STATE OF MARYLAND
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results	)))	Administrative Docket PC22

COMMENTS AND RESPONSES TO QUESTIONS
OF JAMES F. WILSON
ON BEHALF OF SOUTHERN MARYLAND ELECTRIC COOPERATIVE
October 1, 2010

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I. Introduction

1. My name is James F. Wilson. I am an economist, principal of Wilson Energy Economics, and affiliate of LECG, LLC. My business address is 4800 Hampden Lane Suite 200, Bethesda, MD 20814.

2. I have over 25 years of consulting experience to the electric power and natural gas industries. Many of my past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, and market power. Other engagements have included contract litigation and damages; pipeline rate cases; forecasting and market assessment; evaluating allegations of market manipulation; probabilistic modeling of utility planning problems; and a wide range of other issues arising in these industries. I also spent five years in Russia in the early 1990s advising on the reform, restructuring, and development of the Russian electricity and natural gas industries for the World Bank and other clients. I have submitted affidavits and presented testimony in proceedings of the Federal Energy Regulatory Commission ("FERC"), state regulatory agencies, and U.S. district court. I hold a B.A. in Mathematics from Oberlin College and an M.S. in Engineering-Economic Systems from Stanford University. My curriculum vitae, summarizing my experience and listing past testimony, is available at www.wilsonenec.com.

3. I have been involved in electricity restructuring and wholesale market design issues for over twenty years in PJM, New England, Ontario, California, Russia, and other regions. I have also been involved in issues of reliability planning, resource adequacy, and peak load forecasting. With regard to the PJM system, I have been involved in a broad range of market design and resource planning issues over the past several years.

4. Since PJM proposed the Reliability Pricing Model ("RPM") capacity construct in 2005 I have prepared numerous affidavits, reports, and analyses of RPM. My work has been supported by state commissions, consumer advocates, industrial customers, public power entities, and electric distribution companies. These entities represent the interests of electricity consumers – the parties who are directly affected if reliability is not maintained and who also bear the cost of reliability.

5. I filed a Notice of Intent to participate in this proceeding on August 27, 2010. Subsequently, I was asked by Southern Maryland Electric Cooperative, Inc. ("SMECO") to

prepare comments for this proceeding. In these comments I provide analysis and recommendation to assist the Maryland Public Service Commission ("Commission") in its consideration of the important issues raised in the Notice of Public Conference ("Notice"), the list of questions attached to the Notice, and the two questions added on September 16, 2010.[1] These comments are largely based on testimony and articles I have prepared on these subjects over the past few years which are cited in the comments and listed in the References section at the end of the comments.

II. Summary of Comments and Recommendations

6. RPM was designed to have two key features that PJM's former capacity mechanism lacked: three-year-forward obligations and zonal pricing. These features have not produced the results that were intended and expected by RPM's proponents. The manner in which these two features were implemented has led to much higher capacity prices in PJM's zones without commensurate impacts or benefits.

7. Changes to RPM can be directed toward either of two broad objectives: to try to make RPM more effective in attracting additional capacity, or to reduce RPM's cost, possibly accepting more modest and realistic expectations for its impact. There is very little overlap between these objectives –changes that would attempt to make RPM more effective in attracting capacity would generally raise its prices and cost. Therefore, to select on which direction to focus it is first necessary to clarify the appropriate role of a mechanism such as RPM and adopt reasonable expectations of its potential impact.

8. As discussed in detail in these comments, I recommend that the Commission adopt more modest expectations for RPM's role and impact, and focus on reducing its cost. The expectation that RPM would play a significant role in determining where and when new capacity would be built was unrealistic and not grounded in sound economics, and industry conditions have changed over the past five years in directions that makes this role even less realistic.

9. A capacity mechanism can play a valuable role in gaining commitments to provide capacity to the PJM market for a coming delivery year, and a zonal component in this can also be valuable. However, imposing mandatory obligations years in advance in an

[1] The list of questions is included for reference at the end of these comments.

inflexible manner is very costly and does not provide commensurate value. The zonal component also raises consumer cost unnecessarily, because zonal capacity requirements are excessive due to overly conservative planning assumptions and, in addition, zonal pricing creates incentives to withhold from the zones. It is especially the *combination* of these two characteristics of RPM – inflexible, mandatory three-year-forward obligations and zonal capacity pricing based on excessive requirements – that has led to high prices in RPM's zones with little impact.

10. In offering a one-year commitment and payment, RPM will primarily influence the shorter lead time, short-term decisions to provide (or not provide) capacity for the upcoming delivery year, decisions such as: to provide demand response if the price is high enough to make it worthwhile; to keep a high-cost plant in operation an additional year or retire or mothball it now; to reactivate a unit this year or wait and see; to offer an uprate to an existing unit; or to import capacity into PJM or sell into another market area. These decisions generally have short lead times and involve relatively small investments, and a one-year commitment and payment can influence them. In fact, of the incremental capacity offered into RPM's seven base residual auctions to date, these short lead-time incremental resources have represented over 80 percent. The RPM supply curves have reflected a large amount of capacity offered in the $13/MW-day to $80/MW-day range in recent auctions – prices that, for the RTO region, could be above or below the clearing price. Resources offered at such prices are competing with one another and the auction will determine which do and do not clear.

11. By contrast, major investments in new power plants, which have represented well under 20% of the incremental capacity offered into RPM, are unlikely to be much influenced by RPM's auctions. Such investments are chosen based on long-term expectations, and generally require stronger assurance of future revenue than the PJM spot markets, including RPM, can provide. This explains why major new plants are generally offered into RPM at low or zero prices that reflect the fact that the decision is already made to move forward with the project. It was never realistic to believe that the sponsors of major investments with useful lives of 20 or more years would decide whether or not to build based on the result of a single RPM auction that determines a one-year payment, and offer the projects into the auctions accordingly.

12. The notion that by holding RPM's auctions three years in advance they would determine the winners and losers among competing offers to build new power plants should be

dropped. It was never based on any sound economic or business logic, and it is now disproven by RPM results. RPM's auctions have not played a role in influencing these long-term decisions. The expectation of future capacity payments will, of course, be a factor in decisions to undertake major investments. But the outcome of one RPM auction will not be decisive. Nor would it be helpful to offer multi-year price commitments through RPM, or otherwise attempt to stretch RPM to do what it is unable to do.

13. RPM's auctions should be repurposed to more clearly and effectively focus on coordinating the various short-term decisions to provide incremental capacity, and deemphasizing the failed concept that RPM's auctions would coordinate long-term investments such as major new power plants. RPM serves the role of a capacity spot market, offering one-year commitments for the coming delivery year, and coordinating incremental decisions to provide or not provide capacity to the PJM market and zones for that year.

14. These short-term decisions are best coordinated at a time close to the delivery year; requiring these commitments to be made years-forward unnecessarily imposes uncertainty and risk on most of these resources. In its role as a capacity spot market, RPM prices would likely clear at relatively low prices most years, in the range of the offers of high-cost existing plants, demand response, and the other types of incremental capacity noted above, but at times might have to rise to much higher levels to acquire sufficient capacity to maintain reliability.

15. Clarifying RPM's role as a capacity spot market makes clear that major investments likely will require something more than expectations of earnings from PJM's energy, ancillary services, and capacity markets to be built. There is not and cannot be such thing as a "long-term capacity market" – decisions to build long-lived assets must be based upon the value assigned to many attributes of the asset, including its environmental attributes, fuel and fuel flexibility, expected operational attributes, useful life, and location, to name a few. The valuation of these attributes necessarily must reflect state and local energy and environmental policies and priorities. A capacity auction procures a simple capacity product and ranks offers based only on price. Attempts to modify the auctions to select among projects that differ across many attributes would be ineffective and costly. RPM does not accomplish integrated resource planning and such mechanisms cannot be designed to do so.

16. This leads us back to the observation that is so often recognized, but whose implications are never fully accepted – that major new power plants are not going to be built

based solely on expected earnings in PJM's energy, ancillary services and capacity markets. The notion that capacity buyers need not do anything to accomplish resource adequacy because merchant power plants would be built where and when needed has been proven incorrect. Therefore, states, load-serving entities and large customers should be more proactive in anticipating and arranging for future resource adequacy. In the process, they will be able to express and realize preferences for various types of resources and resource attributes.

17. My analysis shows that RPM's three-year-forward mandatory obligations and zonal pricing have greatly raised consumer cost without commensurate benefit, and, rather than attempting to modify RPM to try to have it do something than it cannot, RPM should be modified to do what it can do more efficiently (meaning, at reasonable and necessary cost). Specifically, I recommend consideration of modifications that would reduce the costly impact of mandatory three-year-forward obligations. This could include making three-year-forward obligations voluntary and informational; providing greater arbitrage between the years-forward markets and markets closer to each delivery year subject to market power protections; or acquiring in the forward market only the capacity that we are reasonably confident of needing.

18. With respect to zonal pricing, my analysis calls into question whether zonal pricing has increased the efficiency of the capacity market. The superior results of the Rest of RTO region, where prices have been much lower than in zones and relatively more incremental capacity has appeared (a seemingly paradoxical result) reflect the fact that large and competitive zones lead to weaker incentives to withhold and more offers of incremental capacity. The first priority should be to get the zonal capacity requirements right. Inaccurate forecasting and overly conservative determinations of zonal capacity requirements have forced RPM to purchase far more capacity in zones than needed, and this has raised zonal capacity prices and RPM costs by many billions of dollars. Getting the zonal capacity requirements right, and improvements to lessen the costly impact of three-year-forward procurement, would go a long way toward relieving the excessive zonal prices. However, a broader review of zonal capacity pricing may also be warranted.

19. The remainder of these comments is organized as follows. Section III discusses recent RPM performance and explains that RPM has not performed as intended and expected due to changing industry conditions and a design based on misconceptions that led to unrealistic

expectations. Section IV further discusses the reasons for the high prices in RPM's zones (Questions 1 and 3 from the Notice), focusing on the various reasons the zonal capacity requirements have been excessive. Section V provides recommendations for modifications to RPM (Questions 4 and 5), and Section VI provides comments and suggestions on actions the Commission might take to implement improvements to RPM (Question 9).

III. Evaluation of RPM Performance and Major Design Elements

20. In a 2008 report on RPM[2] and an affidavit in support of the RPM Buyers' complaint[3] I evaluated the results of the "transitional" RPM base residual auctions (those held with less than three years lead time) and found that these results were not consistent with the workings of a reasonably competitive market.[4] PJM has now conducted three post-transition or "steady state" RPM base residual auctions ("BRAs") held with the intended three years of lead time, for the 2011/2012, 2012/2013 and 2013/2014 delivery years. This allows us to evaluate the results of RPM auctions conducted according to the intended schedule and without any confounding impact of shorter lead times.

21. One of the key problems I identified in the transitional RPM auctions was the very "steep" capacity supply curves, reflecting the fact that very little capacity was offered at prices within a broad range around the auction clearing prices.[5] As a result of the steep supply curves, I explained, RPM prices were highly sensitive to small changes in supply or demand. This led to strong incentives for capacity sellers to exercise available flexibility to offer less rather than more capacity into the auctions, and at higher prices, to raise the clearing prices.[6] I described the flexibility sellers had to withhold under the RPM rules[7] and the evidence of withholding.[8] The steep supply curves resulted in RPM prices that were highly sensitive to small changes in supply and also to changes in the administrative capacity demand parameters. This

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[2] Wilson 2008a. Full citations are provided in the References section of these comments.

[3] Wilson 2008b.

[4] *Id*, P 19.

[5] *Id*, P 66 – 72.

[6] *Id*, P 72.

[7] *Id*, P 83.

[8] *Id*, P 83-101.

led to price signals that were volatile and, therefore, unlikely to be effective in attracting new capacity.[9] I also evaluated and critiqued other aspects of RPM design and performance at that time.

22. Proponents of RPM argued that these problems were characteristic of the transitional BRAs, and in RPM's "steady state", the supply curves would be close to horizontal or "flat", as opposed to the steep and near-vertical supply curves of the transitional auctions. If true, this would be an important development that would improve RPM performance because, if RPM clears on flat segments of its supply curves:

- This indicates that there are many supply offers in the vicinity of the clearing prices competing for capacity obligations, resulting in more competitive circumstances;
- Accordingly, changes in supply or demand would have relatively little impact on the clearing price, so incentives to withhold would be weak;
- Prices would be fairly stable and predictable, even if the capacity demand parameters changed, circumstances that could help attract investment.

23. For instance, a 2008 report on RPM by CRA International[10] stated

> "Introducing new entry into the market adds a long, fairly flat segment to the supply curves, as shown in Figure 14A, below [included here as Figure 3]. With new resources contesting for entry into the market, the hypothetical withholding has almost no effect on consumer costs… in steady state, each BRA will be clearing on the long, flat section of the supply curve created by competing offers from new capacity additions…"

24. And in response to the RPM Buyers' complaint, Robert B. Stoddard, on behalf of PJM Power Providers Group, testified[11]

> "One would also expect that, with sufficient lead time in advance of a Delivery Year, the supply curves would exhibit a long, flat section at a price level near actual Net CONE."

[9] *Id*, P 17.

[10] CRA 2008, p. 33-34.

[11] Stoddard 2008, p. 12-13.

A. RPM Continues to Exhibit Very Little New Supply, Steep Supply Curves, Unstable Prices, and Strong Incentives to Withhold in Zones

25. The promised, flatter supply curves have not materialized in the steady state BRAs for PJM's zones. The supply curves for MAAC remain very steep.[12] Figure 1 shows the MAAC supply and demand curves from the 2012/2013 BRA, the most recent for which supply curves are available.[13] Figure 2 shows the MAAC supply curves for the 2012/2013 and 2010/2011 BRAs. These curves reflect very few supply offers at prices in the vicinity of the clearing prices. The supply curves for smaller zones are generally even steeper than for MAAC, with any flat sections representing a single offer.

