BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.	))))	Case No. 10-2929-EL-UNC

DIRECT TESTIMONY OF

ROBERT B. STODDARD

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

April 4, 2012

TABLE OF CONTENTS

I. INTRODUCTION, PURPOSE AND SUMMARY OF CONCLUSIONS

Q. WHAT IS YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Robert B. Stoddard. I am a vice president of Charles River Associates ("CRA"), where I lead the firm's Energy & Environment practice. My business address is 200 Clarendon Street, T-33, Boston, Massachusetts 02116-5092.

Q. WHAT ARE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS?

A. I have over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. My recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and the PJM Interconnection ("PJM"). I have submitted testimony to the Federal Energy Regulatory Commission ("FERC") as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and have testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts.

I was the lead economist for capacity suppliers in developing the capacity markets both in PJM and New England. I represented Mirant (now d/b/a GenOn) and other generation owners throughout the settlement discussions of the PJM Reliability Pricing Model ("RPM")— including the Fixed Resource Requirement ("FRR") Alternative—and developed many of the particular features of the market design. Following the settlement discussions, I was a member of a small team chosen by the settlement judge to draft revisions to the Tariff and RAA language consistent with the discussions. Furthermore, PJM filed affidavits from me and two other economists to provide the record on which FERC could accept the RPM settlement. Subsequent to the adoption of RPM, I participated actively in PJM's Capacity Market Evolution Committee and served as a capacity market advisor to several utilities, generation owners, and financial market participants. I have also testified on capacity market issues in the New York, Midwest, and California markets. In related areas, I served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction. I hold degrees in economics from Amherst College and Yale University. A summary of my experience is attached as Exhibit RBS-1 to this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FirstEnergy Solutions" or "FES").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address areas related to the establishment of a capacity price for CRES providers and the associated issues related to AEP Ohio's entry in the RPM market, and to rebut portions of the testimony of AEP Ohio witnesses Frank Graves, Dana Horton, Richard Munczinski, and Kelly Pearce.

Q. PLEASE BRIEFLY SUMMARIZE YOUR OVERALL CONCLUSIONS.

A. The appropriate capacity price is the RPM RTO auction price. In the short run, the RPM auction price is the "right price" in terms of economic efficiency appropriately compensating AEP Ohio and is the closest approximation to the market value of the reliability value of capacity. In the long run, RPM is designed to provide the appropriate incentives for the entry of new, cost-efficient resources and the exit of inefficient resources over a suitably long investment horizon. Because the RPM RTO auction price is efficient in both the long- and short-term, it follows that incorporating any capacity price in the state compensation mechanism other than the RPM RTO price leads to uneconomic impacts and distorts the competitive landscape. Prior to 2012, CRES providers were charged the RPM RTO rate; after May 2015, CRES providers will once again be charged the RPM RTO rate. During the transition period, economic efficiency and equity compel the use of the RPM RTO rate, as well.

Moreover, the RPM rate is the standard that the Public Utilities Commission of Ohio (the "Commission") should adopt in this case because::

- The RPM rate is fully compensatory to AEP Ohio;
- The RPM rate is the best measure of the true market value of capacity;
- The RPM rate neither subsidizes nor discriminates against CRES providers and shopping customers;
- The RPM rate holds CRES providers and shopping customers harmless from AEP Ohio's election as an FRR Entity;

- Granting a rate increase charged to CRES providers, who are now locked in to using AEP Ohio resources, would be inequitable and would allow AEP Ohio to exploit is position as the monopoly supplier;
- Allowing AEP Ohio to charge a capacity rate other than the market price would distort economic efficiency of actions by CRES providers and Ohio consumers and would adversely affect competition in retail energy.

AEP Ohio seeks to charge CRES providers a capacity rate that is far in excess of the market price for capacity that CRES providers would have paid, but for AEP Ohio's election of the FRR Alternative. AEP Ohio seeks to charge CRES providers a rate for capacity that is based on an estimate of the full embedded costs of the capacity resources, that is, a rate that includes not only the operating costs of those resources but also substantial allowances for AEP Ohio's sunk costs, such as debt charges and depreciation. AEP Ohio also fails to reduce this "embedded cost" rate by profits it will earn by selling the resources' output in the market.

AEP Ohio's proposed rate is contrary to how a capacity price should be set in a competitive wholesale market. In setting the *market* value of capacity, only costs that AEP Ohio could avoid by mothballing or retiring a resource should be considered. Moreover, any earnings expected from the capacity resources from the sale of energy and other services should reduce the capacity price. This is the approach specified in the PJM Tariff and the standard that AEP Ohio will need to abide by as of June 2015. When I compute this avoided cost rate for the AEP Ohio capacity resources, net of expected earnings from the energy and ancillary services markets, I find that the net cost AEP

Ohio's fleet is well below the market price of capacity set in PJM's RPM construct in each Delivery Year of the January 2012–May 2015 transition period.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Section II provides background information about the economic foundation, organization and operation of PJM's capacity markets and the FRR Alternative, showing why the relevant cost metric for capacity in a competitive market is net avoidable costs, rather than embedded costs.

Section III discusses why the RPM rate is the only appropriate rate at which to price capacity to CRES providers and is the closest approximation to the market value of capacity.

Section IV presents my calculations of the net avoidable cost rate for AEP Ohio's capacity resources and compares those rates to the market prices of capacity and to AEP Ohio's proposed capacity rate, concluding that AEP Ohio's net capacity cost is lower than the RPM RTO rate and that allowing a rate above the RPM RTO rate would result in significant over-compensation to AEP Ohio

Section V rebuts claims by AEP Ohio witnesses that the use of the RPM rate would create a subsidy for CRES providers, To the contrary, in this section I conclude that charging a rate other than the RPM RTO rate results in distortions because, inter alia, that rate is the efficient market price and charging any other price distorts competition and economic incentives.

Finally, Section VI discusses why the RPM rate is the only appropriate rate at which to price capacity to CRES providers, noting that the RPM design has cost-effectively met system and local requirements for eight years and, contrary to AEP witness Horton, would not undercompensate AEP Ohio for its risks and costs of providing capacity to CRES providers.

II. BACKGROUND OF CAPACITY ISSUES RELATED TO CRES PROVIDERS AND RETAIL ACCESS

A. BACKGROUND INFORMATION REGARDING CAPACITY PRICING

Q. WHAT ENTITY IS RESPONSIBLE FOR THE BULK POWER SYSTEM IN OHIO?

A. PJM, in its role as the Regional Transmission Organization, is responsible for operation of the bulk power system of a large area of the eastern U.S., from New Jersey southward to northeast North Carolina, and westward to Ohio and the Chicago area. With the recent additions of the FirstEnergy Ohio utilities and Duke Energy Ohio, all of Ohio is within the PJM footprint. PJM also operates financial markets for the purchase and sale of energy, capacity, ancillary services, and transmission rights.

Q. WHERE ARE THE RULES THAT GOVERN HOW PJM OPERATES THE BULK POWER SYSTEM, AND HOW PJM MARKETS FUNCTION, SET FORTH?

A. PJM's rules are set forth primarily in two documents: its Tariff and the Reliability Assurance Agreement ("RAA"). FERC regulates PJM and approves its Tariff and the RAA.

Q. WHAT ENTITY SETS THE TARGET FOR THE AMOUNT OF CAPACITY RESOURCES NEEDED TO SERVE THE RELIABILITY NEEDS OF OHIO CUSTOMERS?

A. PJM does, in its role as the Regional Transmission Organization for the state's utilities.

Q. HOW DOES PJM ENSURE THAT SUFFICIENT CAPACITY RESOURCES WILL BE AVAILABLE?

A. PJM implemented the Reliability Pricing Model ("RPM"), which is designed to provide appropriate economic signals to capacity suppliers to make available sufficient resources to meet the forecast reliability requirements. The rules that govern RPM are set forth principally in Attachment DD to the PJM Tariff and in Section 8 of the PJM RAA.

Q. PLEASE DESCRIBE GENERALLY HOW RPM OPERATES.

A. The goal of RPM is to ensure that there are sufficient qualified resources available under its dispatch control during each Delivery Year, defined as a twelve-month period running from June 1 to May 31 of the subsequent year. Approximately three-and-a-half years prior to the start of a Delivery Year, PJM qualifies existing and planned resources as potential capacity suppliers, and (when appropriate) PJM's Market Monitor determines what caps or floors should apply to each resource's offer prices. PJM also determines what quantity of capacity resources will be needed regionally and in import-constrained locations. PJM then uses an auction process to select the least-cost set of capacity resources, which also determines the capacity prices that will be paid to capacity resources. During the course of the Delivery Year, PJM pays capacity suppliers by collecting a capacity rate from each Load-Serving Entity ("LSE").

Q. HOW ARE CAPACITY RATES USUALLY SET IN PJM UNDER THE RPM?

A. Capacity rates in PJM[1] normally are set via the auction process that constitutes PJM's capacity market.[2] For each Delivery Year, PJM conducts a Base Residual Auction

[1] Throughout my testimony, I use the term "PJM" either to mean the Office of Interconnection of PJM Interconnection, L.L.C., or the geographic area for which PJM is the RTO.

("BRA") approximately three years prior to the start of the Delivery Year. The BRA auction process is designed to secure commitments for the necessary capacity requirements forecasted for the LSEs participating in the BRA. Eligible resources can be generation, demand response, energy efficiency or qualified transmission enhancements. LSEs can also offer their own eligible self-supply into the auction. Each year following the BRA, PJM conducts an Incremental Auction, which allows capacity suppliers to offer to shed, or bid to acquire, a capacity delivery obligation. In the Delivery Year, LSEs are assigned a cost responsibility for their share of the procured capacity in the BRA and the three Incremental Auctions conducted for that Delivery Year. LSEs may financially hedge their cost exposure in the auctions by obtaining or arranging for capacity under bilateral agreements.

Q. ARE ALL LOAD-SERVING ENTITIES REQUIRED TO PARTICIPATE IN THE RPM AUCTION PROCESS?

A. No. Qualifying LSEs may instead elect to meet their resource requirement through the Fixed Resource Requirement ("FRR") Alternative.

Q. HOW DOES THE FRR ALTERNATIVE WORK?

A. The FRR Alternative allows eligible LSEs (such as AEP Ohio) the option to submit a FRR Capacity Plan and meet a fixed capacity requirement as an alternative to participating in the RPM capacity auction. <u>See</u> PJM Reliability Assurance Agreement,

---

[2] In detail, LSE charges for capacity are made up of a weighted average of capacity clearing prices in the BRA, and three incremental auctions. These are clearing auctions, and each sets a corresponding capacity price for the locational delivery areas ("LDAs") within PJM. Load prices would further be modified by adjustments between forecast quantities and actual load allocation shares and peak load responsibility. Generators are paid the price they clear at in any specific auction in which they are sold. For the sake of simplicity and clarity, the RTO price discussed in this testimony reflects BRA prices and not the final charge to load for any specific delivery year.

Schedule 8.1, Sec. D ("FRR Capacity Plans"). Such an LSE is referred to as an FRR Entity. When an FRR Entity first elects the FRR Alternative, it must submit a conforming FRR Capacity Plan for a period of five Delivery Years. If the FRR Entity chooses to continue with the FRR Alternative beyond those five years, it must submit an amended FRR Capacity Plan covering subsequent Delivery Years two months prior to the BRA for that Planning Year.

Q. DID AEP CHOOSE TO BECOME AN FRR ENTITY?

A. Yes. AEP Ohio has voluntarily made the FRR election since the inception of RPM and has continued this election through the 2014/15 Delivery Year. By making the FRR election, AEP Ohio avoids paying auction rates for capacity but becomes responsible for supplying sufficient resources to meet load, with a reserve margin, for the load in its transmission zone.

Q. WHAT LOAD MUST BE COVERED BY AEP OHIO'S FRR CAPACITY PLAN?

A. Under the terms of the PJM RAA, AEP Ohio's FRR Capacity Plan must meet the resource needs of all load served through its distribution system.[3] This requirement has been in place since the establishment of the RPM. Consequently, when AEP Ohio elected to become an FRR Entity, it did so with full knowledge that it would have the responsibility of including all retail load in its distribution areas in its FRR Capacity Plan, regardless of whether that load was a retail customer of AEP Ohio or of a CRES provider.

[3] There is a limited exception if an LSE within AEP Ohio's distribution areas also qualified to be an FRR Entity and so elected, *e.g.* a transmission-dependent municipal utility or cooperative. This limited exception does not, however, extend to CRES providers.

Q. DOES A CRES PROVIDER HAVE THE OPTION TO ESTABLISH ITS OWN FRR CAPACITY PLAN, RATHER THAN RELYING ON THE FRR ENTITY'S PLAN?

A. Yes. The RAA allows any eligible LSE within an FRR designated area that has retail access to establish its own FRR Capacity Plan.[4] However, such an election can only occur after the existing FRR plan for the region (e.g. AEP Ohio's FRR plan) ends. This means that once AEP Ohio has submitted an FRR Capacity Plan, which must include all load within its zone, independent FRR plans cannot be implemented by CRES providers to meet the requirements of load they may obtain until the expiration of the existing FRR plan. Effectively, LSEs such as FES and other suppliers are "locked in" through the 2014/15 Delivery Year – the portion of the ESP term during which AEP Ohio's FRR is in place. Thus, the earliest period an LSE could elect to self supply is for the 2015/16 Planning Year, beginning June 1, 2015. This option will be moot, however, because AEP Ohio is participating in the RPM auctions for that period.

Q. HAVE YOU PREPARED A TIMELINE SHOWING THE DATES THAT ARE RELEVANT TO A CRES CONSIDERING A POTENTIAL FRR CAPACITY PLAN?

A. Yes, it is attached as Exhibit RBS-2.

Q. DOES THE FRR ALTERNATIVE SPECIFY HOW AN FRR ENTITY WILL BE COMPENSATED BY A CRES PROVIDER THAT DID NOT SUBMIT ITS OWN FRR PLAN?

A. Yes. The PJM RAA has provisions for FRR Entities to charge retail suppliers for capacity included in the FRR Capacity Plan. Specifically, under Schedule 8.1, Section D.8, the RAA provides:

---

[4] See RAA Schedule 8.D.9.

> "In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at [rest-of-pool or "RTO" clearing prices], provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's costs or such other basis shown to be just and reasonable."

Thus the RAA establishes a clear sequence to determine the capacity rate that the FRR Entity may charge a CRES provider, with the "state compensation mechanism," if one exists, taking precedence. Absent such a mechanism, the capacity rate is set at the RTO capacity clearing price in the RPM RTO. FERC has ruled that only when there is no state compensation mechanism does an FRR Entity have the option to make a filing with FERC to change to cost-based recovery.[5]

B. <u>PRICING UNDER THE BRA</u>

Q. PLEASE SUMMARIZE HOW THIS BRA PRICE IS SET.

A. The RTO price is set by the supply of capacity resources offering into the BRA and the demand for resources determined by PJM. PJM buys capacity as determined by the Variable Resource Requirement, specified in section 5 of Attachment DD of the PJM Tariff. The supply is determined by offers to sell capacity from owners of planned or existing capacity resources that qualified to participate in the BRA. Owners of existing capacity resources are subject to a must-offer obligation in the RPM markets. Because the independent market monitor ("IMM") has determined that the BRA capacity markets are structurally concentrated (meaning that small coalitions of suppliers theoretically have

[5] *See* American Electric Power Serv. Corp., 134 FERC ¶ 61,039 (2011).

sufficient market power to affect price), all supply offers from existing resources are subject to offer caps in the BRA.

Q. HOW ARE THE OFFER CAPS FOR SUPPLIER OFFERS SET?

A. Offers from existing resources must be based on the costs that a resource's owner could avoid by retiring or mothballing the resource. Specifically, suppliers' caps are established at the Avoidable Cost Rate (the "ACR"), as specified in section 6.8 of Attachment DD of the PJM Tariff. I discuss this further below.

Q. WHAT IS THE LOGIC UNDERLYING THE ESTABLISHMENT OF OFFER CAPS AT THE ACR VALUES?

A. The intent of offer caps in general is to replicate the bidding behavior that would be expected in a competitive environment. In the absence of market power, individual suppliers would be expected to offer capacity resources at their short-term "to go" costs, i.e., the costs that could be avoided by either retiring or "mothballing" an existing unit for a year. The ACR values used in the PJM auction process reflect an attempt to administratively set the determination of such "to go" costs, allowing only for typical out-of-pocket costs incurred by keeping a resource in service.

Q. HOW DO "TO GO" COSTS COMPARE TO "EMBEDDED" COSTS?

A. "To go" costs are a subset of embedded costs. The embedded cost of an asset starts with the "to go" costs, such as: avoidable operations and maintenance labor; avoidable administrative expenses, such as operator training and communications; avoidable maintenance expenses, such as rented equipment; avoidable variable expenses, such as station utilities; avoidable taxes, fees and insurance; avoidable carrying charges related to levels of fuel and spare parts; and avoidable corporate level expenses, such as legal service and environmental reporting.[6] Embedded costs include, on top of "to go" costs, all non-avoidable costs. These may include items such as depreciation, amortization, taxes, and interest; allocated corporate costs, such as risk management and legal; and allocations of facility-level staffing and other costs that would continue even if one unit at the facility were closed.

Q. WHY IS IT THAT COMPETITIVE OFFERS ONLY CONSIDER "TO GO" COSTS, RATHER THAN EMBEDDED COSTS?

A. This is a standard result in economics, usually summarized by the maxim, "sunk costs are sunk." As long as a business can sell a product for more than it costs to make it—the "to go" cost—then it is earning some margin to cover fixed costs of operations, such as debt service and property taxes, and possibly enough margin to generate a return on equity. If instead the business prices its product with these fixed costs priced in, it will likely miss sales opportunities that would have added to the bottom line.

An example may help illustrate the point. Suppose an existing power plant has "to go" costs of $50 million per year. This cost covers items such as staffing, station power, and others that could be eliminated by closing the plant. The plant also has $40 million of additional costs associated with it, such as debt service and property taxes. These costs, however, cannot be reduced by closing the plant—for example, debt repayment doesn't end just because you close the asset for which you borrowed funds. Other costs, such as fuel, are covered by the energy payments the plant earns when it operates. Suppose finally that the capacity price set by PJM would provide the owner $60 million in capacity revenues. Would our hypothetical plant owner want to accept

[6] PJM multiplies the sum of these items by 1.1 to provide a margin of error for understatement of costs.

that money and pledge to be operating for another year, or rather to mothball the plant? The answer is easy: $60 million more than covers the $50 million of the plant's "to go" costs, and further it provides $10 million of contribution margin to help cover sunk costs, leaving the owner with only $30 million of additional monies it will need to earn from energy sales to break even. If, on the other hand, the owner declined the capacity payment, it would lose the full $40 million. The plant owner would, therefore, rationally accept the capacity payment of $60 million, even though this payment is below the full $90 million of costs associated with the plant's total embedded costs.

Q. IS THERE ANY EXCEPTION TO THE GENERAL RULE THAT RPM OFFER CAPS DO NOT ALLOW THE RECOVERY OF FINANCING COSTS OR OTHER FIXED CHARGES?

A. There is one such exception. The PJM Tariff allows (but does not require) capacity offers to include amortized capital costs for major incremental investment that would be expected with maintaining large, capital intensive projects, such as repowering or installation of major environmental controls. The Market Monitor computes the Avoidable Project Investment Recovery ("APIR") Rate for such incremental investments in existing generation using the formulas set forth in the Tariff.

Q. WHO DETERMINES THE OFFER CAP FOR ANY PARTICULAR CAPACITY RESOURCE?

A. The IMM, i.e., Monitoring Analytics, sets a Maximum ACR for each existing capacity resource based on IMM's estimated benchmark costs, which it establishes for major technology types. These maximums are laid out in Attachment DD of the PJM Tariff (pp. 2346-2447). From this Maximum ACR, the IMM subtracts its estimate of the net earnings from the sale of energy and ancillary services, valued at PJM spot market prices, over the prior three calendar years (the "E&AS Offset"). The capacity supplier may contest this bid cap by presenting data to the IMM showing its actual "to go" costs. In my experience working with other PJM utilities, however, the requirement for detailed, unit-specific information is challenging to meet and the default ACR calculation is fairly generous. Consequently, nearly all resource owners price their offers at (or below) the IMM-allowed benchmark offer cap.

C. <u>RPM DOES NOT GUARANTEE RECOVERY OF EMBEDDED COSTS</u>

Q. MR. GRAVES STATES THAT "THE CURRENT RPM PRICE IS MUCH LOWER THAN AEP OHIO'S EMBEDDED COSTS, SO IT WOULD NOT BE COMPENSATORY FOR AEP OHIO."[7] DO YOU CONCUR?

A. No. To be sure, Mr. Graves is correct that the current RPM price is much lower than AEP Ohio's calculation of its embedded costs: for the 41-month period from January 2012 through May 2015, RPM charges to load average $78.55/MW-day, compared to AEP Ohio's $338.14/MW-day (after accounting for a portion of energy earnings).[8] I disagree with Mr. Graves, however, that this difference means that the RPM price is not the correct compensation for AEP Ohio's capacity used by CRES providers in its service area. Mr. Graves works from the false premise that the appropriate capacity charge has any connection with embedded costs in a competitive wholesale market.

---

[7] Direct Testimony of AEP Ohio witness Frank C. Graves, filed March 23, 2012, Case No. 10-2929 ("Graves Direct"), p. 4.

[8] Graves Direct, pp. 5-6.

Q. DOES THE PJM TARIFF OR RAA PROVIDE FOR A CAPACITY SUPPLIER, SUCH AS AEP OHIO, TO RECOVER ITS FULL EMBEDDED COSTS OF CAPACITY?

A. No. “Embedded cost” is a concept nowhere to be found in the RPM Tariff or the RAA. In the BRA, existing resources may not include costs in their offers such as return on and of capital, interest, property taxes, or depreciation. Only the costs explicitly enumerated in the ACR definition may be included.[9] Under the FRR Alternative, nothing in the RAA provides for AEP Ohio or any other FRR Entity to recover its full embedded costs.

Q. MR. HORTON TESTIFIED THAT “THE FRR MECHANISM ALLOWED [AEP] TO CONTINUE TO RECOVER ITS EMBEDDED GENERATION COSTS ASSOCIATED WITH THE CUSTOMERS IT SERVES THROUGH EXISTING COMMISSION APPROVED RATE STRUCTURES.”[10] DO YOU AGREE WITH HIS CHARACTERIZATION?

A. No. Like Mr. Horton, I participated actively in these stakeholder discussions, the substance of which is protected under settlement privilege. There is no provision in the FRR Alternative that provides for recovery of embedded costs of the FRR Entity, either from non-shopping retail customers or from customers of competitive retail suppliers.

Mr. Horton also mischaracterizes the RPM Settlement Agreement later in his testimony. He falsely asserts that “the stakeholders [in the RPM settlement] agreed upon another method under which the level of capacity compensation would be based on the FRR’s embedded capacity cost.”[11] However, the RPM Settlement Agreement itself never mentions recovery of embedded costs, while making clear that the entire agreement

---

[9] As noted earlier, there is a provision to raise offer caps to reflect financing costs of certain major capital upgrades.

[10] Direct Testimony of AEP Ohio witness Dana E. Horton, filed March 23, 2012, Case No. 10-2929 (“Horton Direct”), p. 5.

[11] Horton Direct, p. 10.

between the parties was included within the four corners of the RPM Settlement Agreement. The RPM Settlement Agreement states, the "Settlement Agreement, including any attachments, constitutes the entire agreement between and among the Parties …."[12] Nowhere in the Settlement Agreement or its attachments does the term "embedded cost" appear, and the absence of this term is consistent with my recollection of the agreement among the parties. The RAA filed with the Settlement Agreement contains the same provision that I quoted above, which allows FRR Entities to seek a cost-based rate, in the absence of a state compensation mechanism.[13]

Q. IN DEVELOPING THE RAA, DID THE PARTIES ENVISION RECOVERY OF EMBEDDED COSTS IN THE STATE COMPENSATION MECHANISM?

A. No. Allowing an FRR Entity to recoup its embedded costs from other LSEs in its zone would deviate from the theory and practice underlying the entire RPM design. It was understood that any state compensation mechanism would be part of a larger regulatory framework in a state to implement competitive retail access. The state compensation mechanism should, therefore, operate so as not to discriminate against competitive retail suppliers or to discourage competition. But if competitive retail suppliers had to pay embedded costs for capacity to the FRR Entity, while also having to pay market prices for *energy*, these suppliers would have been at a sharp and discriminatory cost disadvantage to the utility. Consequently, the default rate for capacity set in the RAA is such a price: the RPM RTO price.

[12] Settlement Agreement and Offer of Settlement, Section V, filed in FERC Docket ER05-1410-000 and -001, September 26, 2006.

[13] *Id*, Attachment 1, Original Sheet 44.

Q. DOES CHARGING EMBEDDED COSTS FOR CAPACITY CREATE A DISCRIMINATORY COST DISADVANTAGE FOR CRES PROVIDERS?

A. Yes. Under traditional cost-of-service ratemaking, a utility's retail rates would include recovery of the full embedded costs of its generation. This rate, however, entitled customers to take energy from those facilities at cost. What AEP Ohio proposes is to charge shopping customers this same embedded cost, but AEP Ohio then remains free to sell the energy associated with those facilities and sell it at market rates. This means the value of capacity committed under the FRR Capacity Plan is *unlinked* from the value of the energy. The cost of buying power at market is necessarily higher than the cost of taking power at the variable generation cost.[14] Therefore, faced with the choice of paying AEP Ohio a retail rate equal to the sum of the embedded capacity cost rate plus *at-cost* generation, or paying a CRES provider the same AEP Ohio embedded capacity cost rate plus *market* generation, a customer's preference would be to be a retail customer of AEP Ohio. In short, retail competition in AEP Ohio's service territory would collapse. What's more, as Dr. Lesser notes, it is clear that AEP Ohio is charging its non-shopping customers a rate *lower* than the embedded cost rate it seeks here, further exacerbating the degree of discrimination.

Q. ARE YOU AWARE THAT AEP OHIO HAS CALCULATED THAT THE VALUE OF THE ENERGY CREDIT IS ONLY ABOUT $8/MW-DAY?

A. Yes, that is the testimony of AEP Ohio witness Kelly Pearce.[15]

[14] PJM's wholesale energy markets price power as it does capacity, with the price set by the highest offer(s) needed in any dispatch interval.

[15] Direct Testimony of AEP Ohio witness Kelly D. Pearce, filed March 23, 2012, Case No. 10-2929 ("Pearce Direct"), p. 20.

Q. DOESN'T THAT INDICATE THAT THE SUPPOSED VALUE OF BUYING POWER AT COST IS RELATIVELY SMALL?

A. No, because the calculation, as performed, fails to address that question correctly. AEP Ohio's calculation of $8/MW-day reflects only a small portion of the economic value of the output of AEP Ohio's fleet, after reserving half of the profits for AEP shareholders. That calculation is irrelevant. The relevant point is the earnings from selling energy generated by *one additional MW* of AEP Ohio's fleet at PJM spot market prices. As I demonstrate later, I believe that that value is closer to $346/MW-day when measured using the expected profits metric used by PJM's Market Monitor.

Q. ARE YOU AWARE OF ANY UTILITY IN A COMPETITIVE RETAIL CHOICE STATE WITHIN PJM THAT IS ABLE TO COLLECT EMBEDDED COSTS FROM SHOPPING CUSTOMERS?

A. No. To the best of my knowledge, were the Commission to allow AEP Ohio to charge CRES providers any rate other than the RPM clearing price, AEP Ohio would be the only capacity supplier in PJM that could charge shopping customers its embedded costs for generation.

Q. IS AEP OHIO THE ONLY FRR ENTITY IN OHIO?

A. No, Duke Energy Ohio also opted to enter PJM using the FRR Alternative.

Q. WHAT CAPACITY RATE DOES DUKE ENERGY OHIO CHARGE CRES PROVIDERS?

A. Duke Energy Ohio proposed, and the Commission agreed, to a capacity rate equal to the RPM clearing price for the applicable planning year.

Q. WHAT CAPACITY RATE DO THE FIRSTENERGY OHIO UTILITIES CHARGE CRES PROVIDERS?

A. FirstEnergy's Ohio utilities transitioned from the Midwest ISO to PJM after the BRA had been conducted for some of the future Delivery Years. For these "stub" years (planning years 2011/2012 and 2012/2013), PJM administered on behalf of the FirstEnergy Ohio utilities, transition integration auctions to secure the additional capacity required, and these utilities charge CRES providers that auction price. The results of these auctions were similar to the BRA results, $108.89 for planning year 11/12, and $20.46 for 12/13, compared to the RPM BRA prices of $110.04 for 11/12 and $16.46 in 12/13.

Q. WHAT CAPACITY RATE DOES DAYTON POWER & LIGHT CHARGE CRES PROVIDERS?

A. To date, Dayton Power & Light has participated in the RPM auction process since the inception of RPM. Consequently, it does not charge CRES providers any capacity rate—instead, PJM charges CRES providers the PJM zonal rate determined primarily by the BRA auction clearing price.

Q. WHAT CAPACITY CHARGE HAS HISTORICALLY BEEN USED BY AEP OHIO?

A. Prior to this year, CRES providers have compensated AEP Ohio for capacity at RPM market-based prices.[16] From June 1, 2011 through December 31, 2011, AEP Ohio

[16] Direct Testimony of AEP Ohio witness Richard E. Munczinski, filed September 13, 2011, Case No. 10-2929 ("Munczinski Direct"), p. 7:7.

charged CRES providers $145.79/MW-day, which is the PJM RPM RTO clearing price for the 2011/2012 delivery year adjusted for scaling factors. [17]

III. THE ONLY APPROPRIATE CAPACITY TRANSFER PRICE IS THE RPM PRICE.

Q. WHAT DO YOU FEEL IS THE MOST APPROPRIATE CAPACITY PRICE AS THE STATE COMPENSATION MECHANISM?

A. The appropriate capacity price is the RPM RTO auction price, regardless of whether this is viewed in the long or short run. In the short run, the RPM auction price is the "right price" in terms of economic efficiency. It is the closest approximation to the market value of the reliability value of capacity. We maximize efficiency by pricing or transferring commodities at their market price, so that there is a rational trade-off between the value captured by utilizing a good versus selling it in the market. In the long run, the RPM is designed to provide the appropriate incentives for the entry of new, cost-efficient resources and the exit of inefficient resources over a suitably long investment horizon; the success of this market design has been well documented, particularly in two reports by Mr. Graves' consultancy, The Brattle Group.

Because the RPM RTO auction price is efficient in both the long- and short-term, it follows that setting any other price is less efficient and results in economic distortions. Setting a capacity rate that is higher than market price would have created an incentive to divert capacity into AEP Ohio's FRR region in order to obtain the higher capacity

[17] Pearce Direct, p. 22. The PJM RTO clearing price is subsequently adjusted and is then multiplied by a scaling factor and pool requirement and loss factor to determine the total price paid by CRES providers. *See id*. at 23:5-10.

payments (although the deadline has passed for CRES providers to do so).[18] Because of the specific RPM market rules regarding FRR plans, pricing at something other than the market rate would create significant distortions by effectively encouraging and justifying behavior that would otherwise be equivalent to economic withholding. In that situation, the wrong price incentives would likely raise prices for all consumers in the rest of PJM, while also potentially forcing AEP Ohio into purchasing above-market supplies from CRES providers who shifted more supply into the FRR plan than the final retail loads that they were able to attract.

Similarly, there are inefficient results if the transfer price for capacity is set too low. Efficient supplies will flee the market to be used in potentially lower valued applications, and CRES providers would be encouraged to "lean" on AEP Ohio for capacity, rather than appropriately be indifferent between a market-based price transfer and providing their own supplies. Again, because the deadline has passed for any CRES to develop its own FRR Capacity Plan during the transition period, this concern is moot.

Q. WOULD THE LOWER CAPACITY RATE HARM AEP OHIO NON-SHOPPING CUSTOMERS AND SHAREHOLDERS?

A. Charging the proper price to one customer does not result in harm to another customer. It may, however, eliminate a cross-subsidy or source of over-earning.

---

[18] Although this issue is mooted now that the date for CRES providers to self-supply during any part of the transition period has passed, AEP Ohio admitted that if cost-based capacity rates are used, CRES providers could elect to supply their own capacity into AEP Ohio's FRR plan so long as the election was made three years prior to the delivery year. Direct Testimony of Kelly Pearce 23:14-16, Case No. 10-2929, filed August 31, 2011. If this had occurred, and if the CRES provider overestimated the load it will serve, AEP Ohio would become short of capacity and be forced to compensate the CRES provider for the CRES provider's capacity at the higher cost-based rate. See id. at 25:7-11, 26-27 (discussing this issue and making several recommendations to mitigate the market-distorting impact of using a cost-based capacity rate). As recognized by AEP Ohio, use of a cost-based capacity rate would distort the market and create improper incentives for CRES providers. Of course, these market distorting effects are eliminated by simply using the RPM price as the state compensation mechanism for capacity.

Compared to the "but for" world that AEP Ohio has constructed, in which CRES providers "should" pay on the order of $355.72/MW-day during the transition period, the lower rate of $78.55/MW-day does indeed result in less money paid to AEP Ohio. It is necessary to keep firmly in mind, however, that what CRES providers would pay if the 2011 state compensation mechanism had stayed in place, or if the default RAA were charged, is this $78.55/MW-day rate; it is not appropriate, therefore, to talk about a "loss" of revenues associated with a rate that AEP Ohio has never been authorized to charge.

Assuming that the Commission did not allow rates for non-shopping customers to offset revenues that AEP Ohio is not authorized to collect from CRES providers, AEP Ohio shareholders would face lower earnings—or, put differently, AEP Ohio shareholders would not enjoy the windfall in earnings that would occur if the Commission were to authorize a rate above the RPM RTO price. However, the role of sound markets is not to protect competitors, but competition. Such a reduction in shareholder earnings is not, as AEP witness Munczinski asserts, a subsidy of CRES providers;[19] rather, it would prevent the unjust enrichment of AEP shareholders at the expense of CRES providers and their Ohio customers.

Allowing AEP Ohio to charge the RPM RTO rate puts it in exactly the same position as every other generation supplier in PJM: earning the RPM price, with whatever margins are implied by that rate. Independent power producers certainly have no means to require purchasers to buy capacity at embedded costs, and I am unaware of any other utility in PJM that has the ability to require shopping customers to pay its embedded costs.

[19] Munczinski Direct, 10:22–23.

Q. WOULD USING THE RPM RTO PRICE ALSO AVOID INEFFICIENT BEHAVIOR BY CRES PROVIDERS?

A. Yes. While AEP Ohio's joining RPM for the Delivery Year 2015/2016 settles the risk of inefficient long-run pricing by moving AEP Ohio's shopping customers to market-based pricing, in the short-run, a move to cost-based recovery still provides for above-market payments to AEP Ohio from CRES providers. During the transition period, imposing above-market capacity prices on CRES providers will result in shopping customers paying an uneconomic dividend to AEP Ohio shareholders. This discourages the development of retail choice, and also confers a competitive advantage during the transition period on AEP Ohio, allowing it to hold retail customers who otherwise would have chosen to shop.

Q. WHAT CONCLUSION DO YOU DRAW FROM THESE ADVERSE IMPACTS?

A. Incorporating any capacity price in the state compensation mechanism other than the RPM RTO price leads to uneconomic impacts and distorts the competitive landscape. Prior to 2011, CRES providers were charged the RPM RTO rate; after May 2015, CRES providers will once again be charged the RPM RTO rate. During the transition period, economic efficiency and equity urge the use of the RPM RTO rate, as well.

IV. RPM PRICES ARE COMPENSATORY TO AEP OHIO

A. <u>AEP OHIO'S PROPOSED RATES DIVERGE UNREASONABLY FROM MARKET PRICES</u>

Q. WHAT RATE DOES AEP OHIO SEEK TO CHARGE CRES PROVIDERS FOR CAPACITY?

A. AEP Ohio seeks in this proceeding to charge CRES providers a rate of on the order of $355.72/MW-day for capacity.

Q. WHAT ARE THE RTO CLEARING PRICES FOR THE TERM OF THE TRANSITION PERIOD (JANUARY 1, 2012 – MAY 31, 2015)?

A. AEP Ohio did not pursue an FRR election for the 2015/16 Planning Year and, consequently, will be participating in the RPM auction process for that Planning Year and at least four subsequent years.[20] PJM's BRA auctions for the ESP period have cleared at $110.04/MW-day (for Planning Year 2011/12), $16.46/MW-day (for 2012/13), $27.73/MW-day (for 2013/14), and $125.99/MW-day (for 2014/15). Over the 41 months of the transition period, the weighted average capacity price in the BRAs is $63.23/MW-day. These results are indicative of the current large surplus of capacity in the RTO region, lower demand, and increased participation by demand response. Together they represent the best estimate currently available for the market value of such capacity for the transition period.

These figures are not directly comparable to the AEP Ohio rate cited above. The BRA prices set the rate paid to capacity suppliers for each MW of unforced capacity. The prices proposed by AEP are the rates that would be charged to CRES providers based on the measured contribution to coincident peak loads. The BRA prices need to be grossed up to yield an "apples to apples" comparison. Dr. Lesser has calculated that the billed RPM capacity rates for the four planning years of the transition period will be $145.78/MW-day, $19.89/MW-day, $33.87/MW-day, and $153.99/MW-day.[21] Over the transition period, the weighted average load price is $78.55/MW-day.

[20] Munczinski Direct, p. 7:12.

[21] Direct Testimony of Jonathan A. Lesser, Table 1.

Q. MR. GRAVES OFFERS SOME EXPLANATIONS AS TO WHY THERE IS SUCH A LARGE GAP BETWEEN THESE RPM PRICES AND AEP OHIO'S EMBEDDED COST.[22] DO YOU AGREE WITH HIS ANALYSIS?

A. No. Mr. Graves attributes the gap to a difference in technologies, pointing to the use of gas-fired units as the benchmark for RPM pricing and contrasting that to the broader range of resources in the AEP Ohio portfolio, primarily comprised of coal units. That difference is largely irrelevant, though understanding why is not intuitively obvious.

Gas turbines have lower capital costs, but they also have lower expected earnings from energy sales. Coal plants, by contrast, have higher capital costs but they have higher expected earnings from energy sales. In a balanced portfolio of resources, the *net* capacity payment (costs less expected energy margins) should be equal across all planned economic resources, regardless of whether they are base-load coal units or gas-fired turbines.

To see why, put yourself in the position of a generation developer considering whether to build a new gas turbine or a new coal plant. You would develop *pro forma* financials for both and select the technology with the higher expected profit (giving due weight to various risk factors). Suppose that the turbines offer better profits, and so you move forward with their development. In building the next project the *pro formas* change, reflecting the fact that the fleet is now heavier on gas-fired peakers and relatively shorter on base-load coal. Consequently, the expected earnings to new peakers will be lower, while the expected earnings from new coal will be higher because of the greater competition among peakers created by the prior entry. This process drives the expected profitability from any current generation technology to be equal. In a system as large as

[22] Graves Direct, p. 6.

PJM's, this equilibration process can occur fairly rapidly, and so it is not surprising to see that many different technologies have been installed in PJM over the past decade.

So, contrary to Mr. Graves' assertion, it is not the capital intensity of the generation that matters. Units with high capital cost, like AEP Ohio's coal fleet, were built to achieve lower marginal production costs and, therefore, higher utilization and higher market sales with energy and ancillary services taken into account.

Q. SO IF MR. GRAVES IS WRONG IN HIS ANALYSIS, WHAT IS THE SOURCE OF THE GAP BETWEEN THE PROPOSED AEP RATE AND THE MARKET CAPACITY RATE?

The principle reason for the gap between RPM prices and AEP Ohio's embedded costs is that AEP Ohio includes recovery on and of capital, property taxes, and other non-avoidable costs in its calculation. As I discussed earlier, such costs are not allowed to be included in capacity offers in the RPM auctions from existing resources because, in competitive markets, offer prices only consider "to go" costs, not the full embedded costs. Furthermore, market capacity rates include an offset for the full amount of expected earnings from energy and ancillary services markets, but AEP Ohio has not included a full adjustment for such market-based earnings in its proposed rate.

Q. IF THE RPM RATE DOES NOT ALLOW SUPPLIERS TO INCLUDE FINANCING AND OTHER NON-AVOIDABLE COSTS IN THEIR OFFERS, HOW WILL SUPPLIERS EVER EARN A RETURN ON THEIR INVESTMENT?

A. Suppliers earn a return on their investment by earning a margin between their offer price—based on the "to go" costs—and the prevailing market price. In wholesale markets in the United States, all resources are paid the clearing price, rather than their offer price. The market price is set by the offer from the highest-cost resource selected, which means that lower-cost resources earn a margin above their marginal costs. This margin contributes to paying fixed costs. Resources may earn such contribution margins through the sale of capacity, energy, and ancillary services. For example, in the energy market a particular coal-fired resource might have a marginal operating cost of $30/MWh; when it generates power during an hour where a gas-fired peaker has set the clearing price at $65/MWh, the owner earns $35/MWh of margin. Similarly in the capacity market, if a resource that has "to go" costs net of the E&AS Offset of $10/MW-day, but less efficient resources set the capacity price at $100/MW-day, the resource owner earns $90/MW-day of margin above its "to go" costs.

B. AEP OHIO'S COSTS, PROPERLY DEFINED, ARE BELOW THE RPM RATE.

Q. ASSUMING HYPOTHETICALLY THAT AEP OHIO WERE ALLOWED TO SEEK A COST-BASED CAPACITY RATE, WHAT IS YOUR UNDERSTANDING OF THE "COSTS" THAT WOULD BE CONSIDERED?

A. As an economist who had direct responsibility for negotiating the RPM design, it is my professional opinion that AEP should only be allowed to recover costs that are consistent with how that term is used elsewhere in Section 8 of the RAA, and as used in the parallel Attachment DD of the PJM Tariff: the ACR net of the E&AS Offset. Any other definition of "cost" would provide FRR Entities a (presumably higher) rate that cannot be earned by entities participating in the RPM; consequently, such treatment would encourage some entities to opt out of the RPM auction structure to seek higher capacity rates. But the design intent of RPM was to provide a comprehensive framework for PJM. The FRR Alternative was always viewed as an exception, not the rule, offered for the narrow purpose of helping FRR Entities manage their own portfolios. The FRR Alternative was not intended to create the opportunity for substantial unjust enrichment by opting out of RPM auctions.

Q. WHAT METRIC DO YOU BELIEVE IS THE MOST APPROPRIATE MEASURE OF AEP OHIO'S "COST" IN THE CONTEXT OF SETTING A CAPACITY PRICE IN THE STATE COMPENSATION MECHANISM?

A. The cost metric should be based on the same calculations used to determine the maximum offer price from AEP Ohio's capacity resources, namely the "to go" costs of each resource, minus the expected value of the energy and ancillary services generated by each resource in excess of the variable cost to generate that energy or ancillary service. This metric, the maximum allowed offer price, is the best available measure of the net cost that a competitive wholesale generator would seek, at a minimum, to recover from capacity payments.

Q. HAVE YOU COMPUTED WHAT THE MAXIMUM OFFER PRICE WOULD BE FOR EACH RESOURCE INCLUDED IN THE AEP OHIO FRR CAPACITY PLAN?

A. Yes, to the extent possible using the data available to me, which does not include any AEP proprietary, unit-specific information for future environmental upgrades.

Q. DO YOU REGULARLY ESTIMATE OFFER PRICES FOR CAPACITY RESOURCES IN PJM?

A. Yes. My colleagues and I at CRA have many clients who look to us for advice about the RPM, including proprietary forecasts of future clearing prices in the RPM. In order to produce such results for our clients, we have developed models over the past five years that have allowed us to predict (in advance of the BRAs) the supply curves in each market. Based on the data published after the BRA by PJM and the Market Monitor, I have a high degree of confidence that CRA's models closely match actual bidding behavior and, consequently, do a good job predicting the Market Monitor's offer price mitigation. This is not surprising, because the Market Monitor has published extensively on how it computes offer price caps.

Q. WHAT RESOURCES DID YOU INCLUDE IN YOUR ANALYSIS?

A. I included the generation resources identified in PUCO Forms FE-R4 from the "Columbus Southern Power Company and Ohio Power Company Long-Term Forecast Report to the Public Utilities Commission of Ohio," dated April 15, 2011, and filed with the Commission in Ohio Power Case No. 11-2501-EL-FOR and CSP Case No. 11-2502-EL-FOR.

Q. WHAT ARE THE COMPONENTS OF THE MAXIMUM OFFER PRICE?

A. To replicate the process used by the IMM in determining the offer cap for each of these resources, I followed the methodology laid out in Schedule DD to PJM's Tariff and computed the maximum allowed offer price for AEP Ohio's units using the three components of the offer cap for these resources: (1) the maximum Avoidable Cost Rate, including where applicable (2) the Avoidable Project Investment Recovery Rate ("APIR"), minus (3) the E&AS Offset.

Q. LET'S WALK THROUGH YOUR COMPUTATION FOR EACH OF THESE THREE COMPONENTS. HOW DID YOU DETERMINE THE MAXIMUM ACR FOR EACH RESOURCE?

A. I determined the appropriate ACR for each resource by consulting the PJM tariff to determine the default ACR for each corresponding BRA year. For each auction year, two default ACRs are published: a mothball ACR and a retirement ACR. I have applied the retirement ACR for coal units and the mothball rate for natural gas units and hydro units.

Q. HOW DID YOU DETERMINE THE APIR FOR EACH RESOURCE?

A. I calculate APIR as the appropriately amortized capital investment needed by each plant in order to bring it into environmental compliance for the corresponding BRA year. More specifically, I analyzed the expected costs AEP Ohio coal plants will incur from retrofits for acid gas, particulate matter and mercury controls by the year 2015. To accomplish this I first examined the environmental controls currently in place at each AEP Ohio coal plant.[23] I then determined each of the retrofit technologies that these plants will need to install in order to remain in environmental compliance.[24] I calculated the capital costs for each of the environmental retrofit technologies using a proprietary CRA model. I then computed the APIR using the formula from the Tariff, whereby APIR is the product of the Capital Recovery Cost (CRF) specified in the tariff and the Project Investment for each unit. This approach is conservative because I assume that AEP had perfect foresight as to the retrofit requirements that recently promulgated regulations would imply for their fleet and, therefore, had the opportunity to incorporate those additional costs in their ACR calculation.

My analysis shows that all plants will require additional particulate matter and mercury controls, and approximately half of the units will require additional acid gas control retrofits. In this analysis I have used a 4-year amortization assumption for all units because, as these environmental retrofits are mandatory if the units are to comply with federal environmental regulations, they are required to use a 4-year amortization period under the definition of APIR in Attachment DD to the PJM Tariff, at §6.8(a). I then multiplied the CRF from the Tariff by the cost of the environmental retrofit to

[23] *See* Exhibit RBS-3.

[24] *Id*.

determine the APIR for each unit for the respective BRA year. I have not included any APIR adders for coal units that AEP announced it will retire, as these units will not require retrofits.[25] I further assume that AEP Ohio natural gas units do not need any additional environmental retrofits.

Q. HOW DID YOU DETERMINE THE EA&S OFFSET FOR EACH RESOURCE?

A. I calculate E&AS offsets for each resource by approximating as closely as possible the methodologies described in the 2011 PJM State of the Market Report for net energy and ancillary service revenues for new entrant coal plants, combined-cycle plants and combustion-turbine plants.[26] Following PJM's approach, I calculate these E&AS offsets as a per-MW/day rate, which minimizes issues potentially raised by AEP Ohio resources that are used to support more than one AEP affiliate's load. PJM describes three models—one for each plant technology type—that calculate net energy revenues on an annual basis for each plant type, making assumptions about unit parameters, fuel costs, variable O&M and emission costs, day-ahead and real-time LMP's, and unit availability. CRA independently constructed models that replicate the respective PJM models as closely as possible given the information presented by PJM. These net energy revenue calculations are performed individually for each unit using unit-specific prices and operating parameters from publicly available data.

---

[25] http://www.aep.com/investors/newsreleasesandemailalerts/allNewsReleases.aspx?id=1754 (last accessed April 4, 2012)

[26] Specifically Section 6 of Volume 2 of the 2011 PJM State of the Market Report, a portion of which is attached hereto as Exhibit RBS-4. As this document is 465 pages long, in the interests of space the remainder of this document is available at http://www.pjm.com/~/media/documents/reports/state-of-market/2011/2011-som-pjm-volume2.ashx.

To determine net ancillary service revenues, I used PJM's assumptions as reported in the State of the Market Report for reactive service revenues by plant type. I ignored any potential incremental revenues a unit might make from the sale of ancillary services—such revenues would be difficult to calculate accurately without information as to whether or not each specific unit participates in this market. Further, these revenues are typically small, are only relevant for coal units (according to PJM assumptions), and preclude simultaneous sales in the energy markets. By ignoring regulated or affiliate sales, the units are modeled as participating in PJM's energy markets at all times (except during outage periods), and I believe I have calculated E&AS offsets as accurately and conservatively as possible given the information published by PJM.

I calculated the E&AS offset separately for AEP's Racine hydro unit as there is no published methodology available from PJM for units of this type. I used publicly available data on the unit's annual generation, average production costs, and nodal LMP to calculate net energy revenues on an annual basis. I assume no ancillary service revenues for Racine.

Finally, in order to properly replicate PJM's approach, I have used a three-year historical moving average of annual net energy and ancillary service revenues to determine the appropriate E&AS offset figure to be used in each delivery year. For example, an average of E&AS revenues in 2008, 2009 and 2010 would be used for the BRA delivery year 2014/2015.

Q. WITH THESE THREE COMPONENTS, HOW DID YOU COMPUTE THE NET CAPACITY COST?

A. The net capacity cost for each resource is the sum of its ACR and its APIR, reduced by its E&AS Offset.

Q. HAVE YOU PREPARED AN EXHIBIT THAT SHOWS YOUR CALCULATIONS OF THE COST BASIS FOR AEP OHIO'S GENERATION FLEET, CONSISTENT WITH THE METHODS WE HAVE JUST DISCUSSED?

A. Yes, Exhibit RBS-5 presents the summary of my calculations of the net "to go" cost for AEP Ohio's fleet. The exhibit shows the results for the two cases discussed below: (1) portfolio-average avoidable cost rate, and (2) per-unit avoidable cost rate, following Graves and putting a floor on any unit's net cost at zero but also allowing for replacement of uneconomic resources at market rates. For each case I have calculated the unit-weighted and MW-weighted averages of avoidable cost rate, the Energy & Ancillary Services Offset, and the resulting net capacity cost, with and without APIR, in each BRA year. The MW-weighted average includes only units that are expected to be operational during the BRA year.

Finally, the MW-weighted operational fleet average net capacity cost from January 1st 2012 through May 31st, 2015 is shown, both with and without APIR. This is calculated by taking an average of the annual MW-weighted net capacity costs in the row above with a 50% weight for the 2011/2012 BRA year values relative to the other three BRA years.

Q. PLEASE DESCRIBE THE RESULTS SHOWN ON EXHIBIT RBS-5.

A. Using the first approach, AEP Ohio's generation fleet has an overall negative net capacity cost, which is to say that AEP Ohio is made whole with energy revenues even if the capacity rate charged to CRES providers is zero. Without the APIR rate, AEP Ohio's cost—as defined in the RPM construct—averages ($148.14)/MW-day over the 41-month transition period. Including the APIR rate, as discussed above, increases the cost basis of the AEP Ohio resources to ($51.05)/MW-day. Costs are the avoidable costs, measured pursuant to the PJM Tariff.

Turning to the second approach shown on Exhibit RBS-5, in which strong expected earnings of one AEP Ohio resource are not allowed to net the costs at another resource, but also uneconomic capacity in the AEP Ohio portfolio are replaced by market-priced purchases, I find that the cost before considering the APIR recovery is $2.97/MW-day. Including the APIR recovery at its maximum allowed rate, this rises to $28.11/MW-day. Because many AEP Ohio units would not have cleared in the BRA had they been offered at their maximum APIR rate, the capacity for these units is replaced by market purchases or AEP Ohio is held to a long amortization period for those environmental upgrades. For example, for Delivery Year 2011/12, the three Cardinal units, Conesville 4, the 4 J. M. Stuart units, and John E. Amos 3 could have offered at a price which is many multiples of the clearing price in the BRA of $110/MW-day.

Q. HOW IS IT POSSIBLE FOR THE NET CAPACITY COST TO BE NEGATIVE?

A. The net capacity cost will be negative when a resource has positive cash flows—i.e., its operating revenues exceed its operating costs. This is an entirely normal outcome and implies that the unit would earn a contribution margin even if it received no capacity payment at all.

Q. WHEN APPLIED TO THE RPM AUCTIONS, IS A RESOURCE OWNER REQUIRED TO OFFER A RESOURCE IN AT A NEGATIVE VALUE IF THE COMPUTED NET CAPACITY COST IS NEGATIVE?

A. No. A resource is allowed to offer in at zero even if its E&AS Offset exceeds the resources' ACR – that is, even if these resources do not need any capacity payment to remain in the market.

Q. DO ANY OF AEP OHIO'S UNITS FALL INTO THIS CATEGORY?

A. Yes, nearly all of AEP Ohio's capacity resources have a higher E&AS Offset than their ACR (before adding the APIR, if applicable).

Q. HOW HAVE YOU TREATED SUCH UNITS IN YOUR ANALYSIS?

A. In my analysis, I carried the negative net cost for these resources into the overall revenue requirement calculation because, under a cost-based rate approach, it is the combined earnings on the resource portfolio that is relevant, not the earnings of each individual resource. Under traditional cost-of-service rate-making, earnings from one resource in a utility's portfolio offset costs of another resource.

Q. SEVERAL AEP OHIO WITNESSES HAVE SUGGESTED THAT ANY COST ANALYSIS SHOULD PLACE SOME LIMIT ON THE EARNINGS FROM THE SALE OF ENERGY AND ANCILLARY SERVICES FROM A RESOURCE THAT WOULD BE ALLOWED TO REDUCE THE AEP OHIO CAPACITY CHARGE TO CRES PROVIDERS. DO YOU AGREE?

A. No, I do not. Any such limit is contrary to sound regulatory cost-of-service calculation. A critical issue arises if there is an asymmetric treatment of costs and profits, because it encourages the regulated entity to shift costs from profitable units to unprofitable units. Such cost shifting can be difficult to detect, especially when there are multiple units at a single facility and, consequently, there are many joint costs that must be allocated. It has been generally accepted regulatory practice, therefore, to consider the cost-of-service of portfolios of investment: regulators have not generally granted rates-of-return on individual assets, but rather on a utility's overall invested capital (which, implicitly, allows over-earnings on one asset to offset under-earnings elsewhere).

Q. WHY DO YOU CONSIDER AEP OHIO'S APPROACH TO BE FLAWED?

A. First, as I noted earlier, this approach is inconsistent with standard regulatory accounting, which applies over-earnings on one asset to offset under-earnings on other assets. If AEP Ohio wishes to obtain a non-market recovery for its capacity assets, then it must accept non-market regulatory accounting principles which fully reflect the revenues and costs associated with those units.

Second, if I look at the AEP Ohio portfolio on a unit-by-unit, year-by-year basis, many of AEP Ohio's units are uneconomic in certain years, i.e. the least-cost alternative would have been to replace the AEP Ohio unit with a market purchase of capacity. For example, many of the coal-fired units require environmental retrofits by 2015. Because environmental retrofit costs are allowed to be amortized over 4 years, certain units may be uneconomic in any given year.

In either case, it would be incorrect to assume, in this unit-by-unit world that Mr. Graves is proposing we operate, that we also now require that each resource in the AEP Ohio portfolio be economic. If, as Mr. Graves suggests, it is unreasonable to suppose that AEP Ohio should be required to accept a negative price for any particular unit—because no willing seller will offer an economic good at a price below zero—then it is also unreasonable to assume that CRES providers would be willing to pay an above-market price for any particular unit just because AEP Ohio was offering it in the FRR "bundle" of capacity included in the FRR plan. Either we consider the net cost of the entire "bundle" of capacity assets (as I believe we should) or expose each resource in the "bundle" to a willing-seller/willing-buyer test. If we go down the line of reasoning that says, "it would be unfair to *pay* CRES providers the full energy credits associated with particular capacity resources that they are paying for," then it is equally sensible not to *charge* CRES providers for AEP Ohio resources that are uneconomic compared to other resources available in the market.

Q. DOES AEP WITNESS PEARCE PROPOSE ANOTHER VERSION OF A CAP ON IMPUTED ENERGY EARNINGS?

A. Yes. Mr. Pearce goes even further, proposing an arbitrary cap on the energy earnings credit at "no more than 40% of the capacity rate without the credit."[27] This cap is unsupported by economic theory and is directly contrary to how PJM and FERC have determined proxies for competitive wholesale capacity prices.

Mr. Pearce attempts to rationalize this cap for AEP Ohio units by looking at the energy earnings that PJM attributes to the benchmark generator, i.e. the generator that PJM uses to establish the Gross CONE in the RPM. This approach is completely inapplicable to the AEP Ohio fleet.

There are two logical fallacies in Mr. Pearce's reasoning. First, Mr. Pearce is taking the ratio of the *energy earnings* that single-cycle gas turbines might earn in the PJM market to the *levelized cost* of a turbine. As I discussed earlier, the gap between the levelized cost and the energy earnings, on a $/MW-day basis, should be equal *for new resources*. But it does not follow therefore that the *ratio* of these earnings to cost should be equal across technologies. For example, a new gas-fired peaker might have a levelized cost of $250/MW-day and energy earnings of $50/MW-day, for a net capacity cost of $200/MW-day; note that energy earnings are 20% of cost. A new coal-fired unit, however, might have levelized capital costs of $800/MW-day and expected energy

---

[27] Pearce Direct, p. 24:12.

earnings of $600/MW-day, yielding the same net capacity cost, but with a much higher *ratio*: 75%, compared to 20% for the new peaker.

Which brings us to the second and more fundamental flaw: Mr. Pearce is applying information about *planned* resources to the *existing* resources of AEP Ohio's fleet. The relevant costs for an existing unit are not the same as the relevant costs for a planned resource: the planned resource must have a reasonable likelihood of earning a market rate of return on invested capital to move forward with its investment, while existing resources costs are appropriately limited to their "to go" costs, plus incremental investment when needed to remain in operation. There is no logical connection, however, between the ratios (or even the gaps) of energy earnings to costs between the planned resources used by PJM in its Gross CONE and Net CONE calculations, and the existing resources at issues in this proceeding.

Q. DO YOU HAVE A VIEW AS TO WHICH OF YOUR TWO APPROACHES SHOWN ON EXHIBIT RBS-5 IS MOST RELEVANT IN THIS MATTER?

A. Yes. I believe that the first approach, which applies over-earnings on one asset to offset under-earnings on other assets, is most consistent with a cost-of-service approach, which is the approach that AEP Ohio adopted in this case.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM EXHIBIT RBS-5?

A. In the first, portfolio cost-based approach, the fleet-average cost figure (including APIR) of ($51.05)/MW-day is well below the 41-month average BRA supplier price of $63.23/MW-day. Consequently, I conclude that the RPM rate is more than compensatory to cover the net going-forward costs of AEP Ohio's capacity resources over the course of the 41-month transition period. Furthermore, the RPM rate is more than compensatory to AEP Ohio in each Delivery Year.

Mr. Graves has recommended capping energy credits in each year, by unit, at the unit's cost. If I were to follow Mr. Graves approach, while at the same time recognizing that CRES providers should not be forced to pay for uneconomic capacity in this situation, I also conclude that the RPM rate is more than compensatory to cover the net going-forward costs of AEP Ohio's capacity resources over the course of the 41-month transition period. Furthermore, the RPM rate is more than compensatory to AEP Ohio in each Delivery Year.

Q. IF THE COMMISSION WERE TO ALLOW AEP OHIO TO CHARGE \$355.72/MW-DAY TO CRES LOAD, WOULD THIS RATE OVER-COMPENSATE AEP OHIO, BASED ON YOUR ANALYSIS?

A. Yes, dramatically. The portfolio discussed in Exhibit RBS-5 includes 13,819 MW of capacity, at summer ratings, but AEP Ohio's coincident peak in 2010 was 9,060.8 MW.[28] If the peak load amount was priced at \$355.72/MW-day for the entire transition period, AEP Ohio would collect \$4.7 billion in capacity payments above and beyond the net going-forward costs (plus APIR), as calculated pursuant to the PJM Tariff. Even if you use the second variant and ignore positive earnings and "cap" each unit's earnings in each year at zero, as Mr. Graves urges is appropriate, while also imposing a symmetric cap to prevent AEP Ohio from forcing uneconomic capacity on CRES providers, I calculate that AEP Ohio would over-recover its costs by \$3.7 billion. While it is unlikely that 100% of AEP Ohio's load is served by CRES providers, even 20% to 40% of these excess charges are dramatic.

[28] Horton Direct, Exhibit KDP-6.

V. USING RPM PRICING DOES NOT CREATE A SUBSIDY TO CRES PROVIDERS.

Q. AEP OHIO ALLEGES THAT USING THE RPM RTO PRICE FOR CAPACITY USED BY CRES PROVIDERS WOULD CREATE AN "UNECONOMIC BYPASS OPTION" OR A SUBSIDY. WHAT DO THOSE TERMS MEAN TO YOU AS AN ECONOMIST?

A. The terms are effectively synonyms. In regulatory economics, a subsidy occurs when one class of customers is charged less than the incremental cost of serving those customers and, in turn, some portion of this incremental cost is assigned to other customers. An uneconomic bypass option is any mechanism that allows a customer to change its rate so as to receive a subsidy.

Q. IN YOUR PREVIOUS ANSWER YOU REFERRED TO "INCREMENTAL COSTS" RATHER THAN "EMBEDDED COSTS". IS THIS DISTINCTION IMPORTANT IN UNDERSTANDING A SUBSIDY?

A. Yes. In the power sector, as in many industries, there are common costs that do not increase by serving an additional customer. A familiar industry with many common costs is the commercial airline business. For example, the cost of flying an airplane from Columbus to Boston is little changed by adding an additional passenger—the added cost of a little extra fuel, a can of Coke, and a bag of peanuts. As long as my discounted coach fare is above these incremental costs, my ticket is not being subsidized by the other passengers, even if they paid more than I did.

Q. WOULD AEP OHIO BE PROVIDING AN "UNECONOMIC BYPASS OPTION" OR SUBSIDY TO CRES PROVIDERS IF AEP OHIO PROVIDES CAPACITY TO CRES PROVIDERS UNDER THE TERMS SPECIFIED BY FERC AND THE PUCO?

A. No. The use of PJM RPM capacity charges does not create the opportunity for uneconomic bypass for a simple economic reason: the PJM RTO price more than covers the incremental cost for AEP Ohio to supply capacity to CRES providers. At the RPM RTO price, the CRES providers are more than paying for their seat on the airplane; AEP Ohio is proposing that they also pay for the plane.

Q. FROM YOUR PERSPECTIVE AS AN ECONOMIST, SHOULD AEP OHIO BE ALLOWED TO RECOVER ITS FULL EMBEDDED COSTS IN THE CRES CAPACITY RATE?

A. No, such a high rate is neither efficient nor equitable. I say this for three reasons.

First, as a matter of equity, CRES providers no longer have the ability to make their own FRR election during this transition period (after which AEP Ohio will participate in RPM and, consequently, CRES providers will pay the RPM RTO rate for capacity). Increasing the capacity rate that AEP Ohio can charge now, when CRES providers are forced to buy that capacity regardless of the price, clearly allows AEP Ohio to exploit its status as the monopoly provider.

Q. BUT YOU TESTIFIED THAT CRES PROVIDERS COULD HAVE SUBMITTED FRR CAPACITY PLANS. WOULDN'T THAT HAVE AVOIDED THE RISK OF THEIR BEING EXPLOITED?

A. Theoretically, yes. At the times when CRES providers might have developed their own FRR Capacity Plan, however, they had sound reasons to believe that the capacity available to them would be priced at the RPM RTO rate. The rational way for a CRES provider to manage that uncertainty would not be through an FRR Capacity Plan, which entails some volume management issues that could be particularly challenging to a CRES provider, but rather through financial hedges of the RPM RTO price.

