejection. As a general matter, after the fact, it really isn't fair (or good market design) to pick out one key item from a "package", say it can be done better, and then suggest you modify it, without revisiting the tradeoffs, and the rest of the coordinated elements of the market design. This is a form of cherry picking that ignores the complexity of the market design and the balancing of interests in the final form of RPM. In particular, due to the integrated nature of the role of net CONE in the overall market design, it is inappropriate to revisit or consider such a proposal without recognizing the full range of changes that must be considered in association.

That said, the next issue is, what does the proposal do? What are its properties? And what are the implications of trying to put it in place?

Fundamentally the AF&PA proposal calls for the sale of a very different adequacy product under RPM. Not surprisingly, with a different product there are going to be different rules, and most importantly different risks and costs. Right now in RPM, a generation supplier is basically selling unit-specific capacity with a "weak" call at $1,000 per MWH, i.e. paying no direct liquidated damages (LDs) in a form analogous to the traditional "Firm LD" context found in many energy contracts. The only damage notions in RPM are penalties for failure to deliver capacity, failure to test capacity, the peak period performance adjustments and potential "hits" on the level of future capacity available due to modifications of subsequent Equivalent Forced Outage Rate (demand) EFORd values. There is no direct LD.

The AF&PA proposal calls for the sale of unit-specific capacity with a 100% availability equivalent for Firm LDs on energy at some much lower strike price, e.g. $100. The two products are very different and result in a major shift of risk from load to suppliers. When you change risks like this, there is no free lunch, and something has to show up in price if you require the sale of the riskier product. The notion that you can simply "inject" this type of adjustment without a major change in compensation and overall design is naïve. Who would rationally price the call in the existing RPM structure at the same price as the call proposed under the AF&PA proposal? The simple answer is: no one.

Obviously for two different products there are a number of changes to the market design and pricing that would have to occur, and this is where the proposal breaks down. It presents a simple shift of risk, and suggests that if you only change the product in the fashion described above, everything else can remain the same, including CONE. The reality is that the products are much different, and there would have to be a significant change in price to accommodate the higher risk and value associated with the firm LD-type call at the lower strike price. This would have to show up as a change in CONE, and consequently in the level/shape of the variable resource requirement curve. I raised just these issues when this proposal was initially put forward, and nothing in the current version materially changes that conclusion. If you want to buy a riskier product, expect to pay a different and higher price. Not surprisingly there was little support for the attendant need for a higher CONE.

Implementation of this option is particularly problematic as one considers the analysis needed to price such an option and reflect it in the CONE. The estimation of new CONE in light of the product sold, absent empirical results, is certain to be contentious. The need for complex pricing of options as an additional overlay not only raises serious analytical issues, but injects problems for reasonable, objective and non-intrusive market monitoring as well. Each company offering existing and new resources will have different levels of risk tolerance for providing this product depending on company policies, the exact resources involved (for example, a 30-year-old generating unit or a brand new interruptible demand program), and a host of other factors that will be difficult to empirically calculate or verify.

Beyond this fundamental issue of needing a higher price for a premium product (and difficulty verifying this price), there are secondary problems as well. By forcing the call at such seemingly low prices, all load will be hedged at these relatively low levels, and price signals, including scarcity, will not be visible to those parties. This is a direct disincentive for load response and the associated efficiencies that come from load seeing actual marginal costs, rather than only the call strike price. While hedging is certainly desirable, mandatory hedging across all consumption seems to be at odds with the stated objectives of the Commission to see more real-time price-responsive load. I would expect that as a result the nature of conservation activity will change, but not disappear. Effectively people would now be more focused on controlling annual peak, and not overall consumption. This seems like a poor policy choice, and is actually acknowledged indirectly in the proposal when they make the observation that supply can manage risk better than load, which is a euphemism for saying that suppliers will hedge fuel supplies and load, once it hedges price, will just ignore consumption.

The second additional problem is that the shift of risk to supply isn't likely to be perceived as "linear". For a unit whose production cost is very high, and likely coupled with a higher EFORd, the risks of staying in such an LD-type market will be high, and such a design is likely to force retirements of units that otherwise would be deemed "sufficient" to bolster the overall reliability requirements. This type of churning of the capital stock for units that are rarely used, but whose perceived operational risk is significantly increased is also of questionable value.

In sum, consideration of the AF&PA proposal must recognize the fundamental shift in products that would result, and the consequences for capacity prices and for the other elements of PJM's market design, including those that encourage development of demand response resources.