26. As shown in Figure 1, RPM prices are set at the intersection of capacity demand and supply curves, and because these curves are steep, small changes in either curve can have a large impact on the clearing price. As a result, RPM prices have been quite changeable from year to year, and rose in the past two auctions for the MAAC region and other zones (Figure 4). While volatile, especially in zones, RPM prices have generally been much higher in the MAAC region and its sub-zones than in the "Rest of RTO" region, as summarized in Figure 5.

27. When RPM clears on a steep segment of its supply curves it means that prices are determined primarily by the administrative parameters of the demand curve rather than by supply offers from market participants. It also means that all or nearly all suppliers receive a price that is much greater than their offer price. And it also means that the auction could have cleared almost the same amount of capacity at a much lower price and total cost.

28. The sensitivity of RPM prices to changes in supply or demand was quantified in recent analyses performed by PJM.[14] This work showed that in the 2013/2014 base residual auction for the MAAC region (where the total capacity need or "Reliability Requirement" was 73,142 MW), 1,000 MW of additional low-cost supply (or 1,000 MW lower demand) would have reduced the clearing price over $60/MW-day, from $226.15/MW-day to $165.44/MW-day.

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[12] The slopes of the MAAC and EMAAC supply curves and the impact on price of small changes in supply or demand are quantified in Wilson 2010d p. 34-36.

[13] For the 2013/2014 BRA supply curves have not been made public even in graphical form, due to a dispute over the level of detail that should be provided for this data. While the market monitor included such graphics in its report on the auction, the curves are smoothed and, therefore, cannot be relied upon as providing an accurate depiction of any segment of the supply curve.

[14] PJM, *RPM Scenario Analysis Results*, posted September 14, 2010, and available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/scenario-analysis-results.ashx.

This additional supply or lower demand (1.4% of the Reliability Requirement) would have reduced annual capacity cost by over $1.5 billion.

29. As another indication of RPM's high sensitivity to changes in supply or demand, the supply curve data for the 2012/2013 auction[15] showed that, while 65,078.8 MW could be cleared in MAAC at a price of $133.37/MW-day (the actual clearing price), just 1,420 MW additional demand (or less supply) would send the price up almost $90/MW-day to $222.30/MW-day (very close to the 2013/2014 clearing price).

30. The high sensitivity of RPM's zonal prices to changes in supply or demand means that capacity sellers with portfolios of capacity in the zones still have strong incentives to offer less rather than more capacity into the auctions, and at the highest allowed prices, to help maintain the high clearing prices. While the incentive to withhold is recognized and mitigation is imposed, this mitigation only applies to existing resources, and is only partially effective.[16]

31. A capacity seller's incentive to withhold results from the potential impact on price of withholding, and the size of the seller's portfolio that would benefit from the higher price. The potential impact on price of withholding (or offering incremental supply) can be estimated for each zone based on actual demand and supply curves.[17] Based on the supply and demand curves from the 2012/2013 BRA, capacity sellers in MAAC with portfolios of 7,500 MW or larger, and capacity sellers in Eastern MAAC with portfolios of 3,500 MW or larger, face incentives to exercise available flexibility to withhold capacity in these zones from RPM. Over 55 percent of the generating capacity in MAAC and over 70 percent of the generating capacity in Eastern MAAC is owned in portfolios this large or larger.[18]

32. The results of the recent First Incremental Auction for the 2012/2013 delivery year provide one example of how market participants continue to exercise available flexibility to withhold from the BRAs. In this incremental auction, over 800 MW of capacity in Eastern MAAC that had failed to clear in the BRA, of which some had been offered at over $200/MW-

[15] PJM, Supply curve data for the 2012/2013 Base Residual Auction, posted at http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx earlier this year but since removed. Such data for 2013/2014 is not available.

[16] For further discussion of why mitigation in capacity markets is only partially effective see Wilson 2010d p. 33-40.

[17] For the full analysis of incentives to withhold in MAAC and Eastern MAAC see Wilson 2010d, p. 34-37.

[18] Wilson 2010d, p. 36-37.

day, cleared at a price of $153.67/MW-day.[19] Why would a seller accept $153.67/MW-day in the incremental auction, if $200/MW-day was not enough in the BRA? One explanation is that offering this capacity at a more competitive price in the BRA would have lowered the clearing price in the BRA that is earned by the rest of a capacity seller's portfolio.

33. In the Rest of RTO region, despite much lower RPM clearing prices (see Figures 4 and 5), relatively more incremental capacity has been appearing than in MAAC or smaller PJM zones where prices have been much higher. This seemingly paradoxical result is discussed further in a later section of these comments. In the broader RTO Region, the supply curves in the vicinity of the clearing prices are much flatter, reflecting offers from higher-cost existing plants, demand response providers, and other resources at prices close to the clearing prices (see Figure 6).

34. Perhaps the most competitive BRA to date was for the 2011/2012 delivery year, for which no zones were defined and there was a single RTO-wide price. Because there were no zones, all capacity sellers had to compete in the large, competitive RTO zone where incentives to withhold are weak. In the 2011/2012 BRA, 2,332.5 MW of new units, 181 MW of capacity from reactivated units, and 1,062.8 MW of uprates from existing units were offered, by far the largest amount of new generating capacity offered in any of the seven RPM BRA. In the 2012/2013 BRA with MAAC and other smaller zones defined, the new units, reactivated units, and uprates offered into the auction all declined to less than half these amounts.[20]

35. These results reflect the much more competitive circumstances in the RTO Region that result in more stable prices and lower incentives to withhold. RPM's operation in the RTO Region provides a model for comparison as we evaluate RPM's performance and results for the MAAC and other zones, which is the focus of this proceeding.

B. RPM Results Are Not As Expected and Intended Because Industry Conditions Have Changed

36. RPM prices have been changeable rather than stable, and have not attracted relatively more capacity to the zones where its prices are high. One key reason why RPM has

[19] PJM, *2012/2013 RPM First Incremental Auction Results*, Table 5, p. 9.

[20] PJM, *2012/2013 RPM Base Residual Auction Results*, Table 5 p. 18, summarizing these results for both the 2011/2012 and 2012/2013 BRAs.

not performed as expected and intended is that industry conditions have evolved away from those for which RPM was designed based on conditions at the time (in 2003-2005).[21] At that time, nearly all new capacity was gas-fired, and RPM's design reflects expectations that new plants would be built under "merchant" circumstances, relying exclusively on revenues from PJM's spot energy, ancillary services, and capacity markets. Gas-fired plants require three years to build, and at that time load growth had been and was expected to remain steady. Based on these conditions, it was widely expected that a three-year forward, locational capacity auction could help determine how much new capacity should be built, when, and where.

37. Industry conditions have changed substantially since those years. Of the incremental capacity resources appearing in the first seven RPM base residual auctions according to PJM's tally,[22] only 12 percent was new gas-fired plants, and over 80% was a variety of shorter lead-time resources, including demand response, upgrades to existing plants, withdrawn or cancelled retirements, reactivations, and a net increase in capacity imports (summarized in Figure 7). The notion that new power plants could be built under pure merchant circumstances has long been recognized as unrealistic and it is now understood that financing major investments still requires a long-term source of revenue.

38. In addition, new resources are increasingly being attracted with contracts or incentives reflecting state energy and environmental policies and programs. Potential gas-fired resources are largely homogenous; but the new resources that are anticipated at this time and in the coming years, including demand response and various types of renewables, differ on many environmental, operational, and other attributes, and public policies are increasingly reflecting preferences for cleaner sources of incremental supply, demand-side solutions, and other attributes.

39. Another very significant change is the declining rate of peak load growth. PJM now forecasts its "unrestricted" peak load (that is, before reflecting demand response or price-responsive demand) to grow only 1.1 percent per year from 2015 to 2020; three years ago growth

[21] For a detailed discussion of how forward capacity markets such as RPM have not performed as expected due to changing industry circumstances and now-disproven theories underlying their designs see Wilson 2010f, forthcoming in *Electricity Journal*, November 2010.

[22] PJM, *2013/2014 RPM Base Residual Auction Results*, Tables 7 and 9.

during that period was expected to be 1.4 or 1.5 percent per year.[23] Smart grid developments including advanced metering, smart devices, and increasingly price-responsive demand will further reduce future peak loads and generating capacity requirements. Figure 8 shows how PJM's forecasts of its net peak demand (reflecting load management) have declined over the past several forecasts. The recommendations of a recent consultant's review of PJM's load forecasting methodology may lead to further reductions in PJM's forecasts of future peak loads.[24]

C. RPM Results Are Also Not As Expected and Intended Due to Misconceptions Underlying Its Design

40. That the supply curves for MAAC and other zones continue to be steep rather than flat in the vicinity of the high clearing prices should be no surprise. The theory that new entrants would be attracted by RPM's single-year commitments and would offer their capacity at prices near "Net CONE"[25] was never grounded in any sound economic or business logic.[26] While this theory about conduct in forward capacity markets continues to be expressed[27] there is now abundant evidence from RPM auctions (and also from ISO New England's similar capacity mechanism) that new capacity is not offered at or near Net CONE.

41. For instance, in the 2013/2014 BRA, 1,670.4 MW of new generation, including both uprates and new units, was offered, and all of it – all 1,670.4 MW – cleared.[28] Most of this new capacity (1,147.2 MW) cleared in the Rest of RTO region at a price of $27.73/MW-day. This suggests that new capacity is offered at very low prices into the BRAs. The steep supply

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[23] PJM Load Forecast Report, January 2010, Tables B-1 and F-1, and PJM Load Forecast Report, January 2007, Table B-1.

[24] See Itron 2010. The consultants recommend using a weighted economic activity index for which the forecast exhibits more moderate growth than the gross metropolitan product index PJM has been using.

[25] "Net CONE" is the construction cost of a new power plant (generally assumed to be a combustion turbine), levelized over an assumed plant life ("CONE") net of an estimate of annual average net earnings in PJM's energy and ancillary services markets.

[26] I explained why we should not expect new capacity to be offered at prices based on levelized cost or Net CONE in comments in response to PJM's original application to implement RPM in 2005, and at other times since. See, for instance, Wilson 2005, p. 15-17; Wilson 2009b, P. 194-201; Wilson 2010f section 5.

[27] See, for instance, Affidavit of Robert B. Stoddard on Behalf of New England Power Generators Association, *ISO New England Inc. and New England Power Pool*, FERC Docket No. ER10-787, filed March 15 2010, p. 21 (referring to "the slope of the new-entry segment of the supply curve (which should, in theory, be relatively flat)").

[28] PJM, *2013/2014 RPM Base Residual Auction Results*, Table 6B p. 16.

curves shown in Figures 1 and 2 suggest that very little capacity – new or existing – is offered at prices above about $80/MW-day.

42. The notion that new power plants would be offered into the BRAs at prices near Net CONE never made any sense. Decisions to undertake major investments in resources with useful lives of 20 years or longer are based on long-term expectations over the life of the project. Offering the capacity at Net CONE would presumably mean that the sponsor would proceed with construction if and only if the RPM clearing price was above Net CONE. However, the sponsor of a long-lived project will not rationally allow an auction that sets a payment for a single year to determine his decision whether or not to proceed with construction; that does not make sense for a merchant plant or one with a longer-term source of revenue. These major decisions are taken outside of RPM, based on long-term expectations of energy, ancillary services and capacity prices and available incentives and revenue guarantees. When there is a decision to proceed, the capacity is offered into RPM at a zero price or a low price that reflects going-forward or opportunity costs.[29]

43. One factor considered in decisions to build new capacity is the prospect of capacity payments over the life of the project, augmenting earnings from energy and ancillary services markets and other sources of revenue. However, because RPM prices (and zones and rules) have been and are likely to remain unstable, the prospect of future RPM revenues will be considered highly uncertain and will be discounted.

D. Three-Year-Forward Mandatory Procurement Has Raised RPM Cost Without Commensurate Benefit

44. The other feature of RPM, along with zonal pricing, that significantly raises RPM prices and cost is the mandatory three-year-forward procurement. Implementing this feature was largely motivated by the unfounded hope that if RPM's auctions were held three years forward, there would be competing offers to build new gas-fired power plants, and the auctions could coordinate such decisions, determining which plants would be built and which would not.

[29] Going-forward cost is the amount that must be covered by RPM to make operation in the delivery year (as opposed to shutting down temporarily or permanently) worthwhile. Opportunity cost is the amount RPM would have to provide to make operation under an RPM obligation attractive relative to other opportunities, such as exporting the capacity to a neighboring region.

45. Capacity obligations are calculated approximately 40 months in advance of each delivery year and capacity is acquired in the base residual auctions held three years in advance of the delivery year to meet all obligations not met by self-supplied resources. The three-year-forward mandatory procurement was a new feature of RPM, and in North America, only RPM and its sister forward capacity mechanism, ISO New England's FCM, have this characteristic.

46. Three-year-forward mandatory procurement was expected to lead to more competitive auctions and more stable price signals by allowing new plants not yet under construction to compete in the auctions. It was also intended to provide greater confidence of future adequacy by identifying the capacity that will meet future peak loads well in advance.

47. However, the three-year-forward obligations are determined based on peak load forecasts prepared over 40 months in advance of the summer peak period, and which can be highly inaccurate. Excessive peak load forecasts have repeatedly resulted in acquisition of a large amount of excess capacity through RPM at excessive prices and cost. For the 2009/2010 and 2010/2011 delivery years, the RTO region peak load forecasts used for RPM's base residual auctions were 7,930 MW and 8,332 MW, respectively, in excess of the actual weather-normalized peak load (for 2009/2010) or updated forecast (for 2010/2011),[30] leading to billions of dollars in excess capacity cost. The peak load forecast used for the 2011/2012 base residual auction exceeds PJM's updated forecast for this delivery year by over 5,000 MW.[31]

48. The potential value of three-year-forward procurement was largely based on the expectation that nearly all new capacity would be gas-fired, with three-year construction lead time. Instead, as noted earlier and summarized in Figure 7, only 12% of the incremental capacity that has appeared in seven RPM base residual auctions has been new gas-fired capacity, and over 80% of the incremental capacity has been of types that typically have lead times less than three years. The availability of so much short lead time capacity means there is substantial flexibility to adjust capacity requirements through auctions held closer to each delivery year, and three-year-forward mandatory procurement is not necessary.