As I show in Exhibit RBS-2, which gives the timeline of the FRR, CRES providers had two relevant windows in which they could have developed their own FRR

Capacity Plans. Without such a plan of its own, a CRES provider is necessarily relying on AEP Ohio's FRR Capacity Plan.[29]

The first window was in 2006, after FERC accepted the RPM settlement but before AEP Ohio submitted its own FRR Capacity Plan (which, by the requirements of the PJM RAA, necessarily covered all load in the AEP Ohio area). Pursuant to the requirements of the RAA, AEP's initial FRR Capacity Plan covered Delivery Years 2007/08 through 2011/12. After this initial five-year plan, the FRR Entity must file annual updates to extend its FRR Capacity Plan prior to the BRA for each subsequent Delivery Year. So, unless a CRES provider had arranged for self-supply shortly after the 2006 settlement, the earliest date that a CRES provider could have arranged for its own capacity was for the 2012/13 Delivery Year – and such a plan would have had to be in place in prior to the RPM auction for that year, in May 2009. At this time, however, the CRES providers reasonably anticipated that the capacity price they would be charged would equal the (as-yet unknown) RPM prices, which are the default prices under the RAA and the rate in effect at that time, absent any state compensation mechanism or Section 205 filing at FERC by AEP Ohio. Indeed, AEP referred to the RPM price as the prevailing price for CRES providers in its territory.[30]

The second window was in 2011, prior to the BRA for Delivery Year 2014/15. This was the first auction after AEP Ohio made its Section 205 filing to increase its

[29] After AEP Ohio has filed its FRR Capacity Plan, a CRES provider could ask AEP Ohio to allow the CRES provider to substitute resources from the CRES provider in place of AEP Ohio's resources. AEP Ohio could then, in its sole discretion, reflect this substitution in a subsequent FRR Capacity Plan with PJM.

[30] Direct Testimony of Craig Baker on Behalf of CSP and OPCo, Case No. 08-918-EL-SSO, at 11, lines 11-14, ("PJM Capacity Obligations - This component reflects the cost of PJM's required capacity obligations for load serving entities <u>and was derived from the PJM Reliability Pricing Model (PJM Capacity Auction) results for the relevant time period</u>.")(emphasis added).

capacity charges to CRES providers. This Commission, however, countered that filing by implementing a state compensation mechanism shortly after AEP's FERC filing. The Commission reaffirmed the RPM RTO price as the pricing for capacity.[31] The most rational response of a CRES provider, therefore, would be to operate under AEP Ohio's FRR Capacity Plan and, potentially, to hedge the RPM price risk through financial transactions (which were and are widely traded).

Because AEP Ohio has announced that it has ceased its election of the FRR Alternative beginning in Delivery Year 2015/16, no CRES provider could or would file a FRR Capacity Plan for that year, either.

Hence, there is at most one year, Delivery Year 2014/15, when CRES providers had any notice that AEP Ohio would seek to charge a capacity rate other than the RPM RTO rate. Even for that year, the Commission's interim mechanism maintained the status quo, and CRES providers could reasonably act on the assumption that the Commission would not allow excessive charges to be put into the capacity rate.

Q. BEFORE YOU MOVE ON TO THE SECOND REASON, DO YOU AGREE WITH MR. GRAVES' ANALYSIS OF WHY CRES PROVIDERS DID NOT DEVELOP THEIR OWN FRR PLANS?

A. Mr. Graves' analysis is, at best, incomplete. He omits to mention that the entire question was created, not by the CRES providers, but rather by AEP Ohio's decision to become an FRR Entity. Had AEP Ohio participated in the RPM auction process, as Dayton Power & Light did, the CRES providers could simply have relied on PJM's procurements through the BRA and Incremental Auctions.

[31] January 20, 2011, FERC Case No. ER11-2183-000 ("The Ohio Commission states that the state implicitly adopted the use of the RPM auction price to value capacity since the inception of AEP-Ohio's current standard service offer, <u>and, on December 8, 2010, has now expressly adopted the use of the RPM auction price as its state compensation mechanism</u>.")(emphasis added).

Furthermore, Mr. Graves glosses over the scheduling difficulty created for CRES providers by AEP Ohio's FRR election, discussed above. Allowing AEP Ohio to charge more than the RPM RTO price would be similar to a classic "bait and switch," where the "bait" has been the historic use of the RPM RTO price charged to CRES providers for capacity, which removed any need or motivation for CRES providers to obtain their own capacity. The "switch" is the unilateral attempt to charge embedded costs, exploiting AEP Ohio's absolute monopoly power as the sole supplier of capacity to CRES providers. Allowing such a switch is tantamount to retroactive ratemaking: having locked in CRES providers under the reasonable reliance on a known pricing structure, AEP Ohio now seeks to change the price—radically—without allowing the CRES providers any opportunity to find a more economical capacity source.

The question of whether CRES providers in the AEP Ohio area should, or should not, develop FRR Capacity Plans is now moot, however, given that AEP Ohio has committed to participating in the RPM auction process for at least the five years beginning with the 2015/16 Planning Year.

Q. WHAT IS THE SECOND REASON WHY CHARGING EMBEDDED COST IS NEITHER EFFICIENT NOR EQUITABLE?

A. AEP Ohio would not be subsidizing CRES providers by providing capacity below AEP Ohio's purported "costs" because AEP Ohio is offering unreasonable and inaccurate estimates of the relevant costs. AEP Ohio's case is premised on the assumption that it is entitled to charge a capacity rate based on its embedded costs. Although I am not a lawyer, this assumption does not appear to square with Ohio law. As an economist, I am confident that it does not square with sound economics of how a price should be set in "an era of competition." Even if embedded costs were the appropriate benchmark, FES witness Lesser explains why AEP Ohio's $355.72/MW-day rate is not an accurate measure of those costs.

Earlier I presented the facts supporting a view that AEP Ohio's net "to go" costs are more than covered by the RPM RTO price. Another approach would be to conduct the thought experiment of asking: what is AEP Ohio's foregone revenue from having tied up an additional MW of capacity to service CRES load? That is, what is the price AEP Ohio could obtain from a willing buyer? If AEP Ohio were free to sell this capacity, the best approximation of what it would receive is the RPM RTO rate. AEP Ohio might sell the capacity bilaterally to another PJM LSE—but there is no reason why the buyer would be willing to pay AEP Ohio its embedded costs, rather than a market price for the capacity. AEP Ohio might sell it to another FRR entity in PJM, but aside from transitional FRR plans for FirstEnergy and Duke, there are no other FRR Entities. AEP Ohio might sell capacity to an entity outside of PJM, but capacity market prices in the Midwest ISO and New York ISO have been lower than PJM's RTO rate in most years, these markets do not have the same surety of forward pricing as PJM, and arranging firm transmission for export is costly. So, under any scenario, the maximum price AEP Ohio could get for its capacity, when sold to a willing buyer, is the RPM RTO rate.

The RPM price actually represents an *upper bound* on the economic fair value of this hypothetically released capacity: an FRR Entity cannot sell any capacity into the RPM market unless it holds a sufficiently large surplus, a Threshold Quantity, above its minimum reliability requirement.[32]

[32] RAA § 1.82 and Schedule 8.1(D)(2).

Q. WHAT IS THE THIRD REASON WHY CHARGING EMBEDDED COST IS NEITHER EFFICIENT NOR EQUITABLE?

A. Charging a capacity rate that reflects historical, embedded costs rather than the market value of the capacity is inconsistent with economic efficiency. Ohio adopted retail customer choice to "[e]nsure the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs ."[33] As I discussed above, competition intrinsically means that consumers will pay *market-based* prices, not *cost-based* prices. RPM capacity prices are the best indicators of market price for capacity. AEP Ohio's embedded costs, however, are not a competitively set rate. This inefficiency could manifest itself in three forms.

First, a mismatch between the capacity charge to CRES providers and the market capacity price gives inefficient signals to CRES providers as to whether they should buy capacity from AEP Ohio or from the market. If AEP Ohio charges above the market rate, then CRES providers have an under incentive to rely on AEP Ohio's resources and an incentive to contract with external resources, even if those resources actually have higher "to go" costs than AEP Ohio—that is, if they are not part of the overall least-cost set of resources that should be serving the region's resource adequacy needs. Conversely, if AEP Ohio's rate were artificially set below the RPM RTO price, a CRES provider would have an over incentive to rely on AEP Ohio resources. Although there is no longer a risk of such inefficient activity, the fact that it would have occurred had the Commission adopted AEP Ohio's proposal prior to the lock-in of CRES providers highlights why the proposal is flawed.

[33] R.C. § 4928.02(B).

Second, such a mismatch adversely affects retail switching—particularly if the SSO rate does not include the same level of embedded capacity costs. Retail choice should be driven by the ability of competing retailers to create value for their clients through a combination of price, service, and other value-adding components. If all retail customers—including non-shopping customers—have a common capacity payment obligation to PJM, then customer choice is not skewed by regulatory adjustments to capacity costs. Imposing high capacity costs on shopping customers, but a lower capacity cost on non-shopping customers, discourages shopping even if the CRES provider could otherwise have provided real economic value to the customer.

Third, setting capacity charges at a higher than market rate will almost surely lead to higher retail prices for shopping customers. It is unrealistic to believe that CRES providers will simply "eat" the higher costs that AEP Ohio's proposed rate would impose on them. Higher retail prices are a drag on Ohio's economy and its overall competitiveness.

Q. ON THE QUESTION OF ECONOMIC EFFICIENCY, DO YOU CONCUR WITH MR. GRAVES THAT THE RPM PRICE IS SOMEHOW INCONSISTENT WITH LONG-RUN RESOURCE ADEQUACY?

A. No. Contrary to Mr. Graves' statements, I do not agree that the RPM mechanism is unable to attract the "same kinds of resources that would be preferred for long term resource planning."[34] As the reports issued by Mr. Graves' company, The Brattle Group, aptly demonstrate, RPM provides appropriate price signals to the market.[35] By design, the RPM generates a forward-looking price that provides economic incentives for new

[34] Graves Direct, p. 7.

[35] Brattle Report dated August 26, 2011, p. i, attached hereto as Exhibit RBS-6.

entry, when economic, or the exit of existing resources, when those are uneconomic. On average over time, however, the RPM price is designed to provide investors in efficient new capacity resources the opportunity to earn a compensatory rate of return. What it does not do, however, is to *guarantee* such a rate of return, and certainly not in any given year. As Mr. Graves correctly notes, when the supply of capacity greatly exceeds demand, market prices for capacity fall (as we would expect in any market). And, when many forms of low-cost capacity, such as demand response, reduce the need for costly capital investment in new plants, capacity prices reflect the lower costs of meeting reliability. Allowing consumers to benefit from the lower costs in the market stimulates economic activity, lowers prices for goods and services produced in Ohio, and generally encourages economic development.

Mr. Graves appears to argue that Ohio's shopping customers should be paying a long-term average price for capacity today, even though the short-term price of capacity is undeniably far lower. This argument is completely undermined, however, by the fact that AEP Ohio is shifting to RPM as of June 1, 2015—just as capacity prices are likely to rise as unit retirements accelerate. Thus there is no trade-off being offered, of a higher rate today for a potentially lower rate tomorrow (assuming *arguendo* that RPM prices climb above $355.72/MW-day in the future). All that is being offered is a high rate today and a market rate tomorrow.

Q. AEP OHIO WITNESS GRAVES HAS CHARACTERIZED THE RPM PRICE AS TOO LOW, AND FAILING TO REFLECT THE COSTS OF MAINTAINING RELIABILITY. DO YOU AGREE?

A. No. Interestingly, Mr. Graves' colleagues at the Brattle Group also disagree with this position. The Brattle Group was retained by PJM to evaluate the performance of the

RPM. In its most recent study, which included all of the BRA auctions held to date, Mr. Graves' firm stated:

> "Our primary finding is that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the Regional Transmission Organization ("RTO") and, during the last four BRAs, in all of the individual Locational Deliverability Areas ("LDAs") at capacity prices below the net cost of new entry ("Net CONE"). Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement."[36]

Q. AEP WITNESS MUNCZINSKI STATES THAT AEP'S HIGHER CAPACITY PRICE IS NEEDED TO ENSURE LONG-TERM RELIABILITY, WHILE THE RPM IS ONLY A "SHORT-TERM" PRICE. (PP.13–14) HOW DO YOU RESPOND?

A. I disagree with Mr. Munczinski, and I agree with both FERC —which determined that RPM provides just and reasonable prices to maintain resource adequacy—and the Brattle Group economists in the report I cite above. Long-term reliability implies the ability to retain sufficient existing resources *and* attract new resources, when and where needed. RPM has accomplished exactly this. The clearing prices have not merely been enough to keep existing resources operating. The clearing prices have also incentivized new resources. The Brattle Group economists note:

> "Since RPM was implemented, a total of 28,400 MW of installed capacity ("ICAP") from new resources have been committed on an RTO-wide basis (not counting resources from Fixed Resource Requirement ("FRR") entities and new PJM members, FirstEnergy and Duke). These additions consist of 11,800 MW of demand side resources, 6,900 MW of increased imports and decreased exports, 4,800 MW of new generation, 4,100 MW of plant upgrades, and 800 MW of plant reactivations. These resource

[36] Exhibit RBS-6, p. i.

> additions are partially offset by 5,000 MW of retirements, 2,700 MW of plant derates, 6,800 MW of capacity initially offered into the RPM auctions by FRR entities but that was subsequently withdrawn to serve the entities own requirements, and 700 MW of otherwise excused resources. On net, the amount of committed capacity has increased by 13,100 MW, more than enough to meet reliability requirements."[37]

Furthermore, LS Power has recently announced that it will bring a new gas-fired combined-cycle plant on line, entirely on a merchant (uncontracted) basis. This further underscores the fact that the RPM framework, including cyclical fluctuations in price, are achieving long-term reliability at least cost to consumers.

Although AEP Ohio argues that the BRA prices are below their embedded costs and what their shareholders would like to collect, there is no basis to conclude that they are too low to achieve the goal of long-term resource adequacy in the market. To the contrary, the very fact that AEP Ohio intends to shift from the FRR Alternative to RPM in 2015 attests to the ability of the RPM as a framework for ensuring long-term resource adequacy in the region.

Q. SHOULD THE COMMISSION GRANT AEP OHIO'S RATE REQUEST TO REDUCE THE REGULATORY RISK FOR AEP OHIO TO "INVEST LONG-TERM CAPITAL" IN NEW GENERATION UNITS IN OHIO, AS MR. MUNCZINSKI AVERS (P. 14)?

A. No. Providing AEP Ohio with a capacity price that greatly exceeds the market value provides no assurance to Ohioans that AEP Ohio will construct any new resources.

[37] *Ibid*., p. iii.

Q. MR. HORTON RAISES CONCERNS THAT RPM AUCTION PRICES MAY RISE IN THE FUTURE, IMPOSING COSTS WELL ABOVE THE CURRENT RATES.[38] SHOULD THIS BE A SOURCE OF CONCERN TO THE COMMISSION?

A. First, I note that Mr. Horton's concern is entirely irrelevant to this proceeding because, given that the BRAs have already occurred for all of the Delivery Years in the transition period, the RPM rates are also largely settled.[39]

Even if Mr. Horton's concern had any bearing, the Net CONE rate he cites, $342/MW-day, is less than the rate that AEP Ohio is proposing to charge (on the order of $355.72/MW-day), further highlighting the unreasonableness of AEP Ohio's proposal. As I noted earlier, with AEP Ohio shifting to RPM starting in Delivery Year 2015/16, allowing AEP Ohio embedded cost based capacity rates provides no assurance for long-run price stability. For shopping customers, paying a high price during the transition period and a market rate afterwards is not a lower-cost option than paying the lower market price now and a market rate later.

VI. THE USE OF RPM RTO PRICING SHOULD BE EXTENDED THROUGH THE TRANSITION PERIOD

Q. WHAT IS THE APPROPRIATE RATE TO CHARGE CRES LOAD THROUGH THE STATE COMPENSATION MECHANISM?

A. The simplest and most economically sound solution to the capacity pricing issue is for all CRES load to pay a market-based price during the transition period, just as they will after the transition period. Allowing AEP Ohio to collect capacity rates from CRES customers that are higher than those paid by its non-shopping customers (as FES witness

[38] Horton Direct, p. 14.

[39] Only minor changes could occur from incremental purchases or sales in the remaining Incremental Auctions, but the volumes cleared in these auctions are too small to have much effect on the final RPM price to loads.

Dr. Lesser shows) would provide a continuing advantage for AEP Ohio in terms of insulating AEP Ohio from current market prices, thereby enriching the shareholders at the expense of captive CRES providers. It would also allow AEP Ohio to benefit its own retail affiliate, because AEP corporately is indifferent about the CRES capacity charge: every dollar collected from AEP Retail Energy is paid to AEP Ohio. Eliminating such inappropriate market distortions is exactly the right thing to do if the Commission seeks a level playing field, and diversity and depth of competitive suppliers for retail services.

Pricing capacity at market rates is also consistent with market efficiency and transparency. If AEP Ohio's capacity is priced above the market rate, it results in inefficient incentives to rely on other capacity resources, even if their true economic cost is higher than AEP Ohio's. By contrast, when all resources are priced at the common RPM RTO price, it is the least-cost resources that will be relied on to meet the region's adequacy requirements. Furthermore, above-market capacity prices raise the total cost of electricity supply to Ohio businesses, reducing their competitiveness in the world market, and to Ohio customers, taking money out of their pocket that could be invested or spent on other goods and services.

Q. WHAT IS THE APPROPRIATE BENCHMARK TO MEASURE THE REASONABLENESS OF ANY STATE COMPENSATION MECHANISM?

A, It is appropriate to use the RPM RTO clearing price as the benchmark for analysis for several reasons. First and foremost, CRES providers in the AEP Ohio zone would have been paying the RPM RTO clearing price for their capacity but for AEP Ohio's election to become an FRR Entity. Because AEP Ohio made this election entirely voluntarily and with full knowledge of the requirements of the FRR Alternative, it is reasonable to hold CRES providers harmless from that decision. Second, AEP has no ability to charge its claimed full "embedded cost" rate for shopping customers at this time, absent a change in the state compensation mechanism. The RAA agreement and the prior PUCO policy would allow AEP to charge only the PJM RPM rates. This rate is also consistent with the level of charges AEP has been charging since it joined PJM. Third, the $355.72/MW-day value over-compensates AEP. In testimony by FES witness Lesser, far lower "cost" levels for AEP Ohio capacity are established. And, as discussed above, AEP Ohio's "costs", defined consistently with the PJM Tariff, are below the RPM prices for the 41-month period in question and in each Delivery Year of the transition period; allowing AEP Ohio to charge above the RPM RTO rate would only enhance AEP Ohio's collection of revenues in excess of costs. In particular, allowing the full $355.72/MW-day rate sought by AEP Ohio would result in over-earnings of between $3.7 billion and $4.7 billion compared to its net capacity cost, properly defined.

Q. MR. HORTON HAS OBJECTED TO USING THE RPM AUCTION PRICE BECAUSE IT DOES NOT COMPENSATE AEP OHIO FOR POTENTIAL COSTS OF DEFICIENCY CHARGES AND OTHER PENALTIES.[40] DO YOU AGREE?

A. No. Mr. Horton correctly states that "[i]f a CRES provider relies on AEP for its capacity requirement, AEP is responsible for 100% of the penalties associated with non-performance under the FRR, and does not pass on to the CRES providers any of the penalties incurred."[41] I understand Mr. Horton to imply that AEP Ohio's capacity rate should be set to reflect the risk of these penalties. If that is his testimony, I disagree. But for AEP Ohio's election of the FRR Alternative, no CRES provider in the AEP Ohio area would be subject to deficiency charges or other penalties specified in Attachment DD to

[40] Horton Direct, pp. 12-13.

[41] Horton Direct, p. 13.

the PJM Tariff, §§7–13. These penalties are only collected from capacity suppliers. Furthermore, the RPM prices already *do* include a premium to reflect capacity suppliers' risks of penalties and deficiency charges. The RPM auction price is the whole and entire compensation paid to capacity resources (at least, aside from AEP Ohio) to assume not only the capacity obligation but also the very set of risks that AEP Ohio now asserts it would need additional compensation to carry. The RPM price, therefore, includes the very risk premium that AEP Ohio would seek to add onto the RPM price.

Q. DO YOU AGREE WITH MR. HORTON THAT AEP OHIO CUSTOMERS PAY LESS BECAUSE OF FRR COMPARED WITH THE RPM MARKET?

A. No. In his evaluation of the benefits of the FRR option over RPM, Mr. Horton claims that RPM would have resulted in AEP Ohio having to carry 19.2% in reserves for the 2007/08 auction instead of the 15% target.[42] This additional capacity was added due to the descending nature of the RPM demand curve. He claimed that by being in FRR AEP Ohio customers "saved" having to purchase an additional 4.2% "that wasn't necessary to meet the Company's internal load obligations."[43]

Mr. Horton estimated the value of these "savings" in reference to AEP total company peak load in PJM of approximately 22,000 MW. He claimed a resulting savings of 4.2% of 22,000 MW (rounded to 925 MW) at the final billing rate of RPM

[42] In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929-EL-UNC, Direct Testimony of Dana Horton, March 23, 2012 ("Horton Direct"), p. 6, lines 4-10.

[43] *Id*.

capacity price of $46.73 would be $15.7 million (925 x $46.73 x 365).[44] He views this as a benefit of not participating in RPM.

Q. DO YOU AGREE WITH MR. HORTON'S ANALYSIS OF THESE "SAVINGS?"

A. No. Mr. Horton makes two errors: first, he overstates the relevant capacity, and second he assumes that AEP Ohio is entitled to full embedded costs.

Mr. Horton uses a 22,000 MW metric, but this is for all of AEP's PJM load, not just the AEP Ohio load. AEP Ohio's peak coincident load is 9,060.8 MW, not 22,000 MW.[45] Thus, at a minimum, Mr. Horton's $15.4 million overstates his claim and should be scaled down by the ratio of 9,060.8 : 22,000, yielding a corrected total of $6.3 million.

The correct way to address the cost impacts to AEP Ohio customers, however, is to ask how much less they would have paid under the RPM RTO rate than under a $355.72/MW-day rate, even though the latter comes with a lower reserve requirement. To do this, we calculate what 9,060.8 MW of peak capacity would cost under the $355.72/MW-Day rate AEP Ohio wants to charge versus what 9,060.8 MW of capacity plus an extra 4.2% reserves would cost if purchased under the RPM charge rate that year ($46.73 per MW-day). Using AEP Ohio's $355.72/MW-day price, even with its lower reserve margin, would have resulted in $1.176 billion in charges, compared to $161 million in charges under PJM, even with the higher reserve margin required under the RPM construct. This would have created a huge one-year increase in costs to AEP Ohio customers of $1.016 billion dollars in above-market payments for a lower level of system reliability (15% versus 19.2% reserves).

---

[44] *Id*., p. 8, lines 1-2.

[45] Horton Direct, Exhibit KDP-6.

Mr. Horton's logic also shows the impact of AEP Ohio system embedded cost-based charges to customers versus RPM costs for the first eight RPM auctions that have been concluded. He states that for these eight auctions the difference in increased reserve margins over AEP requirements was 3.5% and the average RPM clearing price was $90, so he mistakenly concludes that staying out of RPM "saved" AEP customers $25 million per year.[46] However, the correct calculation shows that by not participating in RPM, and if AEP Ohio had been allowed to recover $355.72/MW-day for that period, AEP Ohio would have recovered about $6.6 billion in above-market capacity charges from its customers for the eight year period (assuming that all AEP Ohio customers were charged this embedded cost rate).[47]

Q. IS MR. HORTON'S $15.7 MILLION (OR $6.3 MILLION, FOR OHIO ONLY)A TRANSFER FROM AEP OHIO TO CRES PROVIDERS THAT SHOULD BE CREDITED TO AEP OHIO IN THIS PROCEEDING?

A. No. Although I will concede that CRES providers were obliged to pay for slightly less capacity because of the FRR, these were resources that AEP Ohio did not provide and, consequently CRES providers did not pay for them. AEP Ohio gave nothing away that they can now take credit for.

Q. MR. HORTON ALSO ASSERTS THAT THERE IS A BENEFIT TO AEP OHIO'S ELECTION OF THE FRR RELATED TO AVOIDING PENALTIES. DO YOU AGREE WITH HIS ANALYSIS?

A. No. I think his testimony on that point actually demonstrates that AEP's approach was relatively more costly than participation in the normal BRA process. Mr. Horton asserts that under the RPM structure, "if AEP would find itself 1000 MW short of

---

[46] Horton Direct, p.8.

[47] (9060.8 x $355.72 x 365)-(9060.8 x 1.19 x $88.65 x 365) times 8 years = $6.6 billion.

capacity due to an unexpected forced outage, the penalty provisions for the 2009/10 delivery year would be 120% of the RPM clearing price. This would equate to $44M of penalties for a 1000 MW shortage ….” Under the FRR construct, however, “AEP was able to substitute other uncommitted capacity resources within the AEP fleet … to avoid most of the penalties that PJM would have assessed had AEP been in RPM.”[48] Mr. Horton’s testimony is misleading on two important points.

First, the $44M that he calculates is not the correct penalty rate. The *penalty* is only 0.2 (20%) times the capacity price, not 1.2 (120%), or $7 million in Mr. Horton’s example.[49] The non-performing unit would not be paid for the capacity it did not provide, of course, but that should not be considered a “penalty.”

Moreover, Mr. Horton neglects to mention that AEP could have avoided those penalties and lost revenues under RPM just as easily, because the Section 8 of Attachment DD to the PJM Tariff allows replacement of one capacity resource for another to avoid the Capacity Resource Deficiency Charge that is applicable when a unit is on forced outages. Likewise, Section 7 of Attachment DD allows for resource substitution to avoid the Generation Resource Rating Test Failure Charge that might apply if a unit was on extended forced outage. Regardless, the RPM construct allows the same flexibility that Mr. Horton finds beneficial in the FRR.

[48] Horton Direct, p.12.

[49] PJM Tariff, Attachment DD, Section 7.1(b)(iii)

Q. BUT DOESN'T MR. HORTON MAKE A VALID POINT THAT "RPM RULES DO NOT ALLOW LSE'S TO HOLD SOME UNITS IN RESERVE TO COVER UNEXPECTED FORCED OUTAGES"?[50]

A. No. Not all resources that offer into the BRA clear, and thus are not committed to be offered. This leaves a pool of uncommitted resources that may be available during the course of a Delivery Year to replace resources that are unable to perform. To facilitate this process, PJM conducts three Incremental Auctions leading up to each Planning Year, so (if an outage is foreseen), it can be covered.

Furthermore, if AEP does manage to clear all of its capacity resources in a BRA, it is receiving that much more revenue for its fleet to defray costs. Withholding such resources (thereby foregoing the capacity revenue with certainty) is almost surely more costly than committing them all and bearing the low-probability risk that a few units may incur penalties.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

[50] Horton Direct, p. 12.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing *FirstEnergy Solutions Corp.'s Direct Testimony of Robert B. Stoddard* was served this 4th day of April, 2012, via e-mail upon the parties below.

/s/ N. Trevor Alexander
One of the Attorneys for FirstEnergy Solutions Corp.

Steven T. Nourse
Matthew J. Satterwhite
Anne M. Vogel
American Electric Power Corp.
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
stnourse@aep.com
mjsatterwhite@aep.com
amvogel@aep.com

Jeanne W. Kingery
Amy Spiller
139 East Fourth Street
1303-Main
Cincinnati, Ohio 45202
jeanne.kingery@duke-energy.com
amy.spiller@duke-energy.com

Daniel R. Conway
Porter Wright Morris & Arthur
41 South High Street
Columbus, Ohio 43215
dconway@porterwright.com

David F. Boehm
Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street. Suite 1510
Cincinnati, Ohio 45202
dboehm@bkllawfirm.com
mkurtz@bkllawfirm.com

Cynthia Fonner Brady
David I. Fein
550 W. Washington Street, Suite 300
Chicago, IL 60661
cynthia.a.fonner@constellation.com
david.fein@constellation.com

Terry L. Etter
Maureen R. Grady
Jeffrey L. Small
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485
etter@occ.state.oh.us
grady@occ.state.oh.us
small@occ.state.oh.us

Richard L. Sites
Ohio Hospital Association
155 East Broad Street, 15th Floor
Columbus, Ohio 43215-3620
ricks@ohanet.org

Thomas J. O'Brien
Bricker & Eckler
100 South Third Street
Columbus, Ohio 43215-4291
tobrien@bricker.com

Shannon Fisk
2 North Riverside Plaza, Suite 2250
Chicago, IL 60606
sfisk@nrdc.org

Jay E. Jadwin
American Electric Power Service Corporation
1 Riverside Plaza, 29th Floor
Columbus, Ohio 43215
jejadwin@aep.com

Mark S. Yurick
Zachary D. Kravitz
Taft Stettinius & Hollister LLP
65 East State Street, Suite 1000
Columbus, Ohio 43215
myurick@taftlaw.com
zkravitz@taftlaw.com

Michael R. Smalz
Joseph V. Maskovyak
Ohio Poverty Law Center
555 Buttles Avenue
Columbus, Ohio 43215
msmalz@ohiopovertylaw.org
jmaskovyak@ohiopovertylaw.org

Terrence O'Donnell
Christopher Montgomery
Bricker & Eckler LLP
100 South Third Street
Columbus, Ohio 43215-4291
todonnell@bricker.com
cmontgomcry@bricker.com

Lisa G. McAlister
Matthew W. Warnock
Bricker & Eckler LLP
100 South Third Street
Columbus, Ohio 43215-4291
lmcalister@bricker.com
mwarnock@bricker.com

Jesse A. Rodriguez
Exelon Generation Company, LLC
300 Exelon Way
Kennett Square, Pennsylvania 19348
jesse.rodriguez@exeloncorp.com

William L. Massey
Covington & Burling, LLP
1201 Pennsylvania Ave., NW
Washington, DC 20004
wmassey@cov.com

Glen Thomas
1060 First Avenue, Ste. 400
King of Prussia, Pennsylvania 19406
gthomas@gtpowergroup.com

Laura Chappelle
4218 Jacob Meadows
Okemos, Michigan 48864
laurac@chappelleconsulting.net

Henry W. Eckhart
2100 Chambers Road, Suite 106
Columbus, Ohio 43212
henryeckhart@aol.com

Pamela A. Fox
Law Director
The City of Hilliard, Ohio
pfox@hilliardohio.gov

C. Todd Jones
Christopher L. Miller
Gregory H. Dunn
Asim Z. Haque
Ice Miller
250 West Street
Columbus, Ohio 43215
christopher.miller@icemiller.com
asim.haque@icemiller.com
gregory.dunn@icemiller.com

M. Howard Petricoff
Stephen M. Howard
Michael J. Settineri
Lija Kaleps-Clark; Benita Kahn
Vorys, Sater, Seymour and Pease LLP
52 E. Gay Street
Columbus, Ohio 43215
mhpetricoff@vorys.com
smhoward@vorys.com
mjsettineri@vorys.com
lkalepsclark@vorys.com
bakahn@vorys.com

Sandy Grace
Exelon Business Services Company
101 Constitution Avenue N.W., Suite 400 East
Washington, DC 20001
sandy.grace@exeloncorp.com

Gary A. Jeffries
Dominion Resources Services, Inc.
501 Martindale Street, Suite 400
Pittsburgh, PA 15212-5817
gary.a.jeffries@aol.com

Kenneth P. Kreider
David A. Meyer
Keating Muething & Klekamp PLL
One East Fourth Street, Suite 1400
Cincinnati, Ohio 45202
kpkreider@kmklaw.com
dmeyer@kmklaw.com

Steve W. Chriss
Wal-Mart Stores, Inc.
2001 SE l0th Street
Bentonville, Arkansas 72716
stephen.chriss@wal-mart.com

Holly Rachel Smith
Holly Rachel Smith, PLLC
Hitt Business Center
3803 Rectortown Road
Marshall, Virginia 20115
holly@raysmithlaw.com

Barth E. Royer
Bell & Royer Co., LPA
33 South Grant Avenue
Columbus, Ohio 43215-3927
barthroyer@aol.com

Gregory J. Poulos
EnerNOC, Inc.
101 Federal Street, Suite 1100
Boston, MA 02110
gpoulos@enernoc.com

Werner L. Margard III
John H. Jones
William Wright
Steven Beeler
Assistant Attorneys General
Public Utilities Section
180 East Broad Street, 6th Floor
Columbus, OH 43215
werner.margard@puc.state.oh.us
john.jones@puc.state.oh.us
william.wright@puc.state.oh.us
steven.beeler@puc.state.oh.us

Philip B. Sineneng
Terrance A. Mebane
Carolyn S. Flahive
Thompson Hine LLP
41 S. High Street, Suite 1700
Columbus, Ohio 43215
philip.sineneng@thompsonhine.com
carolyn.flahive@thompsonhine.com
terrance.mebane@thompsonhine.com

Emma F. Hand
Douglas G. Bonner
Keith C. Nusbaum
Clinton A. Vince
SNR Denton US LLP
1301 K Street, NW, Suite 600, East Tower
Washington, DC 20005-3364
emma.hand@snrdenton.com
doug.bonner@snrdenton.com
keith.nusbaum@snrdenton.com
Clinton.vince@snrdenton.com

Samuel C. Randazzo
Joseph E. Oliker
Frank P. Darr
McNees Wallace & Nurick
21 East State Street, 17th Floor
Columbus, Ohio 43215
sam@mwncmh.com
joliker@mwncmh.com
fdarr@mwncmh.com

Colleen L. Mooney
David C. Rinebolt
Ohio Partners for Affordable Energy
231 West Lima Street
Findlay, Ohio 45840
cmooney2@columbus.rr.com
drinebolt@ohiopartners.org

John N. Estes III
Paul F. Wight
Skadden, Arps, Slate, Meagher & Flom LLP
1440 New York Ave., N.W.
Washington, DC 20005
jestes@skadden.com
paul.wight@skadden.com

Trent A. Dougherty
Cathryn Loucas (0073533)
Ohio Environmental Council
1207 Grandview Avenue, Suite 201
Columbus, Ohio 43212-3449
trent@theoeg.org
cathy@theoec.org

Tara C. Santarelli
Environmental Law & Policy Center
1207 Grandview Avenue, Suite 201
Columbus, Ohio 43212
tsantarelli@elpc.org

Joel Malina
Executive Director
COMPLETE Coalition
1317 F Street, NW
Suite 600
Washington, DC 20004
malina@wexlerwalker.com

Christopher J. Allwein
Williams, Allwein and Moser, LLC
1373 Grandview Avenue, Suite 212
Columbus, Ohio 43212
callwein@williamsandmoser.com

David M. Stahl
Arin C. Aragona
Scott C. Solberg
Eimer Stahl Klevorn & Solberg LLP
224 South Michigan Avenue, Suite 1100
Chicago, IL 60604
dstahl@eimerstahl.com
aaragona@eimerstahl.com
ssolberg@eimerstahl.com

Jay L. Kooper
Katherine Guerry
Hess Corporation
One Hess Plaza
Woodbridge, NJ 07095
jkooper@hess.com
kguerry@hess.com

Allen Freifeld
Samuel A. Wolfe
Viridity Energy, Inc.
100 West Elm Street, Suite 410
Conshohocken, PA 19428
afreifeld@viridityenergy.com
swolfe@viridityenergy.com

Robert Korandovich
KOREnergy
P. O. Box 148
Sunbury, OH 43074
korenergy@insight.rr.com

Chad A. Endsley
Ohio Farm Bureau Federation
280 North High Street
P.O. Box 182383
Columbus, OH 43218
cendsley@ofbf.org

Roger P. Sugarman
Kegler, Brown, Hill & Ritter
65 East State St., Suite 1800
Columbus, OH 43215
rsugarman@keglerbrown.com

Brian P. Barger
4052 Holland-Sylvania Road
Toledo, OH 43623
bpbarger@bcslawyers.com

Robert B. Stoddard

Vice President and
Practice Leader, Energy & Environment

MA and MPhil Economics
Yale University

BA Economics and Music
summa cum laude
Amherst College

Vice President Robert Stoddard heads CRA's Energy & Environment Practice. He has over twenty years of experience assisting clients in defining, analyzing, and interpreting the economic issues involved with competition and product valuation in energy and other markets. His recent work has focused on electricity industry restructuring and on providing both strategic analyses and testimony for utilities, generation owners, and governments regarding the practical implications of market design and structure, particularly in New York, New England, and PJM. He has submitted testimony to the Federal Energy Regulatory Commission as well as to the utility commissions and legislatures of several states on competitive market design and market power issues, and he as testified in civil litigation and arbitration on the interpretation of, and damages relating to, energy contracts. He recently was the lead economist for capacity suppliers in developing the New England capacity market, played a central role in negotiating the settlement of the PJM Reliability Pricing Model, and developed the leading proposal for the design of a capacity market for California. In related areas, Mr. Stoddard has served as the special economic counsel to the Rhode Island House of Representatives for electricity restructuring and acted as overseer for Connecticut's standard offer energy auction; devised an energy trading strategy audit and strategy redesign for a major northeastern utility; conducted a comprehensive review of operating flaws within the structure of an ISO; designed a market-based transfer pricing system for the distribution, trading, and generation subsidiaries of a leading western utility; and managed the federal and state regulatory filings for several large utility mergers and asset sales.

Clients

Mr. Stoddard has been a consultant on electric market issues to a wide range of energy market stakeholders including ArcLight Capital Management, AES, American Wind Energy Association, Astoria Generating, Bangor Hydro Electric, California Independent System Operator, Citibank, City of New York, Connecticut Department of Public Utility Control, Consolidated Edison Co. of New York, Constellation Energy Commodities Group, CSG Investments, Dayton Power & Light, Devon Canada, Dominion, Duke Energy, Edison Mission Energy, EdF, Electricity Supply Board of Ireland, Emera, Energia dos Portugal, Energy Capital Partners, Energy East, Entergy Nuclear, FirstEnergy, FirstLight, GenOn, Hydro Québec, Independent Energy Producers Association, International Power, J. Aron & Company, Maine Energy Recovery Co., Maine Public Service, Midlands Cogeneration Venture, Morgan Stanley Capital Group, Morris Energy Group, New England Power Generators Association, New York City Economic Development Corporation, New York Energy Buyers Forum, NextEra Energy Resources, North American Energy Alliance, Northeast Utilities, NRG Energy, Orange & Rockland Utilities, Pepco Energy Services, Pinnacle West, PJM Power Providers, Portland General Electric, Powerex Corporation, Rhode Island Speaker and the House of Representatives, San Diego Gas & Electric, Southern California Edison, Sunoco, Tenaska, Tonbridge Power, USGen New England, USPowerGen, and Williams Power.

Strategy

- Led creation of business model and market-entry strategy for company developing an innovative renewable power technology.
- Led creation of business model and business plan for a combined wind-farm / transmission company in Canada.
- Assisted major utility in strategic and tactical plan to support transfer between Regional Transmission Organizations, providing both analytic and regulatory advisory support.
- Directed the development of the master energy infrastructure strategy for the City of New York, working with key stakeholders to develop a strategy to develop the infrastructure needed to meet the city's future energy needs economically and reliably.
- Developing a detailed forecasting model for capacity prices in PJM resulting from the new capacity market design and, using this information, worked with a major market participant's strategy and financing staff to identify under-valued assets for acquisition.
- With senior management of a major utility, developing a transmission investment strategy to reflect shifting competitive opportunities, RTO market design, and state and federal regulation. Identifying of key opportunities to leverage and redirect capital expenditures to significantly decrease cost of delivered power and increase rate of return to corporate shareholders.
- Developing a competitive bidding strategy for a complex hydroelectric generation asset to recognize opportunity costs, limitations of market rules, and effects of key transmission constraints in a two-settlement, locational pricing regime.
- Assisting a leading provider of utility outsourcing services to develop a comprehensive regulatory strategy for its service offerings to a major utility.

Electricity contracts and project valuation

- Testimony (in progress) to support the tax valuation of independent power production facilities in New York and Maryland, evaluating the free cash flows from sales of energy and other products' net of fuel, emissions, and other relevant costs.
- Testimony successfully supporting claims against industrial customer in breach-of-contract claims by a retail energy provider.
- Testimony supporting the cost-effectiveness of a long-term power purchase agreement between Cape Wind and National Grid in furtherance of Massachusetts policy goals.
- Testimony regarding the market value of a nuclear power facility excluding idiosyncratic nuclear risks using a comparable transactions analysis.
- Expert testimony supporting the reliability must-run (RMR) applications of over 2 GW of generation in New England, documenting need for RMR contracts to maintain the financial viability of needed resources. The case resulted in a settlement agreement that provided for significant support payments for these resources during the transition to compensatory market payments.

- Testimony for a bankruptcy court regarding damages arising from a power purchase agreement that had been rejected at the time of bankruptcy.
- Testimony in arbitration proceedings to determine the product specification and price of the capacity product contracted for in a period of regulatory change.
- Support of project financials for major purchase of New York City generation to investor community.
- Testimony in arbitration proceedings about the interpretation of, and damages owed under, the electricity section of a contract for the purchase of a large petrochemical refinery and resale of the refinery's output.
- State-appointed auditor of Connecticut's utilities' first Standard Offer power procurement auction, reviewing reasonableness of pricing and the terms and conditions of contract offers to supply essentially all of the state's power needs for a three-year period.
- Testimony on fuel costs adders reasonably allowable in a long-term power contract between NRG and Connecticut Light & Power and attendant retail rate design to fairly allocate the incremental costs.
- Assisting Consolidated Edison Co. of New York negotiate the sale of its nuclear facilities and linked buyback of power for the license life of the units.
- Working with Pinnacle West staff to develop options-based contracts to transfer power between its generating, trading, and distribution affiliates to preserve appropriate performance incentives.
- Project manager for bankruptcy evaluation of a New England cooperative, involving assessment of value of hydroelectric, nuclear assets, and long-term contracts.

Electricity market design

- Project director and testifying expert for capacity market design litigation and settlement negotiations for the New England and PJM markets, representing coalitions of the major generation owners in the region.
- Principal author of SDG&E and California Forward Capacity Market Advocates' proposal for a centralized capacity market structure to address resource adequacy needs of the California electricity markets. Subsequently offered a market-based approach to backstop capacity pricing in California on behalf of NRG Energy and the Independent Energy Producers Association.
- Working with other CRA experts, prepared a white paper on capacity market design for Energia dos Portugal.
- Principle drafter of the current form of the utility restructuring laws in Rhode Island, implementing improved retail market access.
- Project director for a major policy initiative by a major generation owner to review key flaws in modern RTO design that distort competitive pricing and outcomes.

- Project manager and testifying expert for litigation regarding the market rules governing use of phase angle regulators between New York and PJM. Subsequently, assisting the negotiated design of these rules pursuant to the FERC orders.
- In the redesign of the wholesale power market for the Republic of Ireland, responsible for development of rules regarding demand-side integration, interconnection management, financial transmission rights, and transmission loss representation.
- Testifying expert on behalf of a major importer into the California electricity market on the allocation of financial transmission rights across external interties.
- Project director for a review for the California Independent System Operator of transmission rights allocations in the proposed California wholesale market.

Market power analysis and mitigation

- Testifying expert successfully defending against charges of market manipulation by largest capacity importer to New England.
- Led preparation of report successfully defending against charges of market manipulation by a power marketer scheduling transactions through multiple jurisdictions.
- Lead expert defending a major financial institution against charges of manipulating ICE index markets (ongoing).
- Lead economist in team developing alternative mitigation measures for buyer-side market power in the New England capacity market.
- Testified on appropriate metrics for market power in PJM energy and capacity markets.
- Testifying expert and project director supporting the integration of Virginia Electric and Power (Dominion) into the PJM marketplace.
- Project manager for an acquisition of generation assets in Connecticut by a competing supplier, using detailed hourly analyses of power flows and potential future competition, and presenting the results to the FERC, US Department of Justice, and the Connecticut Office of the Attorney General.
- Project manager for a market power analyses needed to obtain federal and state regulatory approval of the merger of the leading natural gas transporter and distributor in the eastern US with a vertically integrated utility with substantial gas holdings.
- Project manager for study of the potential competitive effects of the divestiture of substantially all the New York City utility generation to independent power producers, including detailed behavioral modeling that took account of the complex transmission system and design of market power mitigation measures for the energy and capacity markets.

Articles

With Edward L. Kim, Richard D. Tabors and Todd E. Allmendinger, “Carbitrage: Utility Integration of Electric Vehicles and the Smart Grid,” *Electricity Journal*, Vol. 25 No. 2, March 2012, pp.16–23.

Testimony and reports

"Update to the Analysis of the Impact of Cape Wind on Lowering New England Energy Prices," CRA report authored by Robert B. Stoddard, on behalf of Cape Wind Associates, LLC, filed in *Petition of NSTAR Electric Company for Approval of a Proposed Long-Term Contract for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83,* March 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-50-000. Affidavit in support of complaint seeking to require allocation of partial-year Auction Revenue Rights, March 2012.

California Independent System Operator, Inc., FERC Docket No. ER12-897-000. Affidavit in support of protest by NRG Energy, Inc. of proposed waiver of provisions of the Capacity Procurement Mechanism, February 2012.

FirstEnergy Solutions Corp. & Allegheny Energy Supply Company, L.L.C. v PJM Interconnection, L.L.C., FERC Docket EL12-19-000. Affidavit in support of complaint seeking to fund Financial Transmission Rights solely from Day-Ahead Market settlement surplus, December 2011.

"Resource Adequacy in Ohio's Restructured Market," CRA report authored by Robert B. Stoddard, on behalf of Duke Energy Ohio, December 2011.

Bangor Hydro Electric Company and Maine Public Service Company Request for Exemptions and Reorganization Approvals, Maine Public Utilities Commission Docket No. 2011-170. Rebuttal testimony on behalf of Emera regarding potential horizontal and vertical market power issues of proposed acquisitions, September 2011; live testimony, December 2011, March 2012.

PJM Interconnection, L.L.C., Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc., FERC Docket No. ER12-91-000. Affidavit on behalf of Duke providing cost-benefit analysis of its proposed transition from MISO to PJM in support of inclusion of transition costs in transmission rates, October 2011; rebuttal affidavit, November 2011.

In the Matter of Portland General Electric Company 2012 Annual Power Cost Update Tariff (Schedule 125), Oregon Public Utilities Commission Docket No. UE-228. Rebuttal testimony on behalf of Portland General Electric assessing reasonableness of its mid-term hedging strategy for gas and electricity procurement, August 2011.

California Independent System Operator Corporation, FERC Docket No. ER11-2256. Affidavit on behalf of the Independent Energy Producers Association protesting flawed elements of the Capacity Procurement Mechanism, December 2010; presentation to FERC Technical Conference, March 2011.

Expert Report on behalf of Mirant Mid-Atlantic, LLC, Maryland Tax Court Case Nos. 09-RP-CH-261-265; 09-RP-CH-280-294; and 09-RP-CH-294-298, July 2010; live testimony, February 2011.

PJM Interconnection, LLC, FERC Docket No. ER11-2288. Affidavit on behalf of GenOn Energy Management, LLC and Edison Mission Energy protesting the creation of a summer-only demand resource capacity product and the continuation of a limited demand resource capacity product in the PJM Reliability Pricing Model, December 2010.

Testimony on behalf of the PJM Power Providers before the Maryland Public Service Commission in Administrative Docket PC22 regarding the PJM Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results, October 2010.

ISO New England Inc. and New England Power Pool, FERC Docket No. ER10-787-000, and *New England Power Generators Association v. ISO New England, Inc.*, FERC Docket No. EL10-50-000 (combined). Affidavit on behalf of New England Power Generators Association supporting need for revisions to Forward Capacity Market design, March 2010. Rebuttal affidavit, April 2010. Pre-filed testimony, July 2010; supplemental affidavits, September 2010.

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Proposed Long-Term Contracts for Renewable Energy with Cape Wind Associates, LLC Pursuant to St. 2008, c. 169, § 83, Massachusetts D.P.U. Docket No. 10-54. Direct testimony on behalf of Cape Wind Associates, LLC, June 2010.

Richard Blumenthal, Attorney General for The State of Connecticut v. ISO New England Inc., Brookfield Energy Marketing Inc., et al. FERC Docket No. EL09-47-000, and *The Connecticut Department of Public Utility Control and the Connecticut Office of Consumer Counsel v. ISO New England Inc., Brookfield Energy Marketing Inc., et al.*, FERC Docket No. EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports. June 2009. Answering testimony, February 2010.

Pepco Energy Services, Inc. v. Constellation Energy Commodities Group, Inc. (ad hoc arbitration); expert report on behalf of Constellation on alleged mis-payment under a bilateral contract for PJM capacity, April 2008; testimony, October 2009.

Application of MidAmerican Energy Company for the Determination of Ratemaking Principles, IUB Docket No. RPU-2009-0003. Rebuttal testimony on behalf of NextEra Energy Resources, June 2009; surrebuttal testimony, July 2009, live testimony, August 2009.

Midwest Independent Transmission System Operator Inc., FERC Docket Nos. ER08-394-007 and -009. Affidavit regarding monitoring and mitigation of resource adequacy auctions on behalf of Duke Energy Corp., July 2009.

Calpine Corporation, Citigroup Energy Inc., Dynegy Power Marketing, Inc., J.P. Morgan Ventures Energy Corporation, BE CA, LLC, Mirant Energy Trading, LLC, NRG Energy, Inc., Powerex Corporation, and RRI Energy, Inc. v. California Independent System Operator Corp., FERC Docket No. EL09-62-000. Affidavit on behalf of complainants, June 2009; reply affidavit, July 2009.

Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements, prepared for New England Power Generators Association, Inc. and filed in *ISO New England, Inc.*, FERC Docket No. ER09-1282-000 (June 2009).

Richard Blumenthal, Attorney General for Connecticut, v. ISO New England Inc. et al., FERC Docket Nos. EL09-47-000 and EL09-48-000. Prefiled testimony on behalf of Brookfield Energy Marketing Inc. regarding scheduling of capacity imports, June 2009.

Master Transmission Plan for New York City, report prepared for the New York City Economic Development Corporation, April 2009.

California Independent System Operator Corporation, FERC Docket No. ER09-589-000. Affidavit on behalf of Powerex Corp. regarding changes to the CAISO credit policy regarding unsecured credit, February 2009.

"Contracting and Investment: A Cross-Industry Assessment" report filed with Post-Conference Comments of Reliant Energy, Inc., *Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-002-000, January 2009.

PJM Interconnection, LLC FERC Docket No. ER09-412-000. Affidavit and reply affidavit on behalf of Mirant, Edison Mission Energy, International Power, and FPL (NextEra Energy Resources) regarding omnibus changes to the PJM RPM capacity market tariff, January 2009.

Midwest Independent System Transmission Operator, Inc. FERC Docket Nos. ER08-394-000, -003, -007. Affidavit on behalf of Duke Energy protesting the market monitoring standards proposed for the voluntary capacity auction in Midwest ISO, January 2009.

Devon Canada Corp. et al. v. Pittsfield Generating Company LP et al. Expert report for defendant regarding damages from alleged breach of natural gas supply contract to a reliability must-run electric generator, December 2008.

Maryland Public Service Commission v. PJM Interconnection, LLC, FERC Docket Nos. EL08-34-000 and EL08-47-000. Affidavit on behalf on Mirant Parties on appropriate structural and behavioral market power tests in PJM, October 2008; reply affidavit, November 2008.

ISO New England, Inc., FERC Docket No. ER08-1209-000. Affidavit on behalf of the New England Power Generation Association on compensation to reliability resources, July 2008; reply affidavit, September 2008.

Midwest Independent Transmission System Operator, Inc. FERC Docket No. ER08-1169-000. Affidavit on behalf of FPL Energy, LLC, regarding revisions to Generation Interconnection Procedures, July 2008.

RPM Buyers v. PJM Interconnection, LLC, FERC Docket No. EL08-67-000. Affidavit on behalf of PJM Power Providers opposing *ex post* changes to initial RPM auction results, June 2008.

Assessment of Maine's Continued Participation in ISO New England and Alternatives, Expert report in Maine Public Utilities Commission Docket No. 2008-156, prepared on behalf of Bangor Hydro-Electric Company, June 2008; testimony to the MPUC, October 2008.

"Reliability at Stake: PJM's Reliability Pricing Model" report prepared for PJM Power Providers in conjunction with FERC technical conference to discuss the operation of forward capacity markets in New England and the PJM region, FERC Docket No. AD08-4-000, May 2008.

Estimation of Indian Point 2 Fair Market Value Using a Statistical Analysis of Comparable Transactions, Testimony in *Consolidated. Edison Co. of New York v. United States*, No. 04-0033C (Fed.Cl.), February 2008.

Critique of the APPA/CMU Study "Do RTOs Promote Renewables?" (with David Riker) commissioned by Electric Power Supply Association, January 2008.

Midwest Independent Transmission System Operator, Inc. Electric Tariff Failing Regarding Resource Adequacy, FERC Docket No. ER08-394-000. Affidavit on behalf of Duke Energy Corp. and FirstEnergy Services Co. on the urgency of implementing a uniform resource adequacy requirement, January 2008.

Mirant Energy Trading, LLC, et al. v PJM Interconnection, LLC, FERC Docket No. EL08-8-000. Affidavit on the flaws in the market power mitigation rules for the Third Incremental Auction of the PJM Reliability Pricing Model capacity market., November 2007.

Wholesale Competition in Regions with Organized Electric Markets, FERC Docket Nos. RM07-19-000 and AD07-7-000. Affidavit on role of demand-side resources in organized electric markets on behalf of Duke Energy Corp., September 2007.

Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, California PUC Rulemaking 05-12-013. Principal author of SDG&E Track 2 Resource Adequacy Program Proposal, March 2007; principal author, "Joint Pre-Workshop Comments of the California Forward Capacity Market Advocates," May 2007, and "Proposal for a Forward California Capacity Market," August 2007.

People of the State of Illinois, ex rel. Illinois Attorney General Lisa Madigan v. Exelon Generating Co., LLC et al., FERC Docket No. EL07-47-000. Affidavit assessing reasonableness of outcomes in the Illinois power procurement auction on behalf of J. Aron & Company and Morgan Stanley Capital Group, July 2007.

PJM Interconnection, LLC, FERC Docket Nos. EL03-236-000 *et al.* Affidavit regarding three-pivotal-supplier market power test and scarcity pricing in PJM's energy markets on behalf of Mirant Energy Trading et al., May 2007.

Midwest Independent Transmission System Operator, FERC Docket No. ER07-550-000. Affidavit regarding resource adequacy issues in ancillary services market design on behalf of Duke Energy Co., March 2007.

PJM Interconnection LLC, FERC Docket No. EL05-148-000 *et al.* Affidavit regarding redesign of the long-run resource adequacy market in PJM on behalf of the Mirant Parties, October 2005; supplemental affidavit on behalf of the Mirant Parties, NRG and Williams Power Co., November 2005; presentation to FERC Technical Conference, February 2006; prefiled comments to FERC Technical Conference Panel 1, May 2006, on behalf of the Mirant Parties, Williams Power Co., and Dayton Power & Light; prefiled comments to FERC Technical Conference Panel 2, May 2006, on behalf of the Mirant Parties; supplemental affidavit on behalf of the Mirant Parties, June 2006; affidavit and reply affidavit supporting settlement agreement, September and October 2006.

Mystic Development, LLC, FERC Docket No. ER06-427-000. Affidavit analyzing future revenues in support of RMR filing, December 2005; supplemental affidavit, September 2006.

In re USGen New England, Inc. Debtor. United States Bankruptcy Court for the District of Maryland, Case No. 03-30465. Expert report on damage resulting from PPA rejection on behalf of USGen New England, March 2006; supplemental report, September 2006.

California Independent System Operator Corporation, FERC Docket No. ER06-615-000. Joint affidavit with Paul Kevin Wellenius regarding FTR allocations under new CAISO market design on behalf of Powerex Corp, June 2006

Fore River Development, LLC, FERC Docket No. ER06-822-000. Affidavit analyzing future revenues in support of RMR filing, December 2005.

Assessment of the New York City Electricity Market and Astoria, Gowanus, and Narrows Generating Stations. Report prepared for Morgan Stanley Senior Funding, Inc. related to financing for US Power Generating Co. and Madison Dearborn Capital Partners IV, L.P., January 2006.

Review of Initial Execution of Protocol for Implementation of Commission Order No. 476. Report to FERC in Docket EL02-23-000, regarding operation of controllable lines between NYISO and PJM, on behalf of Con Edison, September and December 2005.

Honeywell International Inc. v. Sunoco, Inc. AAA Case No. 13 181 Y 02588 04. Expert report, deposition and live testimony on contract energy pricing in petrochemicals, May 2005.

Con Edison Energy, Inc. v. ISO New England, Inc. and New England Power Pool, FERC Docket No. EL05-61-000. Affidavit on behalf of complainant regarding bidding rules in capacity deficiency auction, February 2005.

KeySpan Ravenswood LLC v. New York Independent System Operator, Inc., FERC Docket No. EL05-17-000. Affidavit on behalf of Consolidated Edison Company of New York, Inc. regarding retroactive damage claims from a capacity market, November 2004.

Devon Power LLC et al., FERC Docket No. ER03-563-030. Affidavit and rebuttal affidavit regarding design of locational installed capacity markets on behalf of FPL Energy, April and May 2004; answering testimony on behalf of Capacity Suppliers, November 2004; cross-answering testimony, December 2004; supplemental cross-answering testimony, January 2005; deposition and hearing testimony, February to March 2005; affidavit supporting Settlement Agreement, March 2006.

Application of Dominion North Carolina Power to Join PJM as PJM South, North Carolina Utilities Commission, Case No. E-22 SUB 418. Direct testimony and cost-benefit study on behalf of applicant, April 2004; rebuttal testimony, December 2004; examination, January 2005.

Application of Virginia Electric and Power Company to Join PJM as PJM South, State Corporation Commission of Virginia Case No. PUE-2000-00551; direct testimony and cost-benefit study on behalf of applicant, June 2003; supplemental direct testimony, March 2004; rebuttal testimony, September 2004; examination, October 2004.

Consolidated Edison v. Public Service Electric and Gas Co. et al., FERC Docket No. EL02-23-000 (Phase II); direct testimony on behalf of Consolidated Edison Company of New York, Inc., June 2002 regarding transmission facilities contracts. Remand testimony, January to March 2003.

In the Matter of the Siting of Electric Transmission Facilities Proposed to be Located at the West 49th Street Substation of Consolidated Edison Company of New York, Inc. et al., New York State Public Service Commission Case Nos. 02-M-0132, 01-T-1474, 02-T-0036, 02-T-0061; testimony on behalf of Consolidated Edison Company of New York, Inc., April 2002 (direct) and May 2002 (rebuttal).

Testimony before the Rhode Island Special Legislative Commission on the Quonset-Davisville Steamplant, January and April 2002.

Testimony before the Committee on Corporations, Rhode Island House of Representatives, regarding 2002 House Bill 7786, *An Act Relating to Public Utilities and Carriers,* April 2002.

Keyspan-Ravenswood, Inc. v. New York Independent System Operator, FERC Docket No. EL02-59-000, direct testimony on behalf of Consolidated Edison Company of New York, Inc. regarding implementation of market power mitigation in installed capacity markets, March 2002.

DPUC Investigation Into Viability of Power Supply Contracts to the Connecticut Light and Power Company and the United Illuminating Company, Connecticut DPUC Docket No. 01-12-05, direct testimony on behalf of NRG Energy, Inc. and affiliates, February 2002.

Joint Study by the Department of Public Utility Control and the Office of the Consumer Counsel Regarding Electric Deregulation and How Best to Provide Electric Default Service After January 1, 2004, Connecticut DPUC Docket No. 01-12-06, direct testimony on behalf of NRG Energy, Inc. and affiliates, January 2002.

The Narragansett Electric Co. Rate Changes for January 1, 2002, Rhode Island PUC Docket No. 3402, direct testimony on behalf of the Hon. John B. Harwood, Speaker of the House of Representatives, State of Rhode Island and Providence Plantations, December 2001.

Wisvest-Connecticut, LLC et al., FERC Docket No. EC01-70-000, technical conference presentation on behalf of NRG Energy, Inc. and affiliates, September 2001.

New York Independent System Operator, Inc., FERC Docket No. ER01-2536-000, affidavit on behalf of Consolidated Edison Co. of New York, the City of New York, the New York Energy Buyers Forum, and the Association for Energy Affordability, Inc., July 2001.

Testimony before the Committee on Corporations, Rhode Island House of Representatives regarding electricity restructuring; various dates, 2001.

Consolidated Edison Co. of New York, Inc., FERC Docket Nos. EL01-45-000 and ER01-1385-000, affidavit and rebuttal affidavit (joint with William H. Hieronymus) on behalf of Consolidated Edison Co. of New York, March and April, 2001.

Joint Petition of Consolidated Edison Co. of New York, Inc. and Entergy Nuclear Indian Point 2, LLC, for Authority to Transfer Certain Generating and Related Assets and for Related Relief, NYSPSC Case 01-E-0040, technical conference presentation on behalf of applicants, February 2001.

Professional history

2009–Present	*Vice President and Practice Leader*, Charles River Associates, Boston, MA
2003–2009	*Vice President*, Charles River Associates, Boston, MA
2001–2003	*Principal*, Charles River Associates, Boston, MA
1995–2001	*Managing Consultant*, PA Consulting Group, Cambridge, MA PA purchased PHB Hagler Bailly, formed by the merger of Hagler Bailly and Putnam, Hayes & Bartlett, where Mr. Stoddard had been a Principal.

1993–1995	*Senior Health Economist and Acting Managing Director*, Benefit Research USA, a Quintiles company, Cambridge, MA
1990–1993	*Senior Associate*, Charles River Associates, Boston, MA
1985–1990	*Teaching and Research Fellow*, Department of Economics, Yale University
1983–1985	*Assistant Economist*, Federal Reserve Bank of New York

Education

1990	M.Phil., Economics, Yale University
1986	M.A., Economics, Yale University
1983	B.A. *summa cum laude*, Amherst College; Phi Beta Kappa
1979	Diploma, Westerville (OH) South High School

Exhibit RBS-2
Timeline of RPM Events for AEP Ohio

September 2006	RPM Settlement Agreement filed with revised Tariff and RAA
December 2006	FERC Order accepting Settlement Agreement
March 2007	AEP Ohio submits FRR Capacity Plan for DYs 2007/08–2011/12
June 2007	RPM implemented
July 2008	AEP testimony re ESP and CRES capacity pricing
March 2009	AEP Ohio submits FRR Capacity Plan for DY 2012/13; Deadline for CRES self-provision of capacity for DY 2012/13
May 2009	BRA for DY 2012/13
March 2010	AEP Ohio submits FRR Capacity Plan for DY 2013/14; Deadline for CRES self-provision of capacity for DY 2013/14
May 2010	BRA for DY 2012/13
December 2010	AEP files Section 205 for higher capacity rate; PUCO introduces state compensation mechanism
January 2011	FERC rejects AEP Section 205 filing
March 2011	AEP Ohio submits FRR Capacity Plan for DY 2014/15; Deadline for CRES self-provision of capacity for DY 2014/15
May 2011	BRA for DY 2014/15
March 2012	AEP Ohio announces termination of FRR Alternatives for DY 2016/17

Exhibit RBS-3

Retrofit Assumption & Costs - AEP OH Coal Units

Unit Name	Existing Retrofits			Installation Dates			Announced	Modeled Retrofits for 2014/2015 DY				New Retrofit Capital Costs (2011 $/kW)		
	Acid Gas	NOx	PM	Acid Gas	NOx	PM	Retirement?	Acid Gas	NOx	PM	HG	Acid Gas	NOx	PM + HG
Conesville-3			ESP			Before 1990	Y							
Conesville-4	FGD	SCR	ESP	6/1/2009	4/1/2009	Before 1990				ESP+	ACI			77.01
Conesville-5	FGD		ESP	5/4/1977		Before 1990				ESP+	ACI			92.80
Conesville-6	FGD		ESP	6/3/1978		Before 1990				ESP+	ACI			92.80
Picway-5			ESP			Before 1990	Y							
W H Zimmer-ST1	FGD	SCR	ESP	3/1/1991	3/1/1991	Before 1990				ESP+	ACI			68.31
Walter C Beckjord-6			ESP			Before 1990	Y							
Cardinal-1	FGD	SCR	ESP	3/25/2008	11/11/1998	Before 1990				ESP+	ACI			82.85
Gavin-1	FGD	SCR	ESP	12/10/1994	7/27/1999	Before 1990				ESP+	ACI			68.07
Gavin-2	FGD	SCR	ESP	3/4/1995	12/22/1999	Before 1990				ESP+	ACI			68.07
Muskingum River-1			ESP			Before 1990	Y							
Muskingum River-2			ESP			Before 1990	Y							
Muskingum River-3			ESP			Before 1990	Y							
Muskingum River-4			ESP			Before 1990	Y							
Muskingum River-5		SCR	ESP		6/17/1994	Before 1990		FGD		ESP+	ACI	505.90		82.67
Kammer-1			ESP			Before 1990	Y							
Kammer-2			ESP			Before 1990	Y							
Kammer-3			ESP			Before 1990	Y							
Mitchell (WV)-1	FGD	SCR	ESP	1/1/2007	12/4/1993	Before 1990				ESP+	ACI			77.26
Mitchell (WV)-2	FGD	SCR	ESP	1/15/2007	5/6/1994	Before 1990				ESP+	ACI			76.78
J M Stuart-1	FGD	SCR	ESP	4/30/2008	5/1/1998	Before 1990				ESP+	ACI			82.67
J M Stuart-2	FGD	SCR	ESP	5/15/2008	5/1/1999	Before 1990				ESP+	ACI			82.67
J M Stuart-3	FGD	SCR	ESP	2/15/2008	12/1/1997	Before 1990				ESP+	ACI			82.67
J M Stuart-4	FGD	SCR	ESP	1/7/2008	11/1/1991	Before 1990				ESP+	ACI			82.67
John E Amos-3	FGD	SCR	ESP	3/8/2009	4/22/1998	Before 1990				ESP+	ACI			68.31
Phil Sporn-2		SNCR	ESP		1/1/2009	Before 1990	Y							
Phil Sporn-4		SNCR	ESP		1/1/2009	Before 1990	Y							
Cardinal-2	FGD	SCR	ESP	12/15/2007	11/11/1998	Before 1990				ESP+	ACI			82.50
Cardinal-3	FGD	SCR	ESP		12/20/1999	Before 1990				ESP+	ACI			81.15

PM = Particulate Matter
HG = Mercury
FGD = Flue Gas Desulfurization
SCR = Selective Catalytic Reduction
SNCR = Selective Noncatalytic Reduction
ESP = Electrostatic Precipitator
ACI = Activated Carbon Injection
ESP + denotes an expected upgrade to ESP technology

Exhibit RBS-4

State of the Market Report for PJM

Volume 2:
Detailed
Analysis

2011

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

3.15.2012

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbines (CT), combined cycle (CC), and coal plant (CP) generating units.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

  The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs for both hypothetical new entrant units and for existing units is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources, including a competitive return on investment, when there is a market based need, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Gas prices decreased on average by 10 percent and coal prices increased on average by 19 percent in 2011. The combination of lower energy prices, lower gas prices and higher coal prices resulted in higher energy revenues for the new entrant CT and CC unit in most zones and lower energy net revenues for the new entrant coal unit in all zones in 2011. However, revenue from the capacity market was lower in 2011, which affected total net revenues for all units. Total new entrant CT net revenue decreased in 2011 in all but five zones. Total new entrant CC net revenue increased in all but five zones. Total new entrant coal unit net revenue was lower in all zones except AEP.

- **Actual Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs, is a measure of the extent to which units in PJM may be at risk of retirement.

  It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and run of river hydro technologies generally recover avoidable costs entirely from the energy market.

The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2011 was 5,642 MW. Generally, coal units that did not recover avoidable costs tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs.

Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units not recovering avoidable costs excluding capital recovery, as they may stay in service for the duration of the project life.

Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. The total installed capacity of sub-critical coal and supercritical coal units that do not have NOx, SO_2, or particulate controls in place is 17,104 MW. Of the capacity lacking NOx, SO_2, or particulate controls, 83 percent is associated with plants older than 40 years.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[1] The coal plant is a sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NOx control, a Flue Gas Desulphurization (FGD) system with chemical injection for SOx and mercury control, and a bag-house for particulate control.

Net revenues for 2009, 2010 and 2011 were calculated using the most economic combination of day-ahead and real-time dispatch and more flexible scheduling than previously presented in order to more closely match the expected actual dispatch. As a result, net revenues may not match net revenue calculations from previous years.

All net revenue calculations include the hourly effect of actual hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[2,3] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NOx and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the PJM definition of marginal cost. NOx and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[4]

A forced outage rate for each class of plant was calculated from PJM data.[5] This class-specific outage rate was then incorporated into all revenue calculations. Each plant was also given a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of synchronized reserve service for all three plant types were set to zero. Ancillary service revenues for the provision of regulation service for both the CT and CC plant were also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability was assumed for the reference CT plant configuration in either costs or revenues.

Ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2011, for CTs, the calculated rate is $2,384 per installed MW-year, for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.

Zonal net revenues reflect zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[6] The delivered fuel cost for natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[7] Coal delivered cost incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[8]

Average zonal operating costs in 2011 for a CT were $53.20 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $7.59 per MWh. Average zonal operating costs for a CP were $36.79 per MWh, based on a design heat rate of 9,240 Btu per kWh and a VOM rate of $3.22 per MWh. Average zonal operating costs for a CC were $32.75 per MWh, based on a design heat rate of 6,914 Btu per kWh and a VOM rate of $1.25

1 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.

2 Hourly ambient conditions supplied by Telvent DTN.

3 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour. Therefore, there is a single offer point and no offer curve.

4 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

5 Outage figures obtained from the PJM eGADS database.

6 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.

7 Gas daily cash prices obtained from Platts.

8 Coal prompt prices obtained from Platts.

per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.

The net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. Capacity revenue for 2011 includes five months of the 2010/2011 RPM auction clearing price and seven months of the 2011/2012 RPM auction clearing price.[9] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[10]

Table 6-1 Capacity revenue by PJM zones (Dollars per MW-year)[11]

Zone	2009	2010	2011	Average
AECO	$58,586	$61,406	$45,938	$55,310
AEP	$35,789	$48,898	$45,938	$43,542
AP	$53,440	$61,406	$45,938	$53,595
ATSI	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$63,342
ComEd	$35,789	$48,898	$45,938	$43,542
DAY	$35,789	$48,898	$45,938	$43,542
DLCO	$35,789	$48,898	$45,938	$43,542
Dominion	$58,586	$62,251	$46,530	$55,789
DPL	$35,789	$48,898	$45,938	$43,542
JCPL	$58,586	$61,406	$45,938	$55,310
Met-Ed	$53,440	$61,406	$45,938	$53,595
PECO	$58,586	$61,406	$45,938	$55,310
PENELEC	$53,440	$61,406	$45,938	$53,595
Pepco	$53,440	$61,406	$45,938	$53,595
PPL	$58,586	$61,406	$45,938	$55,310
PSEG	$76,236	$67,851	$45,938	$63,342
RECO	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$50,189

9 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant Base Residual Auctions.

10 The PJM capacity revenues differ slightly from those presented in Table 6-2, Table 6-5 and Table 6-8 as these capacity revenues by technology type are adjusted for technology-specific outage rates.

11 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the RECO zone.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM operations. For this economic dispatch scenario, it was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start up costs. If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least four hours, or any hours bordering the profitable day ahead or real time block.

Table 6-2 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$8,990	$47,188	$0	$0	$2,384	$58,563
2010	$32,781	$55,186	$0	$0	$2,384	$90,351
2011	$34,939	$45,972	$0	$0	$2,384	$83,295

Table 6-3 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[12]

Zone	2009	2010	2011	Average
AECO	$11,373	$40,037	$46,157	$32,523
AEP	$3,275	$11,575	$20,839	$11,896
AP	$10,188	$32,494	$32,958	$25,213
ATSI	NA	NA	$15,129	$15,129
BGE	$13,644	$52,411	$48,642	$38,232
ComEd	$2,286	$9,446	$15,081	$8,938
DAY	$2,866	$11,701	$21,705	$12,091
DLCO	$3,366	$17,525	$24,179	$15,023
Dominion	$14,315	$42,922	$38,945	$32,061
DPL	$12,718	$40,530	$44,339	$32,529
JCPL	$10,527	$39,409	$44,968	$31,635
Met-Ed	$9,982	$39,409	$40,802	$30,064
PECO	$9,703	$38,311	$45,853	$31,289
PENELEC	$6,276	$24,309	$32,090	$20,892
Pepco	$16,205	$50,906	$44,233	$37,115
PPL	$9,104	$33,649	$42,872	$28,542
PSEG	$9,172	$37,626	$37,929	$28,242
RECO	$7,838	$35,022	$32,178	$25,013
PJM	$8,990	$32,781	$34,939	$25,570

12 The energy net revenues presented for the PJM area in this section represent the simple average of all zonal energy net revenues.

Table 6-4 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$70,894	$102,692	$94,495	$89,360
AEP	$40,562	$61,953	$69,177	$57,231
AP	$64,691	$95,149	$81,295	$80,378
ATSI	NA	NA	NA	NA
BGE	$90,378	$121,392	$96,979	$102,917
ComEd	$39,573	$59,824	$63,419	$54,272
DAY	$40,154	$62,079	$70,043	$57,425
DLCO	$40,654	$67,903	$72,516	$60,358
Dominion	$73,836	$106,406	$87,875	$89,373
DPL	$50,006	$90,908	$92,677	$77,864
JCPL	$70,048	$102,063	$93,306	$88,472
Met-Ed	$64,485	$102,063	$89,139	$85,229
PECO	$69,223	$100,966	$94,191	$88,127
PENELEC	$60,779	$86,964	$80,428	$76,057
Pepco	$70,708	$113,561	$92,571	$92,280
PPL	$68,625	$96,304	$91,209	$85,379
PSEG	$85,907	$106,607	$86,266	$92,927
RECO	NA	NA	NA	NA
PJM	$62,533	$92,302	$84,724	$79,853

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM operations. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start up costs.[13] If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least eight hours, or any hours bordering the profitable day ahead or real time block.

Table 6-5 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$44,553	$50,184	$0	$0	$3,198	$97,936
2010	$89,027	$58,324	$0	$0	$3,198	$150,549
2011	$103,726	$48,306	$0	$0	$3,198	$155,230

Table 6-6 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$53,515	$106,643	$126,869	$95,676
AEP	$25,716	$47,591	$82,324	$51,877
AP	$51,473	$91,032	$113,561	$85,356
ATSI	NA	NA	$54,554	$54,554
BGE	$56,858	$124,665	$130,806	$104,110
ComEd	$18,383	$33,906	$46,293	$32,861
DAY	$23,596	$46,647	$82,067	$50,770
DLCO	$22,923	$51,180	$81,642	$51,915
Dominion	$58,612	$116,873	$114,530	$96,672
DPL	$55,142	$106,245	$123,599	$94,995
JCPL	$52,935	$105,474	$124,878	$94,429
Met-Ed	$47,338	$97,665	$111,653	$85,552
PECO	$49,620	$99,951	$121,804	$90,458
PENELEC	$42,010	$80,773	$109,048	$77,277
Pepco	$58,923	$121,952	$121,143	$100,673
PPL	$45,115	$87,314	$111,111	$81,180
PSEG	$50,355	$101,819	$114,951	$89,041
RECO	$44,897	$93,724	$96,235	$78,285
PJM	$44,553	$89,027	$103,726	$79,102

Table 6-7 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$117,477	$173,539	$178,353	$156,457
AEP	$66,034	$101,513	$133,808	$100,452
AP	$110,100	$157,928	$165,046	$144,358
ATSI	NA	NA	NA	NA
BGE	$139,127	$198,247	$182,290	$173,221
ComEd	$58,700	$87,828	$97,778	$81,435
DAY	$63,914	$100,569	$133,551	$99,345
DLCO	$63,241	$105,102	$133,126	$100,490
Dominion	$122,575	$184,646	$166,637	$157,952
DPL	$95,460	$160,167	$175,084	$143,570
JCPL	$116,897	$172,370	$176,362	$155,210
Met-Ed	$105,964	$164,561	$163,137	$144,554
PECO	$113,582	$166,847	$173,288	$151,239
PENELEC	$100,637	$147,669	$160,532	$136,279
Pepco	$117,549	$188,848	$172,628	$159,675
PPL	$109,077	$154,209	$162,595	$141,961
PSEG	$132,624	$175,401	$166,435	$158,153
RECO	NA	NA	NA	NA
PJM	$102,060	$152,465	$158,791	$137,772

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched by PJM operations in the Day Ahead market for all available plant hours, both reasonable assumptions for a large, efficient CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. Regulation revenue is calculated for any hours in which the new

13 All starts associated with combined cycle units are assumed to be hot starts.

entrant CP's regulation offer is below the regulation-clearing price.

Table 6-8 PJM-wide net revenue for a CP under economic dispatch by market (Dollars per installed MW-year)

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$47,467	$47,469	$0	$2,051	$1,783	$98,770
2010	$119,478	$54,670	$0	$898	$1,783	$176,830
2011	$70,665	$44,282	$0	$1,025	$1,783	$117,754

Table 6-9 PJM Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$67,257	$149,022	$75,325	$97,201
AEP	$13,379	$56,227	$72,858	$47,488
AP	$36,322	$98,671	$99,020	$78,004
ATSI	NA	NA	$27,942	$27,942
BGE	$36,606	$80,689	$56,940	$58,078
ComEd	$30,169	$106,599	$94,493	$77,087
DAY	$19,206	$77,082	$65,842	$54,043
DLCO	$14,410	$76,395	$47,075	$45,960
Dominion	$36,506	$144,290	$77,310	$86,035
DPL	$30,404	$147,279	$94,908	$90,864
JCPL	$57,382	$147,559	$71,437	$92,126
Met-Ed	$45,652	$139,228	$61,703	$82,195
PECO	$60,767	$142,542	$74,834	$92,714
PENELEC	$59,243	$122,426	$95,440	$92,369
Pepco	$54,534	$160,627	$73,476	$96,212
PPL	$55,246	$114,549	$76,697	$82,164
PSEG	$135,308	$124,533	$47,550	$102,464
RECO	$54,556	$143,410	$59,111	$85,692
PJM	$47,467	$119,478	$70,665	$79,203

Table 6-10 Zonal combined net revenue from all markets for a CP under economic dispatch (Dollars per installed MW-year)

Zone	2009	2010	2011	Average
AECO	$128,381	$211,318	$122,640	$154,113
AEP	$52,513	$106,646	$119,838	$92,999
AP	$92,558	$161,061	$145,923	$133,181
ATSI	NA	NA	NA	NA
BGE	$115,577	$149,741	$104,070	$123,129
ComEd	$69,425	$156,923	$141,347	$122,565
DAY	$58,242	$127,353	$112,811	$99,469
DLCO	$53,547	$126,764	$93,969	$91,427
Dominion	$97,920	$207,434	$125,181	$143,511
DPL	$69,771	$197,413	$142,154	$136,446
JCPL	$118,581	$209,844	$118,528	$148,984
Met-Ed	$101,945	$201,539	$108,685	$137,390
PECO	$121,923	$204,846	$121,782	$149,517
PENELEC	$115,208	$184,704	$142,161	$147,358
Pepco	$110,759	$222,926	$120,398	$151,361
PPL	$116,455	$176,936	$123,652	$139,015
PSEG	$213,276	$193,147	$95,458	$167,294
RECO	NA	NA	NA	NA
PJM	$102,255	$177,412	$121,162	$133,610

Net Revenue Adequacy

To put net revenue results in perspective, net revenues are compared to the annual, nominal levelized fixed costs for each technology. Nominal levelized fixed cost provides for the full recovery of and on capital and all the expenses of operating the facility over 20 years, at a constant nominal annual rate.

The extent to which net revenues cover the levelized fixed costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue.

In this section, net revenue includes net revenue from the PJM Energy Market, from the PJM Capacity Market and from any applicable ancillary service.

Table 6-11 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	20-Year Levelized Fixed Cost		
	2009	2010	2011
Combustion Turbine	$128,705	$131,044	$110,589
Combined Cycle	$173,174	$175,250	$153,682
Coal Plant	$446,550	$465,455	$474,692

New Entrant Combustion Turbine

In 2011, no zones would have received sufficient net revenue to cover the levelized fixed costs of a new CT.

Table 6-12 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year)

Zone	2009	2010	2011
AECO	55%	78%	85%
AEP	32%	47%	63%
AP	50%	73%	74%
ATSI	NA	NA	NA
BGE	70%	93%	88%
ComEd	31%	46%	57%
DAY	31%	47%	63%
DLCO	32%	52%	66%
Dominion	57%	81%	79%
DPL	39%	69%	84%
JCPL	54%	78%	84%
Met-Ed	50%	78%	81%
PECO	54%	77%	85%
PENELEC	47%	66%	73%
Pepco	55%	87%	84%
PPL	53%	73%	82%
PSEG	67%	81%	78%
RECO	NA	NA	NA
PJM	49%	70%	77%

Figure 6-1 compares zonal net revenue for a new entrant CT for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-2 shows zonal net revenue for the new entrant CT for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Figure 6-1 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)

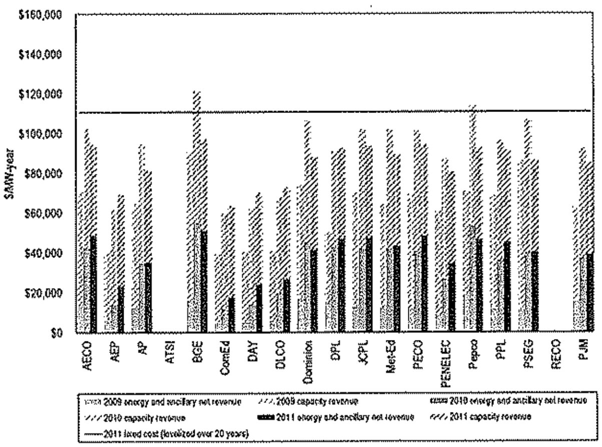


Figure 6-2 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)

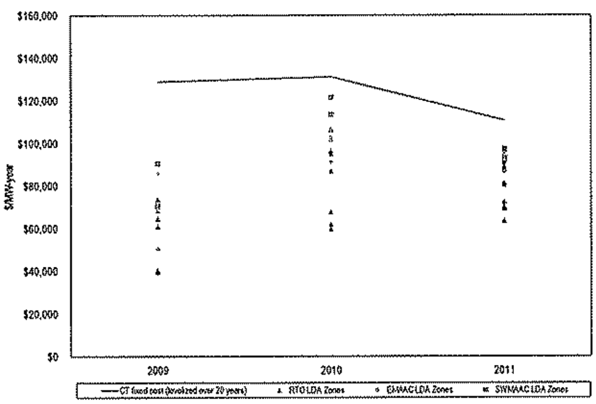
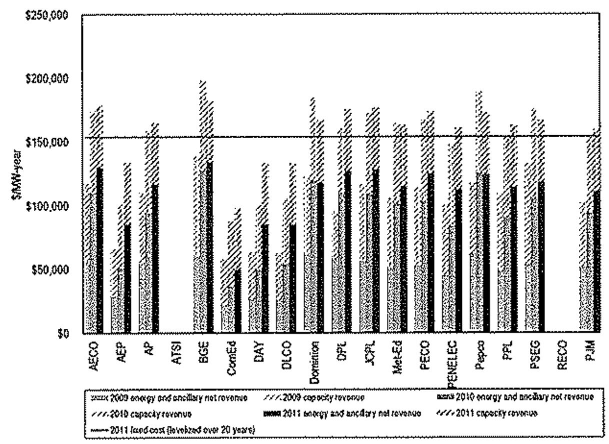


Figure 6-3 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)



New Entrant Combined Cycle

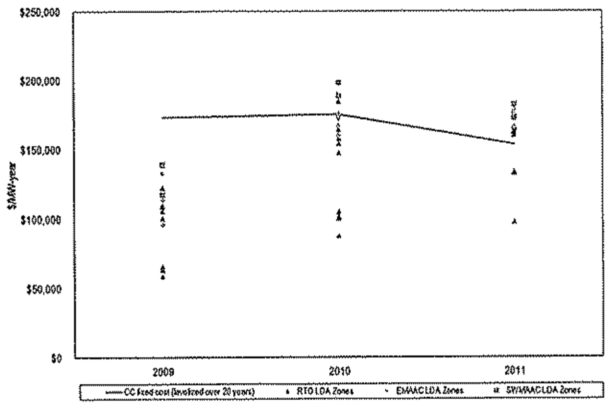
In 2011, all but four zones would have received net revenue sufficient to cover the levelized fixed costs of a new CC.

Figure 6-3 compares zonal net revenue for a new entrant CC for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-4 shows zonal net revenue for the new entrant CC for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Table 6-13 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue

Zone	2009	2010	2011
AECO	68%	99%	116%
AEP	38%	58%	87%
AP	64%	90%	107%
ATSI	NA	NA	NA
BGE	80%	113%	119%
ComEd	34%	50%	64%
DAY	37%	57%	87%
DLCO	37%	60%	87%
Dominion	71%	105%	108%
DPL	55%	91%	114%
JCPL	68%	98%	115%
Met-Ed	61%	94%	106%
PECO	66%	95%	113%
PENELEC	58%	84%	104%
Pepco	68%	108%	112%
PPL	63%	88%	106%
PSEG	77%	100%	108%
RECO	NA	NA	NA
PJM	59%	87%	103%

Figure 6-4 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



New Entrant Coal Plant

In 2011, no zones would have received sufficient net revenue to cover the levelized fixed costs of a new CP. No zone received sufficient net revenue to cover even 40 percent of the levelized fixed costs.

Table 6-14 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue

Zone	2009	2010	2011
AECO	29%	45%	26%
AEP	12%	23%	25%
AP	21%	35%	31%
ATSI	NA	NA	NA
BGE	26%	32%	22%
ComEd	16%	34%	30%
DAY	13%	27%	24%
DLCO	12%	27%	20%
Dominion	22%	45%	26%
DPL	16%	42%	30%
JCPL	27%	45%	25%
Met-Ed	23%	43%	23%
PECO	27%	44%	26%
PENELEC	26%	40%	30%
Pepco	25%	48%	25%
PPL	26%	38%	26%
PSEG	48%	41%	20%
RECO	NA	NA	NA
PJM	23%	38%	26%

Figure 6-5 compares zonal net revenue for a new entrant CP for 2009 through 2011 to the 2011 levelized fixed cost. Figure 6-6 shows zonal net revenue for the new entrant CP for 2009 through 2011 by LDA with the applicable yearly levelized fixed cost.

Figure 6-5 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)

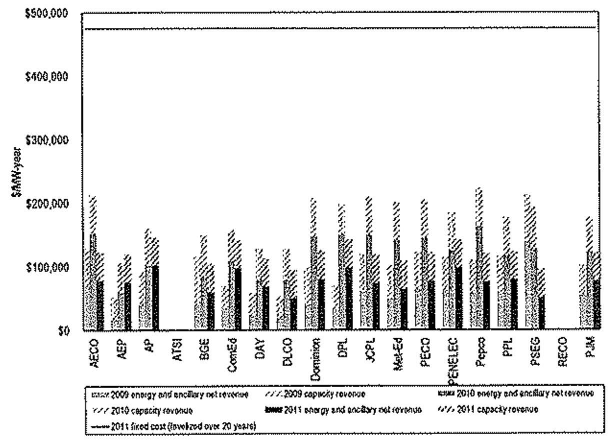
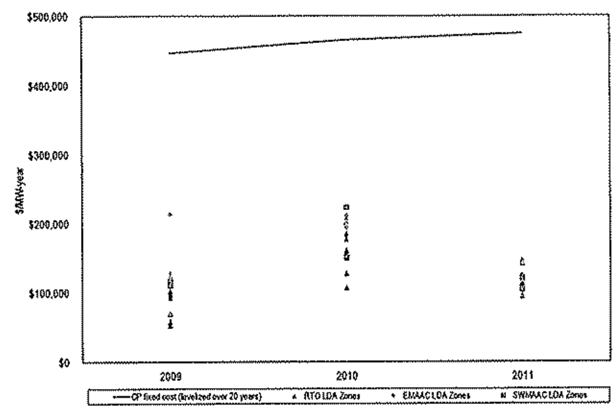


Figure 6-6 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year)



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of net revenue indicates that the contribution of capacity revenue from RPM comprises a larger share of net revenue for a new entrant CT than for the CC or CP technologies. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more

Table 6-15 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$118,089	13.8%	$163,682	13.7%	$504,692	13.7%
Base Case	$110,589	12.0%	$153,682	12.0%	$474,692	12.0%
Sensitivity 2	$103,089	10.1%	$143,682	10.2%	$444,692	10.3%
Sensitivity 3	$95,589	8.1%	$133,682	8.4%	$414,692	8.5%
Sensitivity 4	$88,089	6.0%	$123,682	6.4%	$384,692	6.6%
Sensitivity 5	$80,589	3.5%	$113,682	4.3%	$354,692	4.6%
Sensitivity 6	$73,089	0.5%	$103,682	1.9%	$324,692	2.4%

dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2011, the yearly average operating cost of the CC was lower than the average operating costs of the CP, driven by the decreasing cost of gas and increasing cost of coal.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market. However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which can be an inaccurate estimate of actual net revenues in the current operating year. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2011, zonal energy net revenues increased significantly for most CCs and CTs, while capacity market prices decreased in all zones. As a result, there were some zones that, when both energy revenues and capacity revenues are considered, showed revenue adequacy for a new entrant CC in 2011.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 6-11. The results are shown in Table 6-15.[14]

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 6-16 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR

14 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

falls. Table 6-17 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 6-16 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percentage of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$117,666	$163,034
Sensitivity 2	55%	$114,127	$158,358
Base Case	50%	$110,589	$153,682
Sensitivity 3	45%	$107,050	$149,006
Sensitivity 4	40%	$103,512	$144,330
Sensitivity 5	35%	$99,974	$139,654
Sensitivity 6	30%	$96,435	$134,978

Table 6-17 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$99,512	$139,050
Sensitivity 2	25	$103,698	$144,582
Base Case	20	$110,589	$153,682
Sensitivity 3	15	$116,378	$161,332
Sensitivity 4	10	$124,054	$171,475

Table 6-18 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs, the actual avoidable costs include APIR when unit owners have included APIR in unit offers. This affects the interpretation of the conclusions. Existing APIR is a sunk cost and a rational decision about retirement would ignore such

Table 6-18 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0%	$107,213	$0	0%	$150,034
Sensitivity 2	$4,811	2%	$108,900	$7,692	1%	$151,858
Base Case	$9,622	3%	$110,589	$15,383	2%	$153,682
Sensitivity 3	$14,433	5%	$112,277	$23,075	4%	$155,507
Sensitivity 4	$19,244	6%	$113,965	$30,766	5%	$157,331
Sensitivity 5	$24,055	8%	$115,653	$38,458	6%	$159,155
Sensitivity 6	$28,866	9%	$117,341	$46,149	7%	$160,980
Sensitivity 7	$50,000	16%	$124,756	$50,000	8%	$161,893
Sensitivity 8	$75,000	24%	$133,531	$75,000	11%	$167,822
Sensitivity 9	$100,000	32%	$142,302	$100,000	15%	$173,751

Table 6-19 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	2,236	$15,109	$59,208	$33,169
CC - Two of Three on One Frame F Technology	15,235	$73,628	$120,348	$18,215
CT - First & Second Generation Aero (P&W FT 4)	3,702	$7,436	$52,014	$15,486
CT - First & Second Generation Frame B	3,764	$4,574	$49,920	$12,398
CT - Second Generation Frame E	10,619	$22,231	$67,715	$7,217
CT - Third Generation Aero	3,696	$26,132	$73,816	$16,073
CT - Third Generation Frame F	9,026	$24,920	$69,935	$9,178
Diesel	495	$43,441	$86,074	$7,552
Hydro	1,975	$209,469	$254,535	$25,618
Nuclear	29,741	$240,376	$284,895	NA
Oil or Gas Steam	9,015	$22,308	$62,952	$46,228
Pumped Storage	4,952	$11,586	$61,158	$15,036
Sub-Critical Coal	31,096	$60,180	$98,485	$69,503
Super Critical Coal	24,653	$77,487	$111,428	$96,249

sunk costs. Potential APIR is not a sunk cost and a rational decision about retirement would consider the expected probability of recovering the costs of such new investments over the remaining life of the unit.

The MMU calculated unit specific energy and ancillary service net revenues for several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year based on actual submitted Avoidable Cost Rate (ACR) data for units associated with the most recent 2010/2011 and 2011/2012 RPM Auctions.[15] For units that did not submit ACR data, the default ACR was used.

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2010/2011 and 2011/2012 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[16] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied, which may understate actual revenues, since units may bid an export price into the auction as an opportunity cost and provide capacity to the market with the higher price.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 6-19 provides a summary of

15 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the Base Residual Auction.

16 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

Table 6-20 Energy and ancillary service net revenue by quartile for select technologies for calendar year 2011

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$7,443	$26,432	$90,547
CC - Two of Three on One Frame F Technology	$35,131	$79,038	$102,517
CT - First & Second Generation Aero (P&W FT 4)	$1,960	$4,765	$11,467
CT - First & Second Generation Frame B	$1,128	$3,940	$7,799
CT - Second Generation Frame E	$6,096	$12,826	$33,589
CT - Third Generation Aero	$14,222	$25,227	$34,658
CT - Third Generation Frame F	$10,139	$16,559	$34,776
Diesel	$1,475	$1,990	$5,967
Hydro	$103,780	$202,072	$250,008
Nuclear	$183,106	$266,044	$294,493
Oil or Gas Steam	$1,452	$4,644	$13,004
Pumped Storage	$0	$2,606	$5,064
Sub-Critical Coal	$24,072	$56,123	$86,062
Super Critical Coal	$55,366	$78,780	$97,698

Table 6-21 Capacity revenue by quartile for select technologies for calendar year 2011

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$41,866	$46,794	$47,855
CC - Two of Three on One Frame F Technology	$47,291	$48,149	$49,010
CT - First & Second Generation Aero (P&W FT 4)	$41,809	$44,306	$48,973
CT - First & Second Generation Frame B	$39,182	$47,120	$49,436
CT - Second Generation Frame E	$45,732	$48,737	$49,858
CT - Third Generation Aero	$46,208	$48,862	$49,575
CT - Third Generation Frame F	$44,177	$47,573	$48,533
Diesel	$43,492	$47,175	$51,437
Hydro	$44,259	$48,567	$49,858
Nuclear	$48,015	$49,023	$49,418
Oil or Gas Steam	$40,175	$46,396	$48,534
Pumped Storage	$48,932	$49,181	$49,459
Sub-Critical Coal	$41,468	$46,071	$48,239
Super Critical Coal	$24,231	$44,686	$47,074

Table 6-22 Combined revenue from all markets by quartile for select technologies for calendar year 2011

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$49,310	$73,226	$138,402
CC - Two of Three on One Frame F Technology	$82,422	$127,186	$151,527
CT - First & Second Generation Aero (P&W FT 4)	$43,769	$49,071	$60,440
CT - First & Second Generation Frame B	$40,310	$51,060	$57,235
CT - Second Generation Frame E	$51,828	$61,563	$83,447
CT - Third Generation Aero	$60,430	$74,089	$84,233
CT - Third Generation Frame F	$54,316	$64,132	$83,309
Diesel	$44,966	$49,165	$57,404
Hydro	$148,039	$250,639	$299,865
Nuclear	$231,121	$315,067	$343,911
Oil or Gas Steam	$41,627	$51,040	$61,538
Pumped Storage	$48,932	$51,787	$54,523
Sub-Critical Coal	$65,539	$102,195	$134,302
Super Critical Coal	$79,597	$123,466	$144,772

results by technology class, as well as the total installed capacity associated with each technology analyzed.

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 6-19 incorporate a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis and are useful in presenting the range of data

Table 6-23 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies for calendar year 2011

Technology	Recovery of avoidable costs from energy and ancillary net revenue		
	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	54%	157%	435%
CC - Two of Three on One Frame F Technology	226%	363%	807%
CT - First & Second Generation Aero (P&W FT 4)	23%	65%	104%
CT - First & Second Generation Frame B	12%	37%	83%
CT - Second Generation Frame E	92%	144%	363%
CT - Third Generation Aero	130%	161%	228%
CT - Third Generation Frame F	106%	187%	291%
Diesel	6%	38%	1,731%
Hydro	663%	882%	950%
Nuclear	NA	NA	NA
Oil or Gas Steam	3%	10%	38%
Pumped Storage	NA	NA	NA
Sub-Critical Coal	31%	89%	140%
Super Critical Coal	89%	139%	212%

Table 6-24 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2011

Technology	Recovery of avoidable costs from all markets		
	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	220%	296%	635%
CC - Two of Three on One Frame F Technology	460%	726%	1,100%
CT - First & Second Generation Aero (P&W FT 4)	282%	522%	676%
CT - First & Second Generation Frame B	362%	530%	672%
CT - Second Generation Frame E	659%	709%	921%
CT - Third Generation Aero	387%	573%	632%
CT - Third Generation Frame F	609%	789%	959%
Diesel	420%	707%	2,735%
Hydro	849%	1,061%	1,163%
Nuclear	NA	NA	NA
Oil or Gas Steam	87%	177%	209%
Pumped Storage	186%	443%	664%
Sub-Critical Coal	90%	148%	203%
Super Critical Coal	127%	201%	284%

while avoiding the influence of outliers. The the three break points between the quartiles are presented. Table 6-20 shows average energy and ancillary service net revenues by quartile for select technology classes.

Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivery costs associated with input fuels. The average net revenues for diesel units, the oil or gas-fired steam technology, and several of the older CT technologies reflect both units burning natural gas and units burning oil distillates. The geographical distribution of units for a given technology class across the PJM footprint determines individual unit price levels and thus significantly affects average energy net revenue for that technology class.

Table 6-23 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2011, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone.

Table 6-24 shows the avoidable cost recovery from all PJM markets by quartiles. In 2011, the majority of units in all technology classes received energy, ancillary and capacity revenue well in excess of avoidable costs.

Table 6-25 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets for 2009, 2010 and 2011. Since 2009, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM.

Table 6-25 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2009 to 2011

	2009		2010		2011	
Technology	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets	Units with full recovery from energy and ancillary markets	Units with full recovery from all markets
CC - NUG Cogeneration Frame B or E Technology	57%	96%	83%	92%	64%	89%
CC - Two of Three on One Frame F Technology	63%	89%	84%	100%	87%	97%
CT - First & Second Generation Aero (P&W FT 4)	24%	99%	34%	100%	32%	99%
CT - First & Second Generation Frame B	30%	100%	34%	98%	29%	94%
CT - Second Generation Frame E	60%	100%	67%	100%	82%	100%
CT - Third Generation Aero	23%	99%	49%	99%	87%	99%
CT - Third Generation Frame F	41%	98%	69%	100%	79%	98%
Diesel	69%	97%	71%	97%	61%	91%
Hydro	100%	100%	100%	100%	96%	100%
Nuclear	100%	100%	100%	100%	100%	100%
Oil or Gas Steam	36%	90%	40%	87%	43%	86%
Pumped Storage	45%	100%	90%	100%	70%	100%
Sub-Critical Coal	66%	88%	73%	88%	63%	77%
Super Critical Coal	74%	91%	77%	80%	81%	88%

For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for most units that do not recover 100 percent of fixed costs through energy market revenue.

A significant number of sub-critical and supercritical coal units did not recover avoidable costs from energy market revenues alone in 2011. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal units relies more heavily on energy market revenues.

At-Risk Coal Plants

A number of sub-critical and supercritical coal units did not recover avoidable costs even including capacity market revenues. These units are considered at risk of retirement.

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at-risk analysis.[17]

Energy market net revenues are a function of energy prices and operating costs. Avoidable costs are a function of technology, unit size and age of units and, in some cases, unit specific investments needed to maintain or enhance reliability or to comply with environmental regulations.

Table 6-26 compares characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues, to characteristics of coal plants with greater than or equal to 100 percent recovery. Units that did not cover their avoidable costs were, on average, less efficient and ran less often.

Units that did not cover avoidable costs generally sold capacity in RPM auctions, but some showed reduced capacity market revenues which may be attributable to partial clearing in Base Residual Auctions (BRA), high outage rates affecting the unforced capacity level that can be offered, or performance penalties associated with nonperformance. Units that did not cover avoidable costs tended to have higher avoidable costs. It is possible that these units cleared in the capacity market at a level below avoidable cost recovery due to the lag in market revenues used to calculate offer caps associated with each delivery year which led to an offer cap that understated the annual recovery needed from the RPM, or, these units may have been offered at a price below the avoidable cost based offer cap, including APIR. Such offers are rational, for example, if project costs are considered sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate. In either case, these units may be at a lower risk of retirement than units under recovering

17 This is based on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

avoidable costs exclusive of the recovery of capital investments.

Table 6-26 Profile of coal units

	Coal plants with less than full recovery of avoidable costs	Coal plants with full recovery of avoidable costs
Total Installed Capacity (ICAP)	5,642	36,383
Avg. Installed Capacity (ICAP)	235	319
Avg. Age of Plant (Years)	46	38
Avg. Heat Rate (Btu/kWh)	11,135	10,701
Avg. Run Hours (Hours)	4,300	5,627
Avg. Avoidable Costs ($/MW-year)	512	146

In 2011, 73 coal units had capacity less than or equal to 200 MW. Of these units, 19 percent did not cover their avoidable costs. The risk of deactivation for these units depends on the degree to which revenues from all markets are less than avoidable costs. Table 6-27 shows the installed capacity (MW) associated with levels of recovery for coal plants.

Table 6-27 Installed capacity associated with levels of avoidable cost recovery: Calendar year 2011

Groups of coal plants by percent recovery of avoidable cost	Installed capacity (MW)	Percent of total
0% - 65%	3,793	9%
65% - 75%	111	0%
75% - 90%	465	1%
90% - 100%	1,273	3%
> 100%	36,383	87%
Total	42,025	100%

Impact of Environmental Rules

Environmental rules may affect decisions about investments in existing units, investment in new units and decisions to retire units. There are pending regulations that would require significant capital expenditures on environmental controls for existing units. These capital expenditures, if required, would significantly impact the profitability of coal plants lacking sufficient environmental controls. Coal plants facing capital expenditures may be retired if it is not expected that the plants will recover the associated costs through a combination of energy or capacity revenue. The extent to which capital expenditures affect an individual unit's offer in the capacity market depends upon the size of the unit, the level of investment required, the life and recovery rate of the investment, avoidable costs, and the expected net revenue.

The MMU analyzed the impact that pending environmental regulations regarding SO_2 and NO_x emissions and particulate control may have on coal plants in the PJM footprint.[18] A number of coal plants that would have had to invest in MATS compliant environmental technology have either already started the deactivation process or are expected to request deactivation.[19] Units lacking MATS compliant controls for NO_x emissions, SO_2 emissions, particulates, or all three, were identified as units potentially facing significant capital expenditures on environmental control technologies. Table 6-28 shows the number of units and associated installed capacity lacking MATS compliant environmental controls.

Table 6-28 Coal plants lacking MATS compliant environmental controls

	Coal plants without NO_x controls	Coal plants without SO_2 controls	Coal plants without particulate controls	Coal plants lacking NO_x, SO_2, and particulate controls
Number of units	62	41	52	23
Installed capacity (ICAP)	11,806	7,441	13,806	2,980

Table 6-29 compares attributes of coal plants with controls in place to units that lack controls for NO_x emissions, SO_2 emissions, particulates, or all three.

The MMU estimated the cost of installing MATS compatible environmental controls for each unit to determine at risk units.[20] Table 6-30 shows at risk units, which include units that did not cover their avoidable costs from all market revenues in addition to units that would not be able to cover the cost of installing MATS compliant environmental controls from all market revenues. A comparison of Table 6-30 to Table 6-26 shows that only 122 MW of additional coal capacity, for which plans to retire have not already been indicated, are at risk due to MATS compliance. The additional MW of coal capacity at risk to due to MATS compliance risk increases 1,294 MW if the threshold is increased to 125 percent recovery of avoidable costs.

18 FRR committed units are excluded from this analysis since they receive compensation out of PJM Markets.

19 This is based on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

20 Costs of environmental controls provided by Pasteris Energy, Inc.

Table 6-29 Attributes of coal plants with and without MATS compliant environmental controls

	Coal plants lacking NO_x, SO_2, or particulate controls	Coal plants with NO_x, SO_2, and particulate controls
Number of units (excluding announced or expected deactivations)	80	58
ICAP within MAAC	6,618	5,247
ICAP in rest of RTO	10,487	19,674
Total installed capacity (ICAP)	17,104	24,921
ICAP associated with plants older than 40 years	14,248	9,216
ICAP associated with small coal plants (200 MW or less)	5,958	2,001
ICAP associated with medium coal plants (200 to 500 MW)	2,495	4,915
ICAP associated with large coal plants (500 MW or greater)	8,652	18,005
ICAP associated with 100 percent recovery of avoidable costs	14,927	21,456
ICAP associated with less than 100 percent recovery of avoidable costs	2,177	3,465

Table 6-30 At risk coal plants

	Coal plants covering less than	
	100% of avoidable costs or 100% of APIR (if any)	125% of avoidable costs or 125% of APIR (if any)
Number of units	26	30
ICAP within MAAC	1,630	1,765
ICAP in rest of RTO	4,135	5,172
Total installed capacity (ICAP)	5,764	6,936

Exhibit RBS-5

Maximum Offer Prices for the AEP Ohio Fleet, 2011/12 to 2014/15 With and Wihout APIR

ACR ($/MW-day)	APIR ($/MW-day)	E&AS Offset ($/MW-day)		Net Capacity Cost ($ per MW-day)	Net Capacity Cost + APIR ($/MW-day)
$197.94	$97.08	$345.65	**Base Case**	-$148.14	-$51.05
$197.94	$97.08	$345.65	**Alternative Case**	$2.97	$28.11
[1]	[2]	[3]		[4] = [1] - [3]	[5] = [1] + [4]

Sources: *AEP OH Cost Based Offset_base_UCAP.xlsx*
AEP OH Cost Based Offset_UCAP_0Floor_BRACAP.xlsx

Note: Sums and differences do not match perfectly in this summary due to presence of default APIR values in PJM ACR assumptions. See source files for details.

Exhibit RBS-6

The Brattle Group

Second Performance Assessment of PJM's Reliability Pricing Model

Market Results 2007/08 through 2014/15

August 26, 2011

Johannes Pfeifenberger
Samuel Newell
Kathleen Spees
Attila Hajos
Kamen Madjarov

Prepared for

PJM Interconnection, L.L.C.

Acknowledgements

The authors would like to thank PJM staff, the Independent Market Monitor, state regulatory commissions, and other stakeholder groups for their cooperation and responsiveness to our many questions and requests. We would also like to acknowledge the contributions of The Brattle Group research analysts Robert Carlton and Evan Pittman, and the guidance of Professor Benjamin Hobbs on the probabilistic simulations presented in this report. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone.

EXECUTIVE SUMMARY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. ("PJM") to evaluate the performance of its Reliability Pricing Model ("RPM"), as required periodically under the PJM tariff. The scope of our evaluation includes: (1) a review of all Base Residual Auctions ("BRAs") and Incremental Auctions ("IAs") conducted to date to assess RPM's effectiveness in encouraging and sustaining sufficient capacity investments for reliability; (2) stakeholder interviews to identify key areas of concern; (3) an engineering cost estimate of the Cost of New Entry ("CONE") for each of five CONE Areas; (4) an evaluation of individual RPM design elements, including the Variable Resource Requirement ("VRR") curve, the Energy and Ancillary Service ("E&AS") offset methodology, and other design elements identified by stakeholders; (5) a probabilistic simulation analysis of RPM's performance; and (6) development of recommendations for possible modifications to improve the effectiveness of RPM.

Our primary finding is that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the Regional Transmission Organization ("RTO") and, during the last four BRAs, in all of the individual Locational Deliverability Areas ("LDAs") at capacity prices below the net cost of new entry ("Net CONE"). Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement.

Stakeholders have raised a number of key concerns. We find, however, that several major criticisms of RPM are contradicted by evidence available to date—most notably the arguments that RPM prices are too high, that RPM does not support investment in new generation of the right types in the right places, or that RPM cannot maintain reliability in the face of environmental retirements. Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or elimination of Interruptible Load for Reliability ("ILR"). These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward. However, price uncertainty remains high due to non-transparent, and possibly excessive, fluctuations in modeled transmission limits and other administratively-defined parameters in RPM. We thus recommend a number of refinements to make the determination of transmission limits and administrative parameters more stable and transparent. To increase forward price transparency and facilitate long-term contracting, we also support the development of voluntary auctions or an over-the-counter trading platform for long-term capacity products.

Finally, we have identified several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward. To address these concerns, we recommend the implementation of six safeguards that would mitigate the identified performance risks. First, we recommend calibrating the E&AS offset methodology to E&AS margins actually earned by generation plants similar to the reference technology, which may increase Net CONE in some LDAs. Second, we recommend raising the price cap of the VRR curve to mitigate under-procurement risks. The higher cap will avoid the collapse of the VRR curve following anomalously high E&AS margins, which could result in reserve margins that remain well below reliability requirements. The higher cap will also avoid deterring offers with costs that temporarily exceed the *current* cap due to large differences between actual and administrative Net CONE values. Third, we recommend modeling constrained LDAs more proactively for locations where significant amounts of plant retirements are likely.

Fourth, we recommend maintaining the 2.5% overall Short-Term Resource Procurement Target ("STRPT") for the total resource requirement, but eliminating the "holdback" for Annual and Extended Summer resources. Fifth, we recommend introducing audits of demand-side resources to confirm their contractual and physical ability to respond as often and seasonally as claimed. And finally, we recommend establishing exemptions to the Minimum Offer Price Rule ("MOPR") to better support competitive entry through bilateral and self-supply arrangements.

The report explains these and other more minor recommendations for possible refinements to the RPM design that could further improve market efficiency. It also summarizes the results of the CONE study we conducted, including our recommendations about the choice between levelization methods. The detailed engineering cost study is documented in our separate report, *Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM* ("CONE Report").

A. RPM AUCTION RESULTS TO DATE

RPM introduced a capacity market design based on three-year forward annual auctions for locational capacity, with supply offers clearing against a downward sloping demand curve (the VRR curve). RPM is designed to achieve resource adequacy, improve price stability compared to the previous capacity market construct, and force existing resources to compete with a potentially large supply of new resources.

We previously assessed the overall effectiveness of RPM in our 2008 *Review of PJM's Reliability Pricing Model (RPM)*, which documented RPM auction results for the first five delivery years; from 2007/08 through 2011/12. Since then, three more base auctions have been conducted; the latest in May 2011 for the 2014/15 delivery year.

Based on our analysis of all RPM auctions conducted to date, we present the following findings:

- RPM has attracted and retained sufficient capacity to maintain resource adequacy in the RTO and in all LDAs, in spite of environmental and other challenges faced by suppliers. All regions have demonstrated capacity supplies in excess of their reliability requirements in all delivery years for which procurement was undertaken on a full three-year forward basis. Capacity resources were slightly below the reliability requirements during the first few delivery years in some LDAs, reflecting existing supply largely determined by pre-RPM conditions and a shorter-term forward procurement during the first four auctions that prevented most planned capacity from participating.

- Since RPM was implemented, a total of 28,400 MW of installed capacity ("ICAP") from new resources have been committed on an RTO-wide basis (not counting resources from Fixed Resource Requirement ("FRR") entities and new PJM members, FirstEnergy and Duke). These additions consist of 11,800 MW of demand side resources, 6,900 MW of increased imports and decreased exports, 4,800 MW of new generation, 4,100 MW of plant uprates, and 800 MW of plant reactivations. These resource additions are partially offset by 5,000 MW of retirements, 2,700 MW of plant derates, 6,800 MW of capacity initially offered into the RPM auctions by FRR entities but that was subsequently withdrawn to serve the entities own requirements, and 700 MW of otherwise excused resources. On net, the amount of committed capacity has increased by 13,100 MW, more than enough to meet reliability requirements.

- Similarly in all of the LDAs, net resource additions (including upgrades in transmission import capabilities) have been more than sufficient to meet reliability requirements. This occurred even in eastern LDAs, which showed resource deficiencies (relative to their reliability requirements) in the auctions for the first four delivery years. Furthermore, all areas have had significant amounts of uncleared offers from both new and existing resources, including new generation resources, that could have been procured at higher prices had those supplies been needed for reliability. Perhaps one exception is the PEPCO LDA, where little new generation has been offered, but resource adequacy has been maintained by new demand response ("DR") resources and uprates at prices that were well below the cost of new generation in three of the last four auctions.

- RPM has greatly facilitated competition among various types of capacity resources. The capacity market has attracted commitments from new generation. But it has attracted even larger amounts of new DR resources, retained existing generation, and supported the upgrade of existing plants at prices below the cost of new generation. Competition in RPM's centralized forward auctions has also allowed owners of aging coal plants to make more informed decisions about whether to invest in environmental retrofits or start planning to retire the units, particularly in the most recent auction for the 2014/15 delivery year.

- As a result of offers from a wide variety of new resources, particularly demand response resources, the BRA supply curves have become smoother and less steep over time, mitigating the steep offer curves in the first few auctions. This trend increased competition between resources in the recent auctions and will reduce price volatility going forward.

- Base Residual Auction prices have been consistent with the supply and demand for capacity, including transmission capabilities. Apart from the initial, compressed-schedule forward auctions that were dominated by pre-RPM supply conditions, prices have been below Net CONE because new generation was not needed to maintain resource adequacy given the availability of lower-cost, non-generation alternatives. Nevertheless, auction clearing prices were quite volatile, reflecting changes in market fundamentals, RPM rules, and RPM parameters.

- Clearing prices in the incremental auctions have been persistently below BRA prices, in part reflecting low incremental demand for capacity due to declines in load forecast and increased transmission capabilities. Furthermore, clearing prices and supply curves during the first few incremental auctions appear to have been disconnected from market fundamentals and BRA prices due to deficiencies in the initial auction design. Supply curves observed in the two incremental auctions conducted since the initial design was revised have been more consistent with offers observed in the respective BRAs. In the case of EMAAC, prices have also responded efficiently to declines in LDA import capabilities. Overall, however, the limited experience with the new, revised design does not yet allow for a full analysis of the performance of the incremental auctions.

B. STAKEHOLDER CONCERNS

We conducted interviews with eight groups of stakeholders: transmission owners, generation owners, electric distributors, end-use customers, other suppliers, financial analysts, state utility commissions, and PJM's Independent Market Monitor. The concerns they raised covered a wide range of topics. Stakeholder comments largely agreed on concerns over: (1) the uncertainty and unpredictability of RPM prices; (2) the volatility and lack of transparency in the determination of Capacity Emergency Transfer Limits ("CETL"); (3) the need for better coordination between RPM and transmission planning; (4) a lack of long-term contracting and the need to facilitate such contracting; (5) the potential impacts of EPA's new environmental rules; and (6) challenges created by the use of a historical E&AS offset.

Stakeholder opinions were divided, however, on a variety of topics, including concerns about: (1) a lack of new generation; (2) the treatment of existing and new capacity; (3) the level of CONE estimates; (4) load forecasts and reliability requirements; (5) the shape of the VRR curve; (6) the 2.5% short-term procurement target; (7) the performance and treatment of demand-response resources; (8) the appropriate number of LDAs; (9) the appropriateness of the length of the 3-year forward procurement period between the BRA and the delivery year; (10) how to facilitate long-term contracting; and (11) the efficiency and unintended consequences of the new Minimum Offer Pricing Rule ("MOPR").

Concerns raised by stakeholders are addressed throughout our report. While not all of these themes are RPM design issues, they nevertheless relate directly to capacity procurement costs and price uncertainty in the RPM market. These themes include RPM price uncertainty created by administrative parameters, the need for and the industry trends in long-term contracting, compensation for existing and new generation, the uncertainty created by the new environmental regulations, the dependability of DR, and the determination of reliability targets. Our findings in these areas are:

- *Price Volatility and Uncertainty*. Capacity prices have been volatile and uncertain, which increases the risks and therefore the costs faced by suppliers. Main causes are: (1) market fundamentals, whose effects on price signals should not be dampened; (2) the implementation of improvements to previous design elements regarding DR participation and LDA modeling which had a non-recurring impact on capacity prices; and (3) current methods of determining the value of administrative parameters, including CETL, locational reliability requirements, and load forecasts, which PJM should strive to make more stable and/or transparent.

- *The Lack of Long-Term Contracts*. Many generation projects proposed in PJM cannot obtain financing under the current market conditions. However, while some project developers may cast this as a market failure caused by the inadequacies of RPM or state retail choice constructs, we believe the primary reason that these projects cannot obtain financing is that they are not currently needed and are currently uncompetitive with alternative sources of capacity. In the future, when these projects are needed for resource adequacy, we expect that market prices will rise sufficiently to make these investments attractive. Nevertheless, we also recognize that it will be beneficial to both suppliers and customers if long-term contracts are facilitated and not hindered by RPM design and state retail regulation. To address long-term contracting concerns, we present options for increasing forward price transparency and offer recommendations to mitigate the perhaps unintended consequences of the recent modifications to MOPR.

- *Equal Compensation for Old and New Generation*. A number of state commissions expressed concern that RPM has maintained old generating plants with high emissions, compensating them as much as newer generation. With regard to environmental issues, we find that RPM is well designed to respond to existing environmental regulations and has successfully retained generation that complies with these existing standards. RPM should not be expected to serve as an indirect mean to impose tighter environmental standards than the state and federal governments have deemed appropriate. Moreover, trying to differentiate payments based on age would be inconsistent with a construct in which all resources are selling the same capacity product, and would lead to inefficiencies and higher costs in the long term.

- *Environmental Retirements*. Several stakeholders expressed concern about RPM's ability to replace or prevent simultaneous retirements of a large amount of generation caused by EPA's new environmental regulations. To date, RPM has responded well to such challenges due to its retrofit provisions, the forward period, and centralized clearing. So far, RPM has successfully and economically supported resource adequacy for the 2014/15 delivery year when EPA's new regulations become effective and over the 2009 through 2011 timeframe when Maryland implemented its Healthy Air Act. However, significant uncertainties remain as RPM has not yet been tested with larger amounts of simultaneous retirements within individual LDAs. It is consequently too early to tell how well RPM (or any other construct) will be able to address the challenges caused by the full slate of new EPA regulations planned to take effect between 2015 and 2018. Given the risks, we recommend that PJM continue to monitor potential retirements and implement safeguards such as a more proactive modeling of new LDAs.

- *The Dependability of Demand Response*. Generation and transmission owners expressed the concern that almost 10% of total resources cleared in the 2014/15 auction without assurance that so much DR can be developed and perform. The level of DR capacity committed for the 2014/15 delivery year is approximately 4,000 MW higher (in terms of unforced capacity or "UCAP") than the 10,900 MW of DR, energy efficiency ("EE"), and ILR resources that are already registered for the current 2011/12 delivery year—which appear to have been performing well during the recent heat wave. While substantial, the 4,000 MW increase over the next 3 years compares to a 6,000 MW increase over the past three years. Considering these trends and the fact that penalty provisions for deficiencies and performance violations are roughly comparable to those faced by generation, we anticipate adequate performance on average. However, we also recommend additional safeguards to ensure that all resources can perform as frequently and seasonally as claimed.

- *RPM Procurement Target*. Stakeholders raised concerns about the current methods used to determine the reliability requirement and the load forecast, which together determine the target level of procurement in RPM. We recognize that reviewing the targets themselves is not within the scope of our evaluation. However, in response to stakeholders' concerns, we offer recommendations for further examination of the targets and for improving transparency of the load forecasting process. We also recommend that PJM assess the economic benefits of selected target reserve margins and re-evaluate whether the 1-in-25 LDA reliability requirement should be modified to explicitly depend on the level of import dependence in the LDA and the probability of transmission outages.

C. ESTIMATES FOR THE NET COST OF NEW ENTRY

We recommend maintaining a combustion turbine ("CT") as the reference technology for the determination of Net CONE to define the VRR curve. Based on an examination of plants currently under construction in PJM and the U.S., and an analysis of likely future NO_X emissions standards, the reference plants are assumed to be configured as follows: a 390 MW (summer rating) greenfield CT plant with 2 GE 7FA.05 turbines with selective catalytic reduction ("SCR") for NOx control (only dry low-NO_X burners in Dominion), and evaporative cooling for power augmentation. Combined-cycle ("CC") plants were also evaluated based on a 2x1 configuration using GE 7FA.05 turbines, a cooling tower, SCR, evaporative cooling, and a total capacity of approximately 656 MW (summer rating), of which 72 MW is associated with duct firing.

For these CT and CC plant designs, we developed plant capital costs estimates working with CH2M HILL, a major EPC contractor. CH2M HILL relied on the same engineering cost models it currently uses to bid for actual projects. Resulting estimates of plant capital costs are reported here for each of five CONE areas of PJM. Details of this analysis are documented in the CONE Report prepared concurrently with this report.

The gross CONE is based on levelized plant capital costs plus estimated fixed operation and maintenance costs. The levelization calculation assumes balance-sheet financing by a merchant generator without a long-term power purchase agreement at an 8.5% after-tax weighted-average cost of capital ("ATWACC") and 20-year cost recovery. In Eastern Mid-Atlantic Area Council ("Eastern MAAC" or "EMAAC") for example, levelized CT costs are $134/kw-year ($367/MW-day) for the 2015/16 delivery year using the "level-nominal" capital charge rate method currently used in the RPM design. Our gross CONE estimate for EMAAC is 6% lower than the $142/kW-year ($389/MW-day) inflation-adjusted gross CONE estimate currently used in RPM.

We recommend that PJM and its stakeholders ***consider transitioning from the current "level-nominal" to a "level-real" capital charge rate methodology***. The "level-real" method assumes that the trajectory of future operating margins will grow with inflation as the net cost of new plants increases, which our analysis shows is consistent with the rate of historical cost increases. This recommendation is contingent on the adoption of our other recommendations (summarized below) to improve the E&AS offset and raise the price cap of the VRR curve. If implemented, the "level-real" capital charge rate would yield a gross CONE for 2015/16 of approximately $112/kW-year ($306/MW-day) for EMAAC. However, we estimate this $30/kW-year ($82/MW-day) decline in gross CONE estimates from the inflation-adjusted, current gross CONE will be approximately fully offset in eastern PJM by a lower, more accurate E&AS offset.

The administratively-determined E&AS offset currently over-estimates the E&AS margins actually earned by plants similar to the reference technology, especially in EMAAC and Southwestern MAAC. We consequently recommend that the ***calculation of the E&AS offset be improved to better reflect actual E&AS margins earned by similar plants***. Options include: (a) calibrating the dispatch algorithm used to estimate E&AS offsets so that it accurately reflects actual units' net revenues (*e.g.*, to incorporate significant participation in day-ahead markets even by CTs) or (b) that the E&AS offset be calculated directly from the net revenues earned by comparable new units (and regardless of whether these representative units are located in the same zone used to develop the gross CONE estimate). To reduce RPM price volatility, improve the timing of investment signals, and increase VRR curve performance, we also recommend that PJM and its stakeholders ***continue to explore options for developing either a normalized, forward-looking E&AS offset or an E&AS offset consistent with "equilibrium" market conditions at target reserve margins.*** Finally, we have assessed the potential for an empirical determination of Net CONE based on the bid information from new resources participating in the RPM auctions. Our analysis documents a very wide range of bid levels, leading us to the conclusion that this information is not useful to develop empirical estimates of Net CONE.

D. INCREASING RPM PRICE TRANSPARENCY AND STABILITY

Significant changes in market fundamentals, including the unexpected swings in economic conditions, and several RPM design improvements implemented over the last several years have caused substantial swings in capacity prices. However, excess capacity price uncertainty remains that should be mitigated. The remaining sources of price uncertainty primarily relate to administrative parameters, including unexpected changes in LDA modeling, large and unexpected changes in LDA import constraints (CETL), and unexpected changes in load forecasts.

To reduce excess RPM price volatility, we offer a number of recommendations for further consideration and evaluation by PJM and its stakeholders. They include options that would ***increase CETL transparency and predictability*** (*e.g.*, by providing four, five and ten year CETL projections as part of the transmission planning process) and ***reduce the frequency of large CETL changes*** (*e.g.*, by introducing thresholds that help stabilize transmission plans). We also recommend that PJM and stakeholders consider options to ***improve coordination between RPM and PJM's transmission planning process*** (*e.g.*, by adding economic criteria to the reliability planning process and considering likely plant retirements), to ***minimize the likelihood that resource adequacy concerns related to plant retirements are addressed through reliability-must-run contracts***, and ***facilitate market-based responses to resource adequacy concerns*** that are identified through the transmission planning process.

To increase forward price transparency and facilitate bilateral long-term contracting, we also support PJM's effort to add centralized but voluntary auctions for long-term capacity products as a supplement to the 3-year forward base auctions (*e.g.*, for a duration of 3, 5, and 7 years starting with the BRA delivery year). Such ***voluntary long-term auctions or an over-the-counter trading platform for long-term capacity products*** would increase the transparency and liquidity of the long-term capacity market without risking the kinds of distortions that would be caused to auction prices if the prices for a single delivery year could be locked for multiple years in by broadening the New Entry Pricing Adjustment ("NEPA") or introducing mandatory long-term procurement.

E. Safeguarding Future RPM Performance

While our analyses confirm that PJM has performed well to date, we also identified potential performance concerns. First, probabilistic market simulations identified potential performance problems with the current VRR curve when used in combination with historical E&AS offsets. These performance concerns are related to the current definition of the VRR curve cap (*i.e.*, point "a") as 1.5 × Net CONE. The simulations show that the current design risks the collapse of the entire VRR curve whenever historical energy margins spike (*e.g.*, due to unusual weather, outages, or other unexpected scarcity events). If E&AS offsets reach or exceed the value of CONE, the entire VRR curve disappears (*i.e.*, there is no demand for capacity), which can leave the market "stuck" at reserve margins that remain well below reliability targets. Even without a full collapse of the VRR curve, the current design does not provide the investment signals that can be depended upon to maintain reliability targets. This is the case whenever the historical E&AS offset is high, for example, and the cap of the VRR curve cap drops to levels less than generation developers' actual net cost of new entry.

To guard against such outcomes and maintain investment signals that can reasonably support achieving reliability targets, we recommend that PJM and stakeholders consider ***increasing the***

cap of the VRR curve such that the cap (point "a") exceeds the administratively determined value of Net CONE (point "b") by at least 0.5 × CONE and perhaps by as much as 1.0 × CONE (compared to the current cap, which exceeds point "b" by only 0.5 × Net CONE). This would reduce the likelihood that the cap is too low to attract offers under a variety of circumstances. It would also have avoided a problem encountered in SWMAAC, where a low price cap (relative to the price in the MAAC parent LDA) prevented the LDA from price-separating and continuing to procure local capacity in the 2010/11 auction in spite of shortages. Probabilistic market simulations indicate that increasing the VRR curve cap to 0.5 × CONE above point "b" would likely offset approximately 80% of the performance deterioration associated with the use of historical E&AS offsets. We also recommend that PJM ***clarify that the value of Net CONE cannot drop to levels less than zero*** for the purpose of defining points a, b, and c of the VRR curve and, as noted above, renew efforts to develop a normalized, forward looking or equilibrium E&AS offset.

In addition to modifying the VRR curve, we recommend that PJM and its stakeholders consider implementing a number of additional safeguards:

- ***Proactive LDA modeling***. To address potential locational resource adequacy challenges created by new environmental rules, we recommend that PJM proactively model LDAs in upcoming incremental and base residual auctions. We recommend that LDAs be modeled as soon as it appears that a significant amount of existing resources may be at risk for retiring within the LDAs. Resources at risk for retirement would be existing generation that did not clear in the most recent BRA or that have otherwise been determined to be at risk for retirement.

- ***Modify the 2.5% Short-Term Resource Procurement Target (STRPT)***. We recommend that PJM maintain the 2.5% overall STRPT but eliminate any "holdback" for Extended Summer and Annual resources. Holding back procurement of 2.5% of these higher-quality resources could suppress prices and lead to resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations. Overall, we find that the STRPT does not distort capacity prices because more than 2.5% of total resources offered are unmitigated, allowing suppliers to freely adjust their offers or their decisions to participate in BRAs versus incremental auctions.

- ***Resource Verification***. We recommend that PJM and its stakeholders consider a number of refinements to the existing verification and enforcement provisions for demand-side resources. This would further improve the efficiency of RPM and ensure that all resources can perform as claimed. Our recommendations include testing of DR resources and expanding the resource registration process undertaken prior to each delivery year to include audits of contracts and physical loads to verify the capabilities of zonal resource portfolios to curtail as frequently and seasonally as represented, with appropriately penalties to provide incentives for DR providers to represent their resources accurately. This will allow PJM to confirm that resources can respond as often and seasonally as claimed. For example, this process would verify that resources providing "Annual" DR can respond in all seasons and do not have contractual limitations on the number of events.