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[30] PJM Load Forecast Reports, 2008, 2009, and 2010, Tables B-1 and B-10. It is appropriate to compare the forecasts to weather-normalized peak loads, rather than actual peak loads, because the forecasts and the weather-normalized values both are intended to represent median values.

[31] *Id*.

49. Another drawback of the three-year-forward approach is that it is difficult for many resources to commit to providing capacity that far in advance. For some older resources, future operational performance and market opportunities are uncertain, so committing to provide capacity three years in advance is risky and can lead to premature retirement.[32] An industrial plant may be highly uncertain about its level of production and the amount of demand response it can offer years in advance, so forward procurement imposes additional risk on it that may discourage its participation.

50. Many new resources have lead times less than three years, and often will not be prepared to offer into a base residual auction held three years in advance. Resources such as demand response, price-responsive demand, upgrades to existing plants, and reactivations have shorter lead times and may miss out on a three-year-forward commitment. This problem has been addressed to some extent by deferring some procurement from the base residual auction to incremental auctions, following a recommendation from The Brattle Group's review of RPM.[33]

51. In short, changing conditions have reduced the need for and potential benefits of holding the auctions three years forward, and have also increased the risks associated with forward auctions. As a result, it is unclear that this approach has accomplished anything more than a one-year forward capacity market (such as NYISO's) would have accomplished.

E. Other Regions Achieve Adequate Resources Without a Complex and Costly Mechanism Such as RPM

52. Other regions in North America are achieving resource adequacy without implementing a mechanism such as RPM. At present, only three areas of the country have

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[32] Comments of Gary R. Sorensen, Managing Director, PSEG Power LLC On Behalf of the PSEG Companies, February 3, 2006 Technical Conference in FERC Docket Nos. ER05-1410 and EL05-148, p. 3: "While there may not be an obvious and observable reason why an older generating unit will be physically incapable of operating four years into the future, the owner of the unit may still have legitimate concerns about the unit's physical condition at that time. All plant components have some limit on their useful life and old plant components are more likely to have problems. Requiring the commitment of an older generating unit four years into the future imposes unfair risks on the unit's owner because if the unit does fail prior to the Delivery Year, the owner will be obligated to obtain replacement capacity, perhaps at much higher prices. This "must offer" rule should be modified to allow older units which can demonstrate legitimate long-term operating concerns to be bid into near-term auctions rather than the four-year advance auction. This will provide a reasonable procedure to retire an aging and deteriorating unit as it reaches the end of its physical life. If the "must offer" rule is not modified, however, it may create perverse incentives to retire older units prematurely in order avoid the risk associated with a four-year advance commitment."

[33] Brattle 2008, p. 101. To accommodate short lead-time resources, 2.5% of the reliability requirement is procured in incremental auctions rather than the base residual auction.

mandatory centralized capacity markets: PJM, ISO New England, and New York ISO (Figure 9). These three mechanisms are all based on the same basic design that was proposed in a 2003 report that the three RTOs jointly funded.[34] Of the three RTOs, only PJM and ISO New England operate *forward* capacity markets, in both instances holding auctions three years in advance of the delivery year. Of these, only PJM's RPM has determined market-clearing prices in a forward capacity market; prices under ISO New England's mechanism have always been set at an administrative "floor" price.[35]

53. As to *locational* centralized capacity markets, the list includes only PJM and NYISO; ISO New England has provisions for locational prices but a locational premium has never occurred. The only areas for which there has been a locational price premium are the Mid Atlantic/APS zone of PJM and its subzones, and New York City and Long Island in NYISO. Only for PJM's zones has a locational price premium has been determined in a *years-forward* capacity auction.

54. Other regions in the U.S. and Canada are employing a variety of other approaches to resource adequacy, such as: energy-only markets (ERCOT, Alberta, Ontario); reserve obligations without a centralized capacity market (SPP, California ISO); and a voluntary capacity market (MISO).[36] However, all of these approaches have met or exceeded the objective of adequate resources. According to NERC's 2009 Long-Term Reliability Assessment report, all regions of North America have adequate deliverable capacity resources (including potential resources reduced by a confidence factor) at least through 2018, with the exception of only the Carolinas and Quebec, where resources are adequate at least through 2015 (Figure 10).[37]

55. These facts make it clear that a specific megawatt impact on the availability of capacity to the PJM market cannot be attributed to RPM. In its reports on the RPM base residual auctions, PJM provides a useful tally of the various incremental resources (and decremental resources that did not happen) over the course of RPM's base residual auctions, shown in Figure

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[34] NERA 2003.

[35] ISO New England, *Forward Capacity Market (FCA 2013-2014) Result Report,* August 6, 2010; *Forward Capacity Market (FCA 2012-2013) Result Report,* October 9, 2009; *Forward Capacity Market (FCA 2011-2012) Result Report,* December 16, 2008; *Forward Capacity Market Auction (FCA 2010-2011) Results Report,* February 13, 2008.

[36] Brattle 2009 p. 7-8, Brattle 2010 p. 2.

[37] NERC 2009 p. 2.

7. However, PJM goes further, making the baseless claim that these resources are "the impact of the RPM implementation."[38] The meaning of this statement is undefined, as PJM does not define the "but for RPM" world; is it the capacity mechanism that was in place before RPM was implemented (if so, what prices are assumed?), or no capacity construct at all? Whatever the "but for" assumption, there is no basis for the claim that all or even any portion of this capacity is "the impact of the RPM implementation" and would not otherwise be available.

F. Reconsidering the Purpose and Role of the RPM Capacity Market

56. This analysis suggests, as described in the Summary, that inflexible, three-year-forward mandatory procurement in combination with zonal capacity pricing based on excessive requirements have greatly increased RPM prices without providing commensurate benefit. The RPM design was based on the assumption that its purpose was to coordinate entry of major new power plants, but this has not occurred and the notion that RPM could do this was incorrect.

57. The capacity market's primary purpose should be to arrange commitments to provide adequate capacity for the coming delivery year. The focus should be on the short lead-time, shorter-term decisions that RPM's one-year price can influence: "swing" resources such as existing high-cost resources that, if they fail to clear, may be exported or mothballed or retired; demand response resources that find capacity obligations worthwhile only if the price is sufficient; and plant uprates, among other sources of incremental and decremental capacity. These decisions are best made close to the delivery year, not three years in advance. Close to the delivery year, RPM capacity needs can more accurately be determined, generation owners will have a better idea of the performance of their units and the revenue needed to make further operation worthwhile, and demand response providers will also be able to better judge how much demand response they can provide and the price needed. RPM prices should rise or fall as needed to clear enough of this capacity to meet reliability objectives. It should be accepted that decisions to construct major new power plants will not be determined by RPM's auctions of one-year price commitments and the auctions should not be designed around the costs and offers of such resources.

[38] PJM, *2013/2014 RPM Base Residual Auction Results*, p. 19.

IV. Understanding RPM's High Prices in Zones (Questions 1 and 3)

58. This section further discusses Questions 1 and 3: why RPM results have been higher in the MAAC and other PJM zones compared to the Rest of RTO region; why prices rose in the latest auction compared to earlier auctions; and whether higher price levels would begin to attract investment.

A. High Zonal Capacity Prices Reflect Zonal Capacity Needs That Are Overstated by Thousands of MW

59. Through its auctions, RPM attempts to acquire an amount of capacity for each zone equal to the zone's Reliability Requirement minus the estimated transmission available to the zone under peak load conditions (the zone's Capacity Emergency Transfer Limit, or "CETL"). A zone's Reliability Requirement is based on a peak load forecast plus the estimated reserve margin to meet a target level of reliability (for zones, PJM applies a "one day in 25 years" reliability standard[39]). Therefore, the capacity that must be acquired through RPM from generation and demand response located *within* a zone (the Local Capacity Requirement) can be expressed as follows:[40]

Local Capacity Requirement for a Zone = Zonal Reliability Requirement – Zonal CETL
= (forecast zonal peak load x zonal reserve margin) – Zonal CETL

60. PJM's approaches to determining the forecast zonal peak load, zonal reserve margin, and zonal CETL result in substantially overstating the local capacity requirements.

61. The **zonal reserve margins** over peak load to meet reliability objectives (reflected in PJM's Capacity Emergency Transfer Objective, or "CETO", analyses) are too high, due to overly conservative assumptions and also flaws in PJM's PRISM model that is used for these calculations and in its input assumptions.[41] I have reproduced the PRISM model's

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[39] The "one day in 25 years" criterion is specified in the PJM manuals. See *PJM Manual 20: PJM Resource Adequacy Analysis*, p. 32 ("The Load Deliverability Method requires the selection of a transmission risk level to define the CETO. This risk must be very small when compared to the one day in ten year LOLE applicable to generation risk. A transmission LOLE of 1 D/ 25 Y was judged to be sufficiently small.")

[40] PJM does not use the term Zonal Capacity Requirement, nor does PJM express the Reliability Requirement as based on a zonal reserve margin. These terms are introduced for clarity. The concepts are correct and consistent with PJM's methodology.

[41] PJM's CETO analysis methodology, and PJM's PRISM model used for these analyses, are described in Wilson 2009a, p. 36-38. The overly conservative assumptions and errors in these analyses, and their impacts on the MAAC

calculations based on its probabilistic peak load and generation availability input data. This allowed quantifying the impacts of some of the overly conservative assumptions and two identified errors, and the impacts are substantial.[42] For instance, an error in the manner in which PJM's model links to PJM's load forecast raises the MAAC Reliability Requirement by approximately 1,000 MW.[43] Overly conservative assumptions include an unwarranted "Forecast Error Factor" that is higher than PJM uses in its reserve requirements studies (impact: 700 MW) and generation forced outage rates based on historical averages that are higher than those reflected in RPM offers for future years (impact: 750 MW).[44]

62. The combined impact of conservative assumptions, flaws in determining zonal reserve margins, and application of the "one day in 25 years" criterion result in a Reliability Requirement for the MAAC region that is equivalent to an installed reserve margin over 20 percent.[45]

63. This excessive reserve margin is applied to PJM's **peak load forecasts**, which have also been too high recently, as noted earlier. PJM's recent peak load forecasts have reflected optimistic forecasts of future economic growth and failed to capture recent trends of increasing energy efficiency and slowing peak load growth.[46] PJM's most recent forecast predicts that the Mid Atlantic peak load will grow 7.4% from 2010 to 2013.[47] It is based on an economic forecast from Moody's economy.com that predicted U.S. GDP would grow 13.3 percent from 2010 to 2013.[48] This was a highly optimistic forecast at the time; the contemporaneous "Blue Chip Consensus" U.S. GDP projection, which results from a regular survey of over 50 professional economic forecasters, was for 9.7 percent growth over this

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CETO and Reliability Requirement values, are described in Wilson 2009a, Section IV p. 36-54. The error in the linkage of the load forecast to PJM's PRISM model is also described in Wilson 2009c.

[42] Wilson 2009a p. 53 Table 3 summarizes the impacts.

[43] *Id*, p. 53 Table 3. While this result is based on the 2009 load forecast and CETO analysis, updated values likely would show a similar impact.

[44] *Id* p. 47-53. Updated values likely would show a similar impact.

[45] *Id*, p. 39-40.

[46] This is developed in detail in Wilson 2009a, Section III p. 16-35.

[47] PJM 2010 Load Forecast Report, Table B-1.

[48] Moody's economy.com's real U.S. GDP forecast, November 2009. The PJM 2010 forecast used Moody's regional economic growth forecasts from November 2009 that are consistent with the U.S. projection.

period.[49] This difference in economic forecasts alone translates into roughly a 1,400 MW difference in the MAAC Reliability Requirement,[50] or $2 billion in annual capacity cost. In addition, PJM's forecasting approach fails to fully reflect the impacts of increases in electricity prices over the past five years and increasing efficiency in electricity use.[51]

64. PJM's approach to setting the **CETL values,** reflecting the capability of the existing transmission system during peak periods, has been found to use unrealistic and overly conservative assumptions.[52] That would result in understating the CETL values and, thereby, overstating the Zonal Capacity Requirements. The results of the 2013/2014 base residual auction reflect a 1,917 MW decrease in the CETL for the MAAC region,[53] which increases the amount of capacity that must be purchased in MAAC by the same amount.

65. The recent high prices in the PJM Mid-Atlantic ("MAAC") region and its sub-zones materially overstate the need for capacity in these areas. It can be estimated from the recent MAAC supply and demand curves that had the zonal capacity need for MAAC been lower by 5,000 MW, MAAC would have cleared at a price under $100/MW-day (savings: over $3 billion). If more accurate and realistic assumptions had been adopted in forecasting peak loads, determining zonal reserve margins and Reliability Requirements, and estimating zonal CETL values, the combined impact could easily be 5,000 MW. With more accurate and realistic assumptions, there may have been no need for an RPM price premium relative to the Rest of RTO region to acquire sufficient capacity to meet reliability objectives in MAAC. PJM's sensitivity analyses, cited earlier, show that had MAAC and other zones not been modeled or not had separate prices, the RTO-wide price would have been $60.32/MW-day.

66. The most significant change for the 2013/2014 RPM base residual auction that led to higher prices in MAAC was the large decrease in the CETL. This decrease was noted in the planning parameters document in advance of the auction, and I expect that PJM will provide a more detailed explanation of it in its comments in this proceeding.

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[49] Aspen Publishers, *Blue Chip Economic Indicators*, Vol. 34 No. 10, October 10, 2009. For a discussion of the advantages of consensus or pooled forecasts compared to those of individual forecasters see Wilson 2009a p. 25-30.

[50] Based on 0.64 elasticity of MAAC peak load to the economic forecast reflected in PJM's 2009 load forecast (Wilson 2009a p. 31).

[51] Wilson 2009a p. 20-25.

[52] See Dehdashti 2009 p. 11.

B. Highly Conservative Zonal Capacity Requirements Imposed Years In Advance Unnecessarily Raise RPM Cost

67. Through the mandatory three-year-forward approach, and the manner in which PJM determines zonal capacity needs, RPM embeds a highly conservative approach to resource adequacy that perhaps was suited to industry conditions many years ago, but at this time unnecessarily imposes additional risks and raises consumer cost. In earlier times load growth was strong (for the Mid Atlantic region, 2.6%/year in the 1980s and 2.1%/year in the 1990s[54]) and was met with large power plants that took years to build. Building too late could result in a failure to serve growing peak loads and be very costly, while the cost of building too soon was relatively low, as any excess capacity was quickly absorbed by further load growth. Today, with much slower load growth and many short lead-time incremental resources, capacity commitments can be obtained closer to the delivery year. Years-forward procurement is less necessary and much more likely to result in excess capacity and unnecessary cost.

68. The "one day in ten years" resource adequacy criterion applied in PJM's capacity planning, and the "one day in 25 years" criterion applied to zonal requirements, are highly conservative.[55] For instance, these criteria call for a frequency of outages roughly an order of magnitude lower than many customers experience due to distribution system disturbances.[56] PJM's methodologies, models and assumptions used in applying these criteria result in setting capacity requirements that overshoot even these conservative criteria. Again, highly conservative capacity planning was better suited to the past conditions of high load growth met by large power plants that took years to build. Under current conditions, there is much more flexibility to adapt capacity commitments closer to the delivery year to the slower rate of load growth that now is expected.

69. The "one day in 25 years" reliability criterion PJM applies in determining zonal capacity requirements leads to significantly higher capacity requirements and RPM prices in

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[53] PJM, *2013/2014 RPM Base Residual Auction Planning Period Parameters*, p. 3 Table 3.

[54] Based on Mid Atlantic weather-normalized peak loads adjusted for changes in geographic footprint.

[55] That the "one day in ten years" resource adequacy criterion is overly conservative is developed in detail in Wilson 2010a.

[56] This is further developed in Wilson 2010a.

PJM's zones.[57] This non-standard criterion is not required by any regulatory authority or reliability organization, is not supported by any analysis, and was not established based on regional resource adequacy considerations.[58] Applying "1-in-25" rather than the industry standard "1-in-10" raises the zonal capacity requirement for MAAC by over 1,500 MW.[59]

70. The potential risk if capacity is not built years in advance can be misunderstood, resulting in exaggerated concerns about a capacity "gap". The impact on resource adequacy and reliability of a "gap" between the actual resources available to a zone, and the resources believed needed, can be quantified based on PJM's planning models. Through RPM, PJM procures sufficient capacity for each zone three years in advance to meet the "one day in 25 year" reliability standard. If, in the delivery year, the transmission capability, peak load forecast, and available demand response and generation are exactly as planned three years in advance, the chance of outage should be once in 25 years (equivalent to a Loss of Load Expectation, or "LOLE" of 0.04 outages per year).[60] But what if the transmission capacity is lower, or peak load has grown more than expected, or generation or demand response are lower? PJM acquires additional capacity through RPM's incremental auctions and can also take other actions to adjust to such changes. However, suppose somehow we enter a delivery year with less capacity than needed; how much does the zone's outage risk increase if MAAC is, say, 1,000 MW or 3,000 MW short relative to the planned capacity?

71. The same model used to determine the transmission (or CETL) required to satisfy 1-in-25 can also be used to determine the LOLE if less transmission (or less generation or demand response) is available, or if peak loads grow faster than expected.[61] Figure 11

[57] This is developed in detail in Wilson 2009a, Section V p. 54-62.

[58] Wilson 2009a, Section V p. 54-61, discusses the original rationale for the 1-in-25 criterion when it was selected in 1996 and the current rationale as described in the PJM manuals.

[59] *Id*, p. 53 Table 3. While this result is based on the 2009 load forecast and CETO analysis, updated values likely would show a similar impact.

[60] Note that in these reliability criteria, "one day" represents one outage (of whatever duration) not 24 hours of outage.

[61] See also Wilson 2009a, Section VI p. 62-64, which discusses how PJM's PRISM model can be used to evaluate outage risk in the presence of a gap between planned and actual resources.

summarizes the results, based on modeling performed in 2009.[62] Figure 11 is based on assumptions that determined a CETO of 8,190 MW for MAAC. This means that if the actual transmission available, or CETL, equals the CETO (8,190 MW), the LOLE is 0.04 (1-in-25). The analysis summarized in Figure 11 shows that if, instead, the transmission available is 3,000 MW less (5,190 MW instead of 8,190 MW), the LOLE rises to 0.2 (or one day in five years).[63]

72. This shows that what may sound like a fairly substantial "gap" in the resources relative to the planned amounts (3,000 MW) leads to a higher outage risk in MAAC, of course, but is still far from a situation expected to result in frequent outages. Even a gap of 5,000 MW results in an LOLE of 0.5, or one outage every two years. To anticipate outages on many hot days during the summer peak season (five days would be an LOLE of 5), the gap would have to be much larger. Furthermore, a delivery year shortfall or gap of 3,000 MW or 5,000 MW is unlikely to occur, because a gap of this magnitude would likely take years to develop and PJM would acquire additional short lead time resources (such as demand response, imports, plant uprates, reactivations, or delayed retirements) in incremental auctions once the emergence of the gap became evident.

73. Highly conservative resource planning raises consumer cost (especially given RPM's steep supply curves) without providing commensurate benefit. With the further development of the demand side and increasingly price-responsive demand, approaches to resource adequacy must be adapted else the potential value of "smart grid" investments will not be realized, due to construction of excess generation that obviates the need for and value of an active demand side.[64]

[62] This graphic is based on the author's model that recreates the results of PJM's PRISM model used in PJM's CETO analyses. The graphic is also consistent with PJM's response to data request VAStaff-I-6 in Virginia State Corporation Commission Case No. PUE-2009-00043.

[63] This LOLE pertains to supply and demand specifically in the MAAC zone; customers in MAAC also face some additional outage risk due to the chance of a capacity shortage at the RTO level, although this risk is extremely low due to excess capacity and any curtailment would be spread over a larger group of customers.

[64] The need to adapt resource adequacy planning in anticipation of smart grid developments is further discussed in Wilson 2010b.

C. RPM's High Zonal Prices Have Not Attracted Relatively More Capacity to the Zones

74. RPM prices reflect, in addition to the Local Capacity Requirements, the amount of capacity market participants offer into its auctions in each zone. If market participants were responding to the higher RPM prices in zones by offering more capacity located in the zones, this would moderate zonal prices, but instead, zonal RPM prices have generally risen over time. This reflects the fact that, seemingly paradoxically, market participants have been offering relatively more incremental capacity in the Rest of RTO region than in the zones where prices are so much higher.[65] This result is summarized in Figure 12, which shows incremental and decremental capacity in the 2013/2014 base residual auction and other indicators of capacity increases and decreases.

75. As Figure 12 shows, in the 2013/2014 base residual auction there was relatively more new demand response and energy efficiency offered in the Rest of RTO region than in the zones where prices have been and continue to be so much higher (the comparisons are per MW of zonal peak load, to account for the different sizes of the regions). However, the low price in the Rest of RTO region did result in relatively less demand response clearing there. There was also relatively more new generation (both new plants and also existing plant uprates), and net imports, offered and cleared in the Rest of RTO than in the zones.

76. Figure 12 also shows that capacity losses are also running contrary to the RPM prices. There were relatively more generation decreases in the zones where prices are higher. PJM's current list of planned deactivations[66] also suggests relatively more future retirements will occur in the zones than in the Rest of RTO region.

77. Looking ahead, PJM's interconnection queues again show relatively more capacity being planned for the Rest of RTO region than for the zones. Even focusing on the more recently-queued projects (since February 2009), there are relatively more in the Rest of RTO region than in the zones.

78. I have identified three reasons for the seemingly paradoxical result that market participants are offering relatively more incremental (and less decremental) capacity in the Rest

[65] A detailed review of incremental and decremental capacity in PJM's zones compared to the Rest of RTO region is in Wilson 2010d Section V.B, p. 27-32.

[66] PJM List of Planned Deactivations, updated August 27, 2010.

of RTO region where prices are relatively low than in PJM's zones where prices have been so much higher.[67]

79. First, market participants are apparently not finding RPM's zonal prices and price differentials to be credible and are largely ignoring them. They are set for a single year at a time and are highly changeable. Market participants know that new transmission capacity, new generation, and changes to RPM rules can reduce or eliminate locational price differentials. Market participants also likely understand that RPM's price signals overstate the real need for capacity in the zones due to excessive reliability requirements, as explained above. Volatile and uncertain price signals will not exert much influence over decisions regarding long-term investments.

80. Second, while other market participants may be ignoring RPM's zonal price signals, the owners of portfolios of capacity located in the zones and earning the high prices know that offering incremental capacity there will depress the prices. Most of the capacity in PJM's zones is owned by entities with large enough portfolios to have strong disincentives to expand capacity, as noted earlier.[68] This may help explain why we are seeing more incremental capacity offered in the large and relatively competitive Rest of RTO region than in the zones. In the Rest of RTO region, the auctions clear on a relatively flat segment of the supply curve, and offering incremental capacity has little or no impact on the clearing price, so sellers with portfolios of capacity face no price impact "penalty" if they offer additional resources. This also suggests that, again seemingly paradoxically, more incremental capacity might be offered in the zones if zonal pricing, and the disincentives it creates, were eliminated.

81. Finally, it is also true that the zones tend to be relatively developed areas where it can be more difficult to locate suitable sites and gain all regulatory approvals for new capacity. In addition, the best sites may be the locations of existing power plants whose owners face disincentives to expand capacity.

82. To summarize, RPM prices have been excessive in the zones due to excessive Local Capacity Requirements, and these high prices have failed to attract relatively more capacity to the zones. The fact that higher zonal prices have not led to relatively more capacity

[67] See also Wilson 2010d, p. 33-37.

[68] Wilson 2010d p. 34-37.

offered in the zones calls into question whether RPM's zonal capacity pricing increases the efficiency of the capacity market (as the simple theory suggests) or instead decreases its efficiency.

D. "Net CONE" Is Not a Magic Number for Attracting New Resources

83. The Notice and its Attachment refer specifically to the level of RPM prices compared to the administrative "Net CONE" values:

> Notice, p. 1: "But because these zones cleared just under the Net Cost of New Entry ("Net CONE"), these prices will not, under the theory underlying RPM, incent new generation in Maryland or the relevant zones."
>
> Attachment, Question 1: "Is it true that because the MAAC and DPL South zones cleared below Net CONE, RPM is not incenting new developments in those zones?"

84. It is true that RPM was promoted with a theory that there would be many offers of new capacity at prices around Net CONE, leading to a relatively "flat", competitive supply curve and plenty of new entry if prices reach that level, as noted earlier. There are several reasons why the magnitude of clearing prices relative to an administrative Net CONE value tells little about the incentives to build new capacity in PJM's zones, and it should not be expected that if prices rise above Net CONE, offers to build new capacity will suddenly appear.[69]

a. First, decisions to build long-lived power plants are not made based on the outcome of a single auction that offers a one-year commitment, as noted earlier. Such decisions are rationally based on expectations of costs and revenues over the life of the facility.
b. The notion that prices relative to Net CONE drive entry also assumes "merchant" entry, which, as noted earlier, is unrealistic in recent years. With public policies increasingly encouraging demand response, renewables, and other clean sources, entry will more and more reflect incentives, contracts and other sources of assured revenue rather than pure market forces.
c. The administrative Net CONE value is based on many assumptions regarding costs and revenues for a combustion turbine plant. These assumptions are highly uncertain (especially the future energy and ancillary services revenue

expectations) and, in any case, new combustion turbine plants have represented only five percent of the incremental capacity in RPM's seven auctions (see Figure 7).

V. Potential Modifications to RPM (Questions 4 and 5, Additional Question A)

85. This section addresses Questions 4 and 5 from the attachment to the notice and the additional Question A posed on September 16, 2010:

> ***4.*** *What changes have been considered to RPM or within the PJM stakeholder process that could potentially facilitate more levelized capacity prices throughout the RTO?*
> ***5.*** *What changes could be made to RPM that would stimulate increased generation and demand response investment in Maryland? Should RPM be kept as is, amended or abandoned?*
> ***A.*** *Are PJM's proposals to place limitations on Demand Response within the Reliability Pricing Model reasonable?*

86. The focus is on potential modifications to RPM. As suggested in Questions 4 and 5, there are two main directions to pursue in considering modifications to RPM: (1) To try to make RPM more effective in helping to stimulate increased generation and demand response investment (Question 5), or (2) To moderate RPM's zonal prices and make RPM less costly (Question 4).

A. Potential Modifications to Try to Make RPM More Effective in Stimulating Investment

87. One approach to attempting to make RPM more effective in stimulating major investments would be to try to make its price signals and capacity commitments more attractive to potential developers. In principle, RPM prices could have more influence over longer-term capacity decision-making if they were more stable over time or if longer-term price commitments were available. However, I do not see much prospect for useful modifications in either of these directions, as explained below.

88. **Modifications to increase price stability**. RPM prices should rise and fall to clear supply and demand and to reflect the actual balance of capacity supply and demand at any time. The sloped capacity demand curve already provides some price stability. When supply is

[69] These concepts are all further developed in Wilson 2010f.

abundant, the sloped demand curve clears additional supply at a somewhat higher price than would occur if only the Reliability Requirement was cleared. However, the large excess cleared in one BRA will tend to increase the existing capacity offered into subsequent BRAs, lowering prices. Therefore, while the sloped demand curve may contribute to price stability within each year, it can have the opposite impact on subsequent years as any shortage or excess is carried forward. A "flatter" capacity demand curve would keep prices within a narrower range given the offered supply in any year, but would result in even more carryover of capacity shortages or excesses from year to year due to the muted feedback to the market. Therefore, I do not believe changes to make RPM prices more stable and less responsive to short-term supply and demand conditions would be an improvement.