- ***Exemptions from Minimum Offer Price Rule ("MOPR")***. We recognize that MOPR is important for preventing manipulation of RPM prices by buyers. However, we hope that the present proceeding on MOPR expands exemptions to prevent unintended consequences. Exemptions we recommend considering would apply to any capacity resource that is (1) procured under non-discriminatory competitive processes that are open to supplies from existing and new generation resources; or (2) self-supplied by entities that would not obtain net benefits from RPM price impacts, such as vertically-integrated load-serving entities and other resource owners (and their counterparties) that can demonstrate they do not have a significant net short position in RPM.

TABLE OF CONTENTS

I. BACKGROUND

A. PURPOSE AND SCOPE OF THIS STUDY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. ("PJM") to evaluate the performance and the overall design of its Reliability Pricing Model ("RPM"), as required periodically under the PJM tariff. The evaluation criterion is the effectiveness in meeting RPM's objective, which is to enable PJM to obtain sufficient resources to reliably meet the electricity needs of consumers within PJM. Several corollary objectives are to align capacity pricing with system reliability requirements, to provide transparent information to all market participants far enough in advance for actionable response, to support investment in demand-side resources and alternative supply resources as well as generation, to prevent boom-bust cycles in investments, to coordinate between RPM and Regional Transmission Planning ("RTEP"), and to reduce uncertainty in order to lower overall consumer cost to maintain reliable capacity supply in the long run. The specific scope of this assessment included:

1. A review of all Base Residual Auctions ("BRAs") and Incremental Auctions ("IAs") conducted to date (*i.e.*, through the 2014/15 delivery year) to assess the performance and overall effectiveness of RPM in encouraging and sustaining infrastructure investments;
2. Stakeholder interviews to identify key areas for performance assessment;
3. An evaluation of individual RPM design elements, in particular the Variable Resource Requirement ("VRR") curve and the Energy and Ancillary Service ("E&AS") offset methodology;
4. A simulation modeling analysis of the ability of RPM to reduce uncertainty and support investment sufficient to meet reliability requirements on a probabilistic basis;
5. An empirical and an engineering-cost assessment of the Cost of New Entry ("CONE") for each of five CONE Areas; and
6. Developing recommendations for possible modifications (if any) to improve the effectiveness of RPM.

We previously assessed the overall effectiveness of RPM in encouraging and sustaining infrastructure investments, documented the outcomes of the first five BRAs, analyzed the effectiveness of individual market design elements, and presented a number of recommendations for considerations by PJM and its stakeholders. The results of this prior assessment were presented in our June 2008 report reviewing RPM's performance ("2008 RPM Report").[1]

The remainder of this report is organized as follows. We first provide some background on RPM and summarize its current design. Section II discusses RPM auction results in detail, focusing on resource adequacy achieved and price signals sent under RPM. Section III of this report

1 Pfeifenberger, Newell, Earle, Hajos, and Geronimo, *Review of PJM's Reliability Pricing Model (RPM)*, June 30, 2008.

summarizes comments received in our stakeholder interviews and discusses a number of key themes raised by stakeholders, such as concerns over price volatility and the lack of long-term contracting. Section IV summarizes our analysis of the current Cost of New Entry. Section V presents our analysis of VRR curve, including a probabilistic evaluation of the performance of the VRR curve prepared in cooperation with Professor Benjamin Hobbs based on the simulation model he previously developed and presented. And finally, in Section VI, we analyze a number of RPM and PJM market design elements and, for consideration and further evaluation by PJM and its stakeholders, identify aspects of these design elements that should be adjusted to improve the overall market effectiveness and provide additional safeguards to avoid RPM performance problems and resource adequacy shortfalls in light of future challenges such as the new Environmental Protection Agency ("EPA") regulations and continued reliance on the potentially volatile historical E&AS offsets.

B. RPM BACKGROUND

As we noted in our 2008 RPM Report, RPM replaced PJM's previous capacity market construct, the Capacity Credit Market ("CCM"), starting with the 2007/08 delivery year. The CCM, which had been in place since 1999, was a voluntary balancing mechanism that allowed Load Serving Entities ("LSEs") to satisfy their installed capacity ("ICAP") requirements on a daily, monthly, and multi-monthly basis. The CCM transacted less than 10% of the total PJM capacity obligation and was based on daily market clearing prices that were uniform across the entire PJM footprint. In addition, this original CCM did not include explicit market power mitigation rules, provided only weak performance incentives, and did not permit the participation of demand-side resources. The CCM resulted in capacity prices that, despite significant occasional spikes, were on average well below both the cost of adding new capacity and the cost of retaining some of the region's existing capacity. Importantly, without recognizing locational reliability requirements, the CCM also did not reflect reliability challenges and the higher value of capacity in certain import-constrained areas of PJM, particularly in parts of eastern PJM, such as the northern New Jersey, Delmarva, and Baltimore-Washington areas.

In contrast to CCM, the RPM capacity market design features a three-year forward-looking annual obligation for locational capacity that designed to improve price stability, enhance reliability, and force existing resources to compete with a potentially large supply of new resources. RPM includes a must-offer requirement for all capacity resources as well as mandatory participation by load. The RPM design also adds stronger performance incentives for generation, explicit market power mitigation rules, and direct participation of demand-side resources. RPM introduced an auction format in which offer-based supply curves are cleared against downward-sloping demand curves (the VRR curves) instead of vertical demand curves. The sloped demand curve design provides a number of benefits, including valuing capacity that is procured beyond that which is required to meet reliability requirements.

The stated purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of consumers within PJM. In fulfilling that function, PJM emphasizes that the RPM provides:

- Support for load-serving entities (LSEs) using self-supply to satisfy their capacity obligations for future years;

- A competitive auction to secure additional capacity resources, demand response ("DR"), and qualifying transmission upgrades to satisfy LSEs' unforced capacity ("UCAP") obligations that are not satisfied through self-supply;
- Recognition of the locational value of capacity resources; and
- A backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

RPM was approved by the Federal Energy Regulatory Commission ("FERC") in its order dated December 22, 2006 (Docket ER05-1410-001 *et al.*) after an extensive stakeholder and market design effort lasting more than two years. PJM initially filed a proposed RPM market design with FERC on August 31, 2005 to address the failure of the previous capacity market design to set prices adequate to ensure sufficient resources, which caused current and projected violations of PJM's reliability requirement, particularly in eastern PJM. FERC agreed in an April 20, 2006 order that the preexisting capacity market design was unjust and unreasonable and ordered further proceedings which led to settlement discussions involving more than 65 parties. This settlement effort led to the current RPM design that was filed on September 29, 2006 ("RPM Settlement") and approved by FERC in its December 22, 2006 order.

The first RPM auction took place in April 2007 and procured capacity for the 2007/08 delivery year. Four more were conducted within the next 12 months. The fifth auction, conducted in May 2008 auction for the 2011/12 delivery year, was the first to procure capacity under a full three-year forward commitment. Since then, three more auctions have been conducted with a full 3-year forward commitment, the most recent one in May 2011 for the 2014/15 delivery year.

Attachment DD of PJM's Open Access Transmission Tariff ("OATT") and PJM's Manual 18 describe the RPM market design in detail.[2] Various RPM overviews, training materials, and information for individual delivery years, auction design parameters, and summary auction results are also available online.[3] Additional materials, discussion documents, and agendas documenting the ongoing efforts to refine various aspects of RPM are posted under various stakeholder groups, particularly in the Markets and Reliability Committee (MRC).[4] Design overviews and detailed assessments of RPM auction results and performance to date have also been published by PJM's Independent Market Monitor ("IMM").[5]

C. Summary of the Current RPM Design

We provided a detailed description of the RPM design in our 2008 RPM Report, some of which we repeat here for the convenience of providing a complete design summary. The key design parameters of RPM are:

---

2 PJM's OATT and capacity market manual are publicly posted, see PJM (2011a, q).

3 For training materials, see "Reliability Pricing Model" in PJM (2011u); for auction results, parameters and related documentation, see PJM (2011v).

4 MRC and other stakeholder group meeting materials are available at PJM (2011w).

5 The market monitor publishes a report on the results of every base and incremental auction, as well as publishing reviews within the annual state of the market reports, see Monitoring Analytics (2011a).

- Base residual and incremental auctions that procure capacity and adjustments to capacity obligations on a forward basis;
- LDAs and locational capacity prices that are able to reflect the greater need for capacity in import-constrained areas;
- Provisions that allow demand-side resources and new transmission projects to compete with generating capacity;
- A downward sloping (rather than a vertical) demand curve, called the VRR curve;
- Administrative and empirical determinations of the net cost of new entry ("Net CONE");
- Performance monitoring during the delivery year and peak periods;
- Consistency with self-supply and bilateral procurement of capacity;
- An opt-out mechanism under the Fixed Resource Requirement (FRR) alternative;
- Explicit market monitoring and mitigation rules, including a must-offer requirement for existing generating resources and IMM review and mitigation of new entrant offers.

Base Residual and Incremental Auctions. The initial auctions procuring forward capacity resources for particular delivery years are referred to as Base Residual Auctions or BRAs, in reference to the fact that the auctions procure the residual resources required after taking into account resources self-supplied by load serving entities through asset ownership or long-term bilateral contracts. Each base auction is followed by three "Incremental Auctions"—23 months, 13 months, and 4 months before each delivery year—that can be used by PJM to procure additional resource (if needed) or by market participants to adjust their BRA commitments.

Conducting the capacity market on a three-year forward basis roughly matches the minimum lead time needed to bring new capacity resources online and the lead time needed to delay or cancel projects before irreversible major financial commitments have been made. This improves price stability and reliability by providing forward market signals that can help avoid periods of extreme scarcity or excess capacity. It also forces existing resources to compete with a potentially large supply of new resources that can be brought online within three years.

Locational Deliverability Areas ("LDAs). LDAs are subregions of PJM with limited import capability due to transmission constraints. If an LDA is constrained, locational capacity prices will exceed the capacity price in the unconstrained part of PJM. Currently there are 25 LDAs defined in RPM, although, as shown in

Figure **1** and Figure 2 show only eight LDAs currently modeled such that capacity auctions could yield different clearing prices. The LDAs currently modeled in PJM are: the unconstrained Regional Transmission Organization ("RTO"); the Mid-Atlantic Area Council ("MAAC") which contains subzones Eastern MAAC ("EMAAC") and Southwestern MAAC ("SWMAAC"); SWMAAC contains the Potomac Electric Power Company ("PEPCO") subzone, SWMAAC also contains the Baltimore Gas and Electric ("BGE") zone, which is not a constrained LDA by itself; EMAAC contains the Delmarva Power and Light Company ("DPL") South ("DPL South") and Public Service Electric and Gas Company ("PSEG") LDAs; and PSEG contains PSEG North.

Figure 1
Constrained Locational Deliverability Areas in RPM

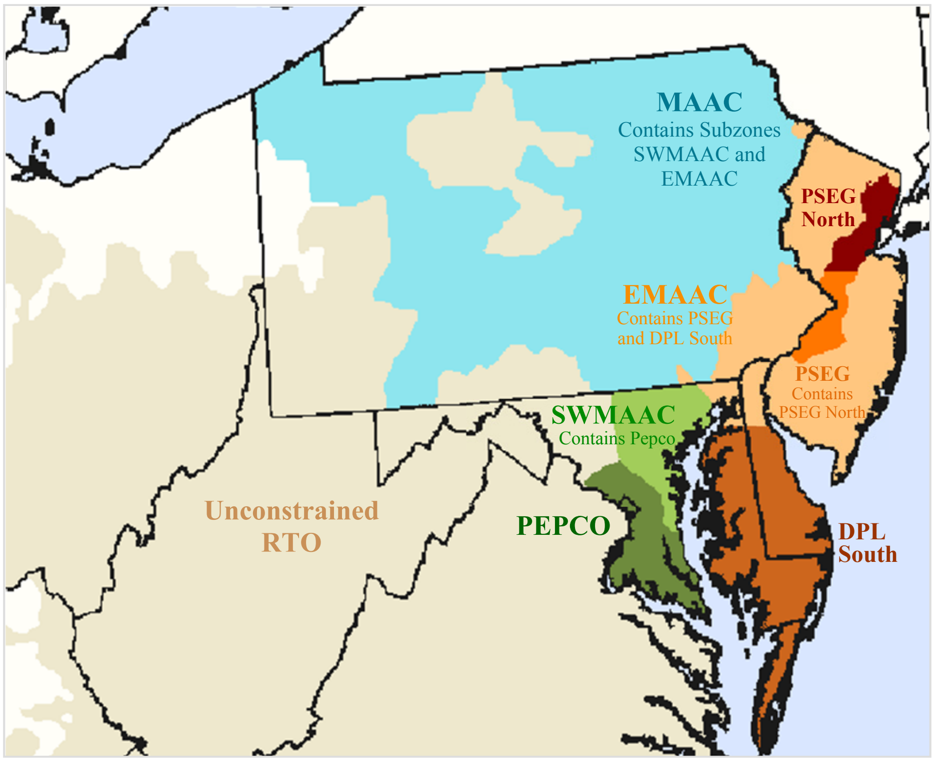
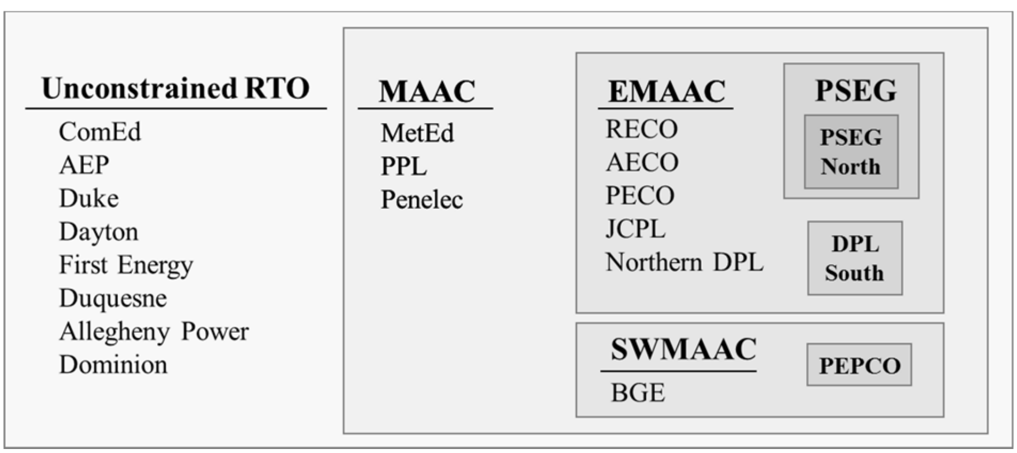


Figure 2
Locational Deliverability Areas and Utility Service Areas



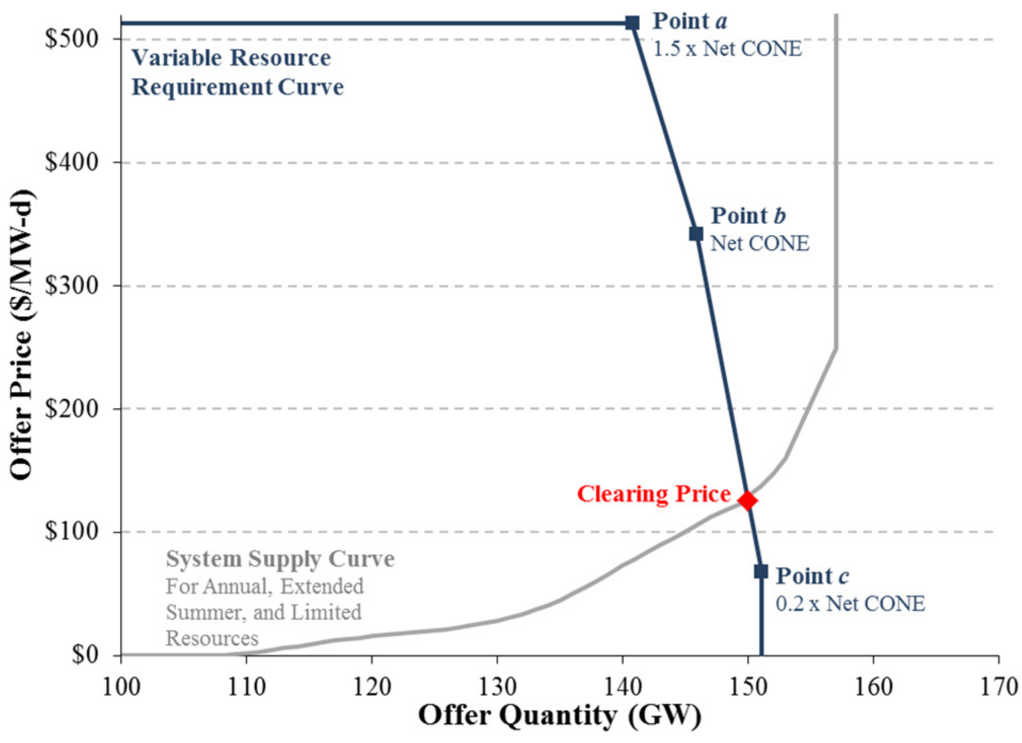
Sources and Notes:
Modeled LDAs are shown as squares with names in bold; other transmission zones are not currently modeled.
LDA definitions and structure from PJM (2011d), pp. 10-11.

Participation by Demand-Side Resources and New Transmission Upgrades. RPM enables participation by demand-side resources and new transmission projects. Capacity provided by these resources is treated equivalently to generating capacity. Eligible transmission projects, called Qualifying Transmission Upgrades ("QTUs"), can participate to increase import capability into a constrained LDA.

Downward Sloping Demand Curve. The VRR curve is anchored at point "b" at a price and quantity that reflects the Net CONE and a reserve margin that is one percentage point above the target reserve margin that satisfy regional and locational reliability standards. Net CONE is determined as the annualized fixed cost of new generating capacity *net* of energy and ancillary service ("E&AS") margins.

The VRR curve is designed to yield auction clearing prices in excess of Net CONE when the amount of cleared capacity falls below the target reserve margin needed to satisfy regional and local reliability requirements. Similarly, capacity prices fall below Net CONE when the amount of cleared capacity exceeds target reserve margins. Figure 3 shows the capacity supply curve, VRR curve, and auction clearing price and quantity for the most recent RPM auction, which procured capacity for the 2014/15 delivery year.

Figure 3
Capacity Supply and Demand in the 2014/15 Base Auction



By definition, this VRR curve yields a capacity price equal to Net CONE at the target reserve margin plus 1 percentage point (point "b"). For lower supply levels, capacity prices increase linearly to reserve margins that are 3 percentage points below target reserve margins, at which point the capacity price is capped at 150% of Net CONE (point "a"). From the price equal to Net CONE at target reserve margins plus 1 percentage point, capacity prices also decline linearly until reserve margins reach target reserves plus 5 percentage points, at which the capacity price is equal to 20% of Net CONE (point "c"). For even higher reserve margins, capacity prices drop to zero.

As was noted in the FERC order approving the RPM design,[6] compared to a system that simply attempts to procure capacity to satisfy a target reserve margin (*i.e.*, a vertical demand curve), the downward-sloping demand curve is designed to provide the following advantages:

- The downward-sloping VRR curve reduces capacity price volatility because capacity prices change gradually as capacity supplies vary over time. The lower volatility due to a sloped demand curve should render capacity investment less risky, thereby encouraging greater investment at a lower cost.

- The sloped demand curve provides a better indication of the incremental and decremental value of capacity at different planning reserve margins. The sloping VRR curve recognizes that incremental capacity above the target reserve margin provides additional reliability benefit, albeit at a declining rate.

- The sloped VRR curve also mitigates the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin. Withholding capacity is less profitable under a sloped demand curve close to the target reserve requirements than under a vertical one because withholding would result in a smaller increase in capacity prices.

Determination and Adjustments of CONE. The value of CONE is estimated as the levelized cost (currently defined in constant nominal dollar terms) that a new entrant needs to recover in power markets—including energy, ancillary service, and the RPM capacity market—to recover its investment costs. The PJM Tariff allows for periodic review and adjustment of the CONE parameter through a combination of index-based adjustment and periodic updates based on engineering cost studies.

Energy and Ancillary Services Revenue Offset. The E&AS offset represents the administratively-estimated net profit that a new entrant with the reference technology earns from the sale of energy and ancillary services. E&AS offsets are used to calculate Net CONE which reflects the amount of annual capacity market revenue that the new entrant needs for profitable entry. Under current RPM rules, E&AS offsets are calculated as a three-year average of estimated historical profits for the reference technology.

Performance Monitoring. The market clearing price is paid to all capacity committed in an auction. However, these payments can be partially, fully, or more than fully offset by performance-based penalties that depend both on the resources' general availability during the delivery year as well as their availability during peak periods when the reliability value of capacity is the greatest. The combination of these payments and penalties is designed to ensure that suppliers have the proper incentives to make their resources available to PJM during reliability events.

Self-Supply and Bilateral Procurement of Capacity. The RPM market design allows LSEs to self-supply resources to meet their capacity obligations either by designating resources they own or purchase bilaterally. Such capacity must be offered into base auctions. The main purpose of the base auctions is to purchase capacity needs not met by self-supplied resources.

[6] December 2006 RPM Order at ¶¶75-76.

Fixed Resource Requirement. The FRR alternative allows LSEs to opt out of RPM and, instead, meet a fixed capacity obligation. LSEs that choose the FRR option are subject to certain qualification requirements and face restrictions on the amount of capacity they may sell in RPM auctions.

Market Mitigation. Sell offers of existing capacity resources in RPM auctions are subject to mitigation. Offers can be mitigated to a level that reflects each individual unit's going-forward, avoidable costs. Sell offers by planned resources are not subject to offer caps, but may be rejected by the MMU if they are found to be uncompetitive.

Changes to the RPM design since our 2008 RPM Review. Since we reviewed RPM performance in 2008, PJM implemented a number of refinements to the RPM design and related elements, including the following:

- Two new CONE Areas and a revised CONE update process to by using annual adjustments based on the Handy-Whitman cost index with CONE updates based on engineering studies only every three years.

- RPM procurement targets and FRR obligations that can increase or decrease after the BRA based on changes in load forecast prior to the delivery year (previously the BRA Preliminary Obligation was the floor). Reallocation of capacity obligations of individual load zones prior to delivery years based on changes in peak loads since BRA.

- A number of modifications specifying when and how LDAs are modeled in RPM auctions, including (1) a requirement to model all regional LDAs in each auction (2) the increase in the Capacity Emergency Transfer Limits ("CETL")/ Capacity Emergency Transfer Objective ("CETO") threshold for modeling other LDAs from 105% to 115%; (3) revised guidelines to create new LDAs (Manual 14B); and (4) incorporation of planned transmission additions into CETL only when there is a reasonable expectation that the project can be online as anticipated.

- Revisions to RPM Auction designs, including (1) the addition of the 2.5% Short Term Resource Procurement Target; (2) improved structure and expanded scope of incremental auctions; and (3) separate clearing of limited summer, unlimited summer and annual capacity products.

- Reduced performance penalties to 1.2 times the higher of: (1) the auction resource clearing price in which the capacity was originally cleared; and (2) the third incremental auction resource clearing price.

- A streamlined generation interconnection process that allows planned resources to qualify for RPM more quickly.

- Options that allow market participants to combine individual partial-year resources as annual resources.

- Revisions to how demand-response resources are integrated into the RPM design, including (1) the elimination of ILR to encourage DR participation in BRAs; (2) elimination of offer caps for DR resources; (3) the creation of multiple DR products (limited summer, extended summer, and annual); (4) accommodation of energy efficiency ("EE") resources; (5) testing of DR resources.

- Revisions to the minimum offer price rule ("MOPR") to guard against suppression of RPM clearing prices through the addition of uneconomic generating capacity.

A number of other refinements, such as improved validation and verification processes for generation and demand resources, modifications of how capacity cost responsibilities are allocated to load serving entities ("LSEs"), and modifications to the New Entry Pricing Adjustment ("NEPA") that provide certainty that new resources will clear in subsequent auctions.

II. ANALYSIS OF MARKET RESULTS

This section documents and analyzes market results under RPM to date. First, we analyze the outcomes under each of the eight base residual auctions (BRAs) and seven incremental auctions (IAs) that have been conducted since RPM was implemented, starting with the 2007/08 delivery year. For each of these auctions, we report the clearing prices and the quantities of cleared and uncleared offers by resource type and location. We also explain the causes of price changes over time. Next, we document the cumulative changes in committed capacity since RPM's inception through 2014/15, the latest delivery year covered by the most recent BRA. Finally, we examine the quantity of proposed new generating projects that are currently under study in the generation interconnection queue as an indicator of potential new additions beyond those already committed through RPM.

Our analysis of market results demonstrates that sufficient capacity has been procured under RPM to ensure resource adequacy at prices consistent with locational market conditions. While moderate capacity deficits initially occurred in some LDAs due primarily to pre-RPM conditions, the last four BRAs have cleared more than sufficient capacity in each LDA. Since RPM was implemented, a cumulative 28.4 GW of gross committed capacity and 13.1 GW of net committed capacity (in ICAP terms) has been added under RPM, excluding FRR capacity and the addition of new PJM members, FirstEnergy and Duke. All auction results are reported in UCAP terms in Sections II.A and II.B below, while the cumulative capacity changes under RPM are reported in ICAP terms in Section II.C.

A. BASE RESIDUAL AUCTION RESULTS

Most capacity under RPM is procured through the base residual auctions. Base auctions have been conducted for each of the eight delivery years spanning 2007/08 through 2014/15. Each auction is held three years prior to the delivery year, with the exception of the first four delivery years when the BRAs were conducted over a compressed period while transitioning to the full three-year forward procurement period after RPM's implementation. Over the first eight auctions, and excluding additions due to territory expansion, total capacity supplies offered have increased by 16.9 UCAP GW while capacity cleared has increased by 11.5 UCAP GW, with most incremental supplies coming from demand response.

With a few exceptions during the first delivery years of RPM, primarily within LDAs, each auction has procured capacity in excess of the procurement target, but with surplus supply in the unconstrained RTO exceeding the surpluses in the smaller constrained LDAs. Clearing prices have been consistent with these supply-demand fundamentals, producing prices below Net CONE under conditions of excess supply, but above Net CONE in locations of tight supply during the first few delivery years. Prices have also been substantially affected by whether an LDA was modeled as constrained, changes in LDA transmission import limits (CETL), changes in PJM's load forecasts, a substantial growth in demand response, and the EPA's proposed Hazardous Air Pollutant ("HAP") regulation.[7]

1. Resource Adequacy Achieved Through Base Auctions

Cleared quantities relative to target procurement for the RTO and all modeled LDAs are shown in Figure 4. The figure charts cleared capacity relative to the procurement target for each BRA. The black horizontal line at 100% represents the target procurement quantity, with points above indicating procurement above the reliability target, while points below the line indicate procurement below the target. Procurement levels can deviate from the target because RPM is structured to commit higher quantities when offer prices are low and procure lower quantities when offer prices are high.

At the aggregate RTO level, procurement levels exceeded the target in every one of the first eight base residual auctions by 1.2% to 4.7%. These results reflect the surplus supply conditions in the system overall. The RTO-wide surplus dropped between the introduction of RPM (the 2007/08 delivery year) and the 2010/11 delivery year, but then increased again starting in 2011/12 due to factors that included load forecast reductions, the exclusion of Duquesne as load for one year, and a large influx of DR into the auctions (starting with the May 2009 BRA for the 2012/13 delivery year).

Within the LDAs, overall trends in procurement levels have steadily increased relative to reliability targets. While some procurement levels were below reliability targets during the first four delivery years (2007/08 through 2010/11), procurement levels in LDAs universally exceeded reliability targets for the most recent four delivery years (2011/12 through 2014/15). During the first four BRAs, several LDAs including MAAC, EMAAC, SWMAAC, and DPL-South were below the target in some years, with procurement as much as 2.6% below the target for SWMAAC for the 2009/10 delivery year. These deficits reflected the relatively tighter eastern PJM supply conditions that existed at the inception of RPM and, in fact, motivated the need for a locational capacity market. The compressed timing of the initial three auctions also limited the ability of new resources to enter, given the short lead times to delivery. Additionally, DR was not yet widely participating in the forward auctions, opting instead to participate as Interruptible Load for Reliability ("ILR"), which was committed for reliability outside the auctions.[8] In subsequent auctions, conducted a full 3 years before delivery, additional new

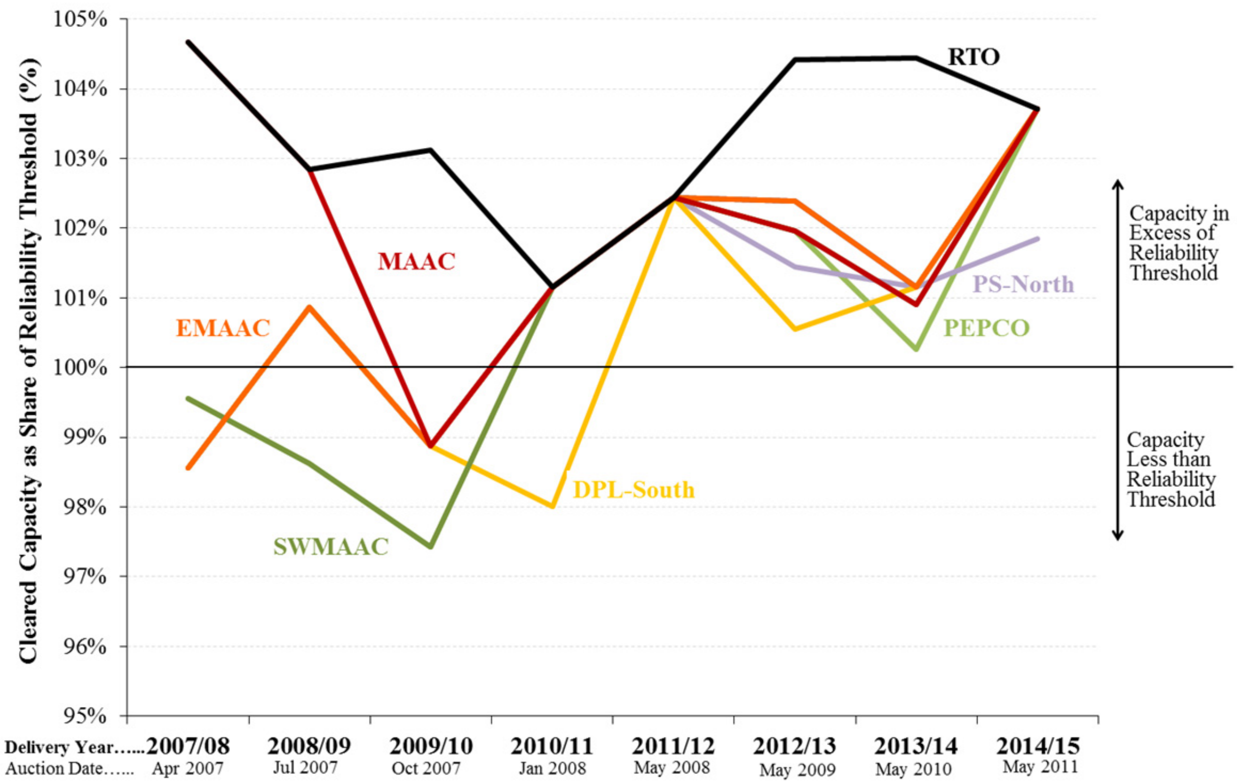
---

7 The proposed rule will institute emissions limits for coal- and oil-fired generators for mercury, particulate matter as a proxy for other toxic metals, and hydrochloric acid as a proxy for all toxic acid gases. See EPA (2011a-b).

8 The first four BRAs under RPM were conducted within one calendar year between April 2007 and January 2008. This means that the 2007/08 BRA was held two months prior to the delivery year, the 2008/09 BRA was held 1 year prior to delivery, the 2009/10 BRA was held 1.5 years prior to delivery, the 2010/11 BRA was held 2.5 years prior to delivery, and all auctions starting with 2011/12 were held 3 years prior to delivery.

capacity resources entered, and the LDA procurement increased to meet or exceed reliability requirements.

Figure 4
Reliability Margins Clearing in Base Residual Auctions



Sources and Notes:

Reliability threshold defined as the reliability requirement less CETL, less forecast ILR or STRPT.
LDAs that did not price separately are reported here at the reliability margin of the parent LDA or RTO level.
From BRA parameters and results, PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011b-c).

2. Market Clearing Prices in Base Residual Auctions

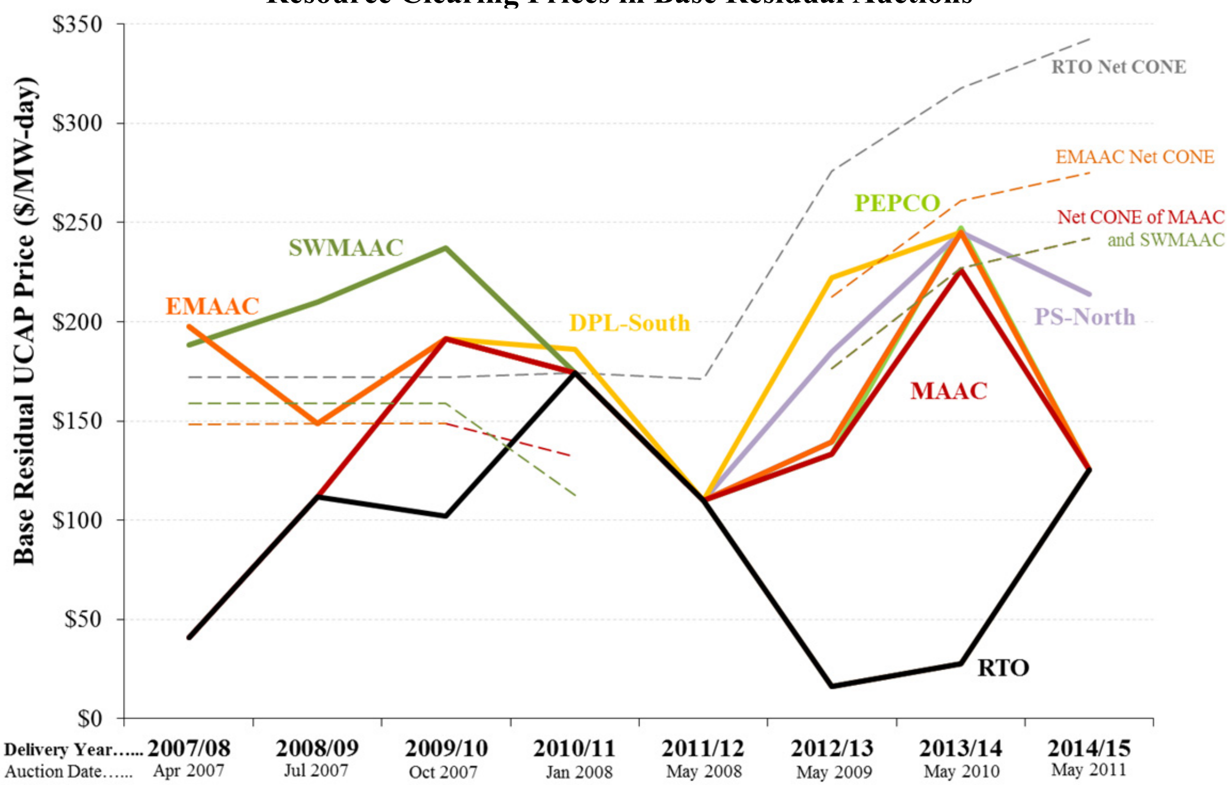
Market prices for capacity can be compared to the Net Cost of Net Entry (Net CONE), representing the fixed cost of a new peaking plant net of operating margins from energy and ancillary service revenues. Net CONE is the capacity price that a developer would need to receive *on average* over the life of its asset to earn an adequate return on invested capital.

In a well-functioning capacity market, capacity prices will be above Net CONE during shortage conditions when new capacity is needed and below Net CONE during surplus conditions when no new capacity is needed. Such market prices will provide sufficient incentives to attract and retain capacity when new supplies are needed, encourage cost savings by postponing new development, and allow economic retirements when supplies are more than sufficient. This is the desirable pattern that has been observed in RPM auctions, as shown in Figure 5.

Figure 5 and Table 1 summarize RTO and LDA clearing prices for each base residual auction conducted to date. Figure 5 also shows Net CONE for each area in dashed lines. Although the administratively-determined Net CONE calculation may deviate from the true Net CONE faced by suppliers (as discussed in Section V), it is still a meaningful benchmark for interpreting auction results. The comparison of Figure 5 to Figure 4 confirms that prices have been above Net CONE under conditions of capacity scarcity and below Net CONE under conditions of capacity surplus.

Prices in the unconstrained RTO have been far below Net CONE in most years, reflecting significant excess capacity and the availability of low-cost resources that obviated the need for new generation capacity. Within the LDAs, several of the initial auctions produced prices above Net CONE—in MAAC, EMAAC, SWMAAC, and DPL-South—consistent with the initial resource adequacy deficiencies. In more recent auctions for delivery years 2011/12 through 2014/15, capacity supply conditions have reduced prices in these LDAs to levels below Net CONE. These observations are not surprising given that RPM is constructed to produce this result, with a sloping VRR curve that procures less capacity at higher prices during shortage conditions and more capacity at a lower price during surplus conditions.[9]

Figure 5
Resource Clearing Prices in Base Residual Auctions



Sources and Notes:
Administrative Net CONE shown only for the years when it was calculated for each modeled LDA.
Year 2014/15 price shown reflects the system clearing price applicable for Limited Summer resources.
From PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011b-c).

9 There are some exceptions to this outcome caused by the 1% quantity adjustment to point b on the VRR curve, which causes prices to clear slightly above Net CONE under slight surplus procurement conditions of less than (1+IRM+1%)/(1+IRM) This occurred in DPL-South in 2012/13 and in PEPCO in 2013/14. For the formula used to calculate VRR curve points, see PJM (2011d), p. 19.

Table 1
Base Residual Auction Clearing Prices

Year	RTO ($/MW-d)	MAAC ($/MW-d)	EMAAC ($/MW-d)	SWMAAC ($/MW-d)	DPL-S ($/MW-d)	PSEG ($/MW-d)	PS-N ($/MW-d)	PEPCO ($/MW-d)	Resource Type
2007/08	$40.80	--	$197.67	$188.54	--	--	--	--	n/a
2008/09	$111.92	--	$148.80	$210.11	--	--	--	--	n/a
2009/10	$102.04	$191.32	$191.30	$237.33	--	--	--	--	n/a
2010/11	$174.29	$174.30	--	$174.30	$186.12	--	--	--	n/a
2011/12	$110.00	--	--	--	--	--	--	--	n/a
2012/13	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	--	n/a
2013/14	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	n/a
2014/15	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	*Limited Summer*
	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	*Extended Summer and Annual*

Sources and Notes:
From BRA results, PJM (2007a, 2008a-c, 2009a, 2009e, 2010b, 2011c).
Prices are reported only for years in which each LDA was modeled under RPM.
MAAC + APS price is listed under MAAC for the 2009/10 delivery year.

In addition to these overall supply and demand conditions, many other factors influenced prices, including the significant growth of DR supply, the economic downturn, new environmental regulations, transmission changes, changes to the RPM market design, and changes in RPM administrative parameters. These factors introduced substantial volatility into the auction prices, with large price changes from one year to the next. We analyzed the major drivers of all price changes for the first eight base auctions by examining offer data, supply curves, administrative planning parameters, and RPM rule changes.

Table 2 summarizes our findings. As documented, supply-side factors explain some of the major changes in base auction prices. Most notably, the costs of meeting EPA's new environmental rules contributed to a price increase of $98/MW-day for the 2014/15 delivery year relative to the previous year.[10] On the other hand, increased DR penetration exerted substantial downward pressure on prices, with the largest impact seen starting with the 2012/13 delivery year, when 8,200 MW of demand resources were first incorporated into the auction, contributing to a $94/MW-day RTO-level price drop relative to the previous year.[11] Modeling multiple demand resource products for the first time in 2014/15 also resulted in a modest price separation of up to $11/MW-day, recognizing the somewhat higher value of Extended Summer and Annual resources. Increases in the supply of other types of resources also contributed to maintaining capacity prices below Net CONE. These other sources of supplies include substantial uprates to existing power plants, increased imports, and reduced exports, as discussed further in Section II.C.

[10] See discussion in Section II.A.3, and EPA (2011a-b).

[11] See Section II.A.3 and PJM (2011d), sections 4.3.5 and 9.3.6.

On the demand side, PJM's peak load forecast is a key driver of PJM prices because it is the primary determinant of the target procurement quantity. Load forecast decreases of 1.7% and 2.8% for the 2012/13 and 2014/15 delivery years (relative to the prior year's peak load forecast for the same delivery years) contributed to price reductions in those years, although in neither case was it the most important driver.[12,13] The initial reduction in load forecasts was caused by the economic downturn. The second reduction in load forecasts was caused primarily by changes in forecasting model coefficients due to revisions in historical economic growth rate data used to estimate those coefficients.[14] For the 2011/12 delivery year, the exclusion of 2.9 GW of peak load from Duquesne contributed to a small reduction in price for one year when the transmission owner had planned to withdraw from PJM.[15] Increases in the administratively-determined Net CONE value also tended to increase prices over time by shifting up the VRR curve, although this trend has not had a large impact in any one year.

Finally, locational price differentials were driven partly by locational differences in supply and demand conditions, with excess capacity in the unconstrained RTO and no (or less) excess supply in the eastern LDAs as discussed above and in in Sections II.C. Additionally, major price changes were caused by whether or not an LDA was modeled as being constrained and how much capacity (CETL) could be imported into the LDA. Prior to a rule change for the 2012/13 delivery year, fewer LDAs were modeled, resulting in a lack of locational price separation during some years that would have price-separated under current rules.[16] For example, the MAAC LDA was not modeled for 2007/08 and 2008/09 and no LDAs were modeled for 2011/12. The administratively-determined Capacity Emergency Transfer Limit ("CETL"), which represents the maximum capacity import capability for each LDA, also significantly affected prices. In particular, CETL decreases for the 2013/14 delivery year were a major cause of high prices in the LDAs, while CETL increases for 2008/09 and 2014/15 were a major cause of price reductions.[17]

---

12 For 2012/13, the most important price-depressing factor was the integration of a large amount of demand resources. For 2014/15, a CETL increase and load forecast reduction both contributed to a price decrease in the LDAs; in the RTO, the price-increasing impact of EPA HAP regulations overwhelmed the price reduction effect of reduced load forecasts.

13 Reported load forecast reductions represent summer coincident peak load forecasts including Duquesne, but excluding ATSI and DEOK. The RTO summer coincident peak load forecast for the 2012/13 delivery year dropped from 147,183 to 144,613 MW between the forecasts prepared in 2008 and 2009; the 2014/15 delivery year forecast dropped from 149,572 MW to 145,404 MW between the forecasts prepared in 2010 and 2011. See PJM (2008d), p. 46; (2009f), p. 50; (2010e), p. 53; (2011g), p. 54.

14 These economic growth rates were revised by the Bureau of Economic Analysis. Confirmed via personal communication with PJM staff. , See Section VI.B for a more detailed discussion of load forecasting.

15 See PJM (2009g), p. 1.

16 Prior to the auction for the 2012/13 delivery year, LDAs were modeled only if their Capacity Emergency Transfer Objective ("CETO") was ≤ 1.05 CETL. Starting with the 2012/13 delivery year more LDAs were modeled, including: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate. See PJM (2011d), pp. 11-12.

17 See Section VI.A for further discussion of CETL uncertainty and recommended mitigation measures.

Table 2
Summary of Major BRA Price Shifts and Causes

Year	Location	Causes of Major Price Changes from Previous Year
2007/08	*RTO* -	Price of $41/MW-day is far below Net CONE, reflecting a capacity surplus.
	EMAAC and SWMAAC -	Prices near $200/MW-day are above Net CONE, reflecting tight supply.
2008/09	*RTO* -	$71/MW-day increase caused by relaxed EMAAC transmission constraint, modest demand growth, and a steep supply curve.
	EMAAC -	$49/MW-day drop caused by 2,085 MW CETL increase.
2009/10	*MAAC+APS* -	LDA is first modeled with prices $89/MW-day above the RTO. If MAAC had been modeled in earlier years, it likely would have had similarly high or higher prices.
	SWMAAC -	Clears slightly below the LDA price cap due to short supply and a steep supply curve.
2010/11	*RTO* -	Modest increases in demand, coupled with somewhat smaller increases in supply and a steep supply curve, cause RTO prices to increase by $72/MW-day.
	SWMAAC -	63/MW-day drop to the parent LDA price caused by lower offer prices for several existing generation supplies relative to 2009/10 offers, nearly 300 MW in generation uprates, a 276 MW increase in CETL, and a 29% reduction in SWMAAC Net CONE which reduced the VRR curve.
2011/12	*RTO* -	Exclusion of Duquesne load for one year causes some price suppression.
	LDAs -	No LDAs are modeled, preventing price separation.
2012/13	*RTO and LDAs* -	Large 8,200 MW influx of previously unoffered demand response is incorporated into the BRA due to a rule change in treatment from ILR to DR; this and a peak load forecast reduction cause a large $94/MW-day price drop in the RTO.
	LDAs -	Rule change permanently causes more LDAs to be modeled, allowing price separation.
2013/14	*LDAs* -	Large CETL reductions of almost 2,000 MW in MAAC and EMAAC and 675 MW in SWMAAC substantially restrict low-cost imports to the LDAs. Prices increase by $93/MW-day in MAAC and SWMAAC and by $205/MW-day in EMAAC.
2014/15	*RTO* -	Prices increase by $98/MW-day due primarily to high bids and excused capacity from coal units related to EPA HAP MACT regulations. More than 6,200 MW less existing generation clears in the unconstrained RTO (excluding ATSI, DEOK, and imports), replaced by a large increase in cleared demand resources.
	LDAs -	2.8% load forecast drop and 1,100 to 1,200 MW increase in CETL in MAAC, EMAAC, and SWMAAC create a supply surplus relative to previous year in eastern LDAs.
	PSEG-North -	Price drop of $31/MW-day is not as substantial as in other LDAs, and is limited by transmission constraints, which are near their historical levels.
	Extended Summer and Annual -	Resource types are modeled separately for the first time, leading to an $11/MW-day price premium for extended summer and annual resources in LDAs and a smaller premium less than $1/MW-day in the unconstrained RTO.

Sources and Notes:
Causes of price changes determined from analysis of auction bid data, supply curves, demand curves, and parameters.
From BRA parameters, results, and bid data, PJM (2007a-b, 2008a-c, 2009a-e, 2010a-b, 2011a-c).

3. Resources Offered and Cleared in the Base Auctions

a. Aggregate Results for the Entire PJM RTO

The total amount of capacity offered in the RTO has increased substantially since the start of RPM, as summarized in Table 3. The table reports total quantities of unforced capacity (UCAP) offered, cleared, and uncleared in the eight base auctions conducted to date for the entire RTO. The tables are non-cumulative with respect to the identification of new generation offers, in that any new generation that clears one BRA is reported as existing generation for all subsequent BRAs.[18] Total offers have increased by 29.6 GW (from 131 to 160 GW) while total capacity cleared has increased by 20.6 GW (from 129 to 150 GW). However, nearly half of that increase is due to PJM's expansion that integrated FirstEnergy (through its subsidiary American Transmission Systems, Inc. or "ATSI") into the BRA starting with the 2013/14 delivery year.[19] Duke Energy Ohio/Kentucky ("DEOK") also began its integration into RPM starting with the 2014/15 BRA, but so far has had little impact on auction clearing quantities.[20]

For the RTO (excluding ATSI and DEOK), capacity offers increased by 16.9 GW while capacity cleared increased by 11.5 GW. Large increases came from new DR and energy efficiency (EE) resources. Cleared quantities of DR and EE increased from just 0.1 GW at the start of RPM to 13.9 GW for the 2014/15 delivery year. DR and EE now amount to 9.9% of total cleared supplies. Cleared imports also increased from 1.6 to 4.0 GW or to 2.9% of cleared supplies.[21]

For PJM-internal generation supplies (including both new and existing resources), total offered quantities decreased by 0.7 GW while total cleared quantities decreased by 4.7 GW. These reductions were almost entirely caused in response to EPA's HAP regulation, which will substantially tighten emissions standards on mercury, other toxic metals, and acid gases. In anticipation of this regulation and the need for environmental upgrades by 2015 or 2016, a large number of coal units of FRR entities were excused from offering into the 2014/15 auction or failed to clear in the BRA after offering at higher levels reflecting the costs of upgrades (and some cleared).[22]

---

18 Also note that the same unit may be listed as new capacity under more than one BRA if the new unit failed to clear the first time it was offered and was offered later in a subsequent BRA. This approach to summarizing new generation is consistent with the definition of new generation as used for market monitoring and mitigation purposes, see PJM (2011d), p. 65. Section II.C contains a cumulative account of capacity additions and reductions over time.

19 ATSI was integrated into the PJM energy market on June 1, 2011, but as a transitional measure for resource adequacy purposes it was not fully integrated into RPM auctions until the 2013/14 delivery year. For the 2011/12 and 2012/13 delivery years, resource adequacy in the zone was assured through transitional FRR plans for which capacity was procured in separate integration auctions. Only small amounts of capacity from ATSI were offered into the BRA. See PJM (2010c) and (2011e).

20 See PJM (2010d), pp. 25-26.

21 These are gross imports cleared in the base auctions without considering exports.

22 The exact date that most generators will be required to either shut down or operate with additional controls is not yet determined. The EPA is required under consent decree to issue a final rulemaking by November 16, 2011, after which generators will have three years to comply, with the possibility of an additional year's extension for compliance if they can show that the additional time is needed to install

Continued on next page

Table 3
RTO Summary of BRA Offered and Cleared Quantities
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total RTO								
Offered	130,844	131,881	133,551	133,093	137,720	145,373	160,898	160,486
Cleared	129,409	129,598	132,232	132,190	132,222	136,144	152,743	149,975
Uncleared	1,435	2,283	1,319	902	5,499	9,230	8,155	10,512
RTO Excluding ATSI and DEOK								
Offered	**130,844**	**131,881**	**133,551**	**133,093**	**137,057**	**145,373**	**147,563**	**147,724**
Existing Internal Generation	129,080	129,408	130,467	129,984	131,013	131,095	131,205	127,418
Existing Imported Generation	1,621	1,667	1,708	1,734	1,750	2,336	3,254	4,031
New Generation	16	89	439	407	2,642	1,442	783	1,016
Demand Response	128	716	937	968	1,652	9,848	11,568	14,430
Energy Efficiency	-	-	-	-	-	653	754	829
Cleared	**129,409**	**129,598**	**132,232**	**132,190**	**132,222**	**136,144**	**142,047**	**140,957**
Existing Internal Generation	127,645	127,346	129,370	129,237	126,964	125,347	128,461	122,603
Existing Imported Generation	1,621	1,626	1,669	1,726	1,748	2,336	3,254	4,031
New Generation	16	89	300	288	2,144	845	769	395
Demand Response	128	536	893	939	1,365	7,047	8,888	13,108
Energy Efficiency	-	-	-	-	-	569	676	819
Uncleared	**1,435**	**2,283**	**1,319**	**902**	**4,836**	**9,230**	**5,516**	**6,767**
Existing Internal Generation	1,434	2,062	1,098	747	4,049	5,748	2,744	4,815
Existing Imported Generation	0	41	39	8	2	-	-	-
New Generation	-	-	139	119	497	598	14	621
Demand Response	-	180	44	29	288	2,800	2,680	1,322
Energy Efficiency	-	-	-	-	-	84	77	10

Sources and Notes:
Calculated from BRA bid data, PJM (2011a).
New generation includes newly build internal and imported generation that has not cleared any previous auction.
Uprates are treated as existing generation.

It is important to note that every auction attracted more offers than were needed, resulting in some capacity offers not clearing. The uncleared capacity *could* have been procured at higher prices if market conditions were tighter and the capacity was needed. The amount of uncleared capacity was quite low in the initial auctions but has been between 3.7% and 6.8% of cleared supplies in the most recent four BRAs. The increase in uncleared capacity coincided with the first year of full three-year forward procurement and exclusion of Duquesne load in 2011/12 (which reduced demand) and the full integration of demand resources into RPM auctions starting in 2012/13.[23] It is also important to evaluate the availability of cleared and uncleared offers for new generation supplies that have been attracted into the auctions. Offers for new generation ranged from 407 MW to 2,642 MW in each auction starting with 2009/10. Of the total 6,834

Continued from previous page
controls, see EPA (2011b), pp. 24986, 25054. Auction impacts from analysis of 2014/15 FRR-excused and BRA biding data as well as PJM's supplemental 2014/15 BRA report, PJM (2011a) and (2011f).

23 Duquesne's reliability requirement of approximately 3 GW was excluded from the BRA in 2011/12, while supply of approximately the same amount was retained and offered in the BRA, see Monitoring Analytics (2008), pp. 10-12. Prior to the 2012/13 delivery year, demand-side resources could certify as ILR immediately prior to the delivery period and receive payments based on auction clearing prices. Starting with 2012/13, all demand-side resources must be committed under an RPM auction or through a bilateral replacement transaction to receive capacity payments, see PJM (2011d), sections 4.3.5 and 9.3.6.

MW of new generation offered into all base auctions conducted to date, 4,847 MW or 71% have cleared.[24]

b. Resources Offered and Cleared within the LDAs

Some stakeholders raised concerns that the RPM auctions are not attracting new resources to ensure reliability within the LDAs, particularly the smaller LDAs. Our analysis of the data shows that is not the case. RPM auctions attracted offers and cleared adequate resources even in the smaller LDAs, except in some of the earlier auctions as discussed earlier and shown in Table 4. Table 4 summarizes the quantity of cleared and uncleared capacity by LDA for all currently modeled LDAs. Note, however, that previous BRAs did not model the same set of LDAs.

Within MAAC, which is the largest of the LDAs and contains all of the smaller LDAs, cleared supply and uncleared potential supply have been robust.

- Penetration of demand-side resources has been higher in MAAC than in the greater RTO, having increased from 0.1% to 11.1% of total cleared resources under RPM.
- Internal generation supplies in MAAC have been relatively constant over the first eight auctions (while internal generation in the unconstrained RTO decreased). Offered generation in MAAC has increased by 1,297 MW, although the total amount cleared generation has decreased by 671 MW or 1% of cleared resources. Unlike the greater RTO, the MAAC region has been relatively less affected by the proposed EPA regulation. Between the auctions for the 2013/14 and 2014/15 delivery years, MAAC had a 1,877 MW or 3.0% decrease in cleared generation (compared to 4.8% in the RTO overall).
- In addition to the resources that cleared in MAAC, another 0.7% to 6.5% of uncleared offers were available that could have been procured at higher prices had they been needed for reliability. Offers for new generation in MAAC have also been substantial, at 3,512 MW of BRA offers, of which 1,798 MW or 51% have cleared. These offers ranged from 110 MW to 1,038 MW in each year since 2009/10. In the smaller LDAs, the changes in supplies offered and cleared have been similar to MAAC overall although varying by location. In particular, penetration of DR and EE has been high in most LDAs, and by 2014/15 these resources contributed a large fraction of cleared internal BRA supply, ranging from 8.9% for EMAAC to 21.5% in SWMAAC.[25]

Most LDAs, even the smallest LDAs, had substantial quantities of uncleared offers for additional capacity that could have been procured at a higher price had they been needed for reliability. In some years, the smallest LDAs—including PEPCO, PSEG, PSEG-North, and DPL-South—did not have any uncleared offers, but almost all of these events occurred in the initial auctions when

---

[24] Note that in some cases the uncleared offers may represent the same unit that failed to clear and subsequently re-offered. However, cleared MW as reported here would in no cases represent the same unit twice as once the unit clears in one RPM auction it is no longer considered a new unit. Cleared or uncleared offers for new capacity in the incremental auctions are not reported in this section of the report.

[25] This does not mean DR and EE represent the same large fraction of total resources available to these LDAs as the number does not account for the capacity resources available through import capability in each location.

the regions were not deemed constrained and were not modeled in RPM.[26] Among modeled LDAs, the only BRA showing no uncleared capacity was in DPL-South in 2013/14, a year in which the cleared capacity had already exceeded the procurement target.[27] We observed in none of the LDAs any potentially concerning pattern of persistently low offer quantities, and it appears that substantially higher quantities of supply, if needed, could have been procured in every LDA at higher prices.

New generation offers have been unevenly distributed, although the data is difficult to interpret in the smallest LDAs, including DPL-South, where a single new plant would be sufficient to meet load growth for a decade.[28]

- EMAAC and its subregions—PSEG, PSEG-North, and DPL-South—have all attracted substantial offers for new generation equivalent to between 8% and 31% of total cleared internal resources within these LDAs. Just over half of these offers cleared due to relatively low prices compared to the cost of new entry and sufficient supply, as discussed earlier.
- In SWMAAC, lower quantities of new capacity were offered in the BRAs, but still equivalent to 4.2% of cleared resources, and almost none of this capacity has cleared.
- The PEPCO subregion has attracted only a negligible quantity of offers for new generation capacity to date. This lack of offers for new generation in PEPCO is a potential concern that may be caused by higher development costs and siting challenges. However, the lack of offers likely is also related to the relatively smaller size of the LDA and developers' understanding that the subregion already has sufficient supply, including from high levels of new demand response, reductions in load forecast, and increases in import capability.[29]

26 The history of which LDAs were modeled in which year can be seen in

Table **1**, which indicates unmodeled LDAs as dashes.

27 As seen in Figure 4.

28 Based on 2,369 MW projected DPL-South peak load in 2014 and 2,637 MW projected peak load in 2024, assuming that DPL-South peak load grows at the same rate as DPL overall. The 268 MW of load growth may translate into a 341 MW increase in the UCAP LDA reliability requirement if it increases proportionally. This increase is smaller than the approximate 650 UCAP MW that may be contributed by a new combined cycle generator as indicated by three recent projects proposed in New Jersey. See PJM (2011b) and (2011g), p. 54; Levitan (2011), p. 2.

29 For example, between the 2013/14 and 2014/15 BRAs, the need for internal PEPCO resources was reduced from 4,959 to 3,345 UCAP MW or by 33%. Contributing factors to this change were a 491 MW reduction in the reliability requirement and a 1,123 MW increase in CETL. See PJM (2010a, 2011b).

Table 4
LDA Summary of BRA Offered and Cleared
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
MAAC								
Cleared	**60,476**	**60,707**	**63,010**	**63,328**	**61,603**	**65,465**	**67,640**	**67,176**
Existing Generation	60,395	60,190	62,158	62,399	60,018	60,299	61,061	59,487
New Generation	16	40	110	21	540	262	556	253
DR and EE	66	478	743	908	1,045	4,904	6,023	7,436
Uncleared	**557**	**1,404**	**432**	**502**	**3,979**	**2,830**	**698**	**3,709**
Existing Generation	557	1,224	427	355	3,325	2,054	684	1,904
New Generation	-	-	-	119	497	463	14	621
DR and EE	-	180	6	29	156	312	-	1,185
EMAAC								
Cleared	**30,782**	**30,214**	**31,622**	**30,787**	**29,365**	**31,080**	**32,835**	**32,554**
Existing Generation	30,722	30,045	31,157	30,474	28,598	29,260	29,856	29,592
New Generation	16	-	93	6	535	162	494	74
DR and EE	45	169	372	306	231	1,658	2,485	2,888
Uncleared	**29**	**1,148**	**34**	**431**	**2,670**	**1,902**	**172**	**1,966**
Existing Generation	29	973	29	300	2,317	1,526	158	741
New Generation	-	-	-	119	277	223	14	621
DR and EE	-	175	4	12	76	153	-	604
SWMAAC								
Cleared	**10,201**	**10,621**	**9,915**	**10,873**	**10,780**	**11,595**	**11,242**	**11,124**
Existing Generation	10,182	10,312	9,558	10,354	10,039	9,661	9,480	8,726
New Generation	-	-	-	-	-	-	2	3
DR and EE	20	309	356	519	741	1,933	1,760	2,396
Uncleared	**-**	**5**	**397**	**55**	**871**	**801**	**526**	**1,334**
Existing Generation	-	-	397	55	612	477	526	1,093
New Generation	-	-	-	-	221	240	-	-
DR and EE	-	5	-	-	39	85	-	240
PSEG								
Cleared	**6,734**	**6,734**	**6,957**	**6,938**	**6,729**	**7,194**	**8,019**	**7,583**
Generation	6,734	6,681	6,856	6,862	6,699	6,731	6,893	6,614
DR and EE	-	52	101	75	31	463	1,127	969
Uncleared	**-**	**150**	**-**	**282**	**674**	**237**	**14**	**601**
Generation	-	102	-	278	655	223	14	423
DR and EE	-	48	-	4	19	14	-	178
PEPCO								
Cleared	**5,019**	**5,125**	**4,686**	**5,498**	**5,664**	**5,357**	**4,792**	**5,615**
Generation	5,014	5,093	4,621	5,464	5,519	4,840	4,209	4,679
DR and EE	5	32	65	33	145	517	583	936
Uncleared	**-**	**2**	**378**	**-**	**6**	**24**	**497**	**261**
Generation	-	-	378	-	-	-	497	131
DR and EE	-	2	-	-	6	24	-	130
PSEG-North								
Cleared	**3,737**	**3,734**	**3,767**	**3,672**	**3,640**	**3,550**	**4,159**	**3,818**
Generation	3,737	3,734	3,767	3,672	3,640	3,453	3,631	3,374
DR and EE	-	-	-	-	-	97	528	443
Uncleared	**-**	**22**	**-**	**199**	**369**	**223**	**14**	**352**
Generation	-	22	-	199	369	223	14	299
DR and EE	-	-	-	-	-	-	-	53
DPL-South								
Cleared	**1,583**	**1,587**	**1,587**	**1,520**	**1,454**	**1,323**	**1,612**	**1,439**
Generation	1,575	1,587	1,587	1,505	1,428	1,177	1,465	1,213
DR and EE	8	-	-	15	26	146	148	226
Uncleared	**-**	**-**	**-**	**26**	**32**	**257**	**-**	**161**
Generation	-	-	-	26	32	257	-	120
DR and EE	-	-	-	1	-	-	-	41

Sources and Notes:

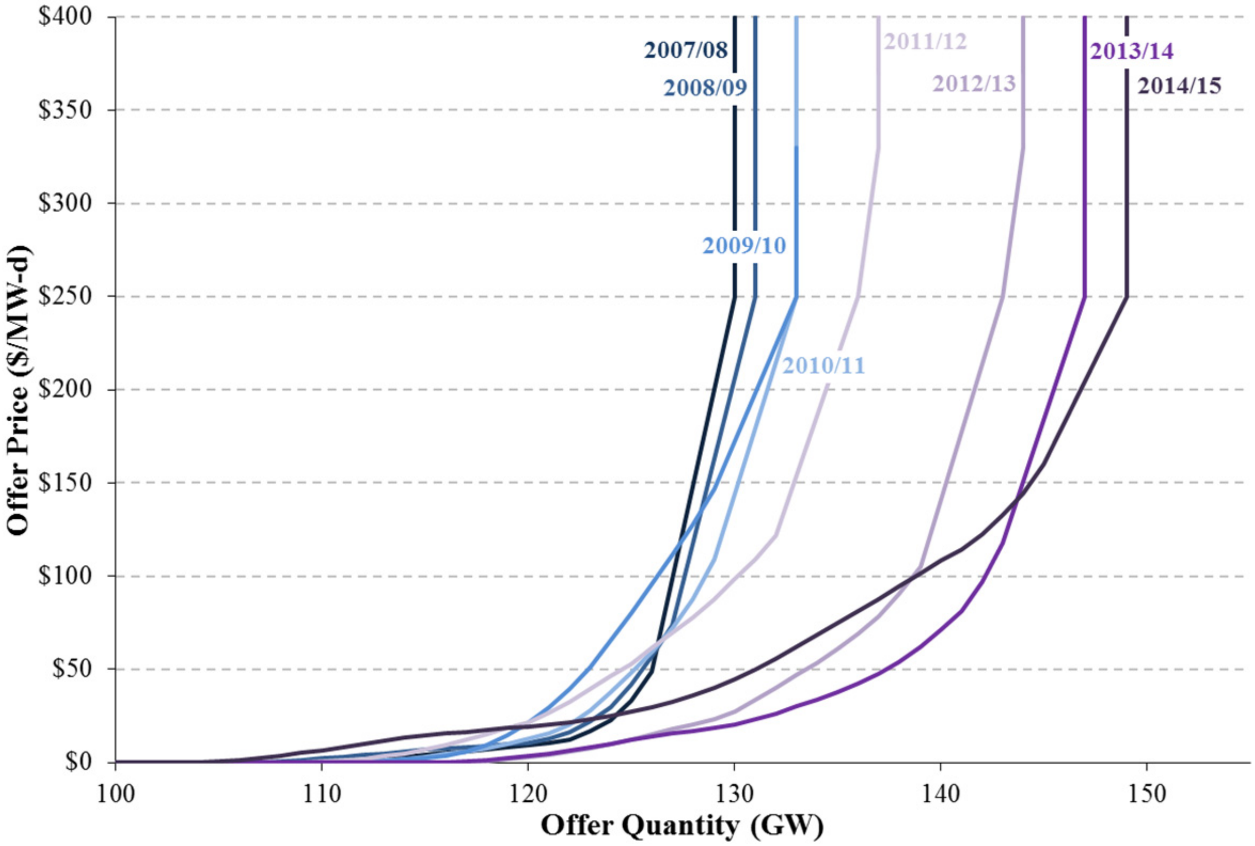
Calculated from BRA bid data supplied by PJM (2011a). Uprates are treated as existing generation.
New and existing generation are aggregated in the smaller LDAs to avoid revealing market-sensitive data.

4. BRA Supply Curves

The previous section described the quantities of resources offered and cleared in the auctions, but did not address the prices at which suppliers offered their resources. In fact, offers from many existing and new resources have changed substantially over time, affecting supply curve shapes and thus auction prices and quantities cleared. This subsection analyzes the shapes of the supply curves and the changes in market rules and fundamentals that have caused them.

Our analysis is based primarily on the mitigated supply curves in each BRA conducted to date, although we have also reviewed the individual resource offers and report observations at an aggregate level. Figure 6 shows the (smoothed) mitigated supply curves offered into the BRA for the delivery years 2007/08 through 2014/15, excluding capacity from ATSI and DEOK to make the curves comparable. The 2014/15 supply curve represents the total system supply of all newly-introduced resource types.[30]

Figure 6
BRA Supply Curves Excluding ATSI and DEOK



Sources and Notes:
Curves exclude supply from ATSI and DEOK zones. Smoothed to mask confidential market data.
From PJM supplier bidding data, PJM (2011a).

[30] The curve includes all Annual, Extended Summer, and Limited resources, but does not double-count capacity that submitted linked offers for multiple product types.

Our primary observations, which we explain in greater detail below, are as follows:

- *Supply curves with decreasing slopes through 2011/12*: Overall, the BRA offer curves have become progressively more gradual over time, ascending from zero through many mid-range offers to higher offers. These flatter curves help stabilize auction prices, all else being equal. Offer curves became more gradual as the forward period increased progressively from 2 months to 3 years during the forward-procurement transition from 2007/08 through 2011/12, allowing resource investments to be offered contingent on auction prices.

- *The full integration of DR starting in 2012/13*. Fully integrating DR into the auctions (instead of procuring it outside of the auctions as ILR) significantly expanded the offer curves. At first, existing DR was mitigated to zero. DR was unmitigated starting with the 2013/14 auction, which stretched out the mid-range of the curve.

- *Incorporation of environmental retrofit costs, especially for 2014/15*: the 2014/15 offer curve had the most gradual shape yet, with many coal generators that were previously offering at zero now offering at a range of non-zero prices related to their expected costs of complying with EPA regulation.

- *The introduction of multiple DR products, starting in 2014/15*: as expected, the offers for higher-value Annual and Extended Summer products are less plentiful and occur at higher prices than Limited DR. The Extended Summary and Annual supply curves are very similar to each other.

Supply Curves with Decreasing Slopes through 2011/12. The decreasing slopes of the supply curves for the 2007/08 through 2011/12 delivery years in large part reflect the fact that the base auctions were held with an increasing forward procurement periods of 2 months, 1 year, 1.5 years, 2.5 years, and 3 years to delivery. These first five auctions were held within a single year—between April 2007 and May 2008—as part of the transition period. The comparison of their supply curves shows a progressive change in supply. With each successive auction, substantially more supplies were offered and the supply curve became more gradual. We attribute these changes to the increasing forward period. Without sufficient lead-time to develop new resources, as was the case for the first BRA in 2007/08, supply curves will be steep as nearly all existing resources offer at (or are mitigated to) a price of zero. A forward period of several years will make the supply curve more gradual, as many investment decisions can be made contingent on the auction clearing price. New supplies such as uprates to existing or new generation can offer in to compete with capacity of existing supplies. Further, existing resources that require major capital expenditures to maintain operational can offer at a price commensurate with costs, and then make the upgrade contingent on clearing. Overall, the more gradual supply curve indicates that the three-year forward period has contributed to increased efficiency and competition among resources. It also contributes to greater stability in clearing prices.

The Full Integration of DR Starting in 2012/13. The 2012/13 supply curve shows a large increase in the quantity of offers due to the influx of DR into the auctions. In 2012/13, existing DR suppliers were required to offer into the capacity market at a mitigated offer price of zero.[31]

[31] See FERC (2009), pp. 10-11.

Starting with 2013/14, offer prices for DR were unmitigated and these suppliers offered over a range of prices.[32] The rapid growth of low-cost DR in the last several auctions contributed to lower prices, which has been a cause for concern among generation owners. We expect that the price-reducing effect of DR will not continue indefinitely, as continued DR growth will result in greater curtailment frequencies and more costly DR resources in the future. In fact, we observed that, starting with the auction for the 2013/14 delivery year, DR suppliers offered over a range of prices, which contributed to a substantially more gradual supply curve. These DR offer levels are likely related to opportunity costs of retail customers and expectations regarding future curtailment levels, as well as a range of customer characteristics. We expect that DR offer curves will eventually stabilize, and cleared amounts will increase or decrease with capacity prices, thereby creating more price stability in RPM.

Incorporation of Environmental Retrofit Costs, Especially for 2014/15. The 2014/15 supply curve has fewer offers at zero prices. Many existing generation resources were offered at non-zero levels, mostly due to coal units offering at prices related to their costs of environmental upgrades to meet EPA regulations. While the total system-wide costs of these upgrades are substantial, and installing them all simultaneously will be a challenge, we note that the three-year forward period of RPM has greatly increased the transparency of this process. Because coal units have bid into the capacity market over a range of prices consistent with their expected costs, the forward capacity auction has effectively prioritized the lowest-cost upgrades. Coal units requiring more expensive upgrades, presumably on older and less efficient plants, did not clear and will likely retire, thereby also reducing the current capacity surplus.

The Introduction of Multiple DR Products, Starting in 2014/15. Given the greater capacity obligations of Extended Summer and Annual resources, the supply curves for these resources are at a higher price and have fewer offers available than Limited Resources. There is a large difference in the quantity of Limited and Extended Summer supplies, and it has been suggested that some Limited Summer resources did not have sufficient time to revise their contracts to allow them to offer an Extended Summer product. We also note the possibly surprising fact that the Extended Summer and Annual supply curves are very similar to each other, implying that the large majority of these non-Limited resources may have annual capability. The similarity between the Annual and Extended Summer supply curves also indicates that DR suppliers may not expect substantially more curtailment for Annual resources under current market conditions. In the future, as DR penetration reaches a level sustainable in the long term, we expect that curtailment frequencies will increase and, as a result, may be quite different for Limited, Extended Summer, and Annual DR products. Under those conditions, we would expect a larger discrepancy between the supply curves for the varying obligation levels.

B. Incremental Auction Results

A small portion of capacity is procured through the incremental auctions. No stakeholder group raised concerns about the incremental auctions. However, these auctions play an essential role in RPM's ability to meet resource adequacy requirements efficiently. The incremental auctions are used to procure 2.5% (starting with the 2012/13 delivery year) of the expected total capacity obligation for the delivery year and are used to procure any unexpected needs that emerge

---

[32] See PJM (2011d), p. 65.

between the BRA and the delivery year. Incremental auctions help short-term resources compete without assuming the risks of three-year forward commitments. They also help reduce the risk of other suppliers assuming forward commitments by providing opportunities to buy (and sell) replacement capacity if needed.

This section explains the timing of incremental auctions, documents rules changes, analyzes offers and buy bids, and reports auction prices. We find that IA prices prior to the auction redesign were consistently below the BRA prices and that the prior IA design created an uneconomic incentive for DR resources to bid just above the BRA price. Results after the auction redesign in 2012/13 show that the new design produces results that are more efficient and consistent with market conditions. However, with only two auctions conducted to date, there is still insufficient evidence to fully evaluate the new IA design. We also find that, while many buy bids in incremental auctions were used to replace existing capacity commitments, a substantial number of low-priced buy bids were also submitted pre-emptively to procure extra capacity that can be used to replace potential future deficiencies.

1. Incremental Auction Mechanics and Redesign in 2012/13

Incremental auctions are held two years, one year, and several months prior to the delivery year.[33] For the first four delivery years of RPM, the IAs were primarily a capacity aftermarket in which suppliers could adjust their capacity commitments for changes to their resource ratings or costs. In these early years, PJM did not procure any net capacity from the first or third IAs for resource adequacy, although a load forecast increase would have triggered a second IA for incremental procurement.[34]

Third incremental auctions have been held for the 2008/09 through 2011/12 delivery years. First IAs have been conducted for 2011/12 and 2012/13. Several early delivery years did not have a full set of IAs due to the compressed forward period when RPM was phased in and because second incremental auctions would only have been held in the case of a load forecast increase.

Starting with the 2012/13 delivery year, a new incremental auction design was implemented. The first, second, and third IAs now have a Short-Term Resource Procurement Target ("STRPT") of 0.5%, 0.5%, and 1.5% respectively. The redesign also fully incorporated DR resources into the capacity auctions instead of awarding auction-based prices to DR certified as Interruptible Load for Reliability (ILR) immediately prior to the delivery year. Additionally, the new incremental auction design includes the uncleared portion of the VRR curve and adjusts the demand for updates in the load forecast and transmission limits in some cases.[35] Suppliers can use these incremental auctions to adjust or replace their capacity obligations.

---

[33] Specifically, the first IA is held 20 months prior to delivery, the second IA is held 10 months prior to delivery and the third IA is held 3 months prior to delivery. A conditional IA may also be held if additional capacity is needed due to a delay in a backbone transmission upgrade. See PJM (2011d), pp. 69-72.

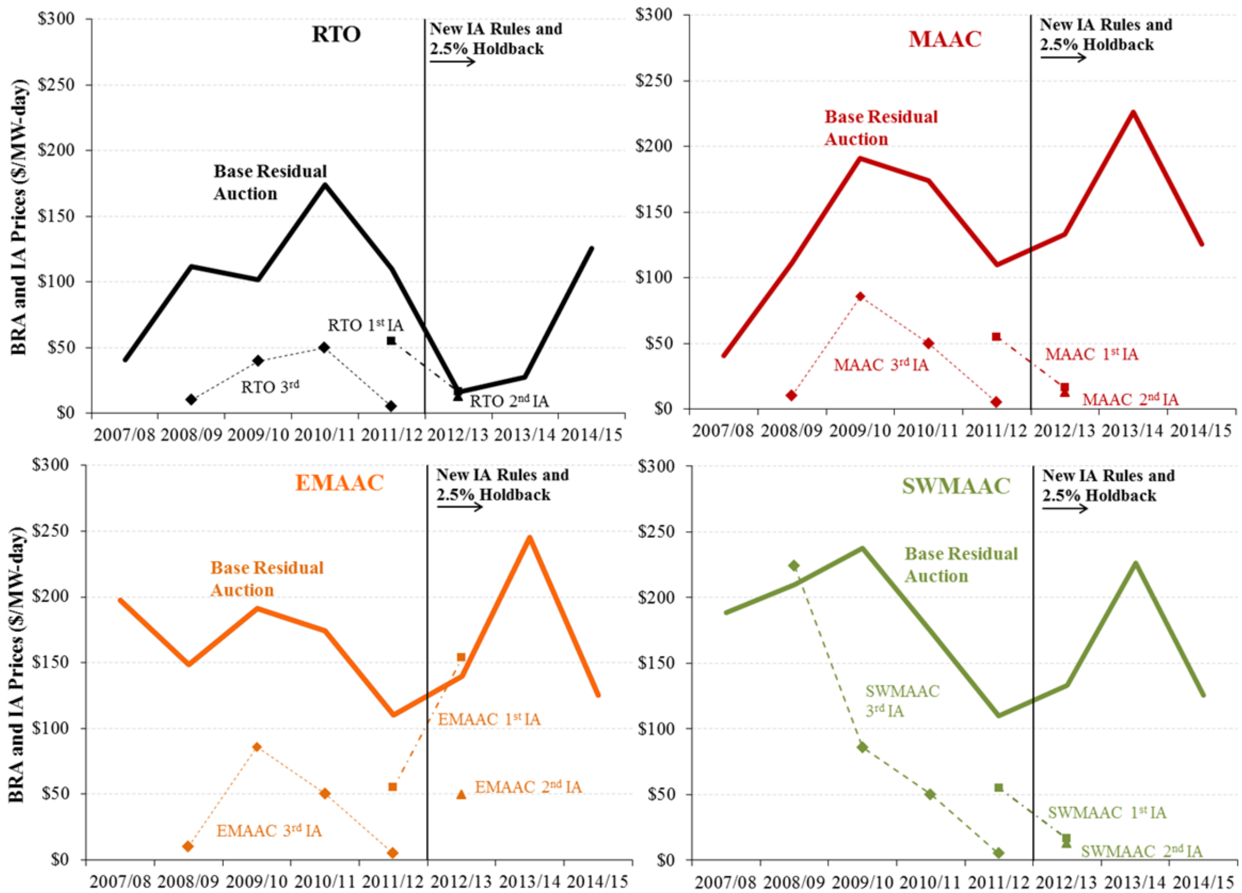
[34] No second IA was ever held for this reason. See *Id.*, p. 72.

[35] See *Id.*, pp. 20-21.

2. Incremental Auction Clearing Prices

Clearing prices in the IAs are summarized in Figure 7 for the RTO and the largest LDAs. (Table 5 shows prices for all locations.) Figure 7 shows BRA prices as a solid line with incremental auction prices shown as dashed lines.

Figure 7
Incremental Auction Clearing Prices



Sources and Notes:
Year 2014/15 BRA clearing prices reflect resource clearing prices without an Annual or Extended Summer price adder.
From BRA and IA results, see PJM (2007a, 2008a-c,e, 2009a,e,h-i, 2010b,f,g, 2011c,g).

As Figure 7 shows, incremental auction prices under the initial design were persistently and substantially below BRA prices—on average $90/MW-day lower in the RTO and on average $115/MW-day lower in MAAC. The only exception occurred in SWMAAC in the third incremental auction for the 2008/09 due to tight supply conditions. Less experience exists to date for the new IA design. However, Figure 7 shows that prices in the first IA for the 2012/13 delivery are very close to BRA prices in the RTO and EMAAC, but much lower than BRA prices in MAAC and SWMAAC.

Table 5
Incremental Auction Clearing Prices

Year	Auction	RTO ($/MW-d)	MAAC ($/MW-d)	EMAAC ($/MW-d)	SWMAAC ($/MW-d)	DPL-S ($/MW-d)	PSEG ($/MW-d)	PS-N ($/MW-d)	PEPCO ($/MW-d)
2007/08	BRA	$40.80	--	$197.67	$188.54	--	--	--	--
2008/09	BRA	$111.92	--	$148.80	$210.11	--	--	--	--
	3rd IA	$10.00	--	$10.00	$223.85	--	--	--	--
2009/10	BRA	$102.04	$191.32	$191.30	$237.33	--	--	--	--
	3rd IA	$40.00	$86.00	$86.00	$86.00	--	--	--	--
2010/11	BRA	$174.29	$174.30	--	$174.30	$186.12	--	--	--
	3rd IA	$50.00	$50.00	--	$50.00	$50.00	--	--	--
2011/12	BRA	$110.00	--	--	--	--	--	--	--
	1st IA	$55.00	--	--	--	--	--	--	--
	3rd IA	$5.00	--	--	--	--	--	--	--
2.5% Holdback Introduced and New Incremental Auction Design is Implemented									
2012/13	BRA	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	--
	1st IA	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	--
	2nd IA	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	--
2013/14	BRA	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14
2014/15	BRA	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47

Sources and Notes:
From BRA and IA results, see PJM (2007a, 2008a-c,e, 2009a,e,h-i, 2010b,f,g, 2011c,g).
Prices are reported only for years in which each LDA was modeled under RPM.
MAAC + APS price is listed under MAAC for delivery Year 2009/10.

To determine the drivers of incremental auction prices and the price changes between the BRA and the IAs, we examined supply and demand offer data for each of these auctions. A detailed explanation of these price drivers is presented in Table 6. Under the new design, prices in MAAC and SWMAAC were much lower than BRA prices because the load forecast for the delivery year decreased in MAAC. The EMAAC price did not decrease despite a reduced load forecast because of a delay of the Susquehanna-Roseland transmission line, which required substantial incremental capacity procurement.[36] Prices in the second IA for 2012/13 were driven by a reduction in the load forecast in most locations, resulting in a small reduction of prices in the RTO, MAAC, and SWMAAC relative to the already low first IA price, and a large $105/MW-day reduction in EMAAC and its sub-LDAs. These price changes under the new IA design are consistent with the changes in capacity requirements experienced during the period between when the BRA and IA were conducted.

Under the prior incremental auction design, IA prices were consistently far below clearing prices in the BRAs. Offer prices and quantities of generation supply were the primary driver of these price reductions. During the incremental auctions for the 2009/10 and 2010/11 delivery years, a substantial amount of capacity uprates offering at low prices contributed lower-priced supply curves in the IAs. In most other IAs, less existing generation capacity was offered than had

36 See PJM (2010h).

previously not cleared in the BRAs, but some of the resources that did not clear in the BRA dropped their offer prices to zero or near zero. This change in offer price behavior for some generators, combined with a reduction in offer quantities, resulted in IA supply curves that were relatively steep in some cases. Resulting IA prices were low, however, because of low demand, which meant that the auctions cleared in the low-priced portion of the supply curves.

In some cases, substantially more DR was offered into the IAs than what went uncleared in the BRA, particularly during the third IA for the 2011/12 delivery year. However, prior to the 2012/13 delivery year, these additional DR supplies had little effect on IA clearing prices as nearly all of these suppliers offered at prices just above the BRA clearing price. The higher-priced DR offers were consistent with incentives under the prior IA design, because suppliers could be certified as ILR immediately prior to the delivery year and receive a capacity payment based on BRA price for that year. Under that structure, DR suppliers had an incentive to bid into the IAs only to possibly capture a price above the BRA price. With the revision of the IA design and the elimination of ILR (and incorporation of these DR supplies into the RPM auctions) for the 2012/13 delivery year, DR suppliers in the both the IAs and BRAs have begun offering significant amounts of supply over a large range of prices.

Market participants' demand bids in the IAs have been for small amounts of capacity at high prices and very high quantities at low prices. In fact, most demand bids submitted at a zero price. The qualitative shape of the demand curve in the first IA is different from the shape in the third IA, with the third IA having higher quantities of demand at higher prices. A relatively higher willingness to pay for replacement capacity in the third IA may be caused by a lack of time to find bilateral replacement transactions between the third IA and the delivery year.

Table 6
Summary of Major Incremental Auction Price Shifts and Causes

Year	Auction	Location	Causes of Major Price Changes Relative to BRA or Previous IA
2008/09	*3rd IA*	*RTO and EMAAC* -	Price decrease of $102/MW-day and $139/MW-day in RTO and EMAAC, respectively, caused by a small increase in supply from existing generation combined with a large reduction in offer prices from existing generation.
		SWMAAC -	SWMAAC IA price clears at the LDA price cap or just $14/MW-day higher than the BRA price, with relatively high prices in both cases caused by tight supply conditions. Only 5 MW of capacity went uncleared in the BRA and 21 MW was offered into the IA.
2009/10	*3rd IA*	*RTO and LDAs* -	Large price reductions of $62-$151/MW-day, depending on the location, are caused by reductions in offer prices from existing generation and generation uprates offered at low or zero prices. Increases in offered DR did not contribute to price reductions because these resources offered at prices above the BRA clearing price.
2010/11	*3rd IA*	*RTO and LDAs* -	Similar to 2009/10 third IA, large price reductions of $124 to $136/MW-day are caused by low offer prices from existing generation and uprates.
2011/12	*1st IA*	*RTO* -	Prices decrease $55/MW-day despite substantially reduced supply relative to uncleared BRA quantities. Demand bids have a large quantity but nearly all demand bids are at or very near zero, causing only a small quantity of low-priced supply offers to clear.
	3rd IA	*RTO* -	Price reduction of $105/MW-day relative to the BRA and $50/MW-day relative to the first IA caused by low generation offer prices relative to the BRA and IA, along with additional low-price DR offers. Despite a substantial increase in DR quantities, the great majority of DR offers were rationally submitted above the BRA clearing price.
			2.5% Holdback Introduced and New Incremental Auction Design is Implemented
2012/13	*1st IA*	*RTO* -	Uncleared portion of the BRA supply curve is very similar to the IA supply curve, with a substantial quantity of offers near the BRA clearing price, resulting in an RTO clearing price identical to the BRA price.
		MAAC and SWMAAC -	Capacity prices decrease by $117/MW-day despite reduced supply relative to BRA uncleared quantity. These reductions were caused primarily by a reduction in peak load forecast in MAAC.
		EMAAC -	Capacity price rises by a modest $14/MW-day in response to a nearly 2,000 MW reduction in CETL caused by a delay in the Susquehanna-Roseland transmission line. This large increase in the required quantity of internal capacity did not result in a large price increase because, similar to the rest of MAAC, existing generators substantially reduced their offer prices relative to the BRA.
	2nd IA	*RTO* -	Capacity prices decreased by $105/MW-day in EMAAC and subzones and by $3/MW-day below the already low first IA prices in all other LDAs. These price reductions were driven by a large reduction in the load forecast.

Sources and Notes:
Causes of price changes determined from analysis of auction bid data, supply curves, demand curves, and parameters.
From BRA parameters, results, and bid data, PJM (2007a-b, 2008a-c,e, 2009a-e,h-i, 2010a-b,f-h, 2011a-c,g).

3. Quantities Offered and Cleared

Table 7 shows the quantities of cleared and uncleared supply offers and demand bids in all incremental auctions conducted to date. BRA uncleared resources are also shown for reference, as a reasonable first assumption would be that many resources failing to clear the BRA might later offer into an IA. Supplier offers are shown separately for new generation, existing generation, and DR and EE. Buyer bids from generation owners are shown separately from bids from DR and EE owners.[37]

Table 7 shows that offered supplies in the third IA exceeded the uncleared BRA capacity by up to 3.7 GW, mostly related to DR that offered only into the third IA (but no earlier auctions) for that delivery year. We do not expect this same result to continue after the 2012/13 incorporation of DR into the auctions, since these resources are now offering significant amounts of capacity into the BRA. For the first and second IAs, offer quantities were less than the BRA uncleared supply by approximately 2 GW and 1 GW, respectively. These reductions in supply for the first and second IAs are mostly related to higher-priced generation that offered into the BRA but did not offer in the IAs. Among new generation resources that failed to clear the BRA, only 30% to 50% have subsequently offered into the IAs. This suggests that some suppliers of new generation or existing generation requiring substantial reinvestment have made their investment decisions contingent on whether they clear in the BRA. If they do not clear in the three-year forward BRA, they likely will not be available for that delivery year.

For existing generation resources, the quantities offered in the IAs for the 2009/10 and 2010/11 delivery years were 1.5 GW and 2.3 GW higher than the quantities uncleared in the BRA. Most of these increases were associated with capacity uprates.[38] For the 2011/12 and 2012/13 delivery years, 2.0 GW and 1.2 GW less existing generation was offered into the first IAs than in the BRA. Most of these reductions are associated with existing resources that have subsequently submitted retirement requests, although some are associated with reduced imports, equivalent demand forced outage rate ("EFORd") changes, derates, or ATSI units that were obligated to offer capacity into the IAs.

For DR and EE resources, the offer levels in the first IAs were 290 MW and 470 MW below the BRA uncleared quantities, while the offer levels in the third IAs were up to 3,980 MW above the BRA uncleared quantities. At first glance, these observations may seem to support the theory that DR and EE have a much greater ability to participate in non-forward auctions, but the data must be interpreted carefully given DR rule changes for the 2012/13 delivery year. Starting with the 2012/13 delivery year, the ILR option was eliminated, so these resources had to clear through auctions.

---

[37] Buy bids are submitted by market participants but are not associated with specific resources. For this reason, we have classified buy bids as DR and EE or generation based on the predominant resource holdings of the market participant. The vast majority of market participants offer only generation or only DR and EE.

[38] Specifically, of the increase in supply from existing resources for those two years, approximately 63% was from generation uprates, 18% was from increased imports, 11% was from small generators that did not offer into the BRA, 5% was from EFORd decreases, and 3% was from FRR resources. From PJM (2011a).

Table 7
Summary of Incremental Auction Cleared and Uncleared Offers and Bids
(UCAP MW)

	2007/08	2008/09	2009/10	2010/11	2011/12		2012/13		2013/14	2014/15
SELL OFFERS										
Base Residual Auction										
Uncleared	**1,435**	**2,283**	**1,319**	**902**	**5,499**		**9,230**		**8,155**	**10,512**
New Generation	-	-	139	119	497		598		14	621
Existing Generation	1,435	2,103	1,136	755	4,714		5,748		4,393	8,454
DR and EE	-	180	44	29	288		2,884		3,748	1,437
Incremental Auctions		*3rd IA*	*3rd IA*	*3rd IA*	*1st IA*	*3rd IA*	*1st IA*	*2nd IA*		
Offered	n/a	**2,339**	**3,256**	**4,554**	**2,843**	**6,538**	**7,086**	**6,448**	n/a	n/a
New Generation	n/a	6	69	30	163	212	179	164	n/a	n/a
Existing Generation	n/a	2,310	2,656	3,073	2,680	2,056	4,492	3,802	n/a	n/a
DR and EE	n/a	23	531	1,452	-	4,270	2,415	2,483	n/a	n/a
Cleared	n/a	**1,032**	**1,798**	**1,846**	**361**	**1,557**	**1,689**	**838**	n/a	n/a
New Generation	n/a	6	19	30	-	175	95	76	n/a	n/a
Existing Generation	n/a	1,003	1,780	1,792	361	844	1,116	525	n/a	n/a
DR and EE	n/a	23	-	24	-	538	478	237	n/a	n/a
Uncleared	n/a	**1,307**	**1,457**	**2,708**	**2,481**	**4,981**	**5,397**	**5,610**	n/a	n/a
New Generation	n/a	-	50	-	163	37	84	87	n/a	n/a
Existing Generation	n/a	1,307	876	1,280	2,319	1,212	3,376	3,277	n/a	n/a
DR and EE	n/a	-	531	1,428	-	3,732	1,937	2,246	n/a	n/a
MARKET PARTICIPANT BUY BIDS										
Incremental Auctions		*3rd IA*	*3rd IA*	*3rd IA*	*1st IA*	*3rd IA*	*1st IA*	*2nd IA*		
Offered	n/a	**2,252**	**2,698**	**5,221**	**11,969**	**8,865**	**9,339**	**11,560**	n/a	n/a
Generation Suppliers	n/a	2,182	2,308	4,789	11,419	8,473	8,581	10,741	n/a	n/a
DR and EE Suppliers	n/a	70	390	432	550	393	758	819	n/a	n/a
Cleared	n/a	**1,032**	**1,798**	**1,846**	**361**	**1,557**	**1,749**	**3,215**	n/a	n/a
Generation Suppliers	n/a	992	1,409	1,414	141	1,164	1,403	2,754	n/a	n/a
DR and EE Suppliers	n/a	40	390	432	220	393	346	460	n/a	n/a
Uncleared	n/a	**1,220**	**899**	**3,375**	**11,607**	**7,308**	**7,590**	**8,345**	n/a	n/a
Generation Suppliers	n/a	1,190	899	3,375	11,278	7,308	7,178	7,987	n/a	n/a
DR and EE Suppliers	n/a	30	-	-	330	-	412	359	n/a	n/a

Sources and Notes:
From PJM supplier bidding data, PJM (2011a).
Buyers are classified as generation or demand suppliers based on the predominant resource type held.

In some cases, after a resource has made a capacity commitment through the BRA, it will have an unforeseen difficulty in meeting this obligation. Reasons might be a construction delay or a major equipment failure or derate. These suppliers can decommit their capacity without penalty as long as they can substitute replacement capacity through self-supply or bilateral transactions or by procuring replacement capacity in the incremental auctions. Market participants may also submit buy bids in the incremental auctions as a hedging measure, even if the procured capacity is not ultimately used to decommit another resource. In the incremental auctions held to date, generation owners have submitted 93% of total buy bids submitted and 80% of bids cleared. DR and EE suppliers have submitted the remaining 7% of buy bids and 20% of bids cleared. Demand in the incremental auctions prior to 2012/13 consisted only of market participants' buy bids, while demand in subsequent IAs also includes a portion related to changes in CETL, reliability requirements (the STRPT), and the incremental portion of the VRR curve.

Among generation owners, it appears that market participants have been using the IAs as a supplement to bilateral and self-supply options for managing their capacity obligations after the

BRA.[39] For generation owners, 79% of their full-year resource replacements have been through self-supply or bilateral transactions; only 66% of the capacity that generators have procured from the IAs has later been used to reduce capacity commitments. Generators have also been very active in substituting capacity for partial years, presumably to avoid penalties.[40] These generators appear to use the IAs as a hedging opportunity by procuring substantial quantities of replacement capacity (as indicated by their high bid quantities), but only if that capacity is available at very low prices (as indicated by their low clearing quantities).

Among DR suppliers, it appears that incremental auctions have represented their primary means of managing capacity obligations after the BRA. For DR suppliers, all capacity procured from the IAs has been used to replace full-year capacity decommitments. This IA capacity has replaced 86% of all decommitments from DR, with the remainder being replaced through self-supply or bilateral transactions.[41] Relative to generation owners, DR suppliers have been much less active in managing partial-year resource replacements.[42]

4. Incremental Auction Supply Curves

We have compared supply curves for each of the IAs to the uncleared portions of the corresponding BRA supply curves. We used this comparison to examine how offer quantities and prices change for supplies that fail to clear the BRA. Figure 8 and Figure 9 below show the (smoothed) mitigated supply curves for the 2011/12 delivery year (prior to the IA redesign and 2.5% holdback) and for 2012/13 delivery year (after the IA redesign and 2.5% holdback).

Prior to the redesign, there were four third IAs and one first IA. One of the most prominent features of the third IA supply curves was the large “shelf” of DR bids submitted at prices just above the BRA price as highlighted in Figure 8. This shelf was caused by inefficient incentives created by the previous ILR mechanism. These resources were allowed to receive a payment based on BRA clearing prices as long as their capacity was certified immediately prior to the delivery.[43] Under that system, demand resources had almost no incentive to offer into the BRA or first and second IAs. Their only incentive to offer in any auction was to capture potentially higher IA prices, which would happen only if the incremental auction cleared at a capacity price

---

39 References in this paragraph to bilateral and self-supply replacement transactions refer only to delivery years 2008/09 through 2010/11. The reason for this is that many replacement transactions do not occur until immediately prior to, or even during, the delivery period, even if the replacement capacity was procured earlier. Partial year transactions especially are more common during the delivery year.

40 For example, for 2010/11, generation owners procured 1,414 MW in the third IA, which were used in 1,014 MW of full-year resource decommitments and another 1,507 MW of partial-year decommitments. Note that the same IA procured MW can be used multiple times for partial-year decommitments as these decommitments may be for only days or weeks. For the same delivery year, self-supply or bilateral capacity transactions were used in order to decommit another 4,373 MW of full-year obligations and another 18,954 MW of partial-year obligations.

41 Again, these reported numbers represent only delivery years 2008/09 through 2010/11.

42 For example for 2010/11, DR suppliers procured 432 MW in the third IA, all of which was used to replace committed capacity for a full year. An additional 54 MW of full-year replacements were made through self-supply or bilateral transactions, and no DR suppliers submitted any partial-year capacity replacements.

43 See PJM (2011d), p. 29.

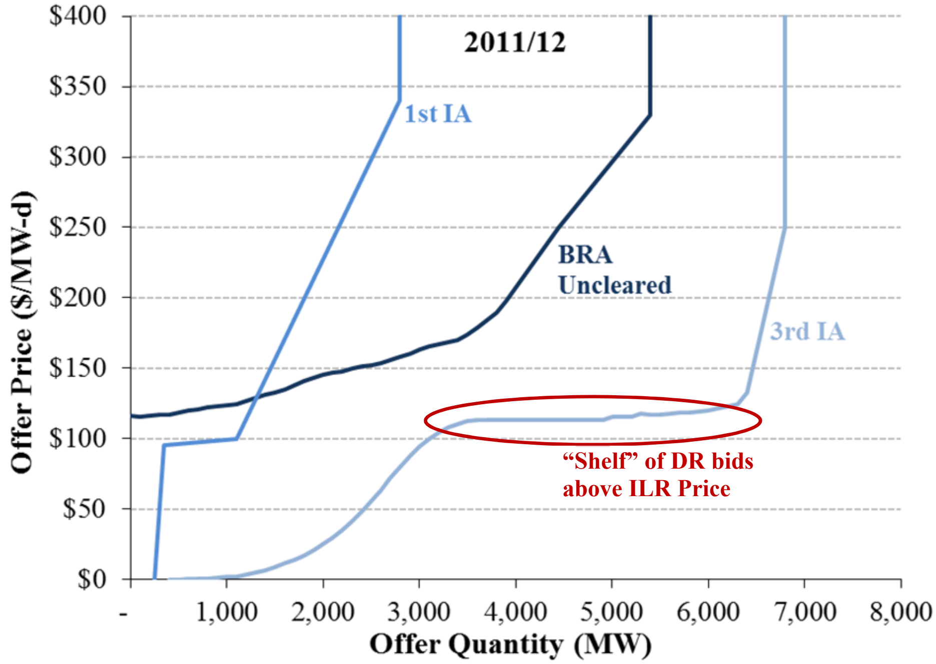
above the BRA prices otherwise awarded to ILR. As a result, prior to the 2012/13 delivery year, a rational DR supplier would either opt out of participating in any of the auctions or participate in the IAs by offering at a price above the BRA clearing price. After the elimination of ILR (and full incorporation of DR into auctions starting with the 2012/13 delivery year), this incentive was eliminated.

After the 2012/13 redesign, there have only been two incremental auctions conducted, providing limited evidence for our evaluation. However, it is noteworthy to observe from Figure 9 that the IA supply curves for the 2012/13 delivery year are very similar in shape to the uncleared portion of the BRA supply curve for prices below approximately $150/MW-day. Much of this supply is from DR offers that had similar offer levels in the BRA and IAs. It is not yet clear how the offer prices for DR supplies may differ in the third IA immediately prior to the delivery year or how substantially these offers are influenced by changing expectations about curtailment levels.

For generation supplies (both before and after the redesign), IA offer curves have been much steeper than the BRA supply curves, with most high-cost supplies dropping out prior to the IAs and many other generation suppliers offering at zero. The withdrawal of high-cost generation supplies above $150/MW-day is visible in the 2012/13 supply curves shown in Figure 8, indicating that some generators have made decisions about whether to invest in a new resource or reinvest in an existing resource contingent on the outcome of the BRA. However, we have also observed occasions when additional generation supplies that were not offered in the BRA were offered into the IAs at a zero price. For example, in the third IAs for the 2009/10 and 2010/11 delivery years, a large number of uprates were offered that were previously not offered in the BRA. Given their zero offer prices in the IAs, we believe it is likely that most of these uprate investment decisions were made based on the suppliers' longer-term outlook for capacity and energy prices and not specifically based on prices available in the IAs.

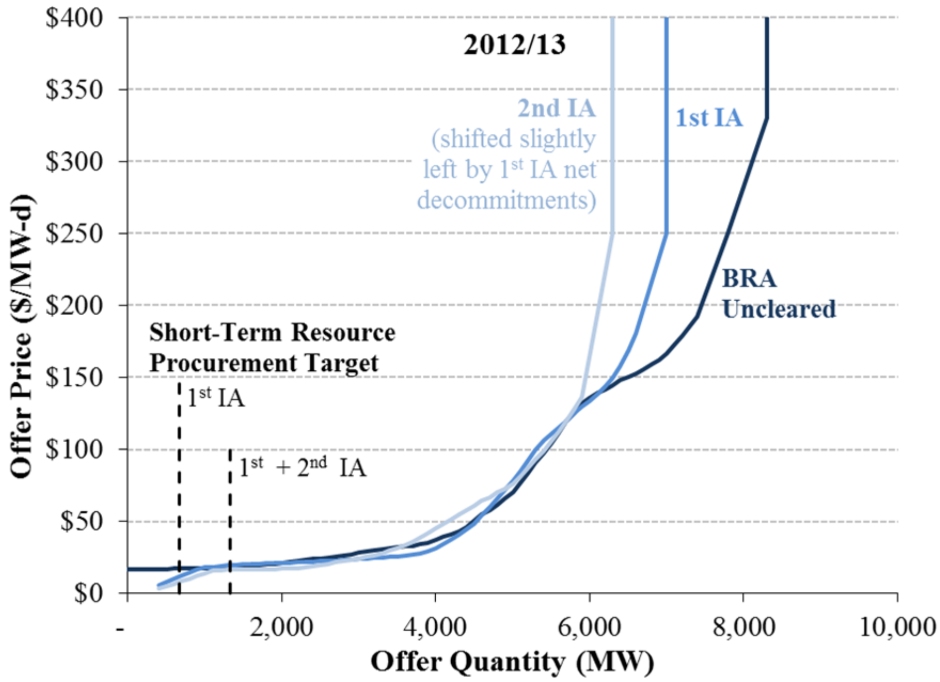
Overall, incremental auction results from the first two auctions after the redesign are promising, but more experience needs to be gained to fully assess IA performance. Prices in the IAs for the 2012/13 delivery year have been consistent with changes in market conditions between the BRA and the IAs, including load forecast reductions and the delay of the Susquehanna-Roseland transmission line. In addition to this preliminary empirical evidence, there are several other reasons to expect that IA prices under the new design will be more consistent with BRA prices and market fundamentals, including: (1) the incorporation of the incremental portion of the VRR curve in the IAs, (2) the reliability requirement adjustments that may be made prior to IAs in the future, and (3) DR and EE resources will have the option to offer into either the BRA or the IAs, which may allow some price convergence.

Figure 8
2011/12 Incremental Auction Supply Curves
(Before 2012/13 Redesign and without 2.5% Holdback)



Sources and Notes:
From PJM supplier bidding data, PJM (2011a). Smoothed to mask confidential market data.

Figure 9
2012/13 Incremental Auction Supply Curves
(After 2012/13 Redesign and with 2.5% Holdback)



Sources and Notes:
From PJM supplier bidding data, PJM (2011a). Smoothed to mask confidential market data.

C. CUMULATIVE ADDITIONS, RETIREMENTS, AND RETENTIONS

The following discussion summarizes the cumulative changes in capacity commitments from all base and incremental auctions to date—since just before the introduction of RPM through the commitments made in the most recent BRA for the 2014/15 delivery year. Unlike the previous sections covering individual auction results on a UCAP basis, the discussion *in this section refers all results on an installed capacity (ICAP) basis*.

We first summarize all gross and net additions to capacity in PJM, including resources contributing to Fixed Resource Requirement (FRR) plans and resources added through new RTO members. We report all current or planned internal generation capacity, total imports and exports, and current or planned demand-side resources. Among these total system resources, we include a breakdown of the capacity that is committed to providing resource adequacy either through FRR commitments or by clearing through auctions, as well as summarizing total resources that are RPM-qualified but that are not committed for capacity purposes either because they have gone uncleared in the auctions or because they have been excused from auctions.

We then examine in greater detail the gross and net capacity additions committed through base and incremental auctions, excluding FRR capacity and new RTO members. We explicitly report the quantities of planned capacity increases that were offered into auctions but failed to clear (indicating that they may not materialize), as well as the quantities of existing capacity that have failed to clear (indicating that they may retire). We also report the net capacity exchange between RPM auctions and FRR entities. We examine these gross and net commitments at the RTO and LDA levels, and compare committed totals to the target commitment levels required for resource adequacy. These committed net resource additions are the most relevant evidence for evaluating RPM's track record for attracting and retaining sufficient capacity for resource adequacy.

1. Net Capacity Additions (Including FRR and RTO Expansion)

Table 8 summarizes installed capacity reductions and additions in PJM relative to the pre-RPM levels in 2006/07 through results for the most recent auction for 2014/15. The table separates auction-committed capacity from FRR-committed capacity and from capacity gained through territory expansions. The top portion of the table reports total historical and planned capacity reductions and additions, while the bottom reports the total capacity commitments for resource adequacy through FRR or auctions (as well as uncommitted capacity that may retire or fail to come online).

Since RPM began with delivery year 2007/08, PJM has added 36.3 GW of ICAP through completed or planned additions, uprates to internal generation, increased imports, decreased exports, and increased demand-side resources. Of these gross additions, 4.9 GW are FRR capacity and 31.4 GW are RPM auction capacity. Derates and retirements over the same time period have totaled 8.4 GW. Of these gross reductions, 0.4 GW are FRR capacity and 8.1 GW are auction capacity. An additional 13.9 GW of pre-existing generation capacity was acquired through RTO expansions to integrate ATSI and DEOK into PJM.

Overall, these additions, reductions, and expansions have resulted in a net increase of 41.7 GW in installed capacity available to meet the required reserve margin. For the 2014/15 delivery year, of the total 205.8 GW of installed or planned capacity in PJM, 33.6 GW is committed to provide reliability through FRR commitments and another 157.3 GW is committed through RPM auctions, sufficient to exceed respective resource adequacy targets. The remaining 14.9 GW of capacity is not committed to provide resource adequacy because it was either excused from offering in auctions or failed to clear in the 2014/15 BRA.

Focusing on generation, PJM had 164.9 GW of internal generating capacity in 2006/07, immediately prior to RPM's implementation. At the outset of RPM, 23.1 GW of this existing capacity was incorporated through the FRR option. Since then, there have been gross additions of 12.7 GW of internal generation capacity in the RTO. This includes 7.6 GW of newly built or reactivated generation,(650 MW from FRR resources) and 5.1 GW of uprates to existing generation (420 MW to FRR resources).[44] These additions have been offset by 8.4 GW of reductions to internal generation through plant derates and retirements. Through the current delivery year of 2011/12, only 710 MW of generation has retired; however, based on pending deactivation requests, the rate of retirement will increase over the next three delivery years to reach a cumulative total of 5.3 GW by 2014/15. Of these retirements, 2.3 GW are coal plants, 1.7 GW are gas (primarily aging gas steam plants), 1.1 GW are oil plants, and the remainder are small units of other fuel types. Including completed and planned new units, reactivation, uprates, retirements, and derates, there has been a cumulative net addition of 4.2 GW to existing internal generating capacity in PJM through delivery year 2014/15.

PJM was a net *exporter* of 2.6 GW in 2006/07. By 2014/15, it will be a net *importer* of 6.4 GW for a total change of 9.0 GW. Gross exports declined after RPM was implemented, decreasing from 5.3 GW in 2006/07 to 1.2 GW in 2014/15. Commitments for imports increased from 2.7 GW in 2006/07 to 7.6 GW in 2014/15. Of the 9.0 GW increase in net imports, 4.2 GW occurred in 2014/15 coincident with the incorporation of DEOK into RPM, primarily from resources owned by Duke but not within the portion of Duke that was incorporated into PJM.

Demand resources have grown substantially since RPM was implemented. During the 2006/07 delivery year, 1.7 GW of demand-side resources contributed to resource adequacy as Active Load Management ("ALM"). For 2014/15, 16.4 GW of DR and EE capacity has been committed through FRR or offered into RPM auctions (in ICAP terms).[45]

---

[44] 650 MW of new generation that offered into the 2014/15 auction did not clear and may not come online.

[45] Note that the apparent decrease in demand resources for 2013/14 relative to the prior and subsequent years is somewhat misleading. The reason for this apparent drop is that no incremental auctions have yet been conducted for 2013/14. We expect that subsequently planned resources that have offered into the 2012/13 IAs and 2014/15 BRA will also offer into the 2013/14 IAs when they are conducted.

Table 8
Cumulative Changes in Capacity under RPM
(ICAP MW)

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
INTERNAL GENERATION	**164,914**	**164,556**	**165,327**	**165,966**	**167,553**	**171,655**	**171,559**	**181,243**	**183,009**
Existing Generation Prior to RPM	**164,914**	**164,914**	**164,914**	**164,914**	**164,914**	**165,663**	**166,460**	**177,035**	**178,769**
Non-FRR Capacity as of 2006/07	141,831	141,831	141,831	141,831	141,831	141,831	141,831	141,831	141,831
FRR Capacity as of 2006/07	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083	23,083
ATSI/DEOK Prior to Joining PJM	n/a	n/a	n/a	n/a	n/a	749	1,546	12,121	13,855
Generation Reductions	n/a	**(904)**	**(1,269)**	**(2,110)**	**(2,412)**	**(2,675)**	**(5,713)**	**(7,136)**	**(8,446)**
Retirements	n/a	*(340)*	*(440)*	*(440)*	*(617)*	*(710)*	*(3,035)*	*(4,331)*	*(5,341)*
FRR Capacity	n/a	-	-	-	-	-	-	-	-
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	(322)
Auction Capacity (w/o ATSI/DEOK)	n/a	(340)	(440)	(440)	(617)	(710)	(3,035)	(4,331)	(5,019)
Derates	n/a	*(564)*	*(829)*	*(1,670)*	*(1,795)*	*(1,965)*	*(2,678)*	*(2,805)*	*(3,105)*
FRR Capacity	n/a	(94)	(138)	(357)	(357)	(357)	(361)	(361)	(364)
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	(470)	(691)	(1,313)	(1,439)	(1,608)	(2,318)	(2,445)	(2,742)
Generation Additions	n/a	**546**	**1,681**	**3,155**	**5,043**	**8,243**	**10,387**	**11,104**	**12,686**
New Generation	n/a	*129*	*340*	*882*	*1,845*	*3,838*	*4,924*	*5,662*	*6,763*
FRR Capacity	n/a	-	-	-	595	595	595	655	655
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	685	708
Auction Capacity (w/o ATSI/DEOK)	n/a	129	340	882	1,250	3,243	4,329	4,322	5,400
Uprates	n/a	*417*	*1,040*	*1,947*	*2,896*	*3,573*	*4,622*	*4,610*	*5,083*
FRR Capacity	n/a	64	84	254	254	295	354	380	416
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	352	956	1,693	2,641	3,279	4,268	4,230	4,667
Reactivations	n/a	-	*302*	*326*	*303*	*832*	*841*	*832*	*841*
FRR Capacity	n/a	-	-	-	-	-	-	-	-
Auction Capacity (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	-	-	-	-
Auction Capacity (w/o ATSI/DEOK)	n/a	-	302	326	303	832	841	832	841
New Generation Later Cancelled	n/a	**-**	**-**	**8**	**8**	**424**	**426**	**240**	**-**
NET IMPORTS	**(2,563)**	**(1,390)**	**(1,590)**	**474**	**35**	**(305)**	**1,375**	**2,173**	**6,390**
Gross Imports	*2,711*	*2,984*	*2,616*	*2,715*	*3,413*	*3,084*	*4,159*	*4,797*	*7,620*
Imports to FRR	n/a	1,275	858	850	1,131	1,095	1,506	1,265	3,328
Imports to Auctions	n/a	1,709	1,758	1,865	2,282	1,989	2,653	3,532	4,292
Gross Exports	*(5,274)*	*(4,374)*	*(4,206)*	*(2,241)*	*(3,378)*	*(3,389)*	*(2,784)*	*(2,625)*	*(1,230)*
DEMAND RESOURCES	**1,679**	**2,135**	**4,467**	**7,576**	**9,344**	**11,026**	**14,621**	**13,732**	**16,350**
FRR DR/EE	n/a	432	438	438	452	450	473	473	501
Auction DR/EE (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	30	124	1,342	1,082
ILR and Auctions (w/o ATSI/DEOK)	1,679	1,703	4,029	7,138	8,892	10,546	14,024	11,917	14,767
TOTAL INSTALLED CAPACITY	**164,030**	**165,300**	**168,203**	**174,015**	**176,930**	**182,378**	**187,556**	**197,150**	**205,762**
Committed Capacity	**n/a**	**163,279**	**165,392**	**172,135**	**174,487**	**174,987**	**171,643**	**187,280**	**190,894**
FRR Commitments	n/a	24,717	24,954	25,316	26,306	25,921	26,302	25,793	33,613
ILR and Cleared DR/EE	n/a	1,703	4,029	7,138	8,892	10,576	8,065	9,634	14,458
Cleared Gen (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	3	-	10,908	8,501
Cleared PJM Gen (w/o ATSI/DEOK)	n/a	135,150	134,693	137,858	137,015	136,548	134,686	137,413	130,030
Cleared Imports	n/a	1,709	1,716	1,823	2,274	1,939	2,590	3,532	4,292
Uncommitted Capacity	**n/a**	**2,020**	**2,812**	**1,880**	**2,444**	**7,391**	**15,913**	**9,870**	**14,868**
FRR Excused	n/a	43	357	553	759	1,178	1,692	1,194	2,546
Uncleared DR/EE	n/a	n/a	n/a	n/a	n/a	n/a	6,083	3,625	1,391
Uncleared Gen (ATSI/DEOK)	n/a	n/a	n/a	n/a	n/a	746	1,546	1,898	4,031
Uncleared PJM Gen (w/o ATSI/DEOK	n/a	1,510	2,047	1,013	1,145	5,015	6,489	3,143	6,191
Uncleared Imports	n/a	0	43	42	8	50	64	-	-
Other Excused	n/a	467	365	272	531	402	40	10	710

Sources and Notes: Generation, DR, and EE are cumulative for all BRAs and IAs, reported in ICAP terms, PJM (2011a).

Among all of these existing and planned resources, 191.1 GW of installed capacity is committed for 2014/15, including 33.6 GW of FRR resources, 33.6 GW of cleared demand resources, 138.5 GW of cleared internal generation, and 4.3 GW of cleared imports. Another 4.0 GW of incremental commitments are expected to be procured, associated with the short-term resource procurement target.[46] Uncommitted existing or planned capacity resources total 14.8 GW. These uncommitted resources include 2.5 GW of excused FRR capacity, 0.7 GW of other excused generation, 1.4 GW of uncleared demand resources, and 10.2 GW of uncleared internal generation. Some of these uncleared resources represent planned resources that may not come online because they have failed to clear the BRA, while others represent existing resources that may retire before the 2014/15 delivery year.

It is particularly instructive to examine the changes in resource commitments between the 2013/14 and 2014/15 years, when the proposed EPA HAP regulations are expected to come into force. Auction-based internal generation commitments decreased by 9.8 GW between the two base auctions, caused primarily by a response to the environmental regulations as well as a reduction in load forecasts. Uncleared internal generation resources totaled 10.2 GW (up from 5.0 GW in 2013/14), mostly consisting of coal units in the unconstrained RTO. There were also 2.5 GW of FRR-excused resources (up from 1.2 GW) and 0.7 GW of other excused resources (increased from near zero). These withdrawals may also be related to a response to the HAP regulation. Despite these reductions in internal generation commitments, the RTO has sufficient existing and planned resources procured to meet resource adequacy requirements in 2014/15 (assuming the 2.5% STRPR will be successfully procured in the IAs). The internal reductions in generation commitment were compensated for by a large 4.8 GW increase in demand resource commitments, a 1.4 GW reduction in exports, and other resource adjustments (all in ICAP).[47]

2. Net Capacity Additions (Excluding FRR and RTO Expansion)

Excluding FRR and new RTO members, PJM has added 28.4 GW (ICAP) of gross committed and 13.1 GW of net committed capacity supply under RPM auctions, as shown in Figure 10 and Table 9. The gross committed additions are from 11.8 GW of new demand resources, 6.9 GW of increases in net imports, 4.8 GW of new generation, 4.1 GW of uprates, and 0.8 GW of reactivations. These additions were offset by 15.3 GW of gross capacity reductions, including 5.0 GW of retirements, 2.7 GW of derates, 6.8 GW of capacity removed from auctions for FRR, and 0.7 GW of generation excused from auctions. As discussed in Section II.A, these net increases have been sufficient to sustain capacity surpluses in the RTO at prices below Net CONE despite some load growth over the period and environmental challenges to supply.

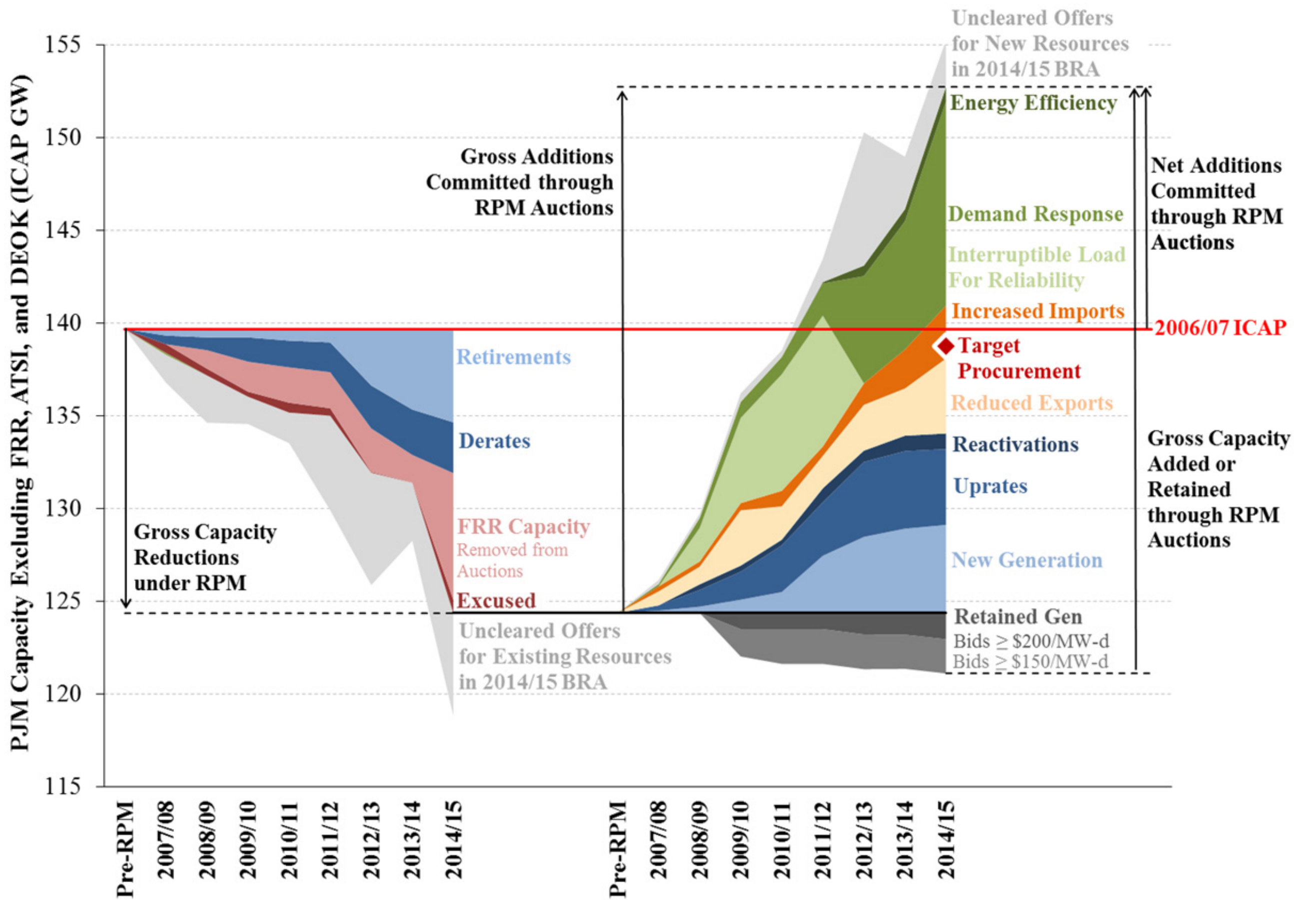
Figure 10 shows these gross and net capacity additions relative to the pre-RPM installed capacity. The red horizontal line at 140 GW shows the 2006/07 installed capacity, including all internal generation, net imports, and Active Load Management resources. The left panel of the chart shows gross capacity reductions of 15.3 GW and the composition of these decommitments. The right panel shows the composition of 28.4 GW in increased resource commitments. A total capacity of 153 GW for the 2014/15 delivery year, after reductions to existing capacity and

46 The STRPT is reported here on an ICAP basis for the entire RTO including territory expansions, see PJM (2011b).

47 Increases in imports and FRR commitments are not reported here as offsetting factors because these commitment increases were largely related to the DEOK territory expansion.

committed increases, is indicated by the dashed line at the top of the right side of the figure. This 2014/15 capacity is greater than the target procurement to meet resource adequacy requirements for the 2014/15 delivery year (shown as the red diamond), demonstrating a capacity surplus through 2014/15.

Figure 10
RTO Net Capacity Additions Committed in RPM Auctions
Excluding FRR Capacity and RTO Expansions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms.
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
From PJM bid and resource data, PJM (2007a).

Reductions. The 15.3 GW (ICAP) of gross reductions include retirements, derates, reductions in imported capacity, withdrawal of FRR capacity that previously offered into auctions, and excused capacity that previously offered into auctions. Deducting these from the 2006/07 baseline creates the new baseline of remaining existing supply at 124 GW.

- The largest share of reductions has been from FRR resources that were offered into the first RPM auctions in 2007/08 but have since stopped offering into RPM auctions. Many of these of 6.8 GW of FRR withdrawals occurred between the 2013/14 and 2014/15 auctions and are likely related to the proposed EPA regulations.

- Retirements of 5.0 GW and derates of 2.7 GW comprise most of the remaining reductions, with a small contribution from other capacity excused from the RPM auctions.
- As shown, there are also 5.0 GW of uncleared existing generation resources that offered into the 2014/15 BRA and failed to clear, but have not yet retired. These resources are shown in light gray at the bottom of the right panel. We do not deduct these from the existing baseline because they have not yet retired and could yet commit through future incremental or base auctions. However, we note that these units would likely retire in the future if they also fail to clear in subsequent auctions. As explained in Section II.A, these potential retirements could reduce, but not eliminate, the overall capacity surplus in the RTO.

Additions: Gross additions under RPM include newly-built generation, uprates to existing generation, reactivations, reduced exports, increased imports, and increases to demand-side resources. Adding these to the 124 GW baseline of remaining existing resources yields a installed capacity of 153 GW for the 2014/15 delivery year. These increases consider only committed additions, while uncleared new resources are shown in light gray at the top of the right panel. The 28.4 GW (ICAP) of committed resource additions under RPM are composed of:

- 11.8 GW of increased demand response and energy efficiency (relative to the pre-RPM levels of ALM resources). Levels of DR under RPM have been steadily increasing, with the exception of 2012/13, when many suppliers stopped using the ILR mechanism and were incorporated into RPM auctions. However, additional demand resources may yet be procured in through the final incremental auction for the 2012/13 delivery year.
- 4.9 GW of new generation construction, 4.1 GW of capacity uprates, and 0.8 GW of reactivations.
- 6.9 GW of increased imports, resulting in PJM becoming a net importer of capacity.
- 2.5 GW of offers for new resources that failed to clear for the in 2014/15 delivery year due to offer prices in excess of auction clearing prices. Prior auctions showed similar or much larger amounts of uncleared new resources. We do not treat these uncleared new resources as additions, however, even though they could have been committed at higher market prices, if they had been needed.

Retentions: "Retained capacity" under RPM is a somewhat arbitrary determination, but for reference we show the quantity of capacity that has cleared in RPM auctions after offering their capacity at prices above $150/MW-day and $200/MW-day thresholds. These relatively high-priced offers from existing resources indicate that the resource required significant investments and would likely have retired had they failed to clear in the auctions.[48] Based on those indicators, 3.3 GW of generation capacity has been retained through RPM after having offered into the RPM auctions at prices of $150/MW-day or more. All of these resources were in the

[48] We recognize that the identification of "retained" generation under RPM is somewhat arbitrary and dependents on what alternative resource adequacy construct would exist in place of RPM. We do not attempt any such theoretical comparison but instead simply report resources that may have been considering retirement (as indicated by their auction bid levels) but cleared in RPM auctions and thus remained committed.

MAAC LDA, where prices cleared above the $150/MW-day threshold. Clearing prices in the unconstrained RTO have been generally been lower than this threshold, but may also have retained generation that otherwise would have retired.[49]

Table 9
RTO Net Capacity Additions Committed in RPM Auctions
Excluding FRR Capacity and RTO Expansions

	Pre-RPM	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EXISTING CAPACITY IN 2006/07									
Internal Generation	164,914	164,914	164,914	164,914	164,914	164,914	164,914	164,914	164,914
Active Load Management	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679
Imports	1,436	1,436	1,436	1,436	1,436	1,436	1,436	1,436	1,436
Exports	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)	(5,274)
2006/07 FRR Generation	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)	(23,083)
Total Capacity in 2006/07	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**	**139,672**
CAPACITY REDUCTIONS									
Retirements		(340)	(440)	(440)	(617)	(710)	(3,035)	(4,331)	(5,019)
Derates		(470)	(691)	(1,313)	(1,439)	(1,608)	(2,318)	(2,445)	(2,742)
Net FRR Capacity Removed from Auctions		(0)	(998)	(1,614)	(1,908)	(1,943)	(2,345)	(1,492)	(6,830)
Excused Capacity		(467)	(365)	(272)	(531)	(402)	(40)	(10)	(710)
Net Reductions in ILR		(99)	-	-	-	-	-	-	-
Total Reductions		**(1,376)**	**(2,495)**	**(3,639)**	**(4,494)**	**(4,663)**	**(7,737)**	**(8,277)**	**(15,300)**
Uncleared Offers for Existing Resources		*(1,291)*	*(1,866)*	*(595)*	*(796)*	*(3,820)*	*(5,360)*	*(2,976)*	*(4,958)*
RETAINED CAPACITY									
Bids Above $200/MW-d		0	0	870	871	871	1,156	1,169	1,417
Additional Bids Above $150/MW-d		-	-	1,478	1,874	1,874	1,874	1,845	1,845
Total Prevented Reductions		**0**	**0**	**2,348**	**2,745**	**2,746**	**3,031**	**3,015**	**3,262**
CAPACITY INCREASES									
New Generation		129	340	707	1,118	3,079	4,095	4,307	4,750
New Generation Later Cancelled		-	-	8	8	8	8	240	-
Uprates		279	902	1,513	2,522	2,885	4,044	4,182	4,088
Reactivations		-	302	326	303	752	606	832	841
Net Reductions in Exports		754	953	2,983	1,799	1,749	2,472	2,546	4,040
Net Increases in Imports		273	280	387	838	503	1,154	2,096	2,856
ILR & DR Additions (from ALM baseline)		124	2,351	5,458	7,214	8,793	5,787	6,917	11,006
Energy Efficiency		-	-	-	-	74	567	654	793
Total Cleared Increases		**1,559**	**5,128**	**11,381**	**13,801**	**17,842**	**18,732**	**21,773**	**28,375**
Uncleared Offers for New Resources		*219*	*224*	*460*	*357*	*1,245*	*7,183*	*2,834*	*2,521*
Net Committed Capacity Additions	**0**	**183**	**2,633**	**7,742**	**9,307**	**13,178**	**10,995**	**13,497**	**13,075**
Installed Capacity Plus Net Additions	**139,672**	**139,855**	**142,305**	**147,414**	**148,979**	**152,850**	**150,668**	**153,169**	**152,747**

Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported).
From PJM bid and resource data, PJM (2007a).