89. **Multi-year price commitments for new resources**. The ability to lock in the RPM price for the first several years of operation could help new plants obtain financing and result in more new capacity. However, the prices set by RPM, which are calculated based on demand conditions and offered supply for a single year, may not be appropriate payments for future years when the supply/demand balance may be very different. In addition, FERC does not allow multi-year pricing for new resources if it finds the provisions unduly discriminatory. Therefore, I doubt RPM can be improved by expanding the availability of multi-year price commitments for new resources (a provision that exists now but in a restricted form that has not been used).

90. **Longer-term commitments for all resources.** I also do not believe RPM should be modified to offer longer-term commitments to all resources. The RPM auction mechanism procures a fairly simple product: a one-year commitment to provide capacity. The RPM auctions select among resources based on a single dimension: the offer price. If longer-term commitments are offered, the commitments would be more likely to determine which resources will and will not be built. It would become much more important that attributes other than just price are considered. For example, if two resources are competing to obtain a 5-year or 10-year commitment to provide capacity, and the winning resource will likely be built while the losing resource will not, the environmental characteristics of the resources, the fuel and energy costs, the reliability characteristics, and many other characteristics that likely will not be reflected in the capacity offer prices should be considered. In addition, consideration of non-price attributes should reflect policies and priorities that will vary from state to state. RPM does not, and such a

mechanism cannot, accomplish integrated resource planning, and modifications to move it in that direction likely would be ineffective while raising consumer cost.

B. Potential Modifications to Better Focus RPM, Make It Less Costly, and Reduce Locational Price Differentials

91. The potential to improve RPM's effectiveness in influencing major capacity investments is very limited. As discussed in the Summary, RPM should instead be focused on coordinating the short lead-time capacity decisions that are best made closer to each delivery year. This focus will also moderate RPM's cost.

92. The potential to reduce the cost imposed by RPM is substantial. This section discusses four main directions: (1) to more accurately determine the reliability requirements and amounts of capacity that must be acquired in zones; (2) to improve the efficiency and reduce the cost impact of forward procurement; (3) to accommodate more resources that can contribute to meeting resource adequacy requirements; (4) to ensure that capacity market results accurately reflect changing revenue opportunities in PJM's energy and ancillary services markets.

1. More Accurate Determination of Zonal Capacity Requirements

93. As described earlier in these comments, the amount of capacity PJM attempts to procure for the RTO and each zone is overstated due to issues around the load forecast, the CETO calculations and zonal reserve margins, and the CETL calculations. The zonal capacity needs are overstated for all zones, but perhaps especially for the MAAC zone, which is very large and relies on transmission for only a small percentage of the peak load. The main areas for improvement in this regard were noted earlier in these comments:

a. Use more realistic economic activity forecasts to drive the peak load forecasts.[70]
b. Improve the peak load forecasting to better reflect recent trends of slowing peak load growth and higher electricity prices.[71]
c. Correct two errors in the CETO calculations (linkage of peak load forecast to PRISM model, representation of standard normal distribution).[72]

[70] Wilson 2009a p. 16-30; Itron 2010.

[71] Wilson 2009a p. 16-30; Itron 2010.

[72] Wilson 2009a p. 42-44.

d. Correct overly conservative assumptions in the CETO calculations (Forecast Error Factor, generation outage rates, variance of peak load distribution).[73]

e. Adopt a more reasonable reliability criterion for CETO analyses ("one day in 25 years" is currently used).[74]

f. Adopt more realistic assumptions in CETL analyses.[75]

g. Adopt a more rational test to determine whether a zone will be modeled for RPM: rather than CETL/CETO less than 1.15, the test should focus on the total capacity available to a zone compared to the total requirement.

h. Eliminate the one percent over-procurement built into the shape of the Variable Resource Requirement capacity demand curves.

i. Set three-year-forward zonal capacity requirements based on values that have a greater likelihood of occurring (discussed further in the next subsection).

j. Ensure that zonal capacity requirements reflect changes in PJM's market rules, and in particular, the additional non-RPM supply that will be called forth under revised shortage pricing rules.[76]

94. Adopting more realistic and accurate estimates of zonal capacity needs is especially appropriate in light of the evidence that locational capacity pricing does not attract relatively more capacity to the zones, and may result in relatively less capacity coming to the zones and less competitive pricing of capacity, as described earlier in these comments.

95. Reducing or eliminating zonal pricing might result in a more frequent need for PJM to delay the retirement of a specific unit needed for reliability under a cost-based, "reliability must run" type agreement, until transmission enhancements or other new generation or demand response becomes available. Such arrangements already exist and an increased likelihood of them would be one consideration if changes to zonal pricing are contemplated.

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[73] Wilson 2009a p. 44-52.

[74] Wilson 2009a p. 54-61.

[75] Dehdashti 2009.

[76] The importance of reflecting the additional supply attracted under revised shortage pricing rules is discussed in Wilson 2010g p. 5, p. 39-40.

2. Changes to Increase the Efficiency of Forward Procurement

96. The following proposals could be considered to increase the efficiency of RPM's forward procurement and reduce the risk of excessive cost resulting from this approach.

a. Make the three-year-forward procurement voluntary and informational rather than mandatory; capacity procurement to satisfy obligations would become mandatory one year or less in advance of the delivery year. There should be appropriate consequences for any load-serving entities that fail to meet their capacity obligations (on a bilateral basis or through the final capacity auction), and should firm curtailment become necessary, it should be imposed on those entities that are short.

b. Base three-year-forward requirements and obligations on forecasted capacity needs with a greater than 50/50 chance of occurring (say, an 80% chance). Presently, capacity requirements are based on forecasted capacity needs that have less than a 50% chance of actually being needed,[77] usually leading to procurement of excess capacity at excessive prices. This is not necessary, especially in light of the availability of short lead-time resources and the flexibility to acquire additional resources through incremental auctions closer to the delivery year as needed.

c. Provide better price convergence between the base residual and incremental auctions by permitting "virtual" capacity bids by entities that lack market power. To date, incremental auction prices have generally been much lower than BRA prices, reflecting the fact that not all capacity that will be available in a delivery year is able to offer three years in advance and will offer into incremental auctions, and possibly some withholding of incremental resources from the base residual auctions to help support prices there. Allowing market participants some limited ability to arbitrage between the base residual and later incremental auctions using virtual capacity offers (similar to INCs and DECs between the Day-ahead and Real-time energy markets) would enhance efficiency and price

[77] While the peak load forecast is intended to be a median or "50/50" forecast, a "Forecast Error Factor" is applied in the determination of capacity needs, which biases results higher. In addition, the analyses rely on other assumptions known to be conservative, such as conservative estimates of transmission availability (CETL).

convergence, moderating base residual auction prices and capacity costs. It could also mitigate the impact of forecast errors, because market participants with different views could take positions in the base residual auction that will benefit from the later corrections to capacity procurement as the PJM forecasts are updated.

d. Further reforms to improve the efficiency of RPM's incremental auctions. In particular, when PJM has cleared excess capacity in earlier auctions for a delivery year, this capacity should be made available to the market through the incremental auctions at prices consistent with the sloped demand curve concept. The current rules call for PJM to hoard excess cleared capacity, if based on the sloped demand curve, rather than make it available to the market.

3. Changes to Accommodate Additional Resources in RPM

97. A primary objective in considering changes to RPM should be to meet reliability and resource adequacy goals in the most efficient manner, which will also result in the lowest cost. To accomplish this objective, the RPM rules should attempt to accommodate all resources that can contribute to meeting capacity requirements. Under current rules some resources are excluded, with the result that other, higher cost resources must be cleared in RPM's auctions, raising prices and costs. In particular, RPM's rules exclude the following types of resources that contribute to reliability and meeting peak loads:[78]

a. Some excess resources of entities that have "opted out" of RPM under the Fixed Resource Requirement ("FRR") rules;
b. Resources available for only part of the year;
c. Resources available only during the summer months.

98. The need to accommodate these resources has been discussed in PJM's stakeholder processes. However, changes to accommodate additional resources have been opposed by some stakeholders and a solution has not been approved.

99. Rather than striving to accommodate all resources that can contribute to meeting peak loads, recently PJM has announced plans to impose new restrictions on the quantity of

[78] Brattle 2008, p. 71-76.

demand response ("DR") that can be cleared in RPM. Demand response providers are required to provide demand reductions ten times per year for up to six hours each time and are subject to penalties if they fail to perform. PJM has observed that as DR on the PJM system grows, and assuming DR providers will reduce only 10 times per year and only for 6 hours each time, at some point the DR resources do not lower the peak load by the full amount of the DR resources, a concept it calls "DR Saturation".[79] Accordingly, PJM proposes to limit the amount of DR that can be cleared in RPM, and to introduce a new DR product that could be called an unlimited number of times and would not be subject to such limits.[80]

100. However, PJM proposes to determine the limits it would impose on total DR resources based on an analysis that assumes a highly inefficient and unrealistic dispatch of DR resources, especially as the quantity of DR increases in the coming years. PJM assumes that all available DR would be called, and called simultaneously, any time any of it is called, even if DR constitutes eight percent or more of the available resources in a zone.[81] This unrealistic assumption would lead to highly inefficient and wasteful use of the DR resource that would also disrupt system operations, lower LMPs and require some generation resources to be backed down. A group called DR Supporters has proposed more realistic and efficient assumptions for the "DR Saturation" analysis that would lead to less stringent limits and accommodate a larger quantity of demand response in RPM.[82] Adopting realistic assumptions reflecting efficient use of demand response for this analysis would result in realistic limits and allow demand response to continue to meet a growing fraction of PJM capacity needs without jeopardizing reliability. Another alternative under consideration is to define new DR products that better meet operational needs without imposing requirements that would discourage further development of DR.

101. Another issue meriting more attention as the fraction of renewables on the PJM system grows is the capacity value assigned to them. Due to their intermittent nature, some types

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[79] PJM, *Demand Response Saturation Analysis*, item 10, Planning Committee meeting, August 11, 2010; and PJM, *RPM Auction Clearing Recognizing Limited Resource Saturation Limits*, item 6A, Markets and Reliability Committee meeting, September 15, 2010.

[80] PJM, *RPM Auction Clearing Recognizing Limited Resource Saturation Limits*, item 6A, Markets and Reliability Committee meeting, September 15, 2010.

[81] See PJM, *Demand Response Saturation Analysis*, cited above, and in particular slide 8.

[82] DR Supporters, *Efficient Dispatch Proposal*, PJM Market Implementation Committee meeting, August 18, 2010.

of renewable resources cannot be relied upon to provide 100% or close to 100% of nameplate capacity during peak times, and, accordingly, they are assigned capacity values much lower than nameplate. These capacity values should be revisited from time to time to ensure they properly reflect the expected contribution of such resources and take into account the diversity across the PJM system.

102. While changes to RPM to accommodate more resources and to assign appropriate capacity values to intermittent resources would be improvements, I expect that they would result in only a modest impact on the total capacity available through RPM, and RPM prices and costs.

4. Changes to Ensure RPM Results Reflect PJM Market Revenue Opportunities

103. In principle, RPM exists because revenues from all other sources available to capacity providers are insufficient to ensure adequate capacity to meet reliability objectives. Accordingly, as revenue opportunities from other sources increase, capacity payments should decline. As the demand side becomes more active in the markets the "one day in ten years" reliability criterion (which references involuntary curtailment of firm load) becomes less of a constraint and revenue opportunities for peaking plants should increase due to prices reflecting increasingly price-responsive demand. The need for capacity payments to achieve reliability objectives should decline and ultimately the capacity market may no longer be needed.[83]

104. However, for this to occur, there must be a strong linkage between PJM's energy and ancillary services markets and the price parameters of the RPM construct.[84] The current design, which uses historical three-year-averages of energy and ancillary services revenues and three-year-forward procurement, creates a lag of several years between changes in revenues and changes in RPM prices. Reforms to shortage pricing rules and increasingly price-responsive demand could result in substantial changes to energy and ancillary services revenues over the coming years, and the enormous lag reflected in the current RPM rules should be eliminated.

[83] This is further developed in Wilson 2010b.

[84] This is further developed in Wilson 2010g p. 31-39.

5. Other Changes to Lower RPM Cost Through Improved Efficiency

105. The RPM mechanism is highly complex and many of its provisions result in inefficiencies and higher costs. There are numerous other areas where improvements could be made that would increase efficiency and lower cost.

106. To note one area: The RPM rules presently allow capacity sellers to sharply raise their offer prices based on "Accelerated Project Investment Recovery" ("APIR"). This issue was raised in the Brattle Report[85], and these rules should be reformed to make RPM's market power mitigation more effective.

VI. Actions the Commission Might Take to Address These Issues (Question 9)

107. Question 9 asks what the Commission could or should do at PJM, FERC or elsewhere to address these RPM and RPM-related issues.

108. On behalf of load interests, I have been involved in the PJM stakeholder processes pertaining to RPM since it was first proposed in August 2005, including the RPM settlement process and multiple rounds of stakeholder processes to consider various changes to RPM. I have also been involved in the litigation at FERC around proposed changes to RPM, and the RPM Buyer's 2008 complaint. In recognition of the large impact of the Reliability Requirements and other planning parameters on RPM prices and costs, I have also been involved in the PJM stakeholder processes pertaining to load forecasting and the reserve margin determination in recent years.

109. This experience leads me to a pessimistic assessment of the prospects for achieving significant improvements to RPM, either to make it more effective or to lower its cost, through PJM stakeholder processes. In stakeholder meetings addressing RPM issues, while the discussions may focus on economic efficiency, resource adequacy, and other "appropriate" topics, the positions and votes tend to reflect financial interests, and generation owners benefit from high RPM prices. While some electric distribution companies in the PJM footprint (both investor-owned and public power entities) align with their customers' interests in achieving adequate reliability at reasonable cost, many EDCs are affiliated with generation interests. In a number of instances, it has not been possible to gain sufficient stakeholder support for changes

[85] Brattle 2008 p. 115.

that would achieve resource adequacy more efficiently and at lower cost. Indeed, changes to RPM that would increase RPM costs may be more likely in the coming months than changes that would make RPM more effective or reduce its costs. Some of the changes under discussion that would raise RPM costs include new limits imposed on demand response resources ("DR Saturation"), as discussed above, and elimination of the "2.5% hold back" from the BRA to accommodate short lead-time resources.