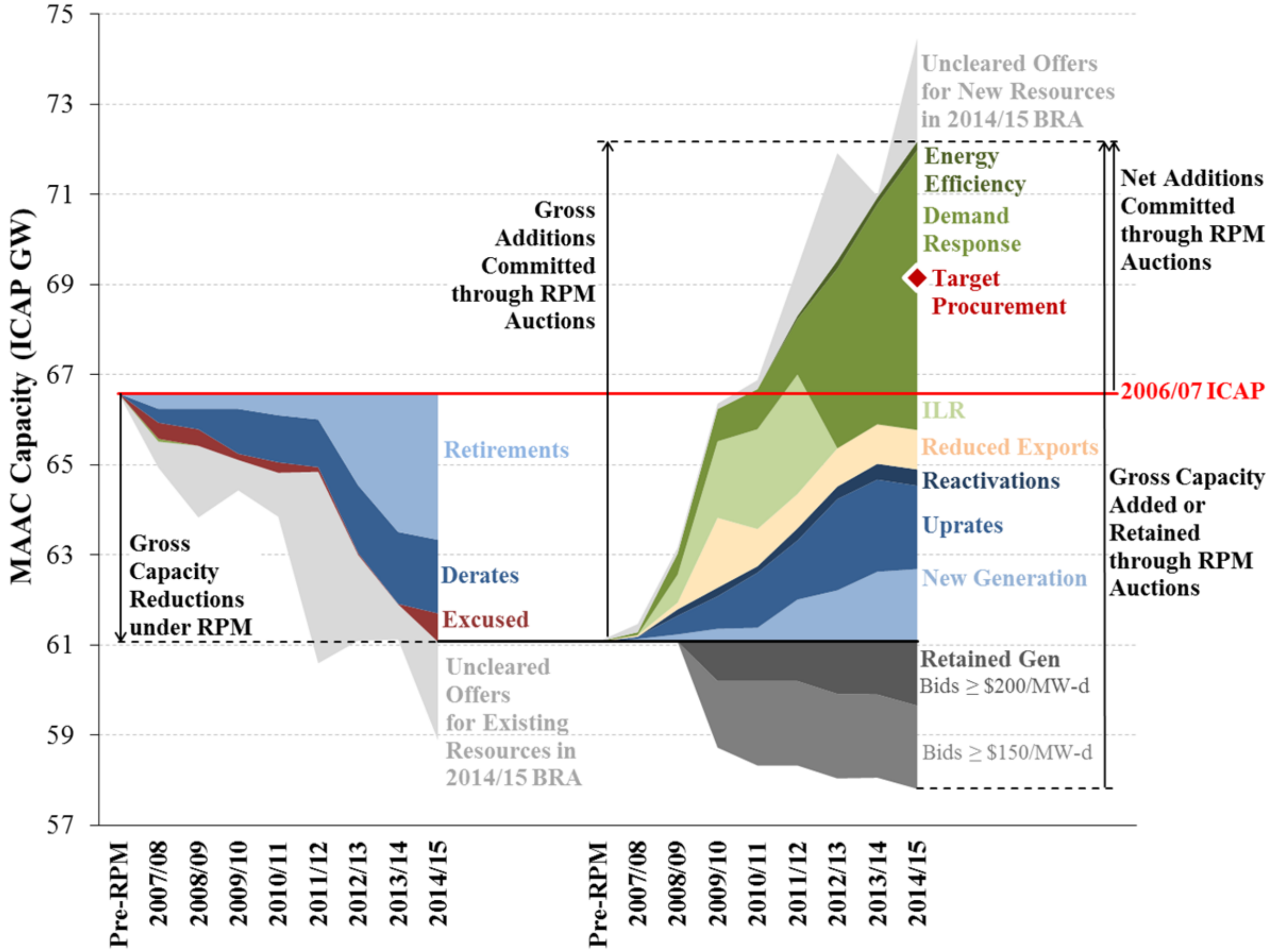
3. Net Additions Committed in the MAAC LDA

Figure 11 and Table 10 report the capacity reductions and committed additions through RPM auctions for the Mid-Atlantic Area Council (MAAC) LDA. In MAAC, a net 5.6 GW (ICAP) of capacity increases has been committed through 2014/15. Compared to the RTO, the LDA saw

[49] Prices cleared above $150/MW-day only one time in the unconstrained RTO, clearing at $174/MW-day in 2010/11. See Table 1.

proportionately somewhat greater reductions in generating capacity, fewer generation additions, but greater increases in demand resources.[50] As of the recent BRA for the 2014/15 delivery year, MAAC has slightly lower uncleared offers for existing resources and slightly more uncleared offers for new resources, consistent with a smaller overall capacity surplus in the LDA.[51]

Figure 11
MAAC Net Capacity Additions Committed in RPM Auctions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms.
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
From PJM bid and resource data, PJM (2007a).

Reductions. Among the 5.5 GW of capacity reductions, the largest share is accounted for in the 3.2 GW of pending retirements, scheduled to occur starting in 2012/13. Capacity derates of

---

50 As a fraction of 2014/15 installed capacity and committed increases, generation additions account for 6.3% of the RTO total and 5.3% of the MAAC total, while demand resource increases account for 7.8% in the RTO and 8.9% in MAAC; generation reductions represented 5.1% of the 2014/15 capacity in the RTO and 6.8% in MAAC.

51 As a fraction of 2014/15 installed capacity and committed increases, uncleared existing resources were 3.2% in the RTO and 2.4% in MAAC while uncleared new resources were 1.7% in the RTO and 3.2% in MAAC.

1.6 GW comprise most of the remaining reductions, with the remaining 0.6 GW from an increase in excused capacity. An additional 1.7 GW of uncleared existing generation resources are units that may be at risk for retirement if they do not clear in upcoming incremental or base auctions.

Additions. The 11.1 GW of additional capacity commitments in MAAC are composed of 6.4 GW of increases in demand-side resources, 1.6 GW of new generation, 1.8 GW of uprates, and 0.9 GW of reductions in exports. In addition to the capacity additions that have been committed under RPM auctions, another 2.3 GW of uncleared new supply was available in the most recent auction.

Retentions. 3.3 GW of generation capacity has been retained through RPM after having offered into the RPM auctions at prices of $150/MW-day or more. The largest quantity of capacity retention occurred in the BRA for the 2009/10 delivery year, in which several generation resources, especially in SWMAAC, required environmental upgrades to continue operating, as discussed in our 2008 report.[52]

Table 10
MAAC Net Capacity Additions Committed in RPM Auctions
(ICAP MW)

	Pre-RPM	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
EXISTING CAPACITY IN 2006/07									
Internal Generation	67,336	67,336	67,336	67,336	67,336	67,336	67,336	67,336	67,336
Active Load Management	795	795	795	795	795	795	795	795	795
Exports	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)	(1,549)
2006/07 FRR Generation	-	-	-	-	-	-	-	-	-
Total Capacity in 2006/07	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**	**66,581**
CAPACITY REDUCTIONS									
Retirements		(340)	(340)	(340)	(482)	(575)	(2,036)	(3,070)	(3,243)
Derates		(307)	(454)	(997)	(1,044)	(1,059)	(1,504)	(1,595)	(1,634)
Excused Capacity		(357)	(365)	(137)	(232)	(102)	(40)	(10)	(630)
Net Reductions in ILR		(64)	-	-	-	-	-	-	-
Total Reductions		**(1,067)**	**(1,159)**	**(1,474)**	**(1,758)**	**(1,736)**	**(3,580)**	**(4,675)**	**(5,507)**
Uncleared Offers for Existing Resources		*(400)*	*(1,141)*	*(32)*	*(566)*	*(3,181)*	*(1,563)*	*(761)*	*(1,698)*
RETAINED CAPACITY									
Bids Above $200/MW-d		0	0	870	871	871	1,156	1,169	1,417
Additional Bids Above $150/MW-d		-	-	1,478	1,874	1,874	1,874	1,845	1,845
Total Prevented Reductions		**0**	**0**	**2,348**	**2,745**	**2,746**	**3,031**	**3,015**	**3,262**
CAPACITY INCREASES									
New Generation		66	164	281	303	929	1,134	1,314	1,614
New Generation Later Cancelled		-	-	8	8	8	8	240	-
Uprates		46	414	721	1,222	1,309	2,022	2,044	1,849
Reactivations		-	142	192	143	272	281	352	361
Net Reductions in Exports		37	149	1,548	825	760	847	875	875
ILR & DR Additions (from ALM baseline)		64	1,092	2,416	3,104	3,880	3,988	4,884	6,209
Energy Efficiency		-	-	-	-	74	182	147	193
Total Cleared Increases		**212**	**1,961**	**5,165**	**5,605**	**7,232**	**8,461**	**9,855**	**11,100**
Uncleared Offers for New Resources		*182*	*128*	*117*	*201*	*1,075*	*2,379*	*34*	*2,283*
Net Committed Capacity Additions	**0**	**(855)**	**801**	**3,692**	**3,848**	**5,496**	**4,881**	**5,181**	**5,593**
Installed Capacity Plus Net Additions	**66,581**	**65,727**	**67,383**	**70,273**	**70,429**	**72,077**	**71,463**	**71,762**	**72,175**

Sources and Notes:

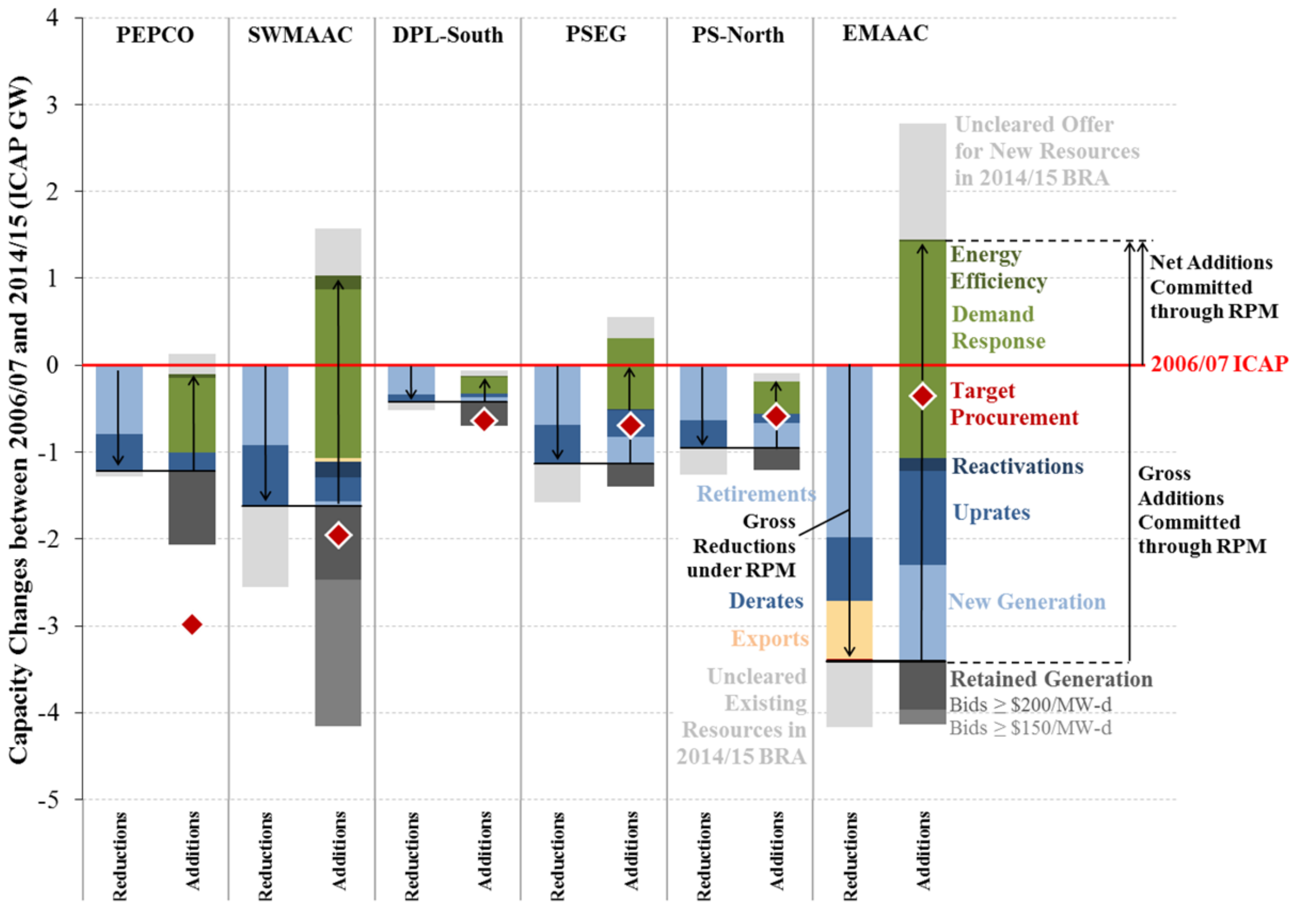
[52] See Pfeifenberger and Newell, *et al.* (2008), pp. 15, 22-24, 112-115.

All generation, DR, and EE values are cumulative totals in ICAP terms. Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported). From PJM bid and resource data, PJM (2007a).

4. Net Additions Committed in Smaller LDAs

Figure 12 and Table 11 summarize capacity reductions and additions similar to that presented in the above discussion for the RTO and MAAC. This information is presented for all of the other, smaller LDAs currently modeled in RPM. For these LDAs, these reductions and additions are not shown on an annual basis but, rather, as the total changes between pre-RPM levels and the results for the 2014/15 delivery year.

Figure 12
LDA Net Capacity Additions Committed in RPM Auctions



Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes represent BRA and IA capacity commitments (offered but uncleared resources are in gray).
Target procurement is reliability requirement less STRPT and CETL, converted to ICAP equivalent, from PJM (2011b).
From PJM bid and resource data, PJM (2007a).

Our primary observations are as follows:

- The largest of these LDAs—EMAAC, SWMAAC, and PSEG—had 1,440 MW, 1,030 MW, and 310 MW of *net capacity additions* under RPM, while the smallest

LDAs—PSEG-North, DPL-South, and PEPCO—had 190 MW, 130 MW and 100 MW of *net reductions* in LDA-internal committed capacity.

- Even though the smallest LDAs had net reductions in committed LDA-internal capacity, the total 2014/15 capacity commitments are sufficient to ensure resource adequacy and, in fact, represent an overall surplus relative to the 2014/15 BRA target procurement (shown as a red diamond in the figure, such that capacity above the red dot represents surplus). Target procurement for LDA-internal resources has decreased primarily due to increased import capabilities (CETL).
- Most LDA-internal capacity increases were from demand response, although EMAAC, PSEG-North, and PSEG also had large increases from new generation and uprates.
- Every LDA has had capacity reductions from retirements and capacity derates, and these have been proportionally larger in the smallest LDAs. These capacity reductions were part of the reason that these LDAs have been modeled as constraint under RPM; the reductions also contributed to triggering transmission upgrades that have increased import capabilities into these locations.
- PEPCO, SWMAAC, and EMAAC all retained large amounts of existing generation with high bids above $150/MW-day, primarily related to the cost of retrofits required to meet state and federal environmental regulations implemented or proposed since 2006/07.
- Most LDAs other than DPL-South and PEPCO also show that a sizeable fraction of their existing generation did not clear in the base auction for 2014/15. These uncleared existing resources were not needed for reliability in the most recent auction, partly because of reductions in the load forecast and increases in transmission import limits. Unless they are cleared in future incremental auctions, these resources must be expected to retire.

All LDAs also had uncleared offers for new resources in 2014/15, ranging from 2.3% to 4.3% of installed resources. In LDAs other than EMAAC, 43% to 70% of these uncleared new resources were demand-side resources, with the remaining 30% to 57% from uncleared uprates to existing generation. EMAAC was the only LDA with uncleared new generation in 2014/15 (650 MW). The lack of uncleared offers for new generation in the other LDAs presumably is related to the lack of need and developer cautiousness surrounding the recession and proposed transmission upgrades. It is important to note, however, that there were other uncleared offers for new generation in prior auctions, but these previously-offered new generating plants were not offered for 2014/15. In prior auctions, *all LDAs* had additional uncleared offers for new resources which could have been procured at higher prices had they been needed for reliability.

Table 11
LDA Net Capacity Additions Committed in RPM Auctions

	RTO	MAAC	EMAAC	PSEG	PS-North	DPL-South	SWMAAC	PEPCO
EXISTING CAPACITY IN 2006/07								
Internal Generation	164,914	67,336	33,022	8,129	4,475	1,715	11,639	6,344
Active Load Management	1,679	795	287	121	60	17	227	-
Imports	1,436	-	-	-	-	-	-	-
Exports	(5,274)	(1,549)	(4)	-	-	-	(48)	-
2006/07 FRR Generation	(23,083)	-	-	-	-	-	-	-
Total Capacity in 2006/07	**139,672**	**66,581**	**33,305**	**8,249**	**4,535**	**1,732**	**11,818**	**6,344**
CAPACITY REDUCTIONS								
Retirements	(5,019)	(3,243)	(1,983)	(686)	(629)	(342)	(922)	(790)
Derates	(2,742)	(1,634)	(727)	(448)	(325)	(75)	(697)	(424)
Net Increases in Exports	-	-	(670)	-	-	-	-	-
Net FRR Capacity Removed from Auctions	(6,830)	-	-	-	-	-	-	-
Excused Capacity	(710)	(630)	(24)	(1)	-	-	-	-
Total Reductions	**(15,300)**	**(5,507)**	**(3,404)**	**(1,135)**	**(954)**	**(417)**	**(1,619)**	**(1,214)**
Uncleared Offers for Existing Resources	*(4,958)*	*(1,698)*	*(766)*	*(439)*	*(301)*	*(101)*	*(932)*	*(67)*
RETAINED CAPACITY								
Bids Above $200/MW-d	1,417	1,417	563	257	257	275	853	853
Additional Bids Above $150/MW-d	1,845	1,845	166	-	-	-	1,679	-
Total Prevented Reductions	**3,262**	**3,262**	**729**	**257**	**257**	**275**	**2,532**	**853**
CAPACITY INCREASES								
New Generation	4,750	1,614	1,108	309	291	52	57	2
Uprates	4,088	1,849	1,079	304	101	34	269	206
Reactivations	841	361	151	16	3	-	181	-
Net Reductions in Exports	4,040	875	-	-	-	-	48	-
Net Increases in Imports	2,856	-	-	-	-	-	-	-
ILR & DR Additions (from ALM baseline)	11,006	6,209	2,487	813	369	197	1,935	864
Energy Efficiency	793	193	20	5	-	5	156	42
Total Cleared Increases	**28,375**	**11,100**	**4,845**	**1,446**	**763**	**288**	**2,646**	**1,114**
Uncleared Offers for New Resources	*2,521*	*2,283*	*1,338*	*248*	*101*	*68*	*545*	*234*
Net Committed Capacity Additions	**13,075**	**5,593**	**1,442**	**311**	**(190)**	**(129)**	**1,027**	**(100)**
Installed Capacity Plus Net Additions	**152,747**	**72,175**	**34,747**	**8,560**	**4,345**	**1,603**	**12,845**	**6,244**

Sources and Notes:
All generation, DR, and EE values are cumulative totals reported in ICAP terms
Gross and net changes are BRA and IA capacity commitments (resources offered but uncleared are separately reported).
From PJM bid and resource data, PJM (2007a).

D. GENERATION INTERCONNECTION QUEUE

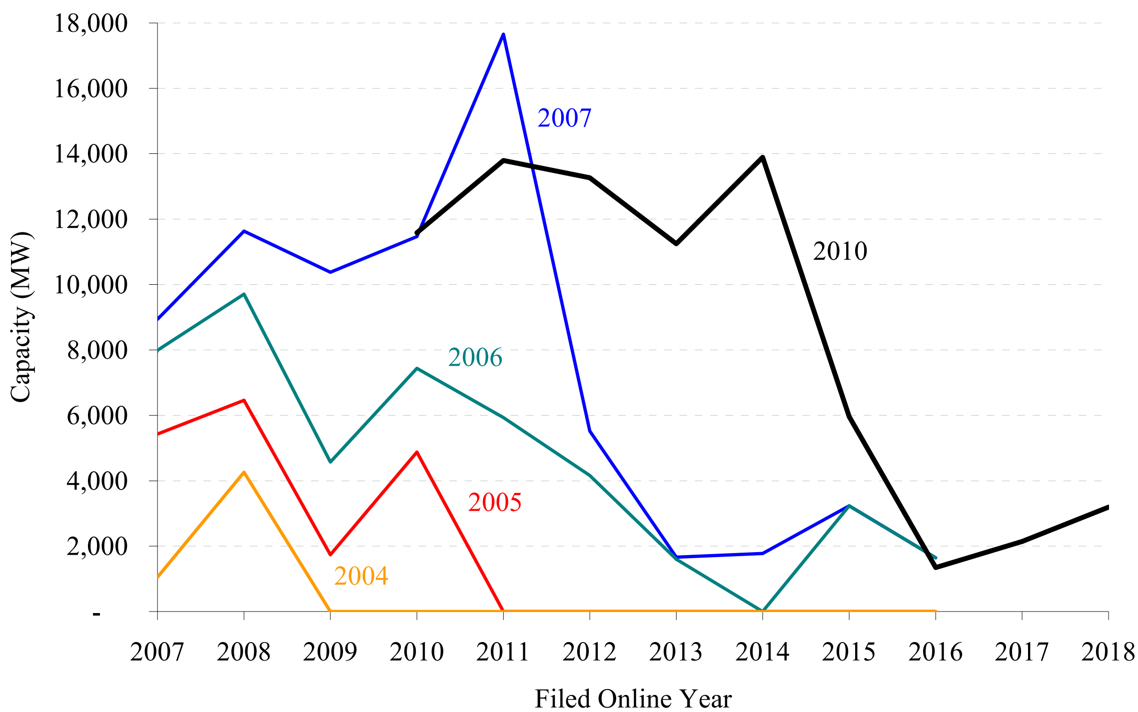
In our 2008 RPM evaluation, we reported that RPM had stimulated the development of an unprecedented amount of potential new resources, including approximately 33,000 MW of new generation projects in PJM's interconnection queue that were eligible to offer into future RPM auctions, with capacity that was not already committed as the result of the first five base auctions. Approximately 28,000 MW of this capacity was from non-renewable resources for which RPM-based capacity payment are likely a major driver.[53] We also documented that a significant expansion in interconnection requests had occurred by 2007, and we observed a spike

[53] 2008 RPM Report, pages 38-39

in interconnection requests with an online date of 2011, just in time for the first 3-year forward auction for the 2011/12 delivery year.

Figure 13 below shows interconnection requests for the period from 2004 through 2007, updated with queue data from 2010, as summarized by the IMM. The total capacity of generation projects submitted in the queue as of 2010 remains high despite the economic downturn, reductions in load forecasts and associated reliability requirements, and significant expansion of capacity from demand-response resources. In addition, the pattern we previously observed has been maintained despite the fundamental economic changes since 2007: at the end of 2010, just prior to the BRA auction for the 2014/15 delivery year, the interconnection queue shows a similar spike of interconnection requests with an online date of 2014.

Figure 13
Capacity of Active Generation Projects in Interconnection Queue
(2004-2007 and 2010, by online date)



Source: 2005-2007, 2010 PJM State of the Market Reports.

Table 12 shows total unforced capacity (*i.e.*, derated to the resources' capacity value) of active interconnection requests currently in the PJM queue by LDA. As shown, generation projects in the interconnection queue that have already passed the feasibility study and, thus, qualify to be bid into RPM, have remained high compared to needs at both the RTO and LDA levels. Interconnection requests with over 26,000 MW qualify for RPM participation the RTO-wide level, 13,000 MW of interconnection requests qualify in MAAC, 3,100 MW in SWMAAC, 1,400 MW in PEPCO, 7,300 MW in EMAAC, 1,900 MW in PSEG, and 500 MW in DPL. We recognize that the status of the projects behind these interconnection requests is generally uncertain, and the same generation project may be represented in multiple interconnection requests.[54] However, the number of interconnection requests, their aggregate capacity value, and their locational distribution suggest that sufficient new generating resources stand ready to be developed if market conditions warrant such additions and development challenges can be overcome.

Table 12
Planned Projects Eligible for RPM Participation

Locational Deliverability Area	TOTAL RPM QUALIFIED MW	TOTAL UNDER STUDY MW
DPL	500.2	1,751.8
PSEG	1,932.1	4,274.0
EMAAC	7,318.7	12,730.6
PEPCO	1,453.8	2,283.8
SWMAAC	3,093.8	3,923.8
MAAC	12,980.8	22,570.2
Unconstrained RTO	13,564.7	21,665.3
RTO TOTAL	**26,545.5**	**44,235.5**

Sources and Notes:
[1] PJM queue data downloaded on 8/15/2011.
[2] Quantities are calculated based on net summer capacity (wind and solar derated to capacity value).

Our 2008 RPM report identified delays in the interconnection process as a significant concern.[55] At that time, PJM had accumulated a substantial backlog of overdue interconnection studies in its interconnection process, following a surge of interconnection requests in response to the implementation of RPM and state renewable portfolio standards.

To improve the interconnection study process, PJM reconvened the Regional Planning Process Working Group and implemented a number of changes to streamline the interconnection process.[56] The most significant accomplishments are:

- PJM introduced three-month queue cycles. As a result, System Impact and Feasibility Studies are now conducted in four cycles per year (as opposed to two cycles per year previously).

54 For example, the 3,100 MW of RPM-qualifying interconnection requests in SWMAAC include a new 1,640 MW nuclear plant in the BG&E service area which, even if developed successfully, would not become available in time for the next several BRAs. Similarly, the PEPCO queue includes interconnection requests for two 725 MW combined cycle plants in the same county, which likely represent overlapping interconnection requests from the same projects. However, even a single 725 MW CC plant built in PEPCO would satisfy load growth-related resource adequacy needs for many years.

55 Section V.B.

56 Interconnection Process Changes and Timetable, presented at RPPWG in March 2009, http://www.pjm-miso.com/committees/working-groups/rrawg/downloads/20090116-item-03-changes-and-dates.pdf

- In order to reduce the number of non-viable projects and multiple interconnection requests submitted for speculative purposes, PJM began requiring deposits that increase each month during the queue and include both a refundable and a non-refundable element.
- In the past, PJM often received a large number of interconnection requests at the end of the queue period, which significantly contributed to the backlog in the queue. Under the revised rules, the timeframe allowed for holding a scoping meeting to initiate interconnection studies decreases the later a request is entered into the queue, thus providing an incentive to submit interconnection requests earlier in the queue cycle.
- Interconnection requests must now specify a primary and a secondary interconnection point. In the past, interconnection customers could choose two points of interconnection, and PJM was required to conduct two simultaneous sets of studies for each of the two locations.
- PJM revised the methodology of allocating the costs of required transmission upgrades. In the past, cost allocation was determined incrementally, based on the position in the queue. As a result, PJM had to perform repeated studies whenever an earlier project in the queue was withdrawn. Under the new method, PJM performs studies in clusters and analyzes all projects in a single queue.
- Other changes include requiring timelier submittal of necessary data, applying commercial probability of success ratios at various stages of the interconnection process, and requiring proof of site control.

While the interconnection process continues to be a source of uncertainty for generation development, particularly with respect to interconnection costs, PJM has made significant progress streamlining the process. Queue requests are now processed in a timelier manner. As shown in Table 13 below, 89% of Feasibility Studies were issued on time in 2010.[57] This is a significant improvement since 2007, when only 53% of Feasibility Studies were completed on time. Similar improvements have occurred with respect to System Impact Studies: while in 2008 only 29% have been completed on time, that proportion had increased to 77% as of 2010.

Table 13
Percentage of Interconnection Studies Completed On Time

Year	Feasibility Study	System Impact Study
2007	53%	44%
2008	70%	29%
2009	83%	51%
2010	89%	77%

Source : PJM

PJM's corporate goal for 2011 is to complete all studies backlogged as of January 1, 2011 by the beginning of 2012, and to reduce the backlog of System Impact and Feasibility Studies below

57 These studies represent two of the main steps in the interconnection process.

25% and 10%, respectively.[58] To address the remaining challenges related to the interconnection process, PJM formed the Interconnection Process Senior Task Force ("IPSTF") in February 2011. IPSTF's goal is to develop enhancements that would lead to more consistent and realistic interconnection cost estimates, more timely completion of interconnection studies, and greater transparency of the overall interconnection process.

E. Summary of Findings from Analyses of Auction Results

After completing auctions for eight delivery years under RPM, the market has thus far achieved its design objective of procuring sufficient capacity to meet reliability requirements. A total of 28.4 GW (ICAP) of gross additions and 13.1 GW of net additions have been added or committed under RPM auctions (excluding FRR and RTO expansions), exceeding reliability requirements. The gross committed additions are from 11.8 GW of new demand resources, 6.9 GW of increases in net imports, 4.8 GW of new generation, 4.1 GW of uprates, and 0.8 GW of reactivations. These additions were offset by 15.3 GW of gross capacity reductions, including 5.0 GW of retirements, 2.7 GW of derates, 6.8 GW of capacity removed from auctions for FRR, and 0.7 GW of generation excused from auctions.

On both an RTO and LDA-specific basis, sufficient capacity was procured under RPM to meet or exceed the reliability targets, with no large or persistent capacity deficits observed to date. Procurement below the reliability target in eastern LDAs during the first years under RPM was related to the overall tight supply conditions that existed prior to the introduction of RPM. All LDAs also had additional uncleared offers from incremental capacity supplies in most years that could have been procured at higher prices had those supplies been needed for reliability.

To date, RPM has performed well in the face of the proposed EPA HAP regulation, which will take effect during the 2014/15 delivery year and impose large compliance costs on many coal generators and force others to retire. Despite this substantial challenge to resource adequacy, capacity procurement through the 2014/15 delivery year exceeded the target procurement on an RTO-wide level as well as in all modeled LDAs. Due to environmental regulations and an overall capacity surplus, 12.8 GW (ICAP) of existing capacity, mostly coal, is currently uncommitted for resource adequacy in 2014/15, having been withdrawn from RPM auctions or failed to clear the BRA. Many of these generators would need to invest in environmental upgrades to continue operating in 2014/15 and will likely retire if they do not clear in upcoming auctions.

Clearing prices in the base auctions have been consistent with market fundamentals—clearing at levels below Net CONE during times and locations of capacity excess and above Net CONE at times and locations of relative scarcity. Large quantities of relatively low-cost capacity additions from DR, uprates, and increased net imports have kept prices below Net CONE most of the time in most locations. These increases in low-cost resources have reduced system costs by postponing the need for expensive additions of new generation and allowing for the retirement of uneconomic existing capacity. Furthermore, the supply curves have become more gradual due to the incorporation of substantial quantities of DR and the three-year forward period of RPM, which will contribute to increase price stability in the future. To date, base auction prices have

[58] For example, see "Interconnection Update," February 16, 2011. http://www.pjm.com/~/media/committees-groups/committees/mrc/20110216/20110216-item-06a-interconnection-update.ashx

been somewhat volatile, with substantial price changes from year to year caused by market fundamentals, changes in market rules, changes to which LDAs were modeled, and changes in administrative auction parameters.

Clearing prices in the incremental auctions prior to the 2012/13 redesign demonstrated a pattern of being persistently far below base auction clearing prices. However, as discussed in Section II.B, the incremental auction design has been substantially improved starting with the 2012/13 delivery year. Initial results show that the new design resulted in prices that are more consistent with base auction prices, though more experience with the new design is needed to fully understand how it will function over time.

III. STAKEHOLDER COMMENTS AND DISCUSSION OF KEY THEMES

As an initial task in our RPM performance review, we gathered input on which aspects of RPM are working well and which should be improved. We gathered input from five stakeholder sectors, financial analysts, public utility commissions, and the Independent Market Monitor.

Stakeholder Sectors — We conducted sector interviews with transmission owners, generation owners, electric distributors, end use customers, and other suppliers. Stakeholders have also provided 13 sets of written comments and several have contacted us for individual follow-up interviews.

Financial Analysts **—** We individually interviewed financial analysts covering RPM from CitiGroup, UBS, and Goldman Sachs.

State Utility Commissions — We contacted members of each public utility commission of 13 states and the District of Columbia. In response, we received input in interviews or written comments from eight commissions (Delaware, the District of Columbia, New Jersey, Ohio, North Carolina, Pennsylvania, Michigan, Virginia). The remaining six commissions either declined to comment (Maryland and Kentucky) or did not respond (West Virginia, Tennessee, Illinois, and Indiana).

Independent Market Monitor — We reviewed the substantial body of evidence and analysis on RPM that has been developed by the independent market monitor (IMM), including the state of the market reports, auction reports, and comments in FERC and state proceedings.[59] We have also had several conference calls and exchanges with the IMM to discuss our recommendations and analysis related to specific elements of the RPM design.

We summarize here stakeholders' comments and identify the key themes that have emerged, which we used to focus our analysis on the topics most important to stakeholders. We respond to each of the most prominent themes here and explain how we have addressed each of them in the body of this report.

---

[59] See reports posted at www.monitoringanalytics.com.

A. Summary of Stakeholder Comments

A detailed summary of stakeholder comments is included in the Appendix. We summarize here the topics that were stressed as the most important issues that we should consider in our performance review.

Level of RPM Clearing Prices — End use customers and state commissions in eastern PJM stated that RPM prices were too high and may not be commensurate with the value of reliability to customers. Some commissioners further stated that existing generation and demand resources should be paid lower prices than new generation. Generation and transmission owners stated that eastern prices are not high enough to attract new investments, while western prices are too low and are creating retirement incentives. Other suppliers noted that incremental auction prices are biased to be much lower than BRA prices.

Uncertainty of RPM Prices — All stakeholder sectors stated that RPM prices are volatile and too difficult to predict. However, generation and transmission owners also indicated that RPM price signals are more stable and locationally appropriate compared to prices in PJM's previous daily capacity market. Financial analysts stated that investors discount the value of RPM revenues due to the uncertainty and that more transparency is needed in the supply curve and administrative calculations to allow for improved projections that would better support investment decisions.

Capacity Additions and Retention — Concerns about a lack of new generation entry were expressed by eastern state commissions, electric distributors, end use customers, some generators, and some transmission owners. Other generators and transmission owners stated that fears of a capacity shortage were overstated and that new investments can be financed when prices are high enough, although more capacity price stability and longer-term hedging mechanisms would help. Generation and transmission owners point out that the EPA HAP regulation will create a resource adequacy challenge and force many plants into retirement.

Reliability Standards and Customer Reliability Requirements — End use customers and state commissions stated their belief that PJM has an institutional bias to overstate load forecast and reliability requirements, causing excess costs to customers. They further question whether the 1-in-10 system reliability standard and in particular the 1-in-25 LDA transmission-contingent reliability standard are appropriate, suggesting that they represent too much reliability given the high cost of capacity. End use customers are further concerned about significant quantity risks that they face due to substantial uncertainties about their ultimate Peak Load Contribution ("PLC") and the slope of the VRR curve, which also makes it difficult and risky for individual large end-users to directly participate in RPM as a demand-response resource.

Cost of New Entry — End use customers stated that CONE should be based on the lowest net cost technology in each region. Generation and transmission owners argued that CONE is understated because of cost estimates that are too low for natural gas interconnections, transmission interconnections, labor, taxes, and financing costs.

Energy Market and E&AS Offset — Electric distributors, other suppliers, transmission owners, generation owners, and state commissions noted that they support greater scarcity pricing in the energy market. Other suppliers and electric distributors stated that the current energy market price cap of $1,000/MWh is too low and creates a disadvantage for DR in the capacity market, especially as an annual resource, because they may value the energy at a higher rate. Generation and transmission owners stated that there should be no capacity payment reductions due to scarcity pricing other than incorporating scarcity prices into the E&AS offset as is currently done. End use customers stated that the lag in the historical E&AS offset will be especially problematic during the transition to scarcity pricing. Other suppliers and financial analysts stated that the E&AS offset should be forward looking, while transmission owners stated that a forward-looking offset would be prone to error and dispute. Generation owners, other suppliers, and transmission owners stated that the calculated E&AS offset was too high given the current low gas prices and energy margins, the use of real-time rather than day-ahead prices, and an optimistic dispatch algorithm.

VRR Curve and FRR Alternative — Generation owners, other suppliers, and transmission owners stated that the VRR curve is too steep and causes price volatility. State commissions stated that the 1% adjustment to point "b" on the curve creates a bias toward over-procurement. State commissions and transmission owners stated that the FRR alternative is valuable but that restrictions on capacity sales and switching to or from FRR should be relaxed.

Demand-Side Resources and Resource Comparability — Generation and transmission owners expressed the concern that lax performance and qualification standards threaten the quality of the capacity procured from demand resources. They further stated that demand resources have fewer obligations than does generation supply, including the lack of a must-offer requirement in the energy market. End-use customers and other suppliers noted that demand resources are disadvantaged due to high credit requirements and risks in the three-year forward BRA. The independent market monitor suggested that all resources should have the same obligations and the same definition of capacity.

2.5% Short-Term Resource Procurement Target — The IMM, generation owners, and transmission owners recommended that the 2.5% "holdback" be eliminated because it artificially suppresses BRA prices. Electric distributors stated that the 2.5% holdback should be maintained, while other suppliers noted that the holdback is too small and artificially inflates BRA prices while suppressing incremental auction prices. End-use customers stated that, with only one incremental auction since the implementation of the holdback, there was not enough information to evaluate the appropriate size of the STRPT amount.

Transmission-Related Issues — Comments on transmission issues did not generally differ across sectors, although multiple views were often expressed within each sector. Stakeholders identified CETL as an important parameter that is volatile and not transparent. Most sectors suggested that major transmission projects should not be cancelled so readily and that RTEP should more fully consider economic criteria in addition to reliability criteria. Stakeholders indicated that greater consistency is needed between RTEP and RPM, including making sure that uncleared RPM resources are not modeled in RTEP. Some stakeholders argued that additional LDAs should be modeled including part of Dominion or APS-South, or that all 23 LDAs should be modeled. Other stakeholders argued that too many LDAs already exist, that LDA are modeled even when no longer constrained, and that only 2 or 3 LDA may be necessary. Transmission and generation owners suggested that the BRA should be conducted on a 5-year forward basis to coincide with RTEP planning horizons.

Market Monitoring and Mitigation — Electric distributors and state commissions stressed that new MOPR provisions will have the large unintended consequences of eliminating self-supply and creating excess risks for new generation developments. Financial analysts, generation owners, and transmission owners emphasized that MOPR must be strong enough to prevent market manipulation through state-sponsored capacity additions. The independent market monitor is also concerned about out-of-market capacity additions, but recommends an exemption for procurement through competitive, non-discriminatory processes. End use customers noted that they are concerned that bid adders allowed under the avoidable project investment rate ("APIR") may be too high and allow for economic withholding, which may be a particular concern as suppliers are forced to comply with EPA's HAP regulations.

Extending Forward Certainty — Stakeholders representing both buyers and suppliers of capacity noted a lack of sufficient long-term contracting. Electric distributors, end-use customers, and generation owners attributed the lack of bilateral long-term contracting to state retail choice and standard offer service programs. Generation owners noted that there is a lack of buyers for long-term bilateral contracts with durations of more than 3-5 years, while electric distributors have stated that they are unable to find suppliers willing to enter into bundled long-term energy and capacity contracts. All stakeholder sectors suggested options for extending forward certainty and providing hedging options under RPM. These options included a continuously-clearing over-the-counter ("OTC") market for capacity and longer-term procurement through multiple forward or strip auctions. Generation and transmission owners were divided on NEPA, with some stating that the mechanism is discriminatory and should be eliminated and others stating that it should be expanded to existing generation, extended in duration, or applied outside the LDAs. Financial analysts stated that extending NEPA would benefit project financing.

We used these stakeholder comments and concerns to focus our performance review on the topics of highest importance. We recognize that many of these comments represent conflicting viewpoints between sectors and sometimes even within individual sectors, but have attempted to evaluate all of the associated arguments. Stakeholders identified concerns with a number of specific design elements, but we also identified a few key themes of several inter-related issues. To help clarify some of these more general concerns, we discuss them in the remainder of this section and note if we have analyzed and addressed them more fully later in this report.

B. Capacity Price Volatility and Uncertainty

The greatest concern expressed by stakeholders from all sectors is that capacity prices under RPM are highly volatile and very difficult to predict. Stakeholders express that this uncertainty imposes additional costs and creates difficulty hedging and making investment decisions. Some stakeholders have expressed a lack of transparency about the underlying causes of major price changes, or have attributed various price changes to causes that they view as arbitrary or inefficient.

In response to these stakeholder concerns, we have reviewed all substantial price changes observed under RPM to date. We have identified and documented the major drivers behind the observed price changes as explained in Section II.A (for the BRA) and Section II.B (for the incremental auctions) of our report. These main drivers of capacity price uncertainty fall into three categories: (1) underlying market fundamentals; (2) RPM design elements that have previously caused significant price adjustments; and (3) current RPM design elements and related administrative parameters that cause significant price uncertainty.

Ideally, only market fundamentals should drive capacity prices or create price uncertainty, factors which should not be dampened by RPM design or administrative intervention. In fact, administrative and regulatory uncertainty, while impossible to eliminate, should be minimized to the extent practical. We briefly discuss each type of uncertainty in the remainder of in this section and more fully address options to mitigate excess price risks related to administrative factors in our discussion of specific RPM design elements.

1. Market Fundamentals

Several changes in underlying market fundamentals have been major drivers of price changes and uncertainty:

- The emergence of surplus capacity in the unconstrained RTO, and to a lesser extent in the LDAs, that has depressed capacity prices to levels well below Net CONE;
- Transmission constraints between the unconstrained RTO and the LDAs have limited the ability to import low-cost supply into eastern PJM and caused large locational price separations in some years;
- Steep supply curves during the first RPM auctions caused prices to be sensitive to small changes in resource demand. The steep supply curves were primarily the result of a short forward period (*i.e.*, less than 2 years) between the auction and delivery year for the first several RPM auctions. This limited the potential quantity of new capacity that could participate in the auctions and be available in time for the delivery year. Supply curves have since flattened significantly, due to the longer forward period and a substantial influx of DR resources with offers covering a wide range of prices;
- Significant growth in low-cost DR resources has contributed to lower prices;
- The economic recession has reduced the outlook for electric demand starting with PJM's 2009 load forecast used for the 2012/13 BRA; and
- Environmental upgrades that will be required by the EPA HAP regulation for operation sometime in during the 2014/15 delivery year have caused prices to rise substantially in the unconstrained RTO in the most recent BRA.

All price uncertainty and volatility will tend to increase risks and therefore increase costs.[60] However, to the extent that these risks consistent with uncertainty in underlying market fundamentals, they are important to ensure the efficient functioning of the market and should not

60 Increased risks of all kinds result in a higher expected required return on investments. See, for example, the empirical finding that "a doubling of industry-wide uncertainty raises the required rate of return on new capital by about 20 percent," by Caballero and Pindyck (1996). For another example, see the empirical finding that increased volatility in cash flows increases the cost of debt and decreases the likelihood of making investments from Minton and Schrand (1999), pp. 423-26.

be suppressed artificially. Stabilizing RPM prices despite underlying uncertainties in market fundamentals would not eliminate the associated risks, but would simply shift the costs associated with these risks from suppliers to customers. For example, a traditional regulatory regime would reduce a generation supplier's development costs by ensuring cost recovery for all prudent investments, but this does not eliminate the fundamental risk that an event like a major recession could render the investment uneconomic. In a traditionally regulated environment, the out-of-market costs of the uneconomic investment would be borne by customers paying for unneeded supplies. In a restructured, competitive wholesale power market like PJM, however, the suppliers bear the market risk of losing money on uneconomic investments.

One of the key benefits of competitive power markets, including the PJM's capacity market, is that market prices can move with market fundamentals and create incentives to respond. Unexpectedly high prices will create a strong incentive for suppliers to quickly develop more demand response and speed the completion of generation under construction. Similarly, unexpectedly low prices will signal that expensive existing generation should be retired and new generation projects should be delayed. Ensuring that these incentives are delivered accurately to marginal resources through capacity prices will allow reserve margins to remain near the target levels, preventing both severe shortages and costly excess of supply. Private investors facing the risks associated with these market fundamentals will carefully assess the likelihood that their investment may become uneconomic and incorporate that possibility into their investment decisions.

Market rules or administrative interventions that dampen these price signals will tend to create an inefficient disconnect between market fundamentals and incentives.[61] For this reason, we are skeptical of some options for reducing RPM price uncertainty, including the further flattening of the VRR curve (as discussed in Section V) or expanding the New Entry Pricing Adjustment (NEPA) mechanism (as discussed in Section VI.F). However, while we recommend that RPM clearing prices should be allowed to continue to reflect changing and sometimes volatile market conditions, this does not mean that market participants should not have opportunities to hedge against these risks. These hedges may take the form of asset ownership or bilateral contracts (as discussed further in Section III.C) or may include other options for facilitating long-term hedging options through RPM design (as discussed further in Section VI.F).

2. Previously-Changed RPM Design Elements

Some of the RPM prices and price changes observed to date were caused by unintended consequences of market design elements that have since been modified. These previously-addressed modifications to RPM design elements include:

[61] For example, the price floor in ISO-NE's forward capacity market (FCM) has created substantial price stability in that prices have cleared at the floor for the first five forward capacity auctions. However, this stability has come at the cost of exacerbating an over-supply situation by preventing expensive existing generation from retiring and attracting substantial new supplies into the market. In fact, the first FCA for 2010/11 cleared at the floor with 1,772 MW of excess capacity, while subsequent auctions cleared at the price floor with increasing excesses of up to 5,374 MW for 2013/14 before dropping to somewhat lower levels for 2014/15 in the face of the EPA HAP regulation. See ISO-NE (2011a) and (2011b), p. 106.

- When RPM was implemented, a large portion of demand-side resources was interruptible load for reliability (ILR), which was accounted for outside the RPM auctions. This meant that auction prices initially failed to reflect the substantial growth in demand-side resources. Incorporating these resources into the auctions starting in the 2012/13 BRA allowed auction prices to reflect these supply fundamentals more accurately, which resulted in a large price drop (mostly in the unconstrained RTO) compared to the previous years.[62]
- For the first five delivery years, the rules governing which LDAs would be modeled in RPM auctions were more restrictive. This resulted in frequent changes in which LDAs were modeled and were allowed separate from the RTO and other LDAs in terms of its clearing price. In some cases this prevented price separation that would have been necessary to reflect market fundamentals as discussed in Section II.A. A set of rule changes implemented in time for the 2012/13 BRA ensured that certain LDAs were modeled, which allowed prices to separate. Going forward, these rule changes will create more stability in which LDAs are modeled and will allow LDAs that might price separate to be modeled more often.[63]

The unintended consequences associated with these RPM design elements resulted in a failure to fully account for demand-side resources and transmission constraints, which led to higher auction prices. Adjusting these design elements caused some of the observed price changes, but resulted in an improved market design with better price signals going forward. We keep these previous changes in RPM design elements in mind as we evaluate related aspects of RPM, because it will be valuable to avoid similar unintended consequences in the future. In particular, we examine the importance of modeling additional LDAs that might price separate in the future (Section VI.A) and examine the potential future implications of incorporating multiple demand response products (in Section VI.C).

3. Current RPM Design Elements and Administrative Parameters

While some market design elements (or adjustments to them) have created price volatility in the past, Stakeholder groups have identified several market design and administrative parameters that are quite uncertain and, as a result, continue to create significant uncertainty in RPM prices beyond changes in market fundamentals. We have identified two sets of design elements and administrative parameters that result in significant capacity price uncertainty:

- *Volatility and uncertainty in CETL*, which determines the quantity of capacity that can be imported into each LDA. Some changes in CETL are driven by changing plans for major transmission upgrades. Other changes are driven by modeling sensitivity to detailed assumptions including load distribution and the forecast of generating units are expected to be online or retired.

---

62 See PJM (2011d), sections 4.3.5 and 9.3.6.

63 Prior to 2012/13, LDAs were modeled only if their Capacity Emergency Transfer Objective ("CETO") was ≤ 1.05 CETL. Starting with 2012/13 more LDAs will be modeled, including: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate. See PJM (2011d), pp. 11-12.

- *Changes in the load forecast and locational reliability requirements*. Some changes in the load forecast and associated reliability requirements are driven by market fundamentals including the recent economic recession. However, other changes may be related to forecasting uncertainty or related changes in administrative assumptions.

These market design issues are primarily related to the difficulty of determining administrative parameters that are inherently uncertain but that have a large price impact on auction prices. One reason that these parameters are so uncertain is that they are related to future market fundamentals that cannot be accurately predicted by market participants or by PJM. However, some of the uncertainty and the impact that these administrative uncertainties have on market prices can be reduced in several ways, including: (1) improving market participants understanding of the uncertainty in these parameters; (2) increasing transparency by providing and more frequently updating the long-term outlook for administrative parameters; (3) reducing the sensitivity of final RPM auction parameters to modeling assumptions; and (4) limiting the impact of changes in administrative calculations on auction results.

We examine several of these options in Section VI.B with respect to load forecasting and reliability requirements and in Section VI.A with respect to CETL and transmission upgrades.

C. The Lack of Long-Term PPAs to Support New Plant Financing

A number of stakeholders have expressed concerns related to an apparent lack of long-term contracting that could support the financing of new generation additions in eastern PJM:

- Regulators in eastern PJM expressed the concern that there is a dearth of new power plant construction under RPM.
- Some generation developers similarly noted that three-year forward RPM prices effective for only one delivery year do not support the financing of new generation projects. They suggest that prices would need to be locked in for up to 10 years or more to support financing of new generation projects.64
- Financial industry participants similarly note that RPM does not support the financing of new generation, which would require revenue certainty over longer periods of possibly 10 years or more.65
- Stakeholders universally reported a current lack of long-term bilateral contracting of more than three to five years forward to provide price certainty beyond that offered directly by RPM. Generation developers stressed that buyers are unwilling to enter long-term contracts, while stakeholders from the public power companies indicated a strong interest in signing long-term contracts, but stated that they were unable to find willing suppliers.

The concerns that longer-term pricing arrangements are needed for financing new plants are seemingly inconsistent with public power stakeholders' concern that suppliers were generally

[64] We note that this view is not uniform in the generation owner sector.

[65] See also letters from Credit Argicole and Union Bank attached to LS Power Associate Comments on New Jersey Electric Power and Capacity Needs, Submitted in State of New Jersey Board of Public Utilities, Docket No. EO 09110920, July 2, 2011.

unwilling to offer long-term contracts. We believe this apparent inconsistency of concerns is explained largely by current market fundamentals.

The main reason for the low activity of new power plant construction in eastern PJM is the fact that new plants are not needed for several more years due to a combination of low load growth on the demand side of the market, and lower cost supply options such as deferred retirements, transmission upgrades, demand response penetration, and upgrades to existing units. That is, RPM has been able to retain or attract the lowest-cost set of resources to maintain resource adequacy. In other words, the lack of feasible long-term contract offers for new generation is explained by market prices for capacity that are below the cost of new plants.

These market fundamentals also explain the lack of long-term contracts with existing generation. Suppliers of existing capacity are unwilling to enter long-term contracts at low current prices because they expect prices will rise. At the same time, buyers are unwilling to pay higher prices or even the cost of new generation when there are less expensive options currently available in the market. It is likely, however, that interest in longer-term contracting will increase as excess capacity diminishes and capacity market prices rise to the cost of new generation on average over many years.

It is also possible, however, that secondary factors create contracting barriers, such as the structure of default service procurement in retail access states. If these barriers turn out to be significant—which is difficult to determine under current market conditions—modifying how default service procurement is regulated at the state level may be the most effective way to address these barriers. If that is not feasible, it may be worth considering longer-term pricing options under RPM. We stress caution in considering these options, however, because we believe that it should not be the role of an RTO to offer or force long-term contracting for capacity resources when load-serving entities do not see the risk management benefit of entering into such contracts bilaterally. Nor would an RTO be able to readily determine the amount of long-term contracting or contract terms that optimally balance risks. Mandating too much long-term contracting would inefficiently expose suppliers to delivery and credit risks while buyers are exposed to larger risk premiums and the potential for stranded costs.

It is also likely that the need for and reliance on long-term power purchase agreements (PPAs) and project financing will diminish as the industry evolves and an increasing share of new plants are developed by larger, partially vertically-integrated companies with load serving responsibilities, a portfolio of merchant generation, and sufficiently strong balance sheets to finance the needed investments. We discuss each of these points in more detail in the remainder of this section.

1. The Role of Current Market Fundamentals

It is correct that relatively few new power plants have been built in eastern PJM since RPM has been implemented. However, as we have explained in Section II, it is not true that no new generation has been built in eastern PJM. Even without considering capacity uprates of existing plants (2,210 MW), reactivations (360 MW), export reductions (930 MW), or increased demand response (6,550 MW), approximately 2,040 MW of new generation capacity has been committed in the MAAC region under RPM, and another 650 MW of new generation offers have been submitted but failed to clear because sufficient capacity has been offered at prices below the cost of new generation.[66]

Nevertheless, the relatively modest level of new generation construction in eastern PJM has not led to resource adequacy shortfalls, as some stakeholders believe. Reserve margins have remained at or above target levels, due to the combination of entry by these new generation units, combined with demand response resources, upgrades to existing capacity, deferred retirements, planned transmission upgrades, and the economic slowdown. Moreover, RPM has maintained resource adequacy at prices that have generally remained below the cost of new generating plants.

It is also correct that market prices for capacity in eastern PJM have been significantly higher than in the remainder of PJM in most years. However, even these eastern PJM capacity prices have generally remained below the cost of new plants in the recent BRAs. Prices will remain below the cost of new plants until new generation is needed and capacity prices rise to clear new offers.

We believe the underlying fact that new generation is simply not cost-competitive with lower cost options such as uprates, deferred retirements, and demand response under these market fundamentals is the primary reason that there has not been more new construction of generating plants in eastern PJM. That capacity prices will remain below the cost of new plants through 2014/15 and possibly for several more years is likely also the primary reason that some developers' new generation projects cannot be financed without long-term contracts. Current market conditions do not support long-term contracts at prices high enough to finance new plants because rational buyers prefer to satisfy their capacity requirements at market prices that are below the contract cost of a new plant.

Under these market conditions, when few or no new plants are needed, the only way to finance additional new generation would be through above-market long-term contracts. Such above-market contracts have recently been offered through a New Jersey legislative mandate, which procured capacity for three new plants under fixed-price 15-year contracts whose costs are not public but that are estimated at approximately \$270-350/MW-day.[67] In comparison, RPM prices in New Jersey have been much lower at \$136-225/MW-day for annual resources in the most recent BRA.

In short, the lack of long-term contracts and financing for new plant construction is a consequence of the fact that investments in new generation are at present inherently unprofitable and not part of the least-cost solution to resource adequacy. Currently, new generation is not a cost effective way to meet anticipated load growth. Under these circumstances we do not expect a well-functioning market to reward investments in new generation. In other words, the absence of new construction is a sign that the market is working.

---

[66] Reported in ICAP. Note that most new generation offers that have failed to clear in one auction have subsequently offered and cleared in later auctions, from PJM (2011a).

[67] See

Table **1** for auction prices. Approximate New Jersey procurement prices were calculated by the New Jersey EDCs (2011), pp. 8-9.

Current market fundamentals are also the likely reason that public power entities looking for long-term capacity contracts have not found willing suppliers. First, given that capacity prices may remain below the cost of new plants for a number of years, buyers interested in long-term contracts will not be willing to sign long-term contracts priced at the full cost of new power plants. Thus, developers of new power plants will be unwilling to offer long-term contracts at prices acceptable to buyers. Second, even owners of existing generating capacity will be unwilling to sign long-term contracts at prices equal to current market prices if they anticipate that RPM prices increase over time. It is likely, however, that buyers' and existing generators' interest in longer-term contracting will increase as excess capacity diminishes and capacity market prices rise to the cost of new generation over the next several years.

2. Availability of Financing

As discussed, current market fundamentals in PJM do not generally support the entry of new plants. Thus, without a need for new plants, financing for such plants will not be available unless supported by (above-market) long-term contracts.[68] However, this does not mean that financing is not available for sound investments at costs that are consistent with market fundamentals. In fact, there has been keen interest in the acquisition of power plants in eastern PJM, and major recent transactions have documented the availability of financing for investments in merchant power plants.

A notable example in eastern PJM is Calpine's 2010 acquisition of 4,490 MW of Conectiv Energy power plants in eastern PJM from Pepco Holdings Inc. ("PHI").[69] The $1.63 billion purchase, which included some existing forward capacity and energy sales commitments as well as a six-year tolling agreement with Constellation Power for the Delta power plant that was under construction at the time, was financed with $1.3 billion of seven-year debt and $100 million of three-year debt.

3. The Role and Implications of "Project Finance"

Generation developers' frequent preference to build new power plants through highly-leveraged "project finance" arrangements appears to be another major driver behind their interest in long-term power purchase agreements. Project finance refers to the use of project-specific debt, also called "non-recourse" debt that is not backed by a guarantee from a larger parent company. Project finance is often the only available option for small project development companies that do not have a significant portfolio of other assets or for companies with weak balance sheets and poor credit ratings.

Such non-recourse debt is secured solely by the revenues and asset value of the specific power plant. It is more risky to the lender and consequently more expensive than corporate debt that is secured by the more diversified revenues and assets of the parent company. However, while more expensive than corporate debt, non-recourse debt is still attractive to developers because it

---

68 See also B. Chin, "Capacity Issues Technical Conference: State of New Jersey," Citi Investment Research, June 24, 2010, noting that "in our view, energy/capacity markets are providing a signal that capital should not be deployed to [new] generation at this time, unless subsidies are enacted."

69 For example, see Calpine (2010).

is less expensive than equity and reduces the potential liability to the parent company if the project proves to be a bad investment.

To reduce financing costs, project developers will similarly prefer to "lever up" their investments by using higher levels of debt and less equity. However, such reductions in financing costs are possible only if project risks are reduced through long-term power purchase agreements that shift market risks from the generation owner to the buyer of the power. In fact, by assuming project risks through a long-term contract, the buyer is reducing (and essentially subsidizing) the financing cost of the new plant. Financing projects with high levels of debt (*e.g.*, 70 to 80% debt) can reduce the levelized annual investment cost of a project by 10% to 20% compared to merchant plant financing, which may allow financing with only 30% to 50% non-recourse debt (backed solely by the project) or 50% to 60% corporate debt (backed by the entire parent company).

In a well-functioning market, a range of financing arrangements will exist under which buyers can assume risks under a long-term contract (that support for more highly leveraged financing by the developers) or developers can assume these risks (which requires financing with more equity) depending on risk sharing preferences and the financial conditions of the counterparties. However, it is not desirable to enable uneconomic investments in new generation through long-term PPAs when those developments are more costly or more risky than capacity from market-based resources, including from existing generation supplies and demand response.

4. The Role of Default Service Procurement in Retail Access States

We believe that longer-term contracting will increase as capacity market prices reach and sometimes exceed the cost of new generation. It is conceivable, however, that market or regulatory barriers could prevent an outcome in which an efficient level of longer-term contracting is achieved, although we do not presuppose to know what that efficient level of long-term contracting might be.

The current nature and regulation of retail services in restructured states may represent such a barrier that might inhibit reaching optimal levels of long-term capacity contracting in PJM. This is because a significant portion of retail load is supplied under regulated "default service" arranged by electric distribution companies ("EDCs") and overseen by the utility commissions. In restructured eastern PJM states, such as New Jersey and Maryland, the EDCs are required to procure bundled energy and capacity supplies for these default service obligations. The contracts for such default service procurement generally have durations of three years or less. This sole reliance on short- or intermediate-term contracts under state-regulated default service procurement appears to deviate significantly from the procurement and risk management practices of large competitive retail service providers.

Competitive retail service providers, including those in PJM, appear to secure a meaningful portion of their supplies through long-term contracts or even the acquisition of generating assets. Such actions are designed to counter the effects of perceived broken linkages between competitive retail and wholesale markets by reducing the transaction costs of securing long-term contracts and effectively vertically re-integrating load serving responsibilities with merchant generation. For example, Constellation's NewEnergy retail supply business obtains energy from a portfolio of various sources, including its own generation assets, contractually-controlled generation assets, exchange-traded bilateral power purchase agreements, unit-contingent power purchases from generation companies, tolling contracts with generation companies, and spot purchases from the regional power markets.[70] This portfolio balances retail sales contracts that are reported to extend from one to ten years and beyond, although these will generally not be exactly matched by long-term capacity procurement contracts.[71] Constellation Energy explicitly stated that its strategic retail-service-operations objective is to buy generation assets in regions where the company does not have a significant generation presence and enter into longer-term agreements with merchant generators.[72] In fact, this objective was a primary reason for Constellation's purchase of generating plants in Texas as well as its recent acquisition of 2,950 MW of generating plants in ISO-NE, which "improved [Constellation's] net load to generation ratio to approximately 55 percent."[73] Direct Energy, another retail service provider, appears to have started pursuing a similar strategy through long-term contracting power from generation suppliers, buying physical generation assets, and even acquiring natural gas production, storage and transportation.[74] Similarly, NRG's recently announced acquisition of Energy Plus holdings was explained as an effort to "expand its retail marketing presence in the Northeast and Mid-Atlantic" to give the company "more of a retail presence to offset its generation assets in periods when wholesale power prices are depressed."[75] NRG's announcement also marked another retail acquisition following Constellation Energy Group's purchase of StarTex Power and its planned acquisition of MXenergy, and Direct Energy Services' purchase of Gateway Energy Services.[76]

We have not analyzed what fraction of total retail load should be supplied through long-term contracts or physical plant ownership. Such decisions will depend upon a company's tolerance for risk and expectations regarding future market conditions. While long-term contracts and physical plant ownership will stabilize procurement costs, they also create the risk that costs will be above market. However we believe it is possible that the most efficient amount and duration of long-term contracting may exceed the amount realized for load under default service procurement. We view this potential concern over whether default service creates a barrier to efficient contracting primarily as a matter for state commissions and state legislatures to examine in the context of retail choice and default service regulations. The best way to realize an efficient level of long-term contracting and asset ownership among retail providers might be for the states to reduce their reliance on default service. This would allow increased interaction between retail service providers and customers that would allow market participants to determine the most efficient retail supply portfolio. Reduced reliance on default service, for example, exists in Texas where most retail customers are served by competitive suppliers after default service was eliminated in 2007 (although a provider of last resort service is still available to customers who lose their competitive service providers).[77] A second option that states could pursue would be to review default service procurement practices to determine the extent to which longer-term

70 See Constellation's 2010 10-K filing in Constellation (2011), Part 1, Item 1, pp. 4-5.

71 *Id.*

72 See Constellation (2010), pp. 29 and 60; Morningstar (2010).

73 For example, see Constellation (2010).

74 Direct Energy (2011).

75 Megawatt Daily, "NRG to buy Energy Plus Holdings for $190 mil," August 17, 2011.

76 *Id.*

77 Kiesling and Kleit (2009), Chapter 8.

contracts (procured on a non-discriminatory basis from existing or new resources) should be part of default service procurement.

Only if states fail to pursue these options and generation investment lags even as market prices reach or exceed Net CONE, it may be necessary for PJM to introduce mandatory long-term procurement of capacity into the RPM construct. However, we consider this to be a far less desirable option and would recommend pursuing this option only if (1) it becomes clear that a review and revision of default service procurement is unlikely, and (2) it can be determined with sufficient confidence that longer-term contracts through RPM-based resource procurement will actually be needed to assure resource adequacy at reasonable costs. We examine this option along with several alternatives more fully in Section VI.F.

5. Does the Electric Power Industry Need Long-Term Contracts?

There is a perception that new generation cannot be built without long-term PPAs or close to 10 years or more. As discussed above, this perception is largely created by current low-priced market fundamentals and the preference among developers to lay off risks onto contract counterparties. Reliance on long-term contracts is also rooted in the regulated past of the industry (including Qualifying Facilities under PURPA). However, a number of observations about customer preferences and contracting practices in other capital intensive industries suggest that widespread perceptions may overstate the need for long-term contracting as the industry evolves.

First, most retail customers are unwilling to commit to long-term contracts. The reluctance is not unique to restructured electric power markets. This is also the case for most energy commodities sold in retail markets, including commodities with even higher price uncertainty, such as gasoline. If contracts are signed in other retail market segments, they rarely go beyond the next season (*e.g.*, heating oil), or the next two years (mobile telecom service). In fact, long-term contracts between retail customers and suppliers are uncommon even in the most risky and capital intensive portions of the energy industry (such as oil and natural gas exploration), despite the unpredictable nature of risks (such as oil price movements based on a wide range of geopolitical influences, including cartel behavior).

Second, other capital-intensive industries with significant price risks generally require that investments are backed by companies with sufficient equity. However, such "balance sheet financing" of major investments is less common in the electric power industry.[78] While numerous examples of balance-sheet financing and generation investments without long-term PPAs or other long-term price hedges exist (including merchant wind power development),

[78] The use of balance sheet financing does not mean that medium- or long-term contracts are eliminated for these projects. Rather, it simply means that the role of medium or long-term contracts is reduced because at least some projects can be built with less of the project costs hedged through long-term contracts. Projects may be built without PPAs, shorter-term PPAs, or PPAs that cover only a portion of the project's expected sales.

project financing arrangements supported by long-term PPAs remain the first choice of most power plant developers.[79]

The lower reliance on balance sheet financing in the power industry does not mean that project developers in other industries would not prefer the lower risk and financing costs that they would be able to achieve if they had long-term sales agreements. Nor does it mean that power industry developers are unable to develop projects without long-term sales agreements. Rather, the relatively low levels of balance sheet financing in the power industry appears to be an artifact of industry evolution. Specifically, the merchant generation sector has evolved based on: (1) long-term PPAs with regulated utilities (starting with mandated qualifying facility (QF) contracts in the late 1980s and early 1990s); (2) project development efforts by small companies without much equity; and (3) a reliance on highly leveraged financing arrangements.

Third, competitive retail electricity providers and companies in other capital-intensive industries, including in oil and gas, also tend to be partially (but not fully) vertically integrated to manage risks and reduce transactions costs. They have bought physical assets or signed a portfolio of contracts to manage overall supply obligations and associated risks. Partial vertical (re)integration also appears to be becoming more prevalent in electricity markets. In the United Kingdom, for example, retail suppliers have re-integrated into the generation business.[80] Similarly, generation owners are integrating vertically into retail sales, as noted in the above discussion of NRG, Constellation, and Direct Energy, and with Exelon's proposed merger with Constellation as another recent example.[81] A transition to a partially integrated industry structure has a number of potential advantages and will reduce the need for, or compensate for the lack of, extensive bilateral contracting.[82] Competition will be maintained or enhanced because the companies have a reduced ability and incentive to exercise market power and, unlike in non-restructured markets, are not *fully* integrated and do not enjoy exclusive service franchises.[83]

Consistent with these observations, we believe the deregulated electricity industry will naturally migrate to a partially vertically integrated structure that, over time, will rely less on long-term

---

79 For example, the DOE reports that in 2009, 38% of all new wind generation capacity was from merchant or quasi-merchant projects that relied on short-term contracts or hedged wholesale spot market sales rather than long-term PPAs. See Wiser, *et al*. (2010), p. 34.

80 In the U.K., for example, restructuring in the early 1990s resulted in completely vertically unbundled industry structure. Today, the six largest competitive retail suppliers (supplying 99% of retail load) also own approximately 70% of the installed generating capacity. See Ofgem (2010). Note, however, that such partial integration by large companies will also tend to make it more difficult for smaller and non-integrated suppliers to enter and compete in the market. (See Ofgem, *Liquidity Proposals for the GB wholesale electricity market*, February 2010, posted at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=95&refer=Markets/WhlMkts/CompandEff

81 See Exelon and Constellation (2011).

82 For a discussion of the implications of vertical re-integration of competitive retail service and generation companies, see Meade and O'Connor (2009); Mansur (2007) "Upstream Competition and Vertical Integration in Electricity Markets," 50 J. Law & Econ. 125. http://www.dartmouth.edu/~mansur/papers/mansur_vi.pdf.

83 See, for example, Bushnell, J. B., Mansur, E. T. & Saravia, C. (2008). "Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured U.S. Electricity Markets." American Economic Review, 98, 237-266.

PPAs to underwrite new generation development. We view these trends to reflect an efficient response to deregulation, which shifts the risks of potentially uneconomic generation investments away from customers and toward developers. As increasingly large and diversified companies, these developers will be in a better position to evaluate, manage, and bear these risks. Regulatory or legislative intervention to force long-term contracting in restructured markets, even if through RPM design, carries the risk of interfering with the natural evolution of the industry with the risk of adverse long-term consequences for the efficiency of future capacity expansion.

In short, we recognize that there may be many generation projects in PJM that cannot get financed and built under current market conditions. However, while some project developers may cast this as a market failure caused by the inadequacies of RPM or state retail choice constructs, we believe the primary reason that these projects cannot get financed and built is that they are not currently needed and are currently uncompetitive with alternative sources of capacity. In the future, when these projects *are* needed for resource adequacy, we believe that market prices will rise and will make these investments attractive. However, we also recognize that it will be beneficial to both suppliers and customers if long-term contracts are enabled and not hindered by the design of RPM and state retail regulation, topics which we examine further in Section VI.F on options for extending price certainty under RPM and in Section VI.E.1 on the minimum offer price rule (MOPR).

D. Equal Compensation for Old and New Generation

A number of stakeholder comments, primarily from state commissions, relate to concerns over why old generation and demand resources receive the same compensation as new generation under RPM. This topic also relates to stakeholder comments about their disappointment that RPM has served to keep online "old and dirty" generating plants while failing to get much (if any) new generation built in eastern PJM despite prices that were higher than in the western portion of the RTO. Some of these concerns have also been raised in a recent report prepared for the American Public Power Association ("APPA").[84]

As discussed in Section II, some new generating units have in fact been built under RPM. However, it is unclear that RPM itself induced these units to come online. Moreover, some stakeholders believe that more generation should have been built in eastern PJM where RPM prices have been higher than in the west. The main reason more generation did not enter is that it is not currently needed to maintain reliability requirements. Despite relatively higher prices in eastern PJM, these prices have been below the cost of new entry. The combination of lower peak loads, available existing generation, deferred retirements, capacity additions to existing generation, and expansion of demand response resources have made it possible to meet resource adequacy requirements at market prices below what would be needed to support the entry of more new generation.

In this section, we briefly address the environmental concerns about retaining old plants. We also discuss the differences in the time profile of capacity prices between regulated and restructure markets, and the feasibility and efficiency of differentiating capacity payments between new and existing plants.

---

84 See Wittenstein and Hausman (2011).

1. Keeping "Old and Dirty" Plants Operational

State and federal legislatures and regulatory agencies set rules to reduce the environmental impacts of power generation. Recent regulations include the Regional Greenhouse Gas Initiative ("RGGI"), state renewable portfolio standards, the Maryland Healthy Air Act, and EPA regulations and related state implementation plans to meet tightening National Ambient Air Quality Standards ("NAAQS") and to reduce the output of hazardous air pollutants (HAPs).

We have not seen any evidence suggesting that existing plants are not complying with environmental regulations, even older units that have higher emission rates than new plants. Nor have we seen evidence indicating that wholesale capacity markets have contributed to greater emissions levels from these facilities. To the contrary, RPM recognizes the costs of the plants' environmental footprint in two ways. First, "dirty" plants that need to install control technology to comply with environmental regulations will include the costs of such investments in their capacity market offers. For example, in the 2014/15 auction, many resources needing environmental retrofits either opted not to offer or offered at higher levels, and not all cleared when other resources could provide capacity more cheaply, as discussed in Section II. Uncleared plants may consequently retire and the cleared resources will install pollution controls. Second, higher emissions rates result in higher allowance costs, which reduces the dispatch frequency and the energy margins these plants earn. This will reduce their emissions and tend to raise their capacity market offers (and the IMM's offer caps), which will make them more likely not to clear in RPM in the future. Thus, RPM internalizes both the variable and fixed costs of complying with existing and planned environmental regulations. With these costs internalized, the competitive wholesale markets facilitate compliance with environmental regulations at lower costs while still maintaining resource adequacy.

If there are any concerns over the remaining environmental footprint of existing generation assets, they should be addressed through stricter federal and state environmental standards. Otherwise, RPM cannot be expected to implement environmental standards that do not exist. Nor should RPM be expected to impose indirectly tighter environmental standards than state and the federal governments have deemed appropriate. In our opinion, RPM is performing well in terms of incorporating the costs of existing and planned environmental regulations. The adequacy of the environmental regulations themselves should not be a factor in the assessment of whether RPM is achieving its objectives.

2. The Time Profile of Capacity Prices in Restructured vs. Regulated Markets

The position that older plants should not be compensated for capacity at the same level as new plants is often related to a misunderstood or under-appreciated difference in the time profiles of capacity prices in regulated and fully-restructured power markets. While it is generally understood, for example, that the price a tomato farmer receives for his tomatoes does not depend on the age of his tractor, this paradigm does not apply in cost-of-service regulated industry. Under cost-of-service regulation, the price charged for a power plant is determined by its accounting costs. As a result, new plants will generally be more expensive than old plants, at least until major capital additions are needed at the old plant. This declining revenue profile for power plants in a cost-of service regulated environment does not exist in restructured markets. In restructured markets, even the administratively-determined cost of new entry is calculated as the "levelized" cost of a new plant, which creates a revenue path that is either constant over time (if costs are levelized in nominal dollar terms) or increasing over time (if costs are levelized in real dollar terms). Long-term PPAs signed through competitive procurement similarly often have pricing paths that are either constant or increasing over time. This time profile of cost recovery means older plants are paid the same for the capacity they provide as new plants. The time profile differs substantially from the time profile under cost-of-service regulation, under which the cost of new plant exceeds their "levelized costs" during the early part of the plants' life but is lower during the latter years.

Moreover, in a cost-of-service regulated environment, retail rates will reflect the cost of generating capacity only after new generating resources are placed in service and reflected in utilities' rate bases. This means there can be a lag of several years before regulated retail rates reflect the addition of expensive new capacity resources. This lag causes a significant misalignment of retail prices and investment signals. Because demand continues to grow due to low rates, more new resources may be added to the system than will ultimately be needed when retail prices increase to reflect the added costs. This can lead to excess capacity, high regulated retail rates, and the risk of stranded costs or regulatory disallowances.

The time profile of capacity prices is quite different in restructured power markets. As in all other competitive markets, the market price for capacity will increase before new generating capacity needs to be added. As market participants perceive an approaching scarcity of generating capacity, market prices for capacity will increase and, in response, market participants will identify the lowest-cost resources that can operate profitably at the anticipated market prices. In order to invest in new generation, competitive suppliers must expect to receive high enough capacity prices over the plant's entire economic life (including later years when the plant is aging). If capacity prices are reflected in retail rates or are otherwise made available to demand-side resources, this market-determined portfolio of resources will also include demand-response resources. The fact that capacity prices increase before new resources are actually added to the system will dampen demand growth and reduce the resource need and long-term costs.

The fact that prices in eastern PJM have increased even before much new capacity has been added, has led some stakeholders to question the value and effectiveness of capacity market and restructuring in general. However, we believe the observed price path is consistent with market fundamentals and efficient market outcomes and will result in lower costs over the long term.

3. Differentiating Capacity Payments for New and Existing Resources

The very design of capacity markets or capacity payment mechanisms raises the question of whether all resources should receive capacity payments, or whether such payments should be limited to new resources and resources which would otherwise retire. Limiting capacity payments to new resources is appealing to some because at first glance it appears that it would reduce the total costs associated with such capacity payments. Arguments of this sort are deceptively attractive, but they fail to consider the long-term impacts that would undermine efficient market signals and ultimately increase system costs.

If a resource adequacy requirement is to be met through a market mechanism, whether a centralized capacity market or solely by relying on bilateral contracts, the capacity from all resources that can be used to satisfy the requirement will have the same capacity value. As a result, capacity revenues available to existing and new resources cannot be differentiated in such a market environment. Even if RTO-administered capacity markets were limited only to new resources, the full market value of capacity would still be captured by all existing resources through bilateral contracts, assuming that the resources are not cost-of-service regulated or under existing fixed-priced contract.

When limiting capacity payments to new resources or existing resources that would otherwise retire, it is also necessary to recognize that a sizeable portion of the existing pool of resources would be forced to retire in the absence of capacity revenues. For example, we have shown in our 2008 RPM Report that in the six years before RPM was introduced in PJM, between 500 MW and 3,500 MW of generating resources retired each year.[85] After RPM was introduced, annual retirement dropped to a range of zero to 500 MW for the first five BRAs. More importantly, however, an analysis of market monitoring data showed that at least 30,000 MW of PJM's capacity resources were at risk for retirement in the absence of capacity payments due to revenue deficiencies in PJM's energy and ancillary services markets. This is not surprising considering that the going-forward costs of many existing resources can be high even in comparison to new resources. As a result, capacity auctions will generally select new capacity resources even when cost-based bids for many of the existing resources do not clear. For example, in PJM's auction for the 2011-12 planning year, a total of 2,337 MW of new capacity cleared in the auction, while 496 MW of new capacity did not clear.[86] In comparison, 4,600 MW of capacity from existing resources did not clear, even though the bid prices for the existing resources were mitigated to reflect their incremental costs. These data show that the all-in costs of retaining existing plants can even exceed the costs of new plants. This is because existing plants are sometimes more expensive, and keeping them operational may require significant ongoing costs (*e.g.*, high annual repair, refurbishment, and maintenance costs) as well as occasional substantial investments (*e.g.*, environmental retrofits or replacements of major plant components).

Only in power markets that do not impose resource adequacy requirements on LSEs can capacity payments be targeted specifically to new resources or the retention of existing resources. However, such a differentiation of payments between old and new generation would cause significant market distortions that, while potentially saving costs in the short-term, would result in substantial inefficiencies and higher costs in the long term.[87] Subsidizing the entry of new plants through above-market long-term contracts results in similar distortions and long-term costs. While these out-of-market mechanisms will suppress market prices in the short term, the market distortions they create will perpetuate and accelerate the need to expand the scope of such subsidies or other out-of-market solutions to maintain reliability. Again, this solution will likely be less efficient and more costly in the long-term.

---

85 Pfeifenberger and Newell, *et al.* (2008), p. 20.

86 Pfeifenberger and Newell, *et al.* (2008), p. 36.

87 For a case study of the adverse consequences of imposing different prices for "new" and "old" resources, refer to the discussion of inefficiencies, reduced investment incentives, and overall welfare losses resulting from the different regulation of prices for "old" and "new" natural gas prior to the implementation of the Natural Gas Policy Act of 1978 as discussed in Viscusi, Vernon, and Harrinton (2000), pp. 616-632.

E. RPM's Ability to Replace or Prevent High Environmental Retirements

Several stakeholders expressed concern about RPM's ability to replace or prevent excessive simultaneous retirements caused by EPA's new HAP MACT and other regulations. Indeed, the slew of regulations currently being promulgated is likely to impose major stresses on electricity markets and the supply chain for environmental control equipment. These challenges are being felt nationally and are not limited to PJM. The reason for particular concern about RPM is that it is a restructured market which, unlike traditionally regulated systems, lacks centralized resource planning. RPM includes "buy bids" for capacity (up to their price cap for existing capacity), but there is no guarantee that enough capacity will retained below that price cap or offered from new resources to replace potentially large amounts of retirements.

1. RPM Facilitates Retrofits and Procures New Capacity Economically

RPM is designed to procure enough capacity to meet resource adequacy targets and to do so in an economically efficient, market-based fashion. RPM facilitates retrofits by allowing offers from existing generation to include the cost of retrofits. If the offer clears, the resource will earn at least its offer price with the prospect of recovering its retrofit costs. Existing resources will not clear only if lower cost resources are available to replace it (or the price cap is hit, which is unlikely). If the resource is not offered at all, replacement capacity can be procured. RPM supports new entry through its 3-year forward period, which provides enough lead time for a variety of new resources to enter, including new demand-side resources, generation uprates, and new generation.[88] Furthermore, RPM's centralized clearing and pricing transparency facilitate efficient economic tradeoffs between all such resource options. RPM also includes three incremental auctions after each base auction, each of which provides opportunities to procure addition capacity.

So far, these provisions have worked as intended. RPM has successfully and economically supported resource adequacy, including when the Maryland Healthy Air Act was implemented in 2009/11 and under the challenging conditions presented by EPA's HAP MACT regulations partially reflected in the most recent BRA for the 2014/15 delivery year. In that auction, 3.2 ICAP GW of existing generation was excused from offering, up from 1.2 GW the prior year (with FRR excused and other excused resources likely withdrawn for environmental reasons); 10.6 ICAP GW cleared at higher prices above \$50/MW-day (4.4 GW above \$100/MW-day), reflecting the costs of scrubbers and other environmental retrofits; and 10.2 ICAP GW (including all new PJM members such as ATSI) of existing generation was offered but did not clear. Despite these reductions of capacity from existing generation, and sufficient replacement capacity was procured, largely in the form of demand side resources. Furthermore, there were new resource offers that did not clear but could have if they had been needed and prices had been higher. (See Section II).

2. The Future is Uncertain and Retirements Should be Monitored

So far, RPM has performed successfully under the challenges presented by EPA's HAP MACT regulation through the 2014/15 delivery year. However, RPM has not been tested with larger

88 As discussed in Section III.C, concerns that RPM does not support new generation are largely unfounded.

amounts of simultaneous retirements within the LDAs. It is too early to tell how well RPM (or any other construct) will mitigate the retirement threats caused by the full slate of tighter new regulations planned to take effect between 2015 and 2018.

Additional emerging regulations on *air quality* to be effective during that period include likely tighter emission limits and regional/state caps on NOx and SO_2 due to EPA's expected revisions to air quality standards for ozone, particulate matters ($PM_{2.5}$), and SO_2. These air quality regulations will affect all fossil fuel generation plants, but especially coal- and oil-fired plants. Furthermore, EPA proposed regulations on *cooling water* intake structures at generation plants to reduce damage to aquatic organisms due to impingement and entrainment. Under the proposed rule, states will determine what specific controls (such as mesh screens or cooling towers) would be required to be installed at each covered generation facility (including nuclear, coal, gas and oil plants). EPA has also proposed regulations on handling and disposal of *combustion by-products* (such as ash) which may require additional equipment on coal plants and may essentially eliminate surface disposal of wet coal ash. Finally, EPA is expected to issue proposed rules this year for *greenhouse gas* ("GHG") performance standards applicable to new and modified generation plants. The impact of this new NSR rule on existing power plants will in part depend on EPA's interpretation of major modifications (*e.g.*, whether repairs are considered major modifications), which has been a central issue in numerous litigation cases between EPA and plant owners with respect to criteria pollutants. The combined and fairly simultaneous impacts of these emerging EPA regulations on air quality, cooling water, combustion by-products, and GHG will likely contribute to early retirements of a significant portion of the existing generation units over the next five years. Future CO_2 prices under a potential federal climate policy would additionally increase the retirement pressures on coal-fired plants.

Hence, despite RPM's design and success to date, it is not possible to predict exactly what will happen if a large number of plants retired simultaneously. Such simultaneous retirements would be a challenge in any system and could lead to difficult-to-manage spikes in retrofit costs. Given these risks, PJM will undoubtedly continue to monitor closely potential retirements through communications with generators and its own analysis.[89] Vulnerabilities identified could be used to ensure that the appropriate LDAs are being modeled and to check that sufficient new resources are being pre-qualified for the auctions. If not, both PJM and the states will need to pursue options to entice existing capacity to stay online or to procure new resources.

Another risk that PJM will need to monitor is the possibility that environmental regulations which force a large number of retrofits during a single year could produce spikes in RPM prices for a single auction, followed by price decreases in the next auctions to levels too low to allow for cost recovery of the retrofit investments. If that occurs, the offer cap provisions for environmental retrofits may have to be revisited. A number of the recommendations we present in the remainder of this report, such as more proactive modeling of LDAs, would provide additional safeguards to ensure RPM can address these challenges.

F. The Dependability of Demand Resources

PJM stakeholders, primarily generators, voiced a range of concerns regarding the dependability of demand-side resources. These stakeholders are concerned that DR development plans may

89 See PJM (2011p); see also PJM (2011z) and ERCOT, MISO, NYISO, PJM and SPP (2011).

not be fulfilled if the market becomes saturated, that DR does not face the same obligations as does generation, that there is no historical record indicating how DR will perform as required at high penetration levels, and that these problems may become more acute as DR penetration rises and starts displacing larger amounts of generation.

1. Market Saturation Concerns about Planned DR

In the 2014/15 BRA, demand-side resources (DR and EE) accounted for 14.9 GW of capacity (UCAP), or 9.4% of total resources committed. This is 4.0 GW more than the demand-side capacity (DR and ILR) committed for the current 2011/12 delivery year. While the amount of DR capacity cleared for 2014/15 is impressive, we see no evidence that its performance should be considered speculative. First, to our knowledge demand-side resources committed for the current delivery year have been performing well during the recent heat waves. Second, while the 4.0 GW increase over the next three years compared to the current delivery year is ambitious, it is smaller than the 6.0 GW increase that occurred over the past three years. Third, demand resources are exposed to verification and penalty provisions for resource deficiencies and performance violations that are roughly similar to those of generation resources and should be sufficient to ensure performance. Finally, DR resources have exchanged their BRA commitments in incremental auctions at a rate no higher than generation resources and future incremental auctions will still be available as safeguards that would allow replacements of commitments that could not be fulfilled.

On the other hand, there is at least some indication that some providers may have overestimated their ability to enroll a sufficient number of customers to fulfill their DR capacity commitments in some areas. For example, one curtailment service provider ("CSP") filed a motion with the Public Service Commission of Maryland to amend its demand response capacity agreements with three utilities, after it encountered a number of problems attempting to contract with new customers to provide DR capacity required under those agreements for the 2011/2012 delivery year. The company cited "substantial competition from other providers also offering demand response services" as one of three reasons.[90]

To incentivize CSPs to offer only realistic amounts of "planned" DR and to develop them, RPM imposes deficiency penalties for failure to produce the resources or procure replacement capacity. As a possible additional safeguard to identify deficiencies early, PJM should consider monitoring development plans more closely, as discussed in Section VII.

2. RPM Design Issues for Accommodating Large Amounts of DR

The primary concern with relying on large amounts of DR (as a substitute for new generation resources) is that the frequency of potential calls increases as DR penetration rises. If DR resources are seasonally limited or contractually obligated to respond to dispatch instructions only a certain number of times, reliability could be compromised at higher levels of DR penetration. PJM has already addressed this concern by restricting the total amount of "Limited Summer" DR resources, introducing new DR products, and imposing minimum requirements for "Annual" and "Extended Summer" DR resources. We find this DR-related extension of RPM auction design to be a reasonable solution to the problem. Based on our

[90] Megawatt Daily, "Enernoc seeks amendments to Md. Contracts," June 30, 2011.

analysis presented in Section II of this report, we also find that this approach is working as intended.

Furthermore, if resources are found to underperform relative to their obligations in the future, they will face penalties similar to those imposed on generators. However, because large amounts of Annual DR is unlikely to be called very frequently under normal system conditions, it might be possible for a CSP to offer some limited resources as Annual resources without a high risk of being called upon and penalized if the resource cannot perform. To provide additional safeguards against such under-performance concerns, we recommend that PJM consider strengthening its verification processes by reviewing just prior to each delivery year whether DR resources would likely be able to respond as claimed. Such a review could include verifying the seasonal or annual nature of the load to be curtailed and whether there are any contractual limitations to the number of calls. These recommendations are discussed further in the context of comparability of DR and generation resources in Section VI.C of this report.

G. RPM Target Procurement

Stakeholders representing load and some of the state commissions raised concerns over the accuracy, economic efficiency, and transparency of reliability targets and load forecasts. A number of these concerns have also been raised publicly.[91] As stakeholders recognize, PJM's reliability targets and load forecasts determine the amount of capacity procured under RPM, both on an RTO-wide and LDA level. There are major implications for total annual capacity payments imposed on PJM load serving entities and capacity payments provided to generators. Under RPM, these payments can range from $5 billion to $15 billion annually and can vary significantly from one year to the next and from one LDA to the other based on market conditions, updates to LDA-internal resource adequacy requirements, and forecasts of future peak loads.

The RPM target procurement of capacity is a function of (1) the forecast of weather-normalized peak load for the RPM delivery year, and (2) the reliability requirement, which determines target reserve margins. At the RTO-wide level, PJM resource adequacy planning is based on a reliability requirement defined as the 1-day-in-10 years Loss of Load Expectation ("LOLE"). Within individual LDAs, the reliability requirement is determined based on a "conditional" LOLE target of 1-day-in-25 years, as explained below.

The purpose of RPM is to procure sufficient capacity so these reliability standards are satisfied on an RTO-wide and LDA-specific basis. As such, the scope of our RPM performance review

---

[91] For example, see Public Power Association of New Jersey, March 8, 2010 and December 2, 2010 letters to John Reynolds and Steven Herling re "Request for Consultant Review of PJM's Load Forecasting Methodology" from a group of residential, commercial and industrial consumers, state regulators and consumer protection agencies, and load-serving entities on the PJM system; Comments submitted on behalf of the Public Utilities Commission of Ohio in FERC Docket No. RM10-10, "Proposed Reliability Standard, BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 27, 2011; J.F. Wilson, "Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?," Public Utilities Fortnightly, April 2010 and "Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid," Public Utilities Fortnightly, May 2010; and J.F. Wilson, "Review of CETO Methodology: LDA LOLE Criterion ('One Day in 25 Years'), presentation to RAAS, April 7, 2011.

includes an evaluation of how well RPM is meeting that goal, not the reliability target that RPM is designed to achieve. However, given the concerns articulated by stakeholders, we recommend that PJM consider re-examining the economic efficiency and cost-effectiveness of RPM reliability targets, in particular the methodology to determine LDA-specific reliability targets.

We also recommend that PJM increase the transparency and stakeholder understanding of the load forecasting process. However, we address load forecasting separately, in Section VI.B of our report, since increasing the transparency of the load forecasting process and increasing market participants' understanding of load forecasting uncertainties would also increase RPM price transparency and reduce RPM-related risks associated with load forecasts as one of the main administratively-determined RPM parameters.

1. The Use of RTO-wide Reliability Targets to Define the VRR Curve

On an RTO-wide basis, the VRR curve is anchored at the target reserve margin plus one%. The target reserve margin is based on a reliability target defined as a 1 day in 10 years Loss of Load Expectation (LOLE). The reasonableness of the 1 day in 10 year standard was reaffirmed by FERC earlier this year.[92] However, the FERC order also emphasized that "the one day in ten years criterion is one common approach for resource adequacy assessment, and by approving this regional Reliability Standard, the Commission does not establish the one day in ten years criterion to be the de facto, or the only acceptable metric for resource adequacy assessment."[93] The Commission further noted that it did "not disagree with commenters' arguments that the one day in ten years criterion could be improved."[94] Some PJM stakeholders also suggested that the standard should be improved, particularly because the economic rationale for the current standard has not been widely discussed. Moreover, stakeholders' doubts about the reliability standard itself seem to undermine their confidence in the efficiency and cost effectiveness of RPM.

As we already noted in our 2008 RPM Report, cost-effective reliability targets will not be entirely independent of the cost of capacity. As the cost of capacity increases, customers presumably would be willing to accept a slightly lower level of reliability. In other words, the economically-efficient demand for reserve capacity will tend to decrease as the cost of that capacity increases—a relationship which can be expressed by a sloped demand curve for reserve capacity. This demand curve for reliability would procure, at least theoretically, an optimal reserve margin that decreases as the cost of adding capacity increases.

To assess this "demand" for reserve capacity and derive an economically-efficient reserve margin target would require a detailed assessment of the value of incremental planning reserves. Others have suggested that the value of additional reserves is equal to the customers' Value of Lost Load ("VOLL"), such that an optimal reserve margin could simply be derived by estimating VOLL, the degree to which additional capacity reduces the expected amount of customer curtailments (*i.e.*, the Expected Unserved Energy or "EUE"), and the cost of additional

---

[92] FERC Order No. 747, Planning Resource Adequacy Assessment Reliability Standard, 134 FERC ¶ 61,212 (issued March 17, 2011).

[93] *Id.* at ¶31.

[94] *Id.* at ¶32.

capacity.[95] However, this is not quite the case. The value of increasing planning reserve margin also includes a number of economic benefits in addition to reducing the amount of curtailed load.[96] As was seen during the California energy crisis, the primary economic consequence of reliability-related events is not necessarily the frequency or duration of firm load shed events, but excessively high power costs. Thus, the economic value of increased reserve margins also includes the high cost of emergency supplies procured or dispatched to avoid customer load curtailments as well as the insurance value of reducing the likelihood of extremely high-cost outcomes. For example, adding a combustion turbine to the system not only reduces the risk of curtailing load during emergency conditions, it also reduces production costs by allowing the dispatch of the turbine whenever the dispatch or opportunity cost of dispatching alternative resources would exceed the dispatch cost of the turbine—including high-cost imports, DR capacity with high dispatch costs, generation dispatched within their emergency limits, or energy-limited resources with high opportunity costs. In fact, these benefits of additional resources can be more important to the determination of economically efficient reserve margins than the value of VOLL, which is difficult to measure and ranges widely across customer types.

Unfortunately, these additional energy cost and risk mitigation benefits of higher reserve margins are also not yet widely understood. Moreover, an explicit analysis of the tradeoff between the marginal benefits and marginal costs of additional capacity is not routinely performed to determine reliability requirements.[97] We have recommended in our 2008 RPM Report that PJM and stakeholders examine the tradeoffs between reliability targets and the cost of new capacity as part of a broader re-evaluation of the level and application of current reliability criteria. While outside the scope of our RPM review, we believe such a study would still be helpful because it would (1) examine the tradeoff between the costs of incremental capacity and the benefits of that capacity including reliability, reduced energy costs, and reduced emergency purchases; (2) inform stakeholders about the value customers are receiving in exchange for paying for reserve capacity; (3) compare the 1-in-10 reliability standard to an economically efficient target; and (4) help determine the natural slope of the demand curve based on a cost-effective tradeoff between target reserve margins and the expected level of and uncertainty of in total reliability-related costs.

---

95 For example, see J.F. Wilson, "Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?," Public Utilities Fortnightly, April 2010 and "Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid," Public Utilities Fortnightly, May 2010; R. Borlick, Comments in FERC Docket No. RM10-10, "Proposed Reliability Standard, BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation," December 27, 2011.

96 Carden, Pfeifenberger and Wintermantel, "The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On," National Regulatory Research Institute Report 11-09, April 2011.

97 We are aware of only a few examples of recent analyses to determine economically efficient reserve margins, including studies by Southern Company, the Tennessee Valley Authority, and Louisville Gas & Electric.

2. The 1-in-25 Standard for Setting LDA-Level Reliability Targets

Stakeholders have raised concerns specifically about the reasonableness of the reliability standard that is applied to individual LDAs.[98] The LDA-level reliability requirement based on the 1-day-in-25 years standard also is a major determinant of RPM auction outcomes within LDAs and—in interaction with other administrative parameters such as CETL, transmission planning decisions, and load forecasts—a significant factor contributing to administrative uncertainty of LDA capacity prices.

As we explained in our 2008 RPM Report, reliability targets within individual LDAs, which define LDAs' transmission import objectives (CETO), are set based on an LOLE of 1 day in 25 years. This is a *conditional* LOLE, because the LDA's imports are treated as if they were 100% available, in spite of the fact that neither the transmission capability into the LDA nor PJM generation outside the LDA is guaranteed to be 100% available in actual operations. The *unconditional* LOLE for the PJM footprint is 1 day in 10 years, which includes the possibility that generation supply is inadequate (but assuming unlimited transmission within the PJM footprint). This means that within an LDA the combined LOLE target is approximately the sum of (1) one day in ten years; plus (2) one day in 25 years; plus (3) the LOLE associated with transmission line outages or derates.[99] This means that within transmission constrained LDAs, the total LOLE is at least 1.4 days in ten years,[100] depending on the transmission dependence of the LDA.

We recommended in our 2008 RPM Report that PJM evaluate whether the 1-in-25 year conditional LOLE target, which is invariant with the transmission dependency of individual LDAs, is reasonably optimal. We understand that PJM is already in the process of reviewing the 1-in-25 standard with its stakeholders and recommend continuation of this effort.

It is likely that a more refined determination of LDAs' LOLE targets would result in targets that vary with the degree of each LDA's import dependence. Presumably, an LDA that is highly reliant on imports would have a more stringent target (recognizing that the assumption that imports are 100% available is particularly optimistic) than an LDA that is less dependent on imports. A more refined determination of LDAs' reliability requirements may be achievable by studying PJM-wide resource adequacy through multi-area reliability simulations that consider the reliability of transmission import capabilities and simultaneously determine both footprint-wide and LDA specific LOLE levels. Such multi-area reliability modeling could also be combined with economic reliability simulations that would assess the economic tradeoffs between the cost and value of additional reliability.

---

[98] J.F. Wilson, "Review of CETO Methodology: LDA LOLE Criterion ('One Day in 25 Years')", presentation to RAAS, April 7, 2011.

[99] See PJM (2011x), Section 4.

[100] 1/10 + 1/25 = 0.14 days per year = 1.4 days in 10 years.

IV. ANALYSIS OF NET COST OF NEW ENTRY

In this section of our report we analyze the Net Cost of New Entry (Net CONE) as used in RPM. We first present the results of our concurrent study updating engineering-based estimates for the gross cost of new entry (CONE) for the 2015/16 delivery year. Detailed documentation of these CONE estimates is provided in our separate report and associated data files. We present here the summary of our recommended CONE estimates for simple-cycle and combined-cycle plants for each of the five PJM CONE Areas.

We provide these CONE estimates for consideration by PJM and stakeholders according to the PJM Tariff, which requires that CONE be fully reevaluated every three years while the other years are updated by trending the previous CONE estimate based on the Handy-Whitman index.[101] The new CONE estimates, if adopted, would be used as a key parameter defining the VRR curve and as inputs to mitigation thresholds under the Minimum Offer Price Rule (MOPR).

Section IV.B analyzes the energy and ancillary services (E&AS) offset used in determining Net CONE. We examine the accuracy of the administratively-determined historical E&AS offset compared to the E&AS margins actually earned by generating units similar to the reference technology. We also evaluate two potential changes to the E&AS methodology, including: (1) whether the E&AS offset should be a backward-looking, forward-looking, or equilibrium estimate; and (2) whether the new scarcity pricing mechanisms, when implemented, would warrant any adjustments to the E&AS approach including possible true-up mechanisms.

Finally, this section of our report briefly examines the prices at which new generating units have offered into RPM to evaluate the feasibility of determining Net CONE empirically based on these offer data.

A. GROSS COST OF NEW ENTRY

Updated CONE estimates are needed once every three years for PJM and stakeholder review. These estimates, if adopted, would be used for two purposes: (1) to calculate Net CONE (in conjunction with the administratively-determined E&AS offset) to define the price points of the VRR curve; and (2) as the basis for calculations to screen for and mitigate capacity offers from new generators that may be uncompetitively low according to the MOPR, as discussed further in Section VI.E. The detailed engineering cost study summarized here is presented in our separate report, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM* (CONE Report).

After summarizing the results of our CONE Report, we explain our recommendation to continue using a combustion turbine (CT) as the marginal resource type to be used as the reference technology for estimating Net CONE. We also examine the implications of using a "level-nominal" versus a "level-real" cost annualization method for determining CONE. We recommend that PJM and stakeholders consider transitioning to a level-real approach to reflect projected escalation in future CONE values and associated market prices due to continued

---

[101] See PJM (2011q), pp. 2278-2280.

escalation of the capital cost of new plant. This recommendation, however, is contingent upon combining it with our recommendations to calibrate the E&AS offset (Section IV.B) and increase the cap of the VRR curve to address identified RPM performance concerns (Section V).

1. Levelized Cost Estimates of a New Simple-Cycle and Combined-Cycle Plant

As discussed in the CONE Report, our effort to estimate the levelized costs of new entry includes:

- A screening and siting study to determine the appropriate technology type and county to use as the basis for our cost estimate in each CONE Area;
- Details on the reference plant performance and technical specifications;
- An engineering cost estimate by CH2M HILL of the plant-proper engineering, procurement, and construction (EPC) costs and major equipment costs;
- Owner's costs incurred during project development, construction, and operations;
- An estimate by Wood Group of the ongoing fixed operations and maintenance ("FOM") costs that would be incurred by such a plant; and
- A study of the appropriate cost of capital for a merchant developer in PJM, for use in annualizing plant capital costs.

Here we simply summarize (1) the selected plant specifications that were used as the basis for developing our estimates and (2) the resulting capital costs of that study in comparison with the most recent previous CONE studies.

Table 14 and Table 15 contain the summary siting and plant specifications used as the basis for the CT and CC CONE estimates in each CONE Area. To determine the site locations shown in Table 14 we first selected locations with access to high voltage transmission infrastructure and at least one major gas pipeline. Among counties with sufficient infrastructure, we identified both the locations with the highest number of gas CCs and CTs recently built or under construction, and whether industrial land is currently available in those locations. Site selection for the SWMAAC CONE Area proved more difficult due to both a lack of recent new entrants (or units under construction) and a lack of vacant industrial land in many parts of Maryland. For SWMAAC we selected Charles County, Maryland based on: (1) gas and electric infrastructure availability; (2) the availability of vacant industrial land as indicated by property listings; and (3) Charles County is the location of the only permitted large gas facility proposed in SWMAAC, which is the 640 MW CPV St. Charles project.[102]

[102] Data on recent gas CC and CT builds based on Ventyx (2011).

Table 14
Site Specifications for CONE Estimates by CONE Area

CONE Area	Sited Plant Location		Interconnection	Gas Pipeline Infrastructure Available
	County	*Zone*	*(kV)*	
1 Eastern MAAC	Middlesex, NJ	JCPL	230	Transco, Texas Eastern
2 Southwest MAAC	Charles, MD	PEPCO	230	Dominion Cove Point
3 Rest of RTO	Will, IL	COMED	345	ANR, NGPL, Midwestern, Guardian/Vector
4 Western MAAC	Northampton, PA	PPL	230	Transco, Columbia
5 Dominion	Fauquier, VA	DOM	230	Transco, Columbia, Dominion

Source: CONE Report, pp. 8.

The reference plants' technical specifications are summarized in Table 15. CH2M HILL used these plant specifications as the basis for engineering estimates of plant construction costs. These specifications were chosen to most closely reflect the types of projects that have been built recently or are currently under construction. Design details, such as the type of environmental controls and dual-fuel capability, were based on both an analysis of recent plant additions and an assessment of environmental compliance requirements.

The chosen simple-cycle reference technology is a plant with 2 GE 7FA.05 turbines, fitted with selective catalytic reduction (SCR) in all CONE areas other than Dominion. The net summer capability of these CT plants is 390 MW (392 MW without an SCR). The combined-cycle reference technology is a 2×1 plant using GE 7FA.05 turbines, fitted with an SCR. The net summer capability of these CC plants is 584 MW at baseload or a maximum 656 MW when duct firing. For both the CC and CT, all facilities are equipped with dual-fuel capability in all locations except CONE Area 3 representing the unconstrained RTO (*i.e.*, western portions of PJM). We also provide estimates for adding dual-fuel capability in CONE Area 3 and adding SCRs in the Dominion CONE Area.

The installed and annualized cost estimates for these reference CT and CC plants are presented in Table 16 and Table 17 in 2015 dollars. These tables also compare our results with the most recent PJM CONE studies conducted by Power Project Management, LLC in 2008, inflation adjusted to 2015 dollars. The overnight capital cost estimates in these tables include all EPC contractor costs, major equipment costs, and other owner's costs incurred during project development and construction. The majority of these capital costs were estimated by CH2M HILL using the same cost estimation methods that they apply when bidding on projects as an EPC contractor. We independently developed a subset of owner's capital costs that are not included in the CH2M HILL estimates, including electric and gas interconnection costs based on costs actually incurred by recent projects. Estimates of ongoing fixed O&M costs are based on O&M fee estimates from Wood Group and our own estimates of other owner's costs, such as plant insurance and property taxes.

Table 15
Plant Technical Specifications for the Reference CC and CT

Plant Characteristic	Simple Cycle	Combined Cycle
Turbine Model	GE 7FA.05	GE 7FA.05
Configuration	2 x 0	2 x 1
Net Plant Power Rating	CONE Areas 1-4 (w/ SCR): 418 MW at 59 °F 390 MW at 92 °F CONE Area 5 (w/o SCR): 420 MW at 59 °F 392 MW at 92 °F	Baseload (w/o Duct Firing): 627 MW at 59 °F 584 MW at 92 °F Maximum Load (w/ Duct Firing): 701 MW at 59 °F 656 MW at 92 °F
Cooling System	n/a	Cooling Tower
Power Augmentation	Evaporative Cooling	Evaporative Cooling
Net Heat Rate (HHV)	CONE Areas 1-4 (w/ SCR): 10,094 btu/kWh at 59 °F 10,320 btu/kWh at 92 °F CONE Area 5 (w/o SCR): 10,036 btu/kWh at 59 °F 10,257 btu/kWh at 92 °F	Baseload (w/o Duct Firing): 6,722 btu/kWh 59 °F 6,883 btu/kWh 92 °F Maximum Load (w/ Duct Firing): 6,914 btu/kWh at 59 °F 7,096 btu/kWh at 92 °F
NOx Controls	Dry Low NOx Burners Selective Catalytic Reduction (Areas 1-4) Water Injection for DFO (Areas 1-2, 4-5)	Dry Low NOx Burners Selective Catalytic Reduction Water Injection for DFO (Areas 1-2, 4-5)
Dual Fuel Capability	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)	Single Fuel (Area 3) Distillate Fuel Oil (Areas 1-2, 4-5)
Blackstart Capability	None	None
On-Site Gas Compression	None	None

Sources: CONE Report, pp. 18.

Estimating the annual revenues required to cover the investment and other fixed costs of a new plant requires translating the plant's investment costs into annualized costs. In a regulated cost-of-service environment, this stream of annualized costs is based on accounting costs, including depreciation expenses, debt service expenses, taxes, and the allowed return on equity. In restructured, competitive markets, annualized costs are often based on what is referred to as "levelized" costs. Levelized costs are calculated such that receiving net revenues equal to these levelized costs over the cost-recovery period (here 20 years) provides sufficient funds to recover the investment, a return on the investment, taxes, and other fixed costs. Such levelized costs are often the basis for the contract price in long-term power purchase agreements, which may be structured as annual payments that are constant over the contract duration or as annual payments that increase over time. Such contract escalation rates are often tied to the expected inflation rate.

A calculation of levelized capital costs requires an estimate of generation developer's financing costs. We recommend financing parameters consistent with the costs of a merchant generator using balance sheet financing without a long-term power purchase agreement (PPA). To the extent generation projects would be developed with long-term contracts, this would reduce overall financing costs because investment-related risks would be transferred to the contract counterparty. As discussed in Section III.C, the lower risk with a PPA reduces financing costs because it allows for financing with a higher proportion of debt and reduces the costs of project-related debt and equity. However, the financing costs of such a highly-leveraged project would be inappropriate as a benchmark for determining the cost of new entry. We believe CONE estimates should represent the costs of a merchant plant exposed to the revenue uncertainty in PJM's capacity market.

As documented in our CONE Report, we estimate these financing costs of a merchant plant to be equal to an 8.5% after-tax weighted average cost of capital. This is equivalent to 50 percent debt and equity financing at a 12.5% cost of equity, a 7.5% cost of debt, and an approximately 40% combined federal and state tax rate.[103] As shown in our CONE Report, this cost of capital estimate is derived for a sample of publicly-traded merchant generation companies and is consistent with financing cost data from a number of independent sources, including fairness opinions prepared by investment banks in the context of recent mergers and acquisitions. In addition to these cost of capital estimates and discussed further in our CONE Report, levelized cost estimates are based on a cost recovery period of 20 years, Modified Accelerated Cost Recovery System ("MACRS") schedules consistent with industry practice and the previous PJM CONE studies,[104] and our estimate of a 2.5% long-term inflation rate.

Table 16
Installed and Levelized Cost Estimates for 2015/16: Reference <u>Combustion Turbine</u>

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CT CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4	n/a
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8	n/a
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Dominion estimate excludes an SCR; with SCR CONE increases to $100.8/kW-year level real and $120.6/kW-year level nominal.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $110.7/kW-year level real and $132.5/kW-year level nominal.

PPM's estimates from Power Project Management (2008).

PPM's numbers are escalated according to historical inflation over 2008-2011 and at 2.5% inflation rate over 2011-2015, see CONE Report Section VI.A.

103 We use slightly different cost of capital rates in different states consistent with the state income tax rate in each location.

104 See, for example, Power Project Management (2008) and Pasteris (2011).

Table 17
Installed and Levelized Cost Estimates for 2015/16: Reference Combined Cycle Plant

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CC CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$621.2	656	$947.5	$16.7	8.47%	$140.5	$168.1	$179.6
2 Southwest MAAC	$537.2	656	$819.3	$16.6	8.49%	$123.3	$147.5	$158.7
3 Rest of RTO	$599.0	656	$913.5	$16.0	8.46%	$135.5	$162.1	$168.5
4 Western MAAC	$597.4	656	$911.1	$15.8	8.44%	$135.1	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6	n/a
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7	n/a
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $138.9/kW-year level real and $136.3/kW-year level nominal.

Pasteris Energy's 2011 CONE estimates were used as the basis for the CC CONE estimate for the 2014/15 delivery year, see Pasteris Energy (2011), pg. 55.

Pasteris Energy's numbers are escalated at 2.5% inflation rate, see CONE Report Section VI.A.

Table 16 and Table 17 report two sets of levelized cost estimates, one based on "level-nominal" and the other based on "level-real" cost recovery. The level-nominal cost recovery reflects levelized payments that are constant over time in nominal dollar terms, which means they do not increase over time with factors such as inflation. In contrast, level-real cost recovery reflects levelized payments that are constant in inflation-adjusted real terms, which means they are assumed to increase with our estimated long-term average inflation rate of 2.5%.

PJM's calculation of CONE is currently based on the level-nominal approach, although level-real costs were used for the purpose of the MOPR until recent changes to MOPR switched to the level-nominal approach to annualize costs. As we explain in more detail below, we believe setting CONE equal to level-nominal costs will overstate annualized costs over time and, as a result, could lead to over-procurement under RPM—assuming administratively-determined E&AS offset are accurate.

2. Selection of Resource Type to be Used as the Reference Technology

We recommend maintaining a CT as the reference technology for the determination of Net CONE for purpose of defining the VRR curve based on several considerations. First, RPM is designed to achieve capacity prices approximately equal to prices one would expect in a long-run market equilibrium. Over time, multiple resource types will be needed including baseload, intermediate, and peaking units. In a market equilibrium, all of these resources will have the same Net CONE. As a result, the choice of reference resource type would not matter as long as the resource type is among those that are economically viable and Net CONE is accurately calculated.

Second, Net CONE for each resource depends on both Gross CONE and the E&AS margin the generating units can expect to earn. Of these two components, estimates of Gross CONE will tend to be more stable, less uncertain, and less dependent on administrative assumptions. Therefore, to minimize the impact of administrative assumptions and uncertainty, it is preferable to choose the economically-viable reference resource type with the lowest E&AS offset. We believe CT technology meets this consideration. While demand resources may have even lower E&AS margins than a CT due to even fewer dispatch hours, there is no standard DR "technology" and its capital costs cannot be determined reliably.

Finally, even if a different technology were to be more economic than a CT under current market conditions, it would be inappropriate to opportunistically switch technologies based on temporary market conditions. While this would reduce average Net CONE values, actual plants do not have an option to switch type, which means no plant would be able to fully recover its fixed costs in the long run unless additional adjustments were made.

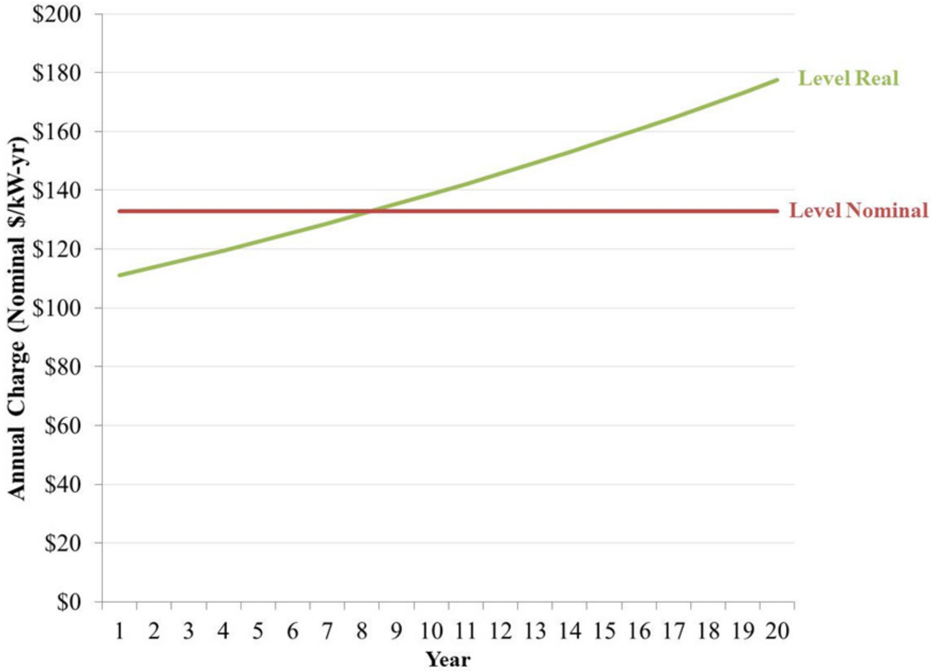
3. The Choice between Real and Nominal Cost Levelization

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how annual payments will likely be received over time to cover the investment and other fixed costs of generating plants in a market environment. Figure 14 shows two such possible time paths for our updated cost estimates of a CT in EMAAC as summarized in Table 16. It shows that "level-nominal" cost recovery implies constant annualized gross CONE of $134/kW-year ($367/MW-day) over the entire 20-year cost recovery period. In contrast, the "level-real" cost recovery path for the CT in EMAAC starts at an annual cost of $112/kW-year ($307/MW-day) in the first year, with expected payments in subsequent years increasing at the 2.5% rate of inflation. The present value of these two revenue streams is the same, both being exactly equal to the sum of investment and fixed O&M cost. This means both cost recovery paths provide for full recovery of all fixed costs, including financing costs.

Full cost recovery could also be achieved with cost recovery paths that deviate from the particular slopes of these level-nominal and level-real cost recovery paths. For example, a third levelization option could be based on technology-specific payment trajectory, such as the forecast inflation of CT plants rather than the economy-wide inflation.

The choice among level-nominal, level-real, and this third technology-specific cost recovery profile depends on how RPM-based capacity payments are expected to evolve. For example, if the cost of a CT plant is expected to increase with the rate of inflation—which would mean Net CONE estimates and offers by new entrants would increase at the same rate—investors would anticipate that, on average, RPM capacity prices would increase at that same rate as well. In this case, setting CONE equal to the level-nominal cost for each delivery year over time will over-compensate capacity resources over the course of their economic life. The annual average amount of overcompensation would be approximately equal to the difference between the starting values of the level-nominal and level-real cost recovery paths shown in Figure 14.

Figure 14
Comparison of Cost Recovery Paths for a New CT Plant



If, on the other hand, the cost of new plants and the associated CONE value are expected to increase over time at an average rate equal to the rate of inflation, then setting CONE equal to the starting point of level-real costs for each delivery year would, over time, result in a payment stream that matches the level-real cost recovery requirements exactly. Such an outcome, however, would only be possible if there are no offsetting factors, such as E&AS revenue losses of existing plants relative to increasingly more efficient new plants.

Because CT cost inflation net of E&AS losses relative to new plants may either fall short or exceed general inflation rates, setting CONE equal to level-real costs may under- or overcompensate resources over time. The level-real approach would *under*compensate plants over time if: (1) CT costs increase by less than inflation; or (2) CT costs increase with inflation but CTS built today experience E&AS revenue erosion relative to new CTs built in the future. The level-real approach, however, could *over*compensate if CT cost increases (net of E&AS revenue erosion) exceed general inflation rates. However, if CT costs net of E&AS revenue erosion are expected to increase at all over time, setting CONE equal to level-nominal costs will always overcompensate new plants over time.

To develop a recommendation concerning the choice between these levelization approaches, we have further explored these factors. We first compared the cost trends for CT and CC plants over time by comparing the annual increases of the Handy-Whitman index for turbogenerators with annual inflation rates from the consumer price index (CPI). As Table 18 shows, the annual average cost increases for turbine generators been approximately equal to inflation over the last 50 years, approximately 60 basis points above average inflation rates over the last 20 years, and approximately 150 basis points above inflation over the last 10 years. Note, however, that the rate of cost increase over the last 10 years has not been constant: CT costs have increased much faster between 2003 and 2008, but have decreased since then.

Table 18
Comparison of Inflation Rates and Average Annual CT Cost Increases

Period	U.S. CPI (%)	Handy- Whitman Index Steam Plant (%)	Handy- Whitman Index Turbogenerator (%)
1960 - 2010	4.07%	4.57%	4.09%
1990 - 2010	2.73%	3.43%	3.36%
2000 - 2010	2.48%	4.13%	4.02%

Sources and Notes:
U.S. CPI from U.S. Department of Labor (2011).
Handy-Whitman Index (2010).

We are not able to offer a forecast of the extent to which CT cost inflation will differ from general inflation, but we believe that the average rate over the last 20 years may be a useful proxy for the 20-year cost recovery period of new power plants. This would imply average anticipated plant cost increases of approximately 60 basis point above general inflation rates—although this historical rate may understate future CT cost increases. Some of the industry experts we consulted have expressed the opinion that, after the recent economy-related declines in plant costs, CT cost increases looking forward will likely continue to exceed general inflation rates due to the continued rapid demand growth for steel and power plants in large developing economies such as China and India. Increasing environmental requirements may further add to plant cost increases looking forward.

For the purpose of selecting a cost recovery path for determining CONE, we also analyzed the extent to which older plants may see an erosion of E&AS margins relative to the new plants over time. To assess this issue, we analyzed average heat rates for CT plants built over the last 20 years and found a linear trend of annual average heat rate decreases (*i.e.*, improvements) of approximately 100 Btu/kWh a year. We estimated that this rate of technological progress is equivalent to an E&AS revenue erosion rate of approximately 50 basis points (*i.e.*, 0.5 percentage points) per year. This means that CT cost increases at a rate slightly above average inflation rates (approximately 60 basis points per year) is almost entirely offset by the effects of E&AS erosion due to technological progress (approximately 50 basis points per year).

The net effect of these two offsetting factors means that new CT plants built today can be expected to achieve a cost recovery path that increases approximately at the rate of inflation. As a result, we believe that levelized carrying charges based on a level-real cost recovery are most appropriate for determining the annualized estimate of CONE. We recognize that PJM's current use of level-nominal charge rate (implicitly assuming level-nominal cost recovery) has been the result of extensive stakeholder and settlement discussions. The level-nominal carrying charge approach has also been approved by FERC. Nevertheless, we believe that the level-nominal approach to determining CONE, if combined with accurate estimates of E&AS margins, will result in the VRR curve being anchored at a level that exceeds the average annual cost recovery needs over new plants over time—the end result of which will be over-procurement of resources relative to the reliability target.

We thus recommend that PJM and its stakeholders consider transitioning from the current level-nominal CONE to a level-real CONE. A level-real approach to calculating carrying charges is more consistent with the historical escalation of new plant costs when adjusted for the improved performance of new plants. Continued increases in net plant costs can be expected to support increasing capacity market prices going forward and allow present-day developers to earn net revenues that grow with inflation (*i.e.*, at a constant rate in "real" dollar terms.)

This recommendation is contingent, however, on combining it with our recommendations that resolve two important factors: (1) the calibration of the current methodology for calculating the E&AS offset, which currently overstates the E&AS margins actually earned by comparable CT plants in eastern PJM and thus creates a downward bias in Net CONE estimates (see next subsection); and (2) the potential VRR curve performance concerns related to the use of historical E&AS averages (*e.g.*, if historical E&AS offsets were to spike due to anomalous weather or outages). As discussed in Section V, we recommend raising the price cap (defined as "point a" on the VRR curve), which is particularly important if PJM and stakeholders are unable to develop a forward-looking approach to calculating E&AS offsets.

If the approach to determining the administrative E&AS offset is not adjusted and the potential VRR performance concerns are not addressed, maintaining the current level-nominal carrying charges to determine CONE will help address—at least in part, though likely inefficiently—these other concerns. The same conclusion, however, does not apply for defining the offer threshold in the MOPR. We believe level-real annualization is more consistent with market fundamentals and competitive bidding behavior. As a result, we recommend against retaining the level-nominal approach for CC and CT offer thresholds under the MOPRs.

4. Summary of CONE Recommendations

To summarize, we offer the following recommendations related to the choice and cost of reference technologies:

- ***Reference Resource Type*** — We recommend maintaining a CT as the reference technology for the determination of Net CONE in the VRR curve.

- ***Reference CT and CC Design Features*** — We recommend the CC and CT design features based on an analysis of PJM and U.S. plants currently under construction and the requirement that new plants are capable of meeting likely upcoming NO_X emissions standards. As discussed in more detail above our recommendations include:

    CT — A 390 MW summer capability greenfield plant with 2 GE 7FA.05 turbines with selective catalytic reduction ("SCR") for NO_X controls (but no SCR in the Dominion CONE Area), and evaporative cooling for power augmentation.

    CC — A 2x1 plant using GE 7FA.05 turbines, a cooling tower, SCR, duct firing and evaporative cooling for power augmentation, and a total summer capacity of 656 MW, of which 72 MW is associated with duct firing.

We also offer the following recommendations related to levelized gross CONE values:

- ***Financing Assumptions*** — We recommend using updated financial assumptions to calculate annualized gross CONE. They reflect a merchant generator using balance sheet financing without a power purchase agreement (PPA), using an 8.5% after-tax weighted average cost of capital and 20 year cost recovery as discussed above.

- ***Recommended Levelized Gross CONE estimates for a CT*** — The level-real estimate of gross CONE for a CT and the 2015/16 delivery year in EMAAC is $112/kW-year ($306/MW-day). Based on level-nominal cost recovery, our estimate of gross CONE is $134/kW-year ($367/MW-day). This compares to the inflation-adjusted, currently-used, level-nominal CONE value of $142/kW-year ($389/MW-day). Results for other CONE Areas are provided in Table 16.

- ***Recommended Levelized Gross CONE estimates for a CC*** — Our updated 2015/16 level-real gross CONE estimate for a CC and the 2015/16 delivery year in EMAAC is $141/kW-year ($385/MW-day) based on level-real annualization. Our level-nominal estimate of gross CONE is $168/kW-year ($461/MW-day), compared to the inflation-adjusted, currently-used value of $180/kW-year ($492/MW-day). Results for other CONE Areas are provided in Table 17.

- ***Levelization Method*** — We recommend that PJM and stakeholders consider transitioning from the current "level-nominal" to a "level-real" levelization approach. This is consistent with average CT cost inflation over the last 20 years (inflation plus 60 basis points) net of an offset from heat rate improvements (approximately 50 basis points). Our recommendation for CT costs to define the VRR curve is contingent on combining it with our recommendation related to the E&AS offset and potential VRR curve performance concerns as discussed below. Our recommendation to transitioning to a level-real approach for MOPR purposes is not contingent upon adopting other recommendations.

B. ENERGY AND ANCILLARY SERVICE OFFSET

To determine Net CONE for the purpose of "anchoring" the VRR curve, the administratively-determined CONE value is reduced by the E&AS offsets earned by the reference technology. This E&AS offset represents an estimate of the "margin" (revenues in excess of variable generation costs) that a new entrant with the reference technology earns from the sale of energy and ancillary services. Under current RPM rules, E&AS offsets are calculated as a three-year average of estimated historical margins for the reference technology.

We address three key questions related to the administrative E&AS offset: (1) How accurate is the administrative calculation of E&AS margins relative to what is actually earned by generators similar to the reference technology? (2) Should the offset be based on a historical or a forward-looking estimate? And (3) how should administratively-set scarcity prices be accounted for in the E&AS offset?

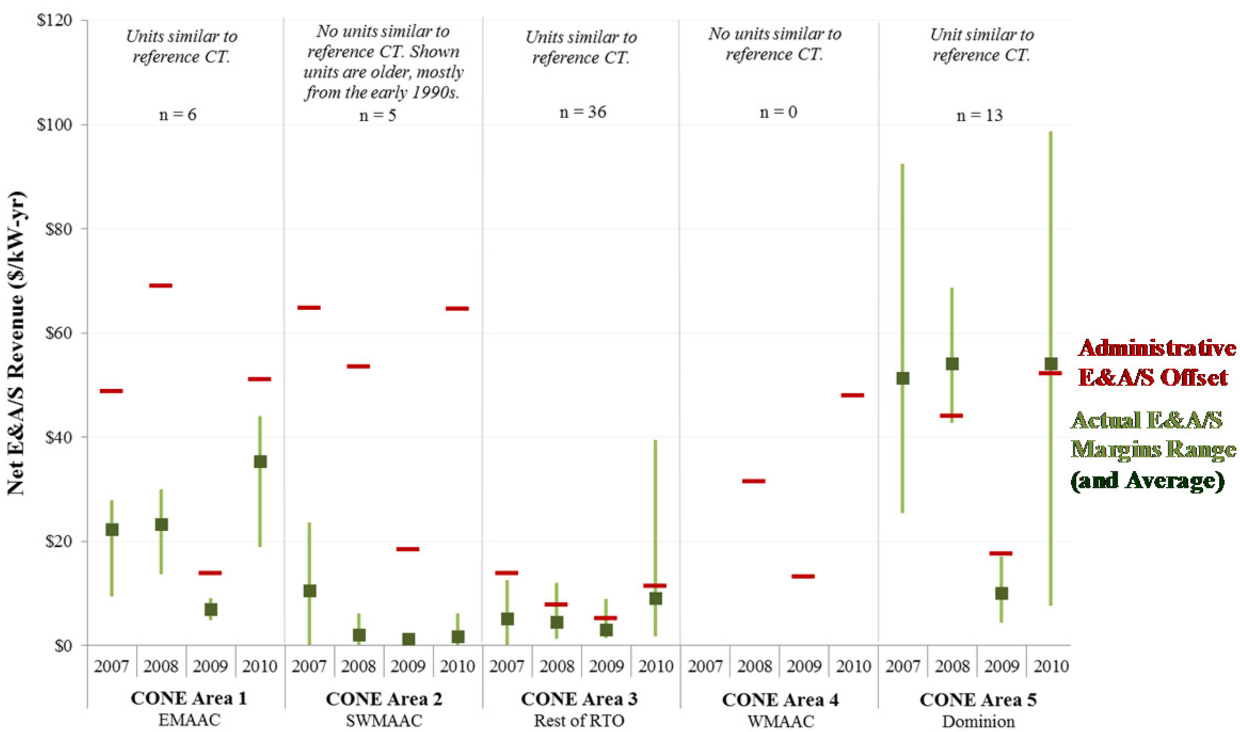
As we explain in more detail, we find that the methodology used to determine the E&AS offset significantly overstates E&AS margins and recommend adjustments to align the E&AS offset more closely with actual E&AS margins. We are also concerned about price volatility and poor price signals associated with relying on historical E&AS offsets, and we recommend that PJM and its stakeholders continue to explore options for forward-looking or an "equilibrium-based" E&AS offset methodology. Finally, we recommend against any netting or other adjustments to energy scarcity revenues actually earned in the energy market.

1. Accuracy of Administrative Historical E&AS Offset

PJM's methodology to estimate E&AS margins uses the "Peak-Hour Dispatch" method and a set of assumptions regarding heat rates, costs, and fuel prices.[105] Under the "Peak-Hour Dispatch" method, the reference resource may be dispatched into the real-time energy market in four independent, four-hour blocks (between hour ending 8:00 and hour ending 23:00) each day. Each block is dispatched if the average real-time LMP is high enough to cover the cost of operation for at least two hours in the given block. The resulting simulated generation pattern and the corresponding revenues net of operating costs yield the E&AS offset for the reference resource.

Figure 15 compares the administratively-determined E&AS offset for CTs with the E&AS margins actually earned by CT units similar to the reference resource in each CONE area. Figure 16 shows the same comparison for CC plants. These comparisons show that the administrative calculation of the E&AS offset determined for historical years has been substantially higher than the E&AS margins actually earned by comparable plants during these years.