110. With respect to the RPM planning parameters (load forecast, reserve margins), in my experience PJM staff have resisted proposals to change the procedures and assumptions it has followed for many years, including proposals that would address recognized shortcomings. In resisting proposals for changes to these practices, PJM is generally backed by a majority of the stakeholders in the relevant committees and working groups, which are dominated by generation interests either directly or through affiliation. Proposals with substantial merit have been rejected based on votes reflecting alignment according to financial interests. Even requests for more complete documentation for greater transparency have been rejected.[86] A request for an additional load forecast scenario, based on a consensus economic forecast, was also rejected based on a committee vote.[87]

111. My efforts to understand and evaluate PJM's load forecasting and reserve margin methodologies were hampered because the assumptions, methodologies, and models are not always fully documented and in some ways not very transparent. In some instances PJM has resisted providing detailed assumptions and has not been able to provide a complete description of the methodology or model logic. As one example, I was not able to reproduce the calculations of the probabilistic representation of peak load used in PJM's CETO analyses and PJM was unable to precisely define the methodology used for these calculations or to identify the specific historical data upon which each parameter is calculated.[88] As another example, PJM apparently adjusts its monthly peak load forecasts upward so that one month equals the seasonal forecast,

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[86] For example, see PJM Reserve Requirement Assumptions Working Group Meeting Notes, September 10, 2009 and October 12, 2009 meetings (noting my request, which was made multiple times, that the reserve requirements report include the calculation of the installed reserve margin as installed capacity divided by peak load; this request was refused and the report does not show the calculation).

[87] Minutes of the PJM Planning Committee, September 16, 2009 and October 22, 2009.

[88] See Wilson 2009a at p. 41 and data requests VAStaff-III-6-a, VAStaff-V-6-a, and VAStaff-V-7 in Virginia State Corporation Commission Case No. PUE-2009-00043.

and this adjustment is reflected in the probabilistic representation of load used in the CETO analyses, but PJM was unable to describe the adjustment methodology in detail and claimed the formulas used are part of a proprietary software code.[89] Multiple times PJM has been unable to provide intermediate model results that would assist in understanding and validating the various steps in the calculations.

112. Over the past year some stakeholders have encouraged PJM to adopt best practice, industry-standard tools for these evaluations. For example, stakeholders proposed that PJM use GE Energy's Multi-Area Reliability Simulation (GE-MARS) model[90] that nearly all RTOs and ISOs use, and that PJM also licenses. However, PJM has resisted this, and instead of applying the GE-MARS model this year, considerable effort was expended to develop a report comparing PJM's PRISM model to GE-MARS. As noted earlier, questions have also been raised regarding PJM's methodology and modeling for determining the CETL values and its load forecasting methodology.

113. Another issue regarding PJM's forecasting and resource adequacy evaluations that may warrant attention is the extent to which PJM exercises judgment and discretion in making these determinations. For example, PJM's peak load forecasting is a mechanical process driven by an updated economic forecast. Other than updating the economic forecast and adding the most recent historical peak load data, few if any other changes are made each year. However, PJM has made "manual adjustments" to its forecast at its discretion. The 2010 forecast, for instance, reflects a 600 MW adjustment in one zone, made at the request of the transmission owner.[91] PJM states that it determined the adjustment was necessary, but its analysis is confidential and it could not describe the methodology it applied, if any, to determine that the adjustment was not already reflected in its peak load forecast or the underlying economic forecast.[92] PJM states in this regard, "It is within PJM's discretion to adjust any forecast value it

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[89] *Id*, and data requests VAStaff-III-6-a, VAStaff-V-7 in Virginia State Corporation Commission Case No. PUE-2009-00043.

[90] Information on GE-MARS is available at http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm.

[91] PJM Load Forecast Report January 2010, p. 1.

[92] PJM *Responses to Follow-Up Questions re: PJM 2010 Load Forecast Report*, March 5, 2010, response to question #5; and *PJM Responses to Questions, Requests and Suggestions re: Draft PJM 2010 Load Forecast Report*, January 28, 2010, responses to questions III.1 and III.2. These questions were submitted by James Jablonski

deems appropriate and PJM discusses these adjustments with the Load Analysis Subcommittee and Planning Committee."[93] In another example, PJM made a change to the economic forecasts used for the state of Virginia for its peak load forecasting, a change it felt was needed and that was discussed with the applicable committees. However, once the impact of the change on the load forecast and capacity cost allocations became clear, the directly affected transmission owner complained, and PJM agreed to undo the change.[94]

114. I have raised various other questions about PJM's load forecasting, reserve margin, and CETO determinations in the past few years that have not, in my opinion, been answered in a satisfactory manner, but I will not lengthen these comments with a complete list.[95]

115. As explained in these comments and its various citations, the RPM zonal capacity requirements are excessive and have a very large impact on RPM prices and cost. The Commission might consider pursuing the following directions to achieve improvements to the RPM planning parameters.

a. Encourage PJM to adopt tools and methodologies that are widely used, reflect industry best practices, and are fully documented and transparent. Request PJM to initiate an independent evaluation of its methodologies and models used in the CETO, reserve margin, and CETL calculations, to lead to recommendations on any changes needed.

b. Continue to pursue evaluation of and enhancement to PJM's load forecasting methodology. At the request of a group of stakeholders,[96] PJM has recently

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of the Public Power Association of New Jersey and the responses were distributed to the PJM Planning Committee and Load Analysis Subcommittee.

[93] PJM *Responses to Follow-Up Questions re: PJM 2010 Load Forecast Report*, March 5, 2010, response to question #5.d.

[94] *Answer of PJM Interconnection, L.L.C. to Complaint of Virginia Electric and Power Company*, Virginia Electric and Power Company, Complainant, v. PJM Interconnection, L.L.C., Respondent, FERC Docket No. EL10-69, p. 6-8.

[95] Additional concerns about the load forecast and related issues are reflected in the two rounds of questions regarding the PJM 2010 Load Forecast Report (cited above), and letter to Steven Herling and John Reynolds, PJM, from James A. Jablonski et al, *Independent Consultant Review of PJM's Load Forecasting Methodology: Comments and Requests Regarding the Scope of Work*, April 23, 2010. Concerns with respect to PJM's PRISM model assumptions, inputs and operation are reflected in numerous documents of PJM's Reserve Requirements Assumptions Working Group during April through September 2009.

[96] *Re: Request for Consultant Review of PJM's Load Forecasting Methodology*, letter to John Reynolds and Steve Herling, PJM, signed by eighteen stakeholders, March 8, 2010.

sponsored an evaluation of its load forecasting methodology, and initial results and recommendations have only recently become available. However, the scope of the evaluation was less than stakeholders had requested, so it is unclear whether the results will address all of the many issues that have been raised.[97]

c. Sponsor an independent effort to forecast PJM loads, perhaps through the Organization of PJM States ("OPSI"). At present, PJM is the only entity that forecasts PJM peak loads, so there is no independent verification of these results. In addition, PJM produces only a single scenario and does not explore the uncertainty of the forecast other than the impact of extreme weather. An independent forecasting effort could produce an alternative forecast, or focus on complementing PJM's forecasting, for instance by producing additional scenarios and sensitivity analysis.

d. Sponsor an independent effort to evaluate RTO and zonal reserve margins and capacity needs (the evaluations presently performed by PJM using its in-house PRISM model). Such an effort would provide a second opinion on these determinations and likely would apply a transparent, industry-standard tool.

e. Request PJM to provide more detailed information and analysis about how reliability would potentially be affected by different levels of zonal capacity and transmission (Figure 9 is an example), and the full range of actions PJM can take with different lead times to the delivery year.

f. Request FERC to require PJM to file its load forecast, reserve margin, CETO, and CETL values. These calculations determine key parameters that have large impacts on RPM prices and costs, and other RTOs file such parameters with FERC or state regulatory authorities. A FERC filing would give stakeholders an opportunity to comment on and challenge the various assumptions and methodologies in a more formal, transparent and rigorous manner than is achieved in stakeholder processes.

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[97] PJM, *Request For Proposal For Load Forecast Model Evaluation*, Planning Committee meeting, June 9, 2010; compare to the scope requested by stakeholders: letter to Steven Herling and John Reynolds, PJM, from James A. Jablonski et al, *Independent Consultant Review of PJM's Load Forecasting Methodology: Comments and Requests Regarding the Scope of Work*, April 23, 2010.

VII. References

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Wilson 2008c. Wilson, James F., Supplemental Affidavit in Support of Answer of the RPM Buyers, July 28, 2008, *Maryland Public Service Commission et al v. PJM Interconnection, L.L.C.*, FERC Docket No. EL08-67-000.

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VIII. Attachment to the Notice: Questions for Response by Parties

Attachment to
Notice of Public Conference – PC22
List of Questions for Response by Parties

The following is a list of questions that all participants in the public conference are invited to address in their filed comments:

1. What value or benefit will customers in the MAAC zones receive in exchange for the higher capacity prices they will pay in 2013-14? Is it true that because the MAAC and DPL South zones cleared below Net CONE, RPM is not incenting new developments in those zones? If the Commissioners were asked by the public to explain the purpose of the capacity market and the benefit customers receive from capacity payments, what should they say?
2. Identify and explain, with specificity, the mechanisms in the tariff, operating agreement, and manuals, that explain the resource clearing price for the MAAC and Pepco LDAs in the BRA for the 2013/2014 Delivery Year being higher than the RTO clearing price.
3. Why was the capacity clearing price for the 2013-14 planning year so much higher in MAAC than the clearing price for the 2012-13 planning year? What changed? What new price signals or economic incentives does the higher 2013-14 clearing price send?
4. What changes have been considered to RPM or within the PJM stakeholder process that could potentially facilitate more levelized capacity prices throughout the RTO?
5. What changes could be made to RPM that would stimulate increased generation and demand response investment in Maryland? Should RPM be kept as is, amended or abandoned?
6. Should the Commission monitor or regulate the participation of regulated electric companies with regard to their capacity offers of Demand Response and Energy Efficiency? If so, how? If not, why not?
7. What mechanism exists in PJM's market rules and procedures that allows PJM to inform and share data with state commissions of the specific measures that could be undertaken by the state commissions to reduce energy and capacity costs for customers, and how do such procedures operate?
8. What duty does PJM have, or should it have, to facilitate levelized capacity prices across the RTO?
9. What can or should the Commission do to address these issues at PJM, FERC or elsewhere?

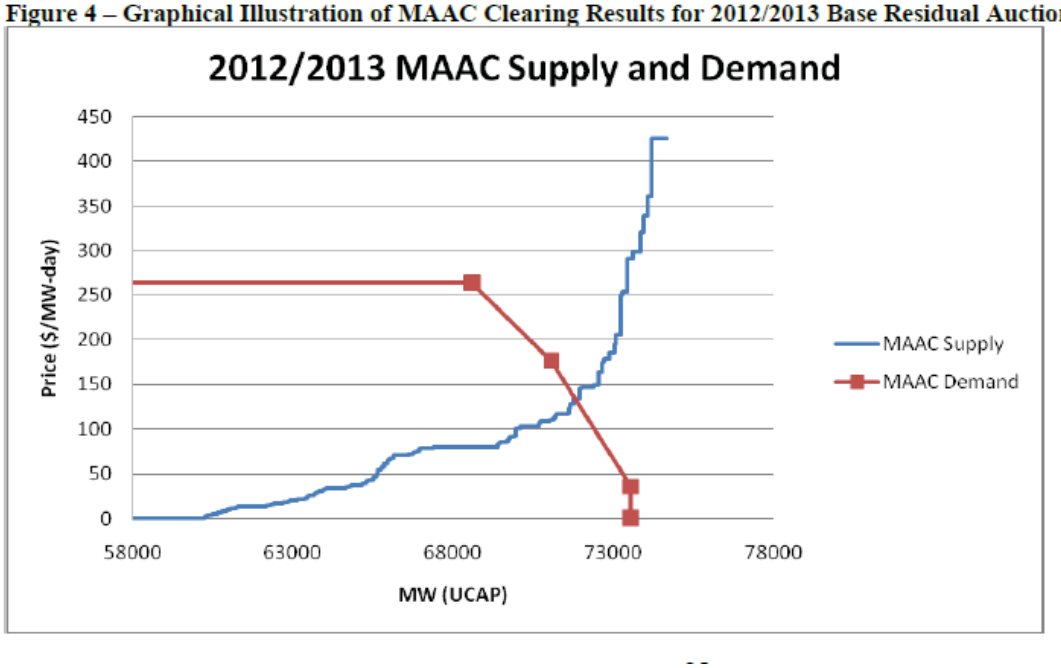
Notice of Additional Questions for Comment (September 16, 2010)

A. Are PJM's proposals to place limitations on Demand Response within the Reliability Pricing Model reasonable?

B. What are the implications to Maryland's Demand Response programs if such limitations are adopted?

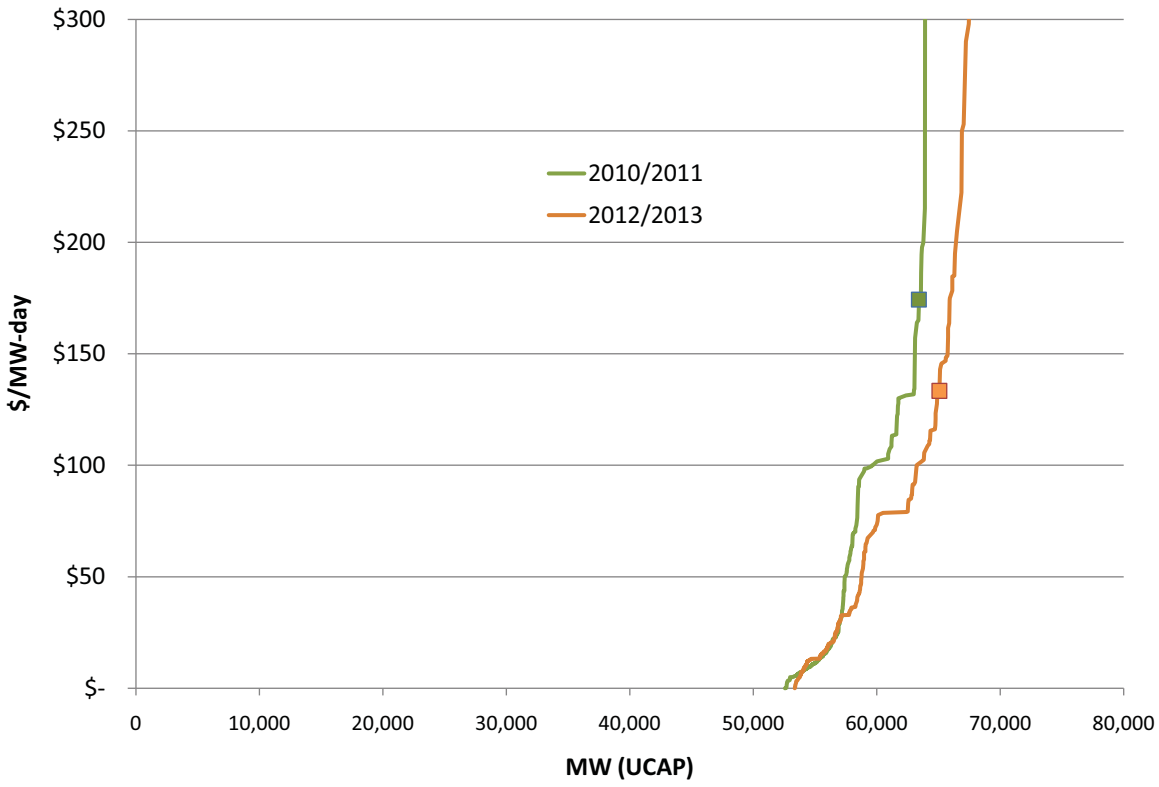
Figure 1: RPM Supply and Demand Curves for the MAAC Zone, 2012/2013 Base Residual Auction

Figure 4 – Graphical Illustration of MAAC Clearing Results for 2012/2013 Base Residual Auction



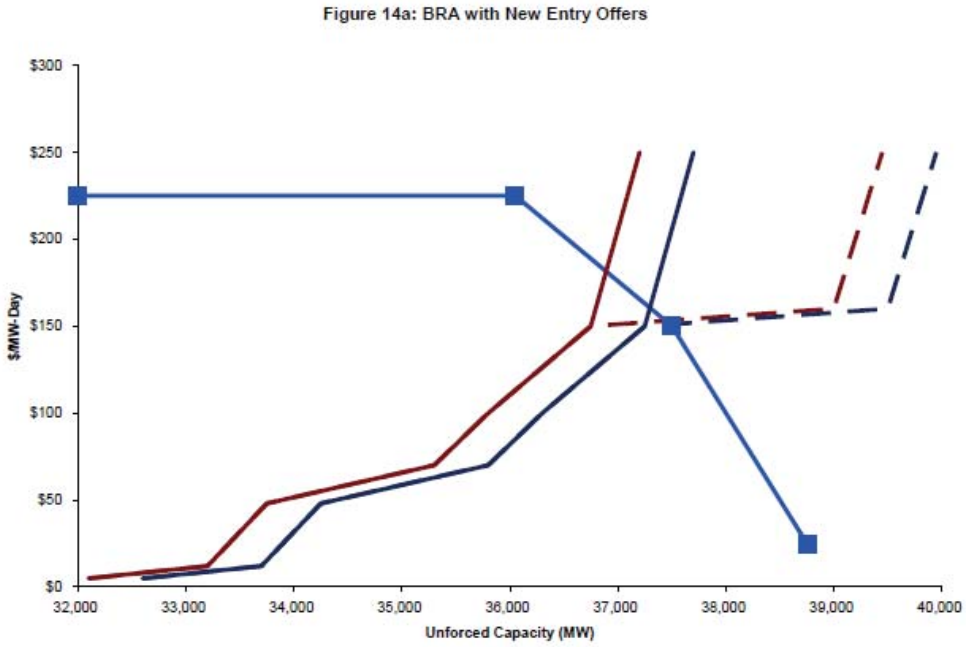
Source: PJM, *2012/2013 RPM Base Residual Auction Results*, p. 25.

Figure 2: RPM Supply Curves - Mid Atlantic Region



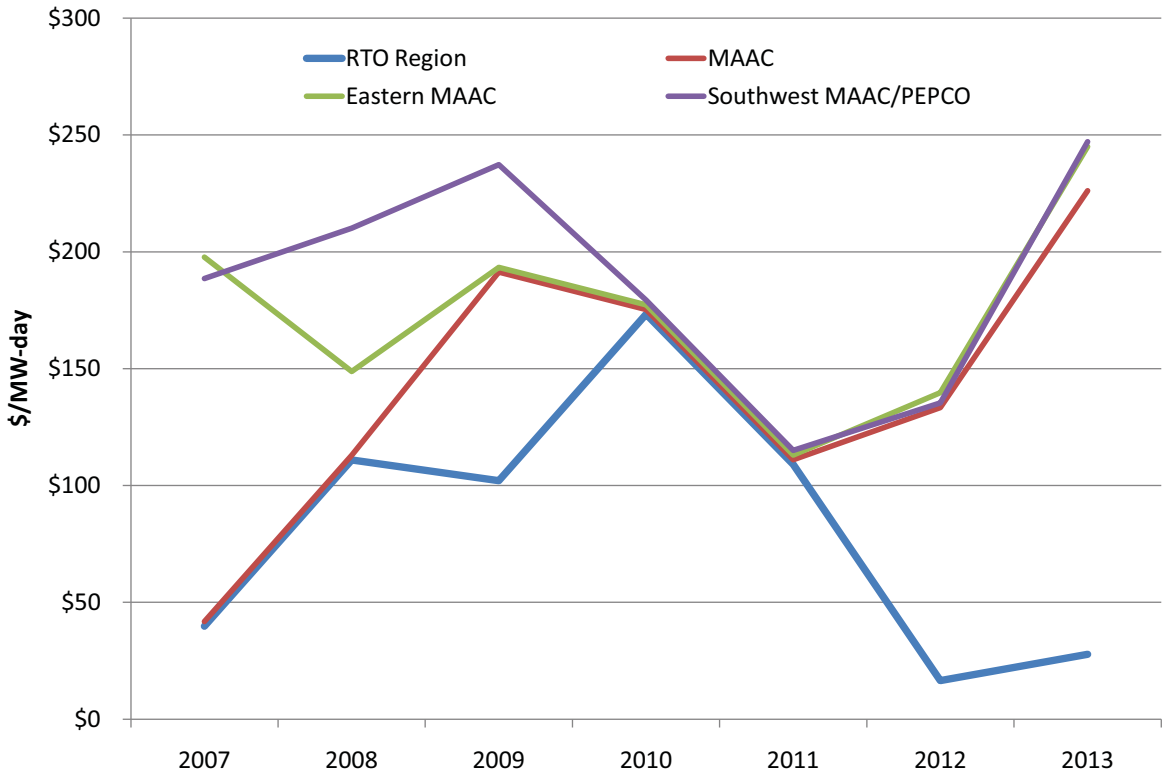
Source: Data posted by PJM.

Figure 3: Theoretical "Steady State" RPM Supply and Demand



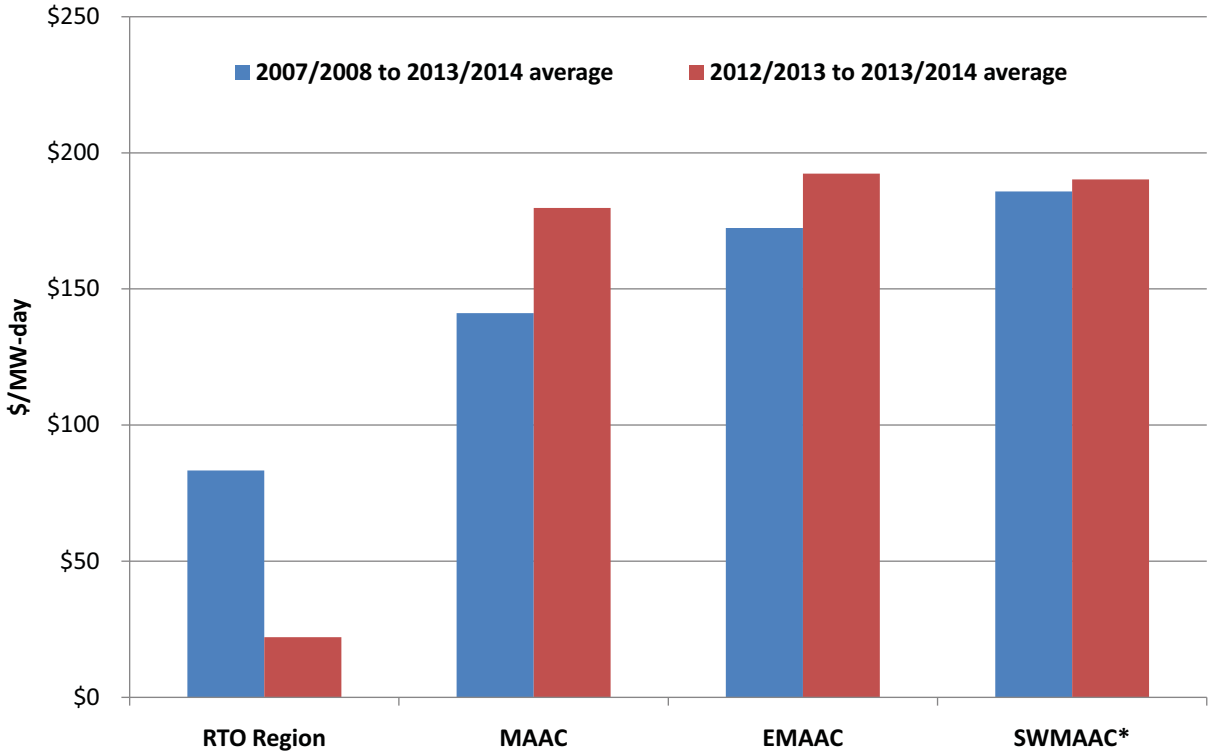
Source: CRA International, *Reliability At Stake: PJM's Reliability Pricing Model,* May 5, 2008, p. 33.

Figure 4: RPM Clearing Prices Over Seven Base Residual Auctions



Source: RPM Base Residual Auction Results reports for various years

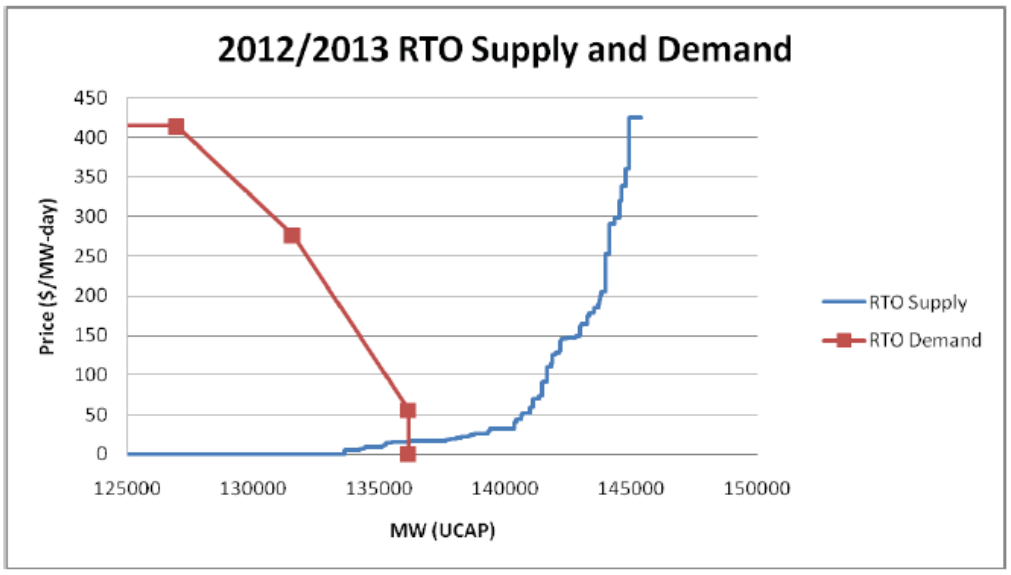
Figure 5: Average RPM Prices By Zone



Source: RPM Base Residual Auction Results reports for various years. The averages are for "rest of" and do not reflect higher prices in nested LDAs. * For SWMAAC, the PEPCO price is used for 2013/2014.

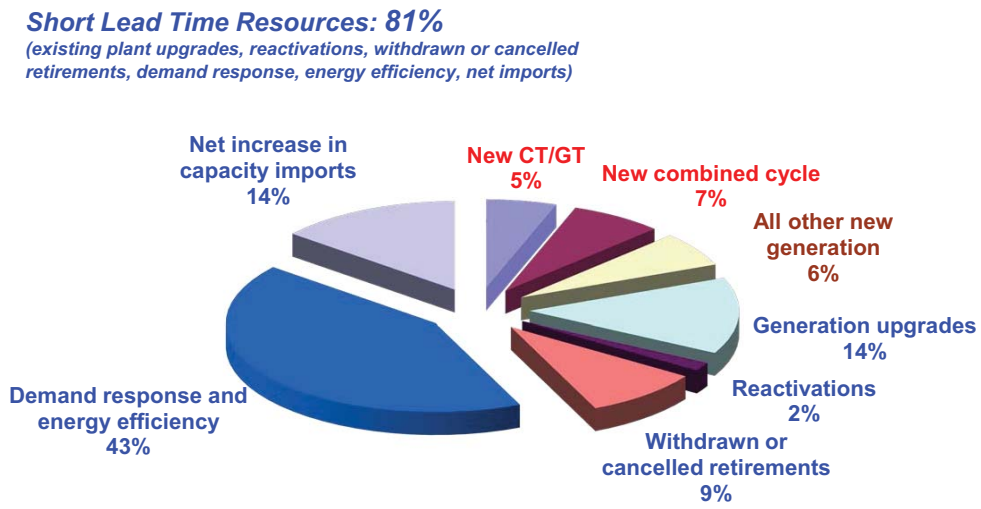
Figure 6: RPM Supply and Demand, RTO Region (2012/2013 BRA)

Figure 1 – Graphical Illustration of RTO Clearing Results for 2012/2013 Base Residual Auction



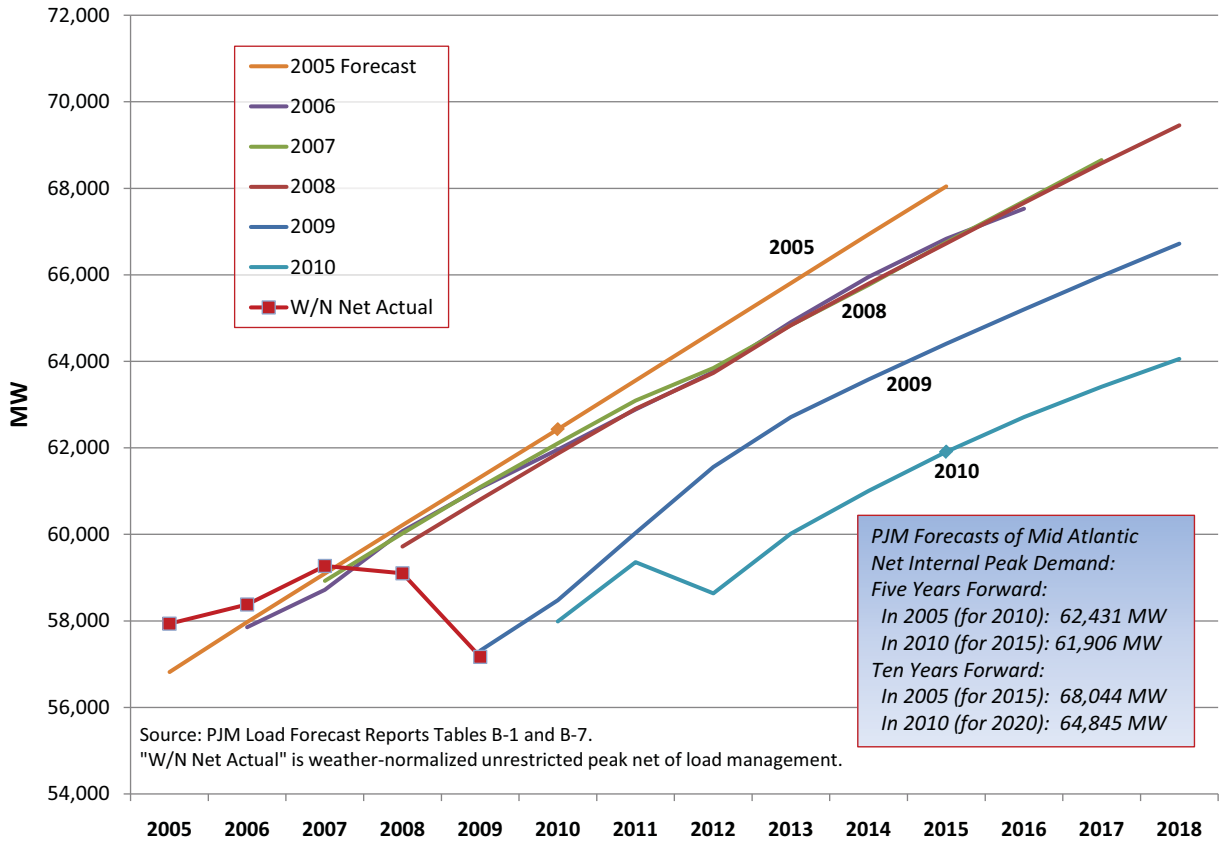
Source: PJM, 2012/2013 RPM Base Residual Auction Results, p. 22.

Figure 7: Incremental Capacity Resources: First Seven PJM RPM Base Residual Auctions



Source: PJM, *2013/2014 RPM Base Residual Auction Results*, Tables 7 and 9; based on offered capacity expressed in installed capacity terms (except Demand Response and Energy Efficiency).

Figure 8: PJM Forecasts of Mid-Atlantic Net (Restricted) Peak Demand

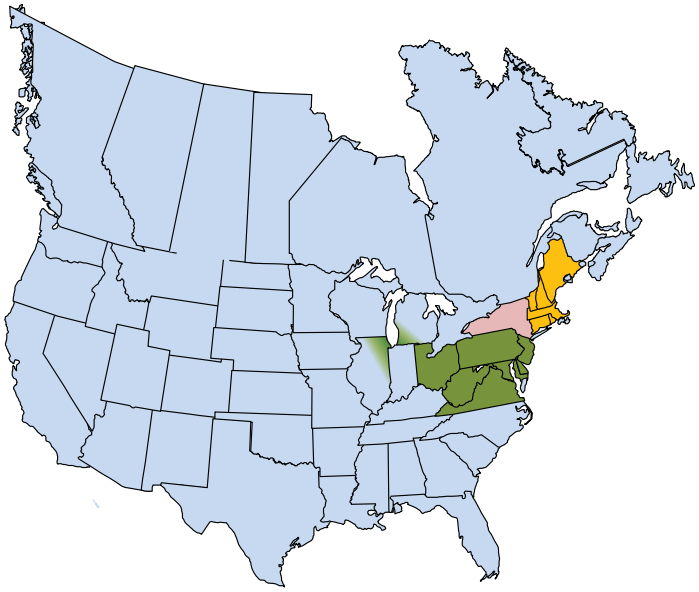


Source: PJM Load Forecast Reports Tables B-1 and B-7.
"W/N Net Actual" is weather-normalized unrestricted peak net of load management.

Figure 9: Regions with Centralized Capacity Markets

Areas with mandatory centralized capacity markets:

- ✓ ISO New England
- ✓ NY ISO
- ✓ PJM



PJM map is approximate.

Figure 10: Regions with Adequate Capacity

Areas with deliverable capacity resources in excess of reserve margin:*

- ✓ **until 2015 or 2016 (Quebec; Carolinas)**
- ✓ **at least until 2018 (rest of N. America)**

*Including potential resources reduced by confidence factor

Source: NERC 2009 Long-Term Reliability Assessment, p. 2

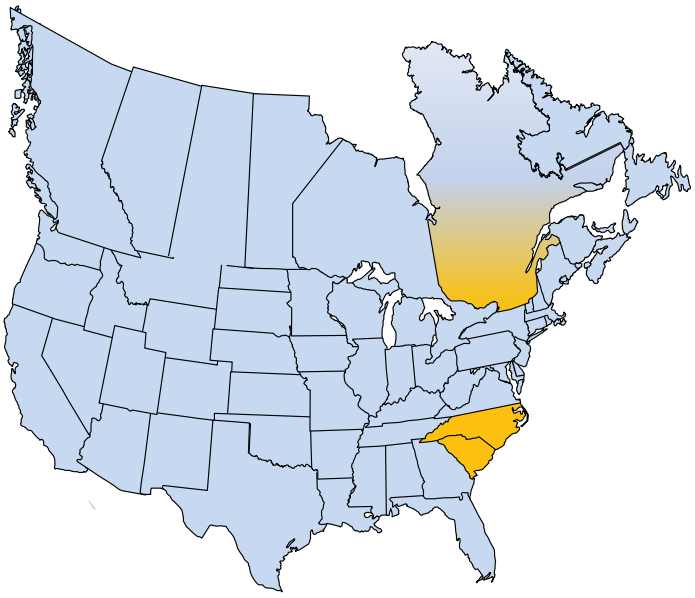
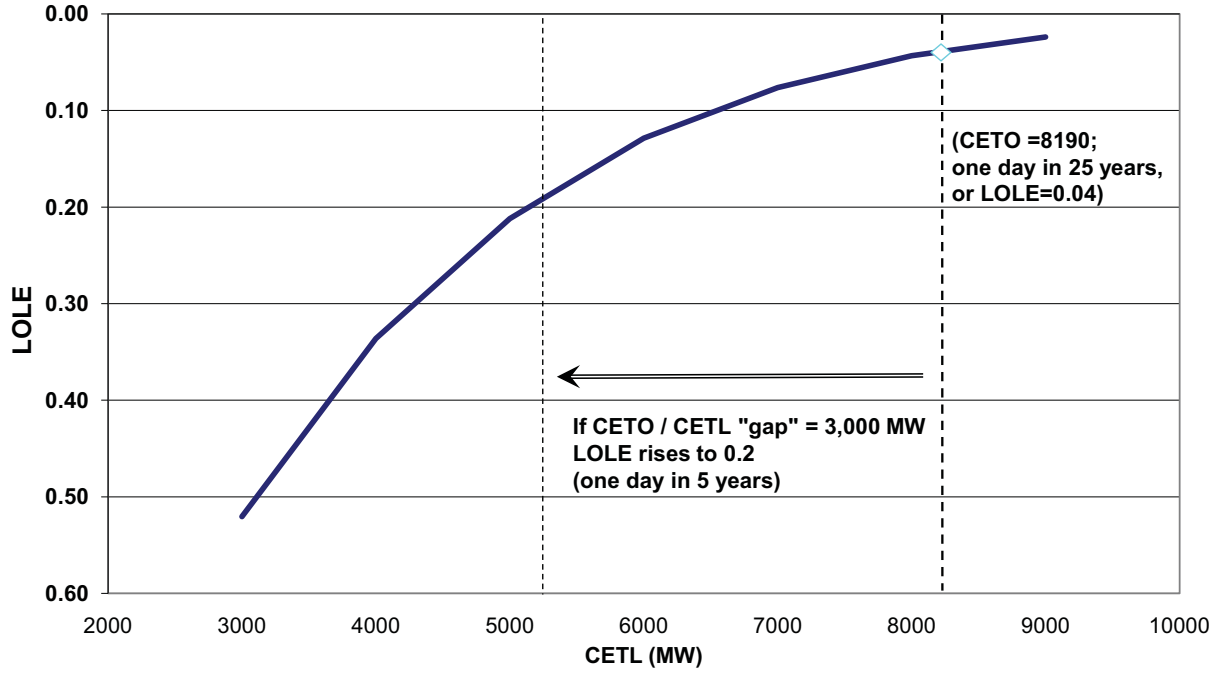
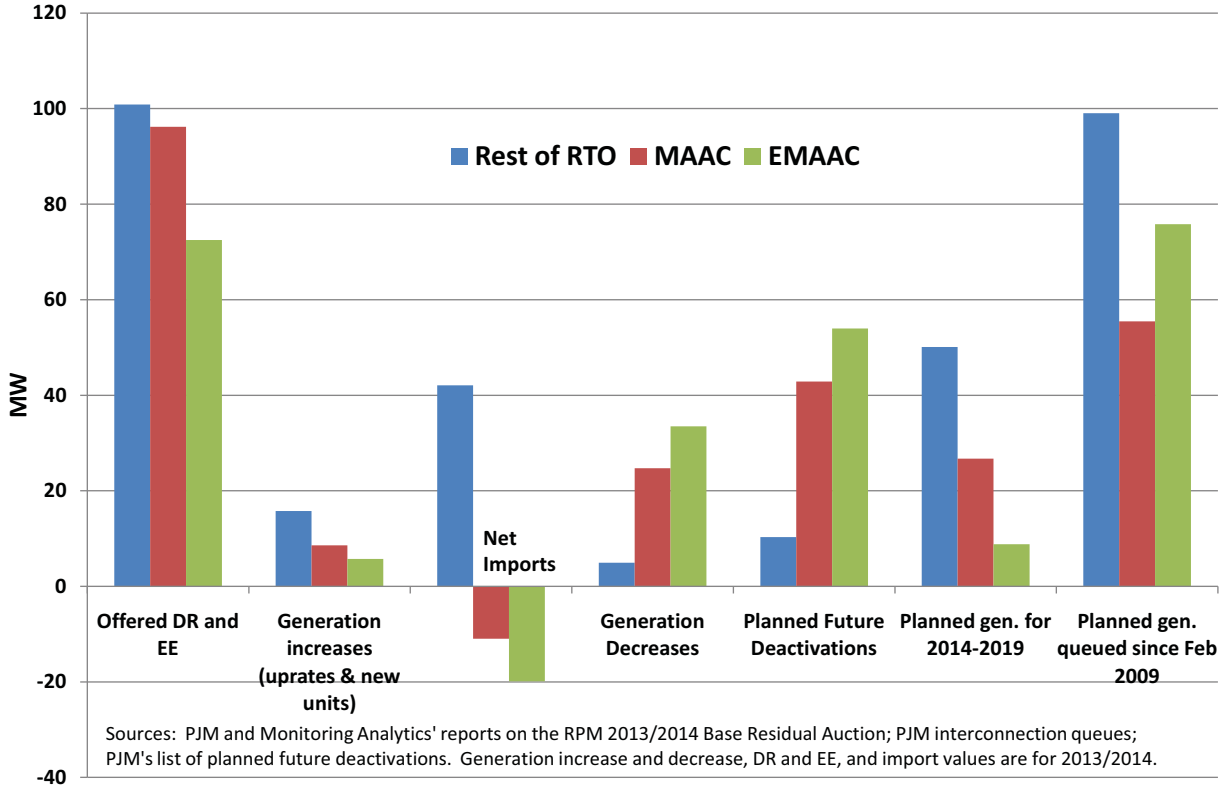


Figure 11: CETL and LOLE for Mid Atlantic Zone, 2014
Based on assumptions from PJM's April 2009 Study (CETO=8190)



Source: PJM's Response to data request VAStaff-I-6 in Virginia State Corporation Commission Case No. PUE-2009-00043.

Figure 12: Incremental and Decremental Capacity by RPM Zone
(2013/2014 BRA, in MW per 1,000 MW of Zonal Peak Load)



Sources: PJM and Monitoring Analytics' reports on the RPM 2013/2014 Base Residual Auction; PJM interconnection queues; PJM's list of planned future deactivations. Generation increase and decrease, DR and EE, and import values are for 2013/2014.