Figure 15
Administratively-determined and Actual E&AS Margin of Combustion Turbine Plant

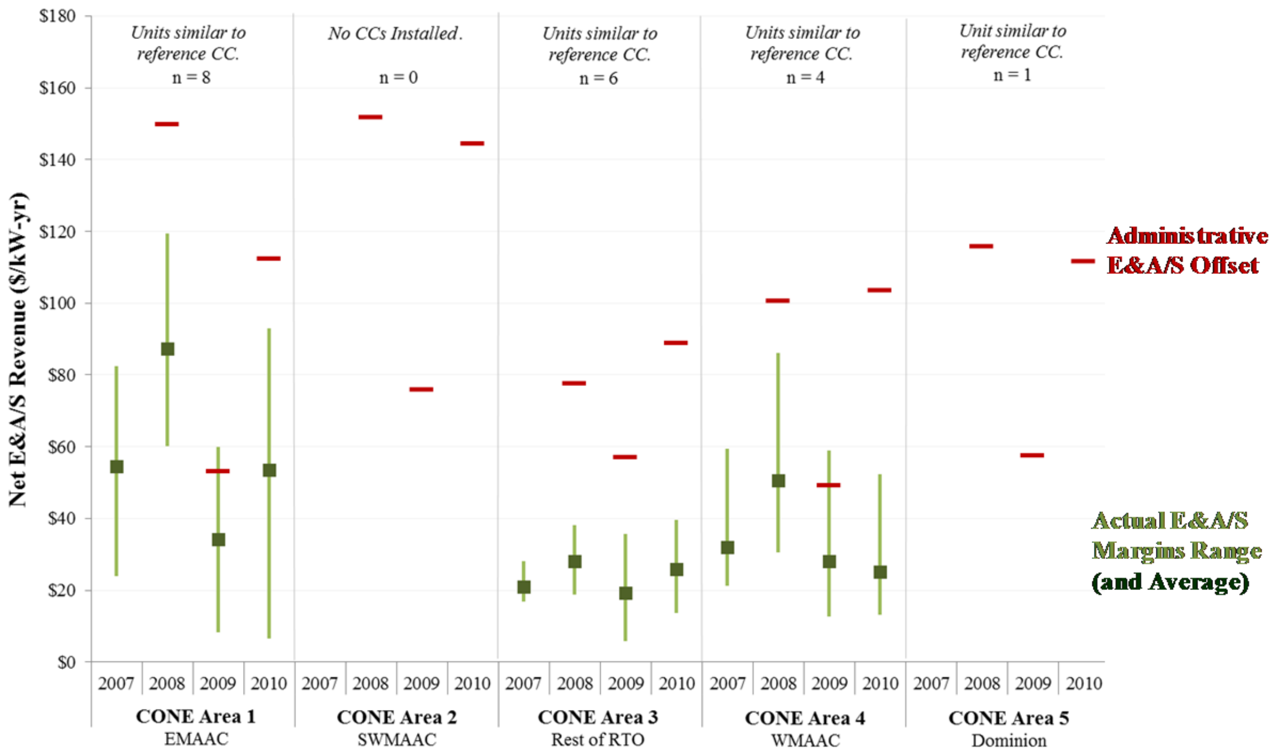


As shown in Figure 15 for CT plants, the administrative offset is substantially higher than actual CT margins in EMAAC and higher than all but the highest margins for some of the plants in the Rest of RTO Area. The E&AS offset for CTs is relatively accurate in Dominion. New CT plants comparable to the reference technology are not available in the other CONE Areas, but actual E&AS margins earned by older CT plants in SWMAAC and WMAAC suggest that the

105 The E&AS calculations assume a heat rate of 10,500 BTU/kWh, variable O&M expenses of $5/MWh, $2,254/MW-year ancillary service revenues, and use actual fuel and hourly electricity prices.

administratively-determined E&AS offset may be significantly overstated in SWMAAC but approximately right in WMAAC.

Figure 16
Administratively-determined and Actual E&AS Margin of Combined-Cycle Plant



The discrepancy between administratively-determined E&AS offsets and actual E&AS margins is shown in Figure 15. This discrepancy is likely driven by three main factors: (1) the peak-hour dispatch methodology only uses real-time prices, which is not consistent with the fact that the majority revenues are obtained through day-ahead commitments, even for CTs; (2) the E&AS offset for CTs is determined based on the average LMP for the zone in the CONE region for which the gross CONE value was developed, which may not be representative of locations where plants are actually built; for CCs (used for MOPR purposes) the E&AS offset is based on the highest-priced zone within the CONE Area, which is not necessarily a location where generators are able to site new plants or build them at a cost-effective rate; and (3) dispatch costs of actual plants may be higher than estimated for a variety of reasons.

The first of these three factors may account for a significant portion of the observed differences. It is generally understood that CC plants earn most of their revenues in the day-ahead market. However, as PJM's independent market monitor has previously noted, even new CT plants similar to the reference technology earn only approximately 40% of their energy revenues in the day-ahead market,[106] compared to 100% assumed in the current dispatch methodology. The dispatch logic should attempt to replicate realistic participation in both the day-ahead and real-time energy markets.

[106] Joseph Bowring, "CT Revenues: Day Ahead vs. Real-Time," CMEC, September 29, 2009, p. 6.

In addition, based on preliminary research provided to us by PJM's independent market monitor, the actual dispatch costs of CTs and CCs may be higher than assumed in the administrative calculations due to factors such as penalty gas charges, fuel oil consumption of dual-fuel plants during periods of limited gas availability, and less efficient heat rates. Based on information provided by the IMM, for example, in some load zones with CTs that experience natural gas deliverability issues, average operating costs were 150 percent higher in 2010 due to fuel switching and the high cost of fuel oil compared to natural gas. Actual E&AS margins may also be lower than estimated due to other plant-specific factors such as local transmission limitations or operating limitations (*e.g.*, 24 hour minimum run times) which make dispatch less attractive and operations less profitable.

There are also some examples of CT and CC plants with actual E&AS margins that are close to or above the administratively-determined E&AS offset. On average, however, the available data suggests that the administratively-determined E&AS offset unrealistically overstates the E&AS margins actually available to new plants. All else equal, this will downward bias the VRR curve and lead to under-procurement of capacity resources relative to reliability targets. As discussed further in Section V of our report, discrepancies between the administratively-determined E&AS offset and the margins that market participants can actually expect to earn with new plants could also lead to outcomes in which the actual cost of new entry exceeds the cap of the VRR curve, deterring needed entry.

We therefore recommend that PJM and its stakeholders more fully evaluate and, if necessary, address the identified concern of overstated E&AS offsets. To avoid such overstated E&AS offsets, we recommend tying the administrative calculation of E&AS revenues more closely to the margins actually earned by resources similar to the reference resource in the day-ahead, real-time, and AS markets. This can be achieved by revising and calibrating the dispatch algorithm so that it accurately reflects actual units' revenues and operating costs within the respective CONE areas. A revised dispatch algorithm could address day-ahead versus real-time dispatch and possibly also improve operating cost and fuel type assumptions. Alternately, it can be achieved by calculating the E&AS offset directly from the net revenues of comparable new units (but avoiding distortions due to idiosyncratic factors affecting individual units).

The location of units and associated generation-specific LMPs used to determine the E&AS offset for each CONE area ideally should be selected using the same principle as in our CONE Report: based on locations that have been demonstrated to support new development, as evidenced by recent and ongoing development of actual plants. The availability of operational plants also enables calibration of the E&AS dispatch methodology. For areas that lack such units, such as SWMAAC, direct calibration may not be possible, but the dispatch algorithm calibrated to other areas could be applied.

2. Historical, Forward-Looking and "Equilibrium" E&AS Offsets

We noted in our 2008 Report that estimation errors for Net CONE have consequences for both reliability and customer costs, although these impacts are partially mitigated by the downward-sloping nature of the VRR curve. If the "true" cost of new resources is above the administratively-determined Net CONE, fewer resources will be procured through RPM than what is needed to meet reliability targets. If the true cost of new entry is below Net CONE, RPM will over-procure relative to reliability targets.

The E&AS offset strongly affects the accuracy of the Net CONE estimate. It is difficult to develop estimates that will be consistent with generation developers' actual expectations. As we also noted in our 2008 Report, Net CONE estimation errors are magnified by the use of a historical E&AS offset. This is because anticipated E&AS revenues will vary with market conditions that will not generally be consistent with the E&AS offset that PJM calculates based on historical data. Using an historical E&AS offset to determine Net CONE and the VRR curve can thus lead to uneconomic and inaccurate price signals. Moreover, as we discuss further in Section V of our report, our probabilistic analyses show that the use of a historical E&AS offset can lead to substantial performance deterioration of the VRR curve that can undermine investment incentives and make it difficult to achieve reliability targets. It also needs to be considered that historical E&AS offsets within constrained LDAs can significantly exceed anticipated future E&AS offsets, which may reflect reduced future congestion premiums caused by the planned construction of new generation and transmission upgrades into the LDA.

An E&AS offset can be consistent with developers' expectations only if it accounts for anticipated changes in market fundamentals. The current use of an administratively-determined E&AS offset based on a 3-year average of historical market conditions means that the data used to determine the offset is between four to seven years out of date relative to market conditions during the delivery year. The reliance on historical market conditions will also increase RPM price volatility and pricing discrepancies between LDA areas simply because the E&AS offset will be influenced by unusual historic market conditions, such as extreme weather or unusual generation and transmission outages. Such events can lead to spikes in the administratively-determined E&AS offset that not only lead to capacity price volatility, but are also are inconsistent with forward-looking market conditions even if there are no other material changes in market conditions. Even based on the RPM experience to date, which does not yet include any years of exceptionally challenging market conditions, the variance of E&AS offsets has been considerable. In SWMAAC, for example, the administratively-determined E&AS offset increased from $57/MW-day for the 2009/10 delivery year to $154/MW-day for the 2012/13 delivery year.

In addition, the reliance on actual historical market conditions can lead to capacity prices that undermine efficient investment incentives. For example, the most resource-constrained locations with the greatest investment needs will tend to have the highest energy market prices, which lead to high E&AS offsets. These higher E&AS offsets will lower Net CONE. If market participants' expected future E&AS margins are below these historical margins (for example, reflecting an expectation of resource additions or transmission upgrades), their true net cost of new entry will be above the administratively-determined Net CONE, which will mean fewer resources will be procured through the RPM mechanism. On the other hand, in locations with excess capacity, historical E&AS offsets will generally be low, which leads to a higher Net CONE and stronger investment incentives. In other words, the use of E&AS offsets based on historical market conditions will tend to reduce investment incentives in LDAs with higher investment needs while increasing investment incentives in LDAs with lower investment needs. Price spikes caused by shortages (even if only caused by unusual weather or outage conditions) reduce the administrative Net CONE and VRR curve exactly when and where new investments are needed most.

Such outcomes are not only a theoretical possibility. For example, during the last three BRAs the E&AS offsets for LDAs in eastern PJM were between $130-150/MW-day, which was approximately *$100/MW-day higher* than the E&AS offset for the rest of PJM. If the E&AS margin anticipated by market participants for eastern PJM was *half* the historical value, the VRR-curve-based price signal sent in the more constrained eastern LDAs would be understated by about $65-75/MW-day. In more extreme cases of high historical energy market prices due to unusual market conditions and resource needs, this potential disconnect between the historical administrative E&AS offset and the anticipated future E&AS margins of market participants could even result in outcomes where the true cost of new entry exceeds the cap of the VRR curve, which leads to RPM performance problems as further discussed in Section V.[107]

Options to mitigate some of the price distortions caused by the use of historical E&AS offsets based on actual market conditions include the use of (1) normalized forward-looking E&AS offsets that reflect normalized weather and outage conditions as well as anticipated resource additions; and (2) E&AS offsets estimated based on equilibrium market conditions, which would also reduce price distortions caused by temporary shortage or excess capacity conditions. Any form of forward-looking E&AS offsets would improve VRR curve performance and more stable capacity prices that better reflect anticipated market conditions.

One approach to estimating such forward-looking E&AS offsets would be to develop forecasts based on detailed market simulations, for example, by calibrating a simulation model to current market conditions and then modifying the data inputs to reflect changes in fuel prices, supply, demand, and transmission that will likely exist during the delivery year. We recognize, however, that FERC rejected PJM's proposal to develop its own forecasts on the basis that such forecasts may be too speculative. In addition, simulation-based forecasts may not be sufficiently transparent and reproducible by market participants. Nevertheless, an E&AS offset estimate consistent with "equilibrium market conditions" (rather than forecast or historical conditions) would stabilize the VRR curve and anchor it at a Net CONE level that is consistent with target equilibrium capacity prices and corresponding E&AS margins. (Such an equilibrium E&AS offset approach would also be consistent with Prof. Hobbs's probabilistic simulations of the settlement curve.) An alternative could be to develop estimates of forward-looking E&AS margins from forward prices for fuel and power. However, we also recognize that PJM and its stakeholders already explored this option in 2008 but were not able to identify an acceptable methodology.

In summary, we believe that the disadvantages of using an administratively-determined E&AS offset based on historical market conditions are significant. As a result, we recommend that PJM and its stakeholders continue to consider options to develop acceptable forward-looking or equilibrium-based methodologies to determine the E&AS offset. If a forward-looking offset cannot be developed, it is critical to increase the cap of the VRR curve to mitigate the most significant risks associated with historical E&AS offsets as discussed in Section V.

[107] For example, assume CONE=400/MW-day and the historical E&AS offset is $250/MW-day, such that the administratively-determined Net CONE = $400 - $250 = $150/MW-day. The VRR curve would be capped at $225/MW-day or 1.5×Net CONE. If the anticipated future E&AS margin was only $150/MW-day (*e.g.*, due to anticipated resource additions relative to the historical period and unusual weather and outage conditions during the historical period), the "true" net cost of new entry would be $250/MW-day (*i.e.*, $400-150).

3. Scarcity Pricing and Energy True-Up Options

As discussed above, we recommend that the E&AS offset reflect E&AS margins earned by a CT plant under equilibrium or expected normalized forward conditions. This should include margins associated with price spikes and administratively-determined scarcity pricing. We do not recommend excising scarcity prices from the administratively-determined E&AS offsets (thus raising Net CONE and capacity prices); nor do we recommend netting out any scarcity prices actually earned in the delivery year, as suggested by the IMM.[108] Doing so would reduce incentives for resources to perform during actual scarcity conditions when they are needed most. It would also distort price signals for capacity resources that are dispatched more often or less frequently than the reference technology for which CONE and E&AS offsets are determined. Instead of reducing E&AS volatility by excluding scarcity events from the determination of the E&AS offset, we recommend in Section V options for refining the VRR curve to mitigate the most significant risks associated with the higher volatility of historical E&AS offsets.

4. Summary of E&AS Offset Recommendations

As discussed above, we recommend that PJM and its stakeholders consider the following recommendations:

- ***Increase the Accuracy of the E&AS Offset*** — We recommend that the calculation of the E&AS offset be improved to better reflect actual E&AS margins earned by plants similar to the reference unit through either (a) calibrating the dispatch algorithm so that it accurately reflects actual units' net revenues (e.g., significant participation in day-ahead markets even by CTs) or (b) that the E&AS offset be calculated directly from the net revenues of comparable new units.

- ***Forward-Looking or Equilibrium Net CONE Estimate*** — We recognize that PJM and its stakeholders have previously explored developing a forward-looking E&AS offset but were not able to identify an acceptable methodology. However, we recommend that PJM and its stakeholders continue exploring options for forward looking or "equilibrium-based" E&AS offsets because these options would offer improved VRR curve performance and yield more stable capacity prices that better reflect future or equilibrium market conditions.

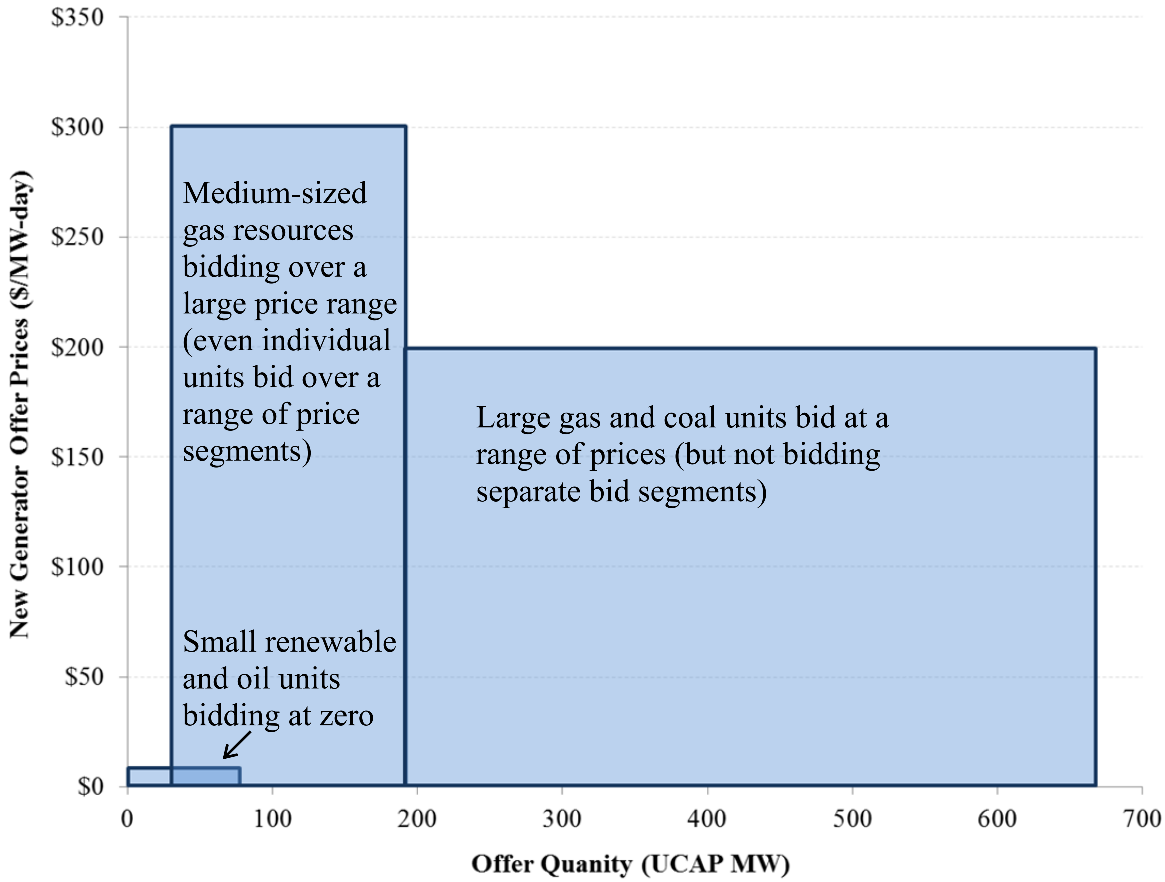
- ***Treatment of Scarcity Pricing*** — We recommend that the E&AS offset include the historical (if historical E&AS offsets continue to be used) or expected future level of scarcity revenues from the energy and ancillary service markets. We recommend against any netting or other adjustment of energy scarcity revenues actually earned in the energy market.

[108] Note, however, if scarcity events are excluded out in administratively-determined historical E&AS offsets, it would also be necessary to net out actual or typical margins earned due to scarcity prices during the delivery period. Implementing the former without the latter would overcompensate resources or lead to over-procurement.

C. Empirical Net CONE from Bid Data

We reviewed all offers for new generating units and found that offer levels vary substantially, with the overall range of these offer prices and sizes shown in Figure 4. Most of these bids are for small renewable and diesel resources that offered in at a zero price. However, natural-gas-fired generation projects have similarly submitted offers at a large range of prices, both above and well below Net CONE. Some individual units have even offered sections of their capacity over a large range of prices. Although we do not know the ultimate cost- or non-cost justification behind the wide range of bids for new natural gas units, offers seem to reflect a wide range of different bidding, hedging, and market-timing strategies. Based on these results of our analysis, we conclude that BRA offer data does not provide a sound basis for determining Net CONE empirically from offers for new resources.

Figure 17
Offers for New Generation in PJM



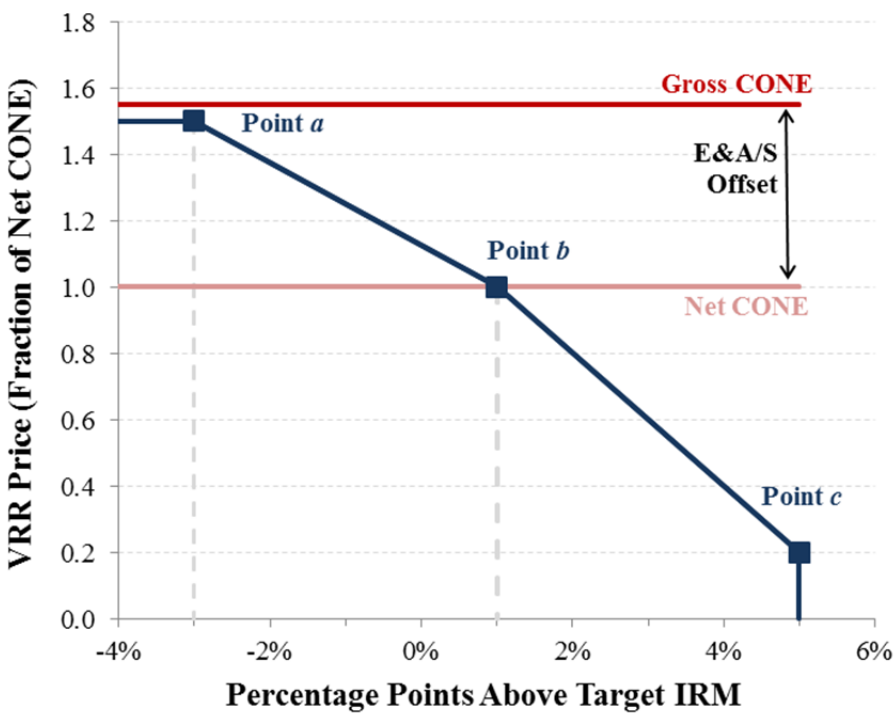
Sources and Notes:
Summarized from BRA and IA bid data, PJM (2011a).
Offer quantity is based on the total bid MW for each unit across all offer segments.
Offer price is the range of prices for each unit across all offer segments.

V. ANALYSIS OF VARIABLE RESOURCE REQUIREMENT CURVE

A. BACKGROUND

As explained in more detail in our 2008 report, the VRR curve represents the administratively-determined demand for capacity in the RPM auctions.[109] Figure 18 shows that the VRR curve, which was the result of settlement discussions among stakeholders, is anchored around point *b,* with the price equal to Net CONE and the capacity procured is at the target installed reserve margin ("IRM") plus 1 percentage point (IRM+1%).[110] From this anchor point, the VRR curve slopes upward and to the left until it is capped at point *a,* which is at a quantity of IRM - 3% and a price of 1.5 times Net CONE. For clearing prices below Net CONE, the curve drops to point *c*, at IRM + 5% and a price of 0.2 times Net CONE.

Figure 18
PJM Variable Resource Requirement (VRR) Curve



Sources and Notes:
Based on 2014/15 SWMAAC VRR curve parameters, PJM (2011b).

---

109 See Pfeifenberger and Newell, *et al.* (2008), Section IV; PJM (2011d), Section 3.4.

110 That is, if the target installed reserve margin is 15.3% (as it was in the 2014/15 BRA), then the quantity at point *b* is equivalent to an IRM of 16.3%. This represents a procurement quantity of 0.9% on top of the reliability requirement based on the year 2014/15 parameters. The exact quantity calculation at point *b* is: Reliability Requirement · (100% + IRM + 1%) / (100% + IRM) – STRPT. See PJM (2011d), p. 19; (2011b).

During the first five BRAs, the VRR curve was shifted to the left of IRM+1% by the estimated amount of ILR resources obtained just prior to the delivery year. Since ILR was eliminated, starting with the BRA for the 2012/13 delivery year, the entire VRR curve is shifted to the left by the Short-Term Resource Procurement Target (STRPT). In the BRA, the STRPT is equal to 2.5% of the reliability requirement.[111]

In our 2008 RPM report, we evaluated the shape and performance of the VRR, both qualitatively and through simulations with a probabilistic model originally developed by Professor Benjamin Hobbs.[112] That analysis compared the VRR curve as currently implemented in RPM through a stakeholder settlement (the "Settlement Curve") with the VRR curve that was originally developed and filed by PJM with Prof. Hobbs's input and testimony (the "Original Hobbs Curve"). Our 2008 probabilistic simulation analysis evaluated: (1) the impact of conducting the auctions three versus four years ahead of delivery; (2) the impact of using historical average for the E&AS offset versus projected E&AS offset; (3) the impact of understating or overstating CONE; (4) the impacts of CONE changes due to changes in construction costs; and (5) the performance of the sloped VRR curve versus a vertical demand curve.[113] Based on these analyses, we previously offered a number of recommendations for further consideration by PJM and its stakeholders. These recommendations included maintaining the 3-year forward auction design, maintaining the shape of the VRR curve, and moving to a forward-looking E&AS offset.

In our current examination of the VRR curve, we evaluated the performance of the VRR curve qualitatively, with updated probabilistic simulations, and using scenario analyses of historical auction results. This led us to revisit some of the same questions we have previously examined as well as examining some additional questions as follows.

First, and perhaps most importantly, we address our previous finding that the Settlement Curve with a historical E&AS offset performed poorly in our probabilistic simulations in terms of long-term resource adequacy, which contributed to our previous recommendation to move to a forward-looking E&AS offset. Because the stakeholder process that explored this option in 2008 was not able to identify an acceptable forward-looking E&AS offset methodology, we now explore alternatives that would improve the performance of the Settlement Curve when using historical E&AS offsets.

Second, we examine the impact that the current point *a* definition has already had. We document that E&AS offsets have already problematically suppressed the VRR curve in constrained LDAs, which could have led to a failure to procure an adequate level of location-specific resources.

Third, we present updated results of our probabilistic simulations with the model developed by Prof. Hobbs. The results from these analyses document the poor performance of the Settlement Curve in combination with historical E&AS offsets. We also present simulation results for four alternative definitions of point *a* in the current VRR curve that could significantly improve the performance of the VRR curve.

---

111 The STRPT as a percent of the reliability target is 2% in the first incremental auction, 1.5% in the second incremental auction, and 0% in the third incremental auction.

112 For a description of the Hobbs model as developed and used to develop the original VRR curve, see Hobbs (2005, 2007).

113 See Pfeifenberger and Newell, *et al.* (2008), Section IV.C.

Finally, we explore the impact that a vertical demand curve or a flatter VRR curve would have had on RTO and LDA clearing prices during the first seven BRAs. We also explore whether less steep VRR curves applied to LDAs would be an effective tool to attract investment and reduce capacity price volatility within the LDAs. We document that price volatility experienced in BRAs to date would have been significantly higher with a vertical supply curve, but find that a more gradual VRR curve would not have significantly reduced capacity price volatility. We also recommend against applying a more gradual slope selectively in constrained LDAs because this would increase the risk of under-procurement without substantially reducing price uncertainty.

B. Impact of Historical E&AS Offset and Net CONE Estimation Error

In our 2008 simulations, we identified a number of concerns related to using a historical E&AS offset and the impact of potentially understated administrative CONE estimates. More specifically, we found that the use of historical E&AS averages could lead to "resonances" with highly unstable Net CONE values and result in high total costs, high price volatility, and poor reliability. We also found that the VRR curve performed poorly if the Net CONE value used to anchor the VRR curve was below the true value of Net CONE, causing reliability challenges, higher costs, and higher volatility as clearing prices more frequently reached the capped portion of the VRR curve.

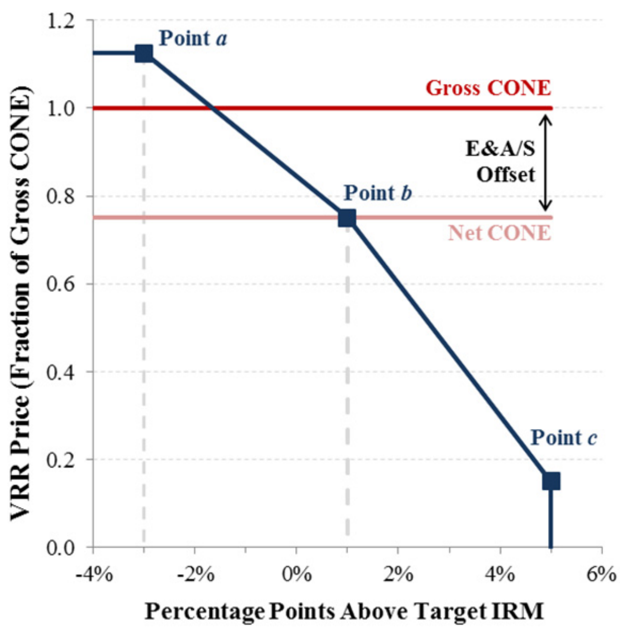
To address these concerns, we previously recommended that PJM and stakeholders consider: (1) determining the E&AS offset to gross CONE based on estimated future E&AS margins; and (2) whether restrictions to the magnitude of annual Net CONE changes should be introduced. A stakeholder process initiated by PJM subsequently explored options for forward-looking E&AS offsets, but found that proposed options were not sufficiently accurate, robust, or transparent enough to offer an acceptable alternative to using historical E&AS offsets. As we discuss in Section IV.B, we renew our recommendation to explore options for determining the E&AS offset based on either normalized forward-looking market conditions or based on estimated offset under "equilibrium market conditions." However, recognizing that a forward-looking E&AS offset methodology that stakeholders found acceptable could not be developed in 2008, we now also analyze other options for addressing the identified performance concerns of relying on the current Settlement Curve combined with historical E&AS offsets.

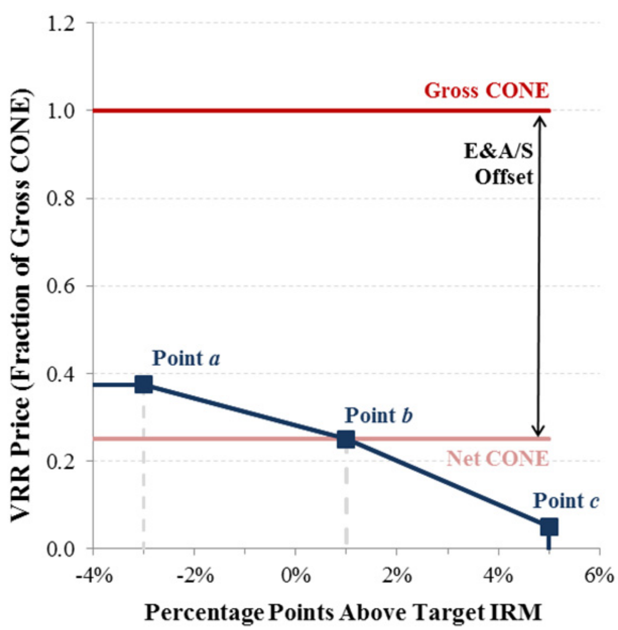
Our first step was to develop a better understanding of why reliance on historical E&AS averages resulted in poor performance in terms of simulated cost and reliability outcomes. We found that the poor performance of the Settlement Curve in simulations with a historical E&AS offset were primarily a function of: (1) how the price cap at point *a* of the VRR curve is defined and (2) how quickly Net CONE values can drop over time in response to volatile energy market conditions.

The VRR curve is currently capped at point *a* at 1.5 times Net CONE. Because Net CONE declines whenever historical E&AS offsets are high, the price cap (at point *a*) will decline 1.5 times as fast as the E&AS offset increases. In other words, the higher the historical E&AS offset, the lower the price cap and the slope of the VRR curve between points *a* and *b*. If the level of historical E&AS offset ever reaches or exceeds gross CONE, both Net CONE and the slope of the VRR curve will drop to zero. At that point the VRR curve, collapsed to zero, can no longer provide any incentive to add resources even if reserve margins drop well below the reliability target. Entry in this case would be solely a function of high and volatile E&AS margins. Even if the average E&AS offset is equal to CONE at that point, the system can become "stuck" at a reserve margin well below the reliability target because no additional investment incentives would be provided by the VRR curve to attract entry and move the system back to the target reserve margin.

The two panels in Figure 19 illustrate the shape and slope of the VRR curve for historical E&AS margins that are equal to 75% and 25% of gross CONE. It shows that if the E&AS offset is equal to 75% of gross CONE, such that Net CONE is only 25% of gross CONE, the VRR curve is capped at 38% of CONE. This also means that the difference between point *b* and point *a* is only 13% of CONE. This difference is well below the extent to which the administrative value of Net CONE (used to define point *b* of the VRR curve) can differ from the "true" Net CONE that suppliers may forecast for the delivery year. That is, the true net cost of entry could easily be higher than the price cap on a sustained basis or in a large fraction of years due to fluctuations in the energy market. If RPM prices are capped below the true net cost of new entry, the outcome will be fewer capacity additions and lower reliability.

Figure 19
VRR Curves with E&AS Offset Equal to 25% and 75% of CONE





Note: Procurement target is defined as the reliability requirement minus the short-term procurement target.

The potential for low reliability with the current VRR curve is exacerbated by the asymmetric nature of the curve. The VRR curve slope to the left of point *b* is flatter than to the right of point *b*, with prices rising only slowly in response to dropping reserve margins. Another asymmetry is that RPM prices can only rise 0.5 times above Net CONE, whereas they can drop as low as zero (*i.e.*, a level 1.0 times below Net CONE). The practical result of this asymmetry is that one should expect capacity prices to average at a level below Net CONE if the reserve margin were to be maintained. This means that reserve margins must drop below the target in order for the VRR curve to produce prices that are consistent with Net CONE on average over the long term. The fact that the VRR curve is anchored at the reliability target plus 1 percentage point helps offset some of this asymmetry in VRR curve slopes.

The historical E&AS offset used to determine Net CONE has ranged from a low of 9% of gross CONE (in the 2014/15 BRA for the unconstrained RTO) to a high of 48% of gross CONE (for the 2010/11 BRA in SWMAAC) since RPM was implemented. While this means that E&AS offsets have not yet reached levels close to CONE, the experience to date has not yet included delivery years with resource adequacy deficiency, unusual price spikes due to extreme weather conditions, or unusual generation and transmission outages that could increase the E&AS margins earned by a peaking plant to levels well above the value of gross CONE. As more demand response resources with high dispatch costs are added to the system, we also anticipate that the E&AS revenues of peaking plants will increase over time—which will flatten the VRR curve and increase the risk that the VRR curve collapses entirely and resource adequacy can no longer be ensured through RPM.

The definition of the current VRR curve cap may have been an inadvertent outcome of the VRR curve settlement. The curve originally filed by PJM, based on Prof. Hobbs recommendation, was capped at two times gross CONE minus the E&AS offset. This is equal to the sum of Net CONE *plus* gross CONE, which meant that the difference between points "a" and "b" was equal to CONE irrespective of the size of the E&AS offset.[114] The settlement reduced the cap (point *a*) to 1.5 times Net CONE, which is equal to 1.5 times gross CONE minus 1.5 times the E&AS offset.[115] The problem associated with the flattening VRR curve and the possibility that point *a* collapses to zero would not exist if the factor of 1.5 were only applied to the gross CONE portion. In other words, if point *a* was defined as "1.5×CONE – E&AS" instead of "1.5×(CONE – E&AS)," the difference between points *a* and *b* would be equal to 0.5×CONE and remain constant even if point "b" declined to zero.[116]

As discussed further below, the probabilistic simulations show that the performance deterioration of the Settlement Curve in assuring resource adequacy is very pronounced if a constant or forward-looking E&AS offset is replaced with a historical E&AS offset. However, because these simulations are quite stylized, it is not clear how high the risk of such outcomes would actually be under real-world conditions. Nevertheless, to reduce the risks of resource adequacy challenges due to a collapsing VRR curve or a VRR curve capped at a level below the true net cost of new entry, we recommend that PJM and its stakeholders reconsider developing a normalized forward-looking or equilibrium offset. If not, we recommend that PJM and its stakeholders consider and more fully evaluate the following combination of recommendations:

- ***Clarify that the value of Net CONE for purpose of defining points a, b and c of the VRR curve cannot be less than zero.*** In cases where historical E&AS offset would exceed CONE, Net CONE could become negative. This could inadvertently lead to negative capacity prices (*i.e.*, cleared resources, if any, would be charged for providing capacity). We believe this would not be a meaningful outcome. Of course, Net CONE could ultimately become *zero*, if continued entry of demand response resources resulted in increased E&AS margins for peaking resources to the point where the need for explicit capacity payments would be eliminated. Under such conditions, points *b* and *c* of the

[114] 2×CONE – E&AS = CONE + (CONE – E&AS) = CONE + NetCONE

[115] 1.5×NetCONE = 1.5×(CONE-E&AS) = 1.5×CONE – 1.5×E&AS

[116] If a = (1.5×CONE–E&AS) and b = NetCONE = (CONE-E&AS), then a-b = 1.5×CONE – CONE = 0.5×CONE

VRR curve and the associated capacity price should be allowed to become (and possibly remain) at zero without obtaining negative values.

- ***Increase the cap of the VRR curve.*** A more robust VRR curve would require a higher cap. We recommend redefining point *a* by setting it equal to point *b* plus at least 0.5×CONE, possibly to 1.0×CONE above point *b* as proposed in the originally-filed VRR Curve developed by Prof. Hobbs.[117] This would prevent the collapse of the VRR curve and outcomes well below reliability targets when the E&AS offset becomes anomalously high. It would also produce a steeper and more stable upward slope between points *a* and *b* compared to the current VRR curve (which defines point *a* as 1.5×NetCONE). The higher cap will also preserve resource adequacy by reducing the risk of deterring offers that may be temporarily above the current cap because the historical E&AS offset differs significant for expected future E&AS margins or due to errors in the Net CONE estimation). As discussed below, probabilistic simulations suggest that increasing point *a* to 0.5×CONE above point *b* would offset approximately 80% of the performance deterioration caused by combining the Settlement Curve with a historical E&AS offset.[118]

If the cap of the VRR curve cannot be increased, the identified performance risks could be addressed through a combination of (1) a floor for point *a* and (2) a limit on maximum annual reductions to Net CONE. Based on our probabilistic simulations, this floor for point "a" would need to be *at least* 0.5×CONE. Based on our probabilistic simulations, this floor would mitigate approximately *half* of the performance deterioration caused by combining the Settlement Curve with a historical E&AS offset. To further increase VRR Curve performance, the floor on point *a* would also need to be combined with cap on year-to-year *reductions* to Net CONE values. This would help reduce the likelihood that the VRR curve is suppressed below the true cost of new entry due to year-to-year fluctuations that do not reflect normalized forward-looking market conditions. To counteract the asymmetric nature of the VRR curve, no limit would apply to annual increases in Net CONE values. As discussed below, the simulation results indicate that the combination of a 0.5×CONE floor for point "a" and the 20% limit on downward annual Net CONE adjustments would also offset approximately 80% of the performance deterioration seen with the current VRR curve under historical offset simulation conditions.

We make the recommendation to increase point *a* of the VRR curve based on two considerations. First, our probabilistic simulations show that this significantly improves VRR curve performance. But second, the resulting difference between points *a* and *b* would, for the most part, also likely be large enough to exceed the range of likely discrepancies differences between *administratively-determined* Net CONE values (*i.e.*, based on administratively-determined CONE and administratively-determined historical E&AS margins) and *true* Net CONE values (*i.e.*, the actual cost of new entry less actual E&AS margins that suppliers forecast for the delivery year).

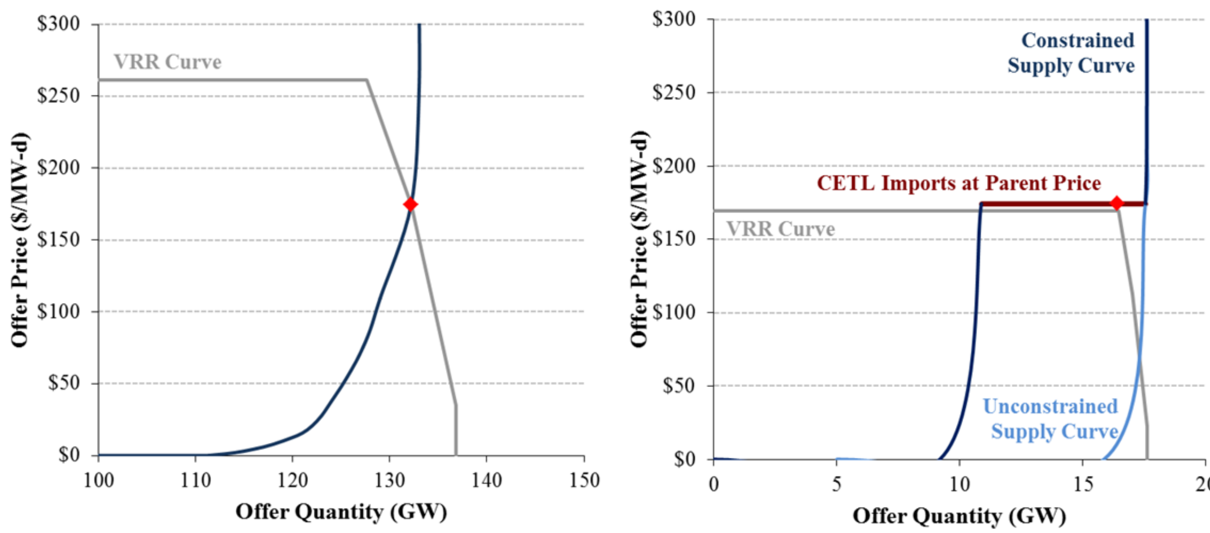
---

117 For point b values equal to or greater than zero.

118 Using the current definitions of points "b" and "c" but setting point *a* to 1.5×CONE (i.e., without subtracting any E&AS offset) would eliminate over 90% of the performance deterioration caused by combining the Settlement Curve with a historical E&AS offset. Simulations of the originally-filed VRR curve which defined the cap as 2×CONE minus E&AS show only very modest performance deterioration.

Our recommendation to increase the cap of the VRR curve would also avoid VRR performance risk within LDAs that have already been encountered. For example, in the BRA for the 2010/11 delivery year the E&AS offset in SWMAAC was $130/MW-day while it was only about $30/MW-day for the unconstrained RTO. As shown in Figure 20, the resulting cap for the VRR Curve of SWMAAC was less than Net CONE for the unconstrained RTO. This meant that SWMAAC cleared at a price above its cap, because the LDA did not price separate. More importantly, however, it also means that RPM would not have been able to procure sufficient resources within SWMAAC, had the LDA (including CETL import capability) been resource deficient. Even if resources would have been available within SWMAAC at higher prices above Net CONE for the RTO, they would not have been procured due to the low cap of the VRR curve in SWMAAC.

Figure 20
2010/11 VRR Curves and BRA Results for RTO and SWMAAC



C. PROBABILISTIC SIMULATIONS OF THE VRR CURVE

As part of PJM's analysis of the originally-filed and subsequently settled VRR Curve design, PJM's witness, Professor Benjamin Hobbs, developed a dynamic, agent-based, economic simulation model that conducts probabilistic simulations of generation investments over time in response to price-based incentives in the energy, ancillary service, and capacity markets. The model calculates profits earned by generators in the E&AS markets as a function of actually achieved reserve margin in a particular delivery year. The model assumes that investors will add combustion turbines based on their recent profitability and forecast profits based on their expectations for future demand, capacity prices determined by the shape of the VRR curve, E&AS margins, and the riskiness of their revenue stream. Section IV.C of our 2008 RPM Report contains a more detailed description of the model developed by Professor Hobbs and our updates to it.[119]

[119] For a complete description of the Hobbs model, see Hobbs *et al.* "A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model," *IEEE Transactions on Power Systems*, Vol. 22, NO. 1, February 2007. The simulation analysis was originally presented in the

Continued on next page

We find that the probabilistic simulations are very helpful in analyzing how certain changes in the VRR design may affect RPM performance. It is important to recognize, however, that the simulations are not forecasts of likely outcomes. Actual RPM performance under real-world conditions will necessarily differ, potentially significantly, from the simulations results. To allow for probabilistic simulations, the model is only a stylized representation of RPM and investment behavior and is based on significant simplifications. For example, model simulates only one market area (*i.e.*, the RTO without LDA structure) and only one type of generation technology (*i.e.*, a combustion turbine; without demand response or other type of generation technologies). It also employs a supply curve that is vertical beyond the CT capacity planned on a three-year forward basis (*i.e.*, essentially assumes a hockey-stick shape of the supply curve) without an ability to adjust plans through the means of incremental auctions. Nevertheless, we believe that the simulation results provide a strong indicator of the direction and magnitude of the likely impacts of design elements on RPM performance.

1. Updates to Simulation Parameters

As we did for the purpose of our 2008 RPM Report, we have updated model input parameters to reflect current values for CONE, peak demand, CT dispatch costs, and other input parameters. **Table 19** summarizes the input parameters used in the original simulations by Prof. Hobbs, in our 2008 RPM Report, and the current simulations.

Table 19
Original and Updated Simulation Model Parameters

Parameter		Hobbs 2005 Analysis	2008 Analysis	2011 Analysis
Developer Gross CONE	*($/MW-y ICAP)*	$61,000	$72,000	$112,868
Admnistrative Gross CONE	*($/MW-y ICAP)*	$72,000	$72,000	$112,868
CT Variable Cost	*($/MWh)*	$79	$74	$48
EFORd	*(%)*	7.0%	6.2%	6.2%
Initial Peak Demand	*(MW)*	63,957	144,644	135,080
Load Growth	*(%/y)*	1.7%	1.4%	1.3%

Sources and Notes:
See Hobbs (2005, 2007); Pfeifenberger and Newell, *et al.* (2008), p. 59. Updated developer and administrative gross CONE from PJM (2011q), pp. 2226-7. Updated CT variable cost based on 9,289 btu/kWh heat rate, $4.50/mmbtu gas price, and $6.47/MWh VOM. EFORd from 2010/11 planning parameters, PJM (2008b). Load growth from PJM 2011 load forecast report, PJM (2011g).

Continued from previous page
Affidavit of Prof. Hobbs, filed as Attachment H to PJM's initial RPM application on August 31, 2005 in FERC Docket Nos. ER-05-1410 and ER-05-148. Updated simulations that included the settlement-based VRR Curve were presented in the Supplemental Affidavit of Prof. Hobbs, filed at FERC with the Settlement Agreement on September 29, 2006.

2. Updated Simulation Results Using a Constant E&AS Offset

The simulation results of the originally-filed VRR curve, the Settlement Curve (*i.e.*, the currently applicable VRR curve), and a vertical demand curve (capped at 2×CONE-E&AS) are shown in Table 20. These results are based on 25 simulations of 100 years each for each of the three curves. As shown in the table, the Settlement Curve performs quite well. Based on generator commitments, forecast planning reserves for the delivery year exceed the reliability target during 86% of all years. Average actual reserve margins during the delivery years are 0.74 percentage points above the reliability target with a standard deviation of 5.1 percentage points due to uncertainties such as weather and generation outages.[120] Total consumer payments for capacity and E&AS margins are $142/kW-year with a standard deviation of $47/kW-year. As shown, this level of reliability and costs approaches the performance of the Original VRR curve. In contrast, simulations of the Vertical Demand Curve show much lower performance in terms of reliability (with average reserve margins 2.4 percentage points below the reliability target) and substantially higher average customer costs ($245/kW-year) and pricing uncertainty (a standard deviation of $176/kW-year).[121]

Table 20
Hobbs Simulations with Updated Parameters and Constant E&AS Offset

	Fraction of Time Cleared Resources Exceed Requirement	Realized Reserve Margin minus Target Reserve Margin	Generator Profits after Capital and Operating Cost	Scarcity Revenue (Portion of E&A/S From Scaricity Pricing)	Average Capacity Price	Consumer Payments for Capacity and Scarcity
	(%)	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/peak kW-y)*
Original Hobbs Curve (*a* = 2 x CONE - E&A/S)						
Average	96%	1.18%	9	15	105	140
Standard Deviation		*(5.1%)*	*(31)*	*(27)*	*(13)*	*(42)*
Settlment Curve: Current RPM VRR Curve (*a* = 1.5 x Net CONE)						
Average	86%	0.74%	11	17	105	142
Standard Deviation		*(5.1%)*	*(34)*	*(29)*	*(13)*	*(47)*
Vertical Demand Curve (price cap = 2 x CONE - E&AS)						
Average	27%	-2.44%	94	47	157	245
Standard Deviation		*(6.2%)*	*(132)*	*(64)*	*(95)*	*(176)*

Sources and Notes:
Each simulation involves 100 runs through 100 years each.
Reported numbers represent the average of run averages and the average of run standard deviations.
Generator profit, revenue, and capacity price reported on a UCAP basis; consumer payments normalized by peak load.

3. Updated Simulation Results Using a 3-Year Historical E&AS Offset

As noted, the results shown in Table 20 above are based on simulations holding the E&AS offset constant over time. (This is consistent with an approach in which the E&AS offset would be

[120] As noted above, the reliability target is one percentage point below the anchor point (point "b") of the VRR curve.

[121] As we noted on page 66 of our 2008 RPM Report, these simulations overstate the level of costs and uncertainty associated with a vertical demand curve. However, the vertical demand curve resulted in modestly higher costs and uncertainty even under more conservative alternative modeling assumptions.

estimated based on equilibrium market conditions, as discussed in Section IV.B.) Table 21 shows simulations results for an E&AS offset based on the 3-year average of the simulated historical E&AS margins.

As Table 21 shows, simulated RPM performance of the Settlement Curve drops *substantially* when the constant E&AS offset is replaced with a historical E&AS offset. Most notably, forecast planning reserves for the delivery year exceed the reliability target during only 26% of all years (down from 86%). Average actual reserve margins during the delivery years are more than 5 percentage points *below* the reliability target (down from 0.7 percentage points *above*). Total consumer payments for capacity and E&AS margins increase to $207/kW-year (up from $142/kW-year) with a standard deviation of $146/kW-year (up from $47/kW-year). Table 21 shows, however, the use of historical E&AS offsets deteriorates performance only modestly for the originally-filed VRR curve.

Table 21
Hobbs Simulations with Updated Parameters and <u>Historical</u> E&AS Offset

	Fraction of Time Cleared Resources Exceed Requirement *(%)*	Realized Reserve Margin minus Target Reserve Margin *(%)*	Generator Profits after Capital and Operating Cost *($/kW-y)*	Scarcity Revenue (Portion of E&A/S From Scarcity Pricing) *($/kW-y)*	Average Capacity Price *($/kW-y)*	Consumer Payments for Capacity and Scarcity *($/peak kW-y)*
Original Hobbs Curve (*a* = 2 x CONE - E&AS = b + 1.0 x CONE)						
Average	77%	0.57%	17	19	109	151
Standard Deviation		*(5.3%)*	*(49)*	*(33)*	*(30)*	*(67)*
Settlment Curve: Current RPM VRR Curve (*a* = 1.5 x Net CONE)						
Average	26%	-5.18%	31	78	64	207
Standard Deviation		(6.2%)	(77)	(70)	(44)	(146)
Vertical Demand Curve (price cap = 2 x CONE - E&AS)						
Average	26%	-2.62%	72	49	133	222
Standard Deviation		*(6.2%)*	*(126)*	*(65)*	*(88)*	*(174)*
Settlement Alternative 1 (*b* ≥ 0, *c* ≥ 0, *a* ≥ 0.5 x CONE)						
Average	37%	-2.24%	26	42	95	170
Standard Deviation		*(5.6%)*	*(64)*	*(55)*	*(29)*	*(108)*
Settlement Alternative 2 (Alt. 1 w/ 20% limit on Net CONE reductions)						
Average	53%	-0.39%	17	24	104	151
Standard Deviation		*(5.3%)*	*(49)*	*(40)*	*(22)*	*(72)*
Settlement Alternative 3 (*b* ≥ 0, *c* ≥ 0, *a* = *b* + 0.5 x CONE)						
Average	55%	-0.47%	19	25	104	153
Standard Deviation		*(5.4%)*	*(53)*	*(42)*	*(25)*	*(79)*
Settlement Alternative 4 (*b* ≥ 0, *c* ≥ 0, *a* = 1.5 x CONE)						
Average	67%	0.24%	17	20	107	149
Standard Deviation		*(5.2%)*	*(48)*	*(34)*	*(26)*	*(67)*

Sources and Notes:
Each simulation involves 100 runs through 100 years each.
Reported numbers represent the average of run averages and the average of run standard deviations.
Generator profit, revenue, and capacity price reported on a UCAP basis; consumer payments normalized by peak load.

These marked performance deteriorations observed in the Hobbs model simulations with historical E&AS offsets were already noted in our 2008 RPM Report, which explained:

> …the use of historical E&AS averages can create "resonances" in the simulations that can lead to unstable results. For instance, in an extreme weather year, E&AS margins could be very high. As a result, even after averaging over three historical years, the resulting value for Net CONE could be very low. As a result of the low Net CONE value, however, little or no entry occurs in the model. Because of this lack of entry, reserve margins decline further, which may increase E&AS margins to the point at which Net CONE is zero or even negative. At that point, entry is mostly a function of high but very volatile energy and ancillary service revenues. At other times, however, load fluctuations may artificially depress the E&AS margins, at which point Net CONE may return to meaningful values for some period of time. This dynamic leads to highly unstable simulations with high average costs and high volatility. Even utilizing longer-term averages of historical E&AS margins and imposing limits on realized E&AS margins did not alleviate the problem in the simulations. Whether such instabilities would be very likely under real-world conditions is unclear, but these simulation results nevertheless highlight the risk of relying on outdated E&AS margins that are not consistent with investors' anticipated market conditions.[122]

We have analyzed these simulation results in more detail and found that the primary reason for the poor performance of the Settlement Curve using historical E&AS offsets relates to how point *a* (the cap of the VRR curve) is defined. As discussed qualitatively in the previous subsection, the simulations frequently get "stuck" at points well below the reliability target when the VRR curve collapses due to historical E&AS margins that are equal to or exceed CONE—until load or generation outage fluctuations depress the E&AS margins below CONE, at which point the VRR curve re-emerges and its slope returns the system to the reliability target.

Table 21 also summarizes the simulation results of four alternative definitions for points *a* of the Settlement Curve, including simulations that limit the extent to which Net CONE values can decrease from one year to the next. Points *b* and *c* remain unchanged at 1.0×NetCONE and 0.2×Net CONE, but are limited to values greater or equal to zero (as is assumed in the simulations of the Settlement Curve).

Alternative 1 simply adds a floor of 0.5×CONE to point *a*, which becomes active only if the 3-year average historical E&AS offset exceeds ⅔×CONE. As the simulation results show, this design change increases average achieved reserve margins by almost 3 percentage points (from negative 5.18 to negative 2.24 percentage points below the reliability target), mitigating approximately half of the performance deterioration caused by the historical E&AS offset.

Alternative 2 adds a 20% limit on annual *decreases* of Net CONE to Alternative 1 (which imposed a 0.5×CONE floor for point "a" of the Settlement Curve). This combination mitigates over 80% of the performance deterioration and achieves an average reserve margin that is only 0.4 percentage points below the reliability requirement. Total customer costs are reduced to $151/kW-year (down from $207/kW-year) and volatility is reduced to a standard deviation of

[122] 2008 RPM Report page 61-62 (footnote omitted).

customer costs of $72/kW-year (down from $146/kW-year). While average outcomes are still slightly below the reliability target, the performance of this combination is similar to the originally-filed VRR curve, which had a much higher cap (2×CONE less E&AS) and a flatter bottom half of the curve. We have also evaluated limiting both annual increases and decreases of Net CONE values, but found that such a symmetric limit does not improve the identified VRR Curve performance risks that are created by the asymmetric nature of the curve.

Alternative 3 defines point *a* to as "point *b* plus 0.5×CONE," which is also equal to "Net CONE plus 0.5 CONE" or "1.5×CONE minus E&AS" (with a floor of zero). This definition yields a higher cap than the current cap of the VRR curve (1.5×CONE minus 1.5×E&AS), which also results in a slightly steeper and stable upward slope between points *a* and *b*. The simulations results show that this change increases average achieved reserve margins by almost 5 percentage points to an average that is only 0.5 percentage points below the reliability target, mitigating approximately half of the performance deterioration caused by the historical E&AS offset. Customer costs and volatility are similar to the simulation results for Alternative 2.

Finally, Alternative 4 defines point *a* as 1.5×CONE without subtracting any E&AS offset. This achieves a simulated average reserve margin that is 0.26 percentage points above the reliability requirement with customer costs of $149/kW-year and a volatility of $67/kW-year. This level of simulated performance is close to the performance of the Settlement Curve with a constant E&AS offset as shown earlier in Table 19.

The simulations of these alternatives show that point a, the cap of the VRR curve, would need to be approximately 1.0×CONE above point *b* (*i.e.*, as proposed in the original Hobbs curve) to yield an average reserve margin that is above the IRM target.

We believe these simulations will accurately capture the nature of the discussed performance risks, even though the simulations will likely overstate volatility associated with the use of historical E&AS margins due to the hockey-stick nature of the modeled supply curve and the absence of adjustments to resource procurement through incremental auctions. However, the simulations are likely to understate actual RPM uncertainties related to capacity prices and resource adequacy within LDAs.

4. Updated Simulation Results Using a Normalized 3-Year Forward-Looking E&AS Offset

As noted in our 2008 RPM Report, we also simulated an E&AS offset that is consistent with *anticipated* (*i.e.*, normalized forward-looking rather than historical) market conditions.[123] Using this normalized forward-looking E&AS offset performed markedly better than the highly unstable simulations based on historical averages of actual E&AS margins. The results from our updated simulations in Table 22 below show that determining Net CONE based on the projected normalized E&AS margins performs slightly better than the simulations undertaken by Prof.

[123] These simulations are based on the average of projected (normalized) E&AS margins for the three years leading up to the delivery year, taking into account the capacity commitment already known for these years. Determination of these 3-year forward looking E&AS margins is possible in the simulations because achieved reserve margins (relative to forecast peak load) is already known through the previous BRA results and the model determines E&AS profits as a simple function of projected reserve margins.

Hobbs using a fixed E&AS offset to determine Net CONE. More specifically, relying on projected E&AS margins—and assuming accurate projections of normalized future E&AS margins—offers improvements over the updated Hobbs simulations based on fixed E&AS revenues (Table 20 above) in terms of costs, price volatility (as measured by standard deviations), and reliability.

Table 22
Hobbs Simulations with Normalized Forward-Looking E&AS Offset

	Fraction of Time Cleared Resources Exceed Requirement	Realized Reserve Margin minus Target Reserve Margin	Generator Profits after Capital and Operating Cost	Scarcity Revenue (Portion of E&A/S From Scaricity Pricing)	Average Capacity Price	Consumer Payments for Capacity and Scarcity
	(%)	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*	*($/peak kW-y)*
Original Hobbs Curve (a = 2 x CONE - E&A/S)						
Average	97%	1.15%	9	16	104	141
Standard Deviation		(5.2%)	(31)	(28)	(11)	(42)
Settlment Curve: Current RPM VRR Curve (a = 1.5 x Net CONE)						
Average	90%	0.83%	10	16	105	141
Standard Deviation		*(5.1%)*	*(32)*	*(29)*	*(11)*	*(45)*

Sources and Notes:
Each simulation involves 100 runs through 100 years each.
Reported numbers represent the average of run averages and the average of run standard deviations.
Generator profit, revenue, and capacity price reported on a UCAP basis; consumer payments normalized by peak load.

D. The Slope of the VRR Curve

In this section we examine the slope of the VRR curve and its impacts on RPM price volatility based on a scenario analysis of the first eight base auctions undertaken to date. This analysis indicates that the slope of the VRR curve has reduced the price volatility that would have been experienced if RPM employed a vertical demand curve. However, the reductions in price volatility are smaller than we might have expected. In response to some stakeholder comments, we have also tested the extent to which VRR curve with a lower slope would have further reduced price volatility. Making the VRR curve flatter does not appear to have a large enough impact in price stability to be a desirable design change given the additional quantity uncertainty that would be introduced.

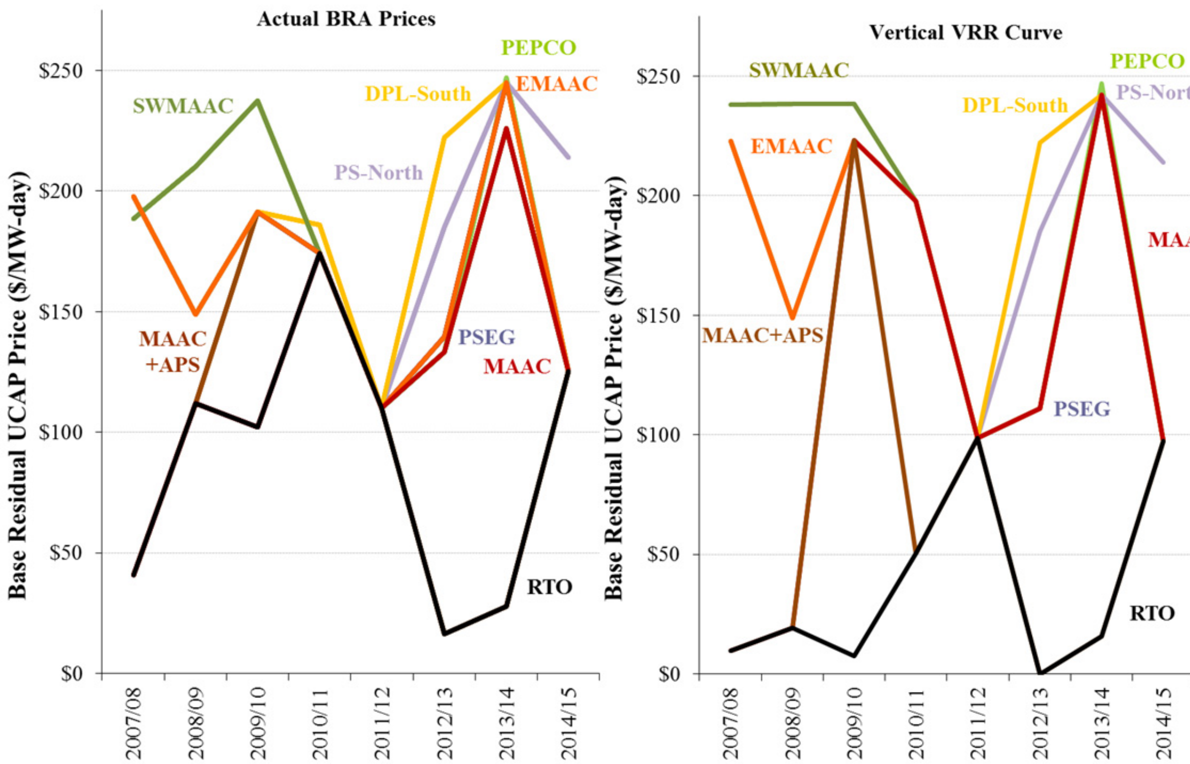
We also examined, and ultimately rejected, the idea that more gradual VRR curve slope could be a valuable design change to reduce price uncertainty in small LDAs. While such a change could potentially produce more price stability in small LDAs, we find that it would reduce the incentive to develop incremental capacity in these locations.

1. VRR Curve Slope in the RTO and LDAs

As discussed in our 2008 RPM report and confirmed by our updated probabilistic simulations, the sloped VRR curve results in lower average costs and lower uncertainty than a vertical demand curve. In addition, a sloped VRR curve: (1) helps mitigate the potential exercise of market power by reducing the incentive for suppliers to withhold capacity when aggregate supply is near the target reserve margin; and (2) recognizes that capacity above the target reserve margin provides some incremental reliability benefits, although at a declining rate.[124]

We were able to explore the extent of price risk mitigation due to the sloped VRR curve based on a scenario analysis of results from the first eight base auctions. Figure 21 shows the results of this scenario analysis, which re-simulates prices of previous BRAs assuming that, but for the VRR curve slope, all other historical auction parameters and supply curves would have remained unchanged. We also recognize, however, that assuming identical historical supply curves is not a realistic assumption, as different supplier expectations would have driven different bidding behaviors and different clearing results would have affected subsequent auctions. For these reasons, we consider these scenario analyses to be helpful indicators of the impacts of the VRR curve slope but recognize that they must be interpreted with caution.

Figure 21
Actual BRA Prices (left) and Prices with a Vertical VRR Curve (right)



Notes:
Left chart shows actual BRA prices.
Right chart shows a scenario analysis of historical BRA prices if the VRR curve had been vertical at point *b*.

The left chart of Figure 21 shows actual BRA auction prices while the right chart shows prices that would have been realized with a vertical VRR curve. The comparison of these two charts shows that the volatility with the actual VRR curve is somewhat lower than under a vertical curve. For example, actual MAAC prices between 2008/09 and 2009/10 increased by $79/MW-day, while the price increase for the vertical VRR curve simulation was $204/MW day,

124 The value of these incremental reliability benefits do not necessarily reflect the value implied by the VRR curve however, since the VRR curve is not tied to any such calculations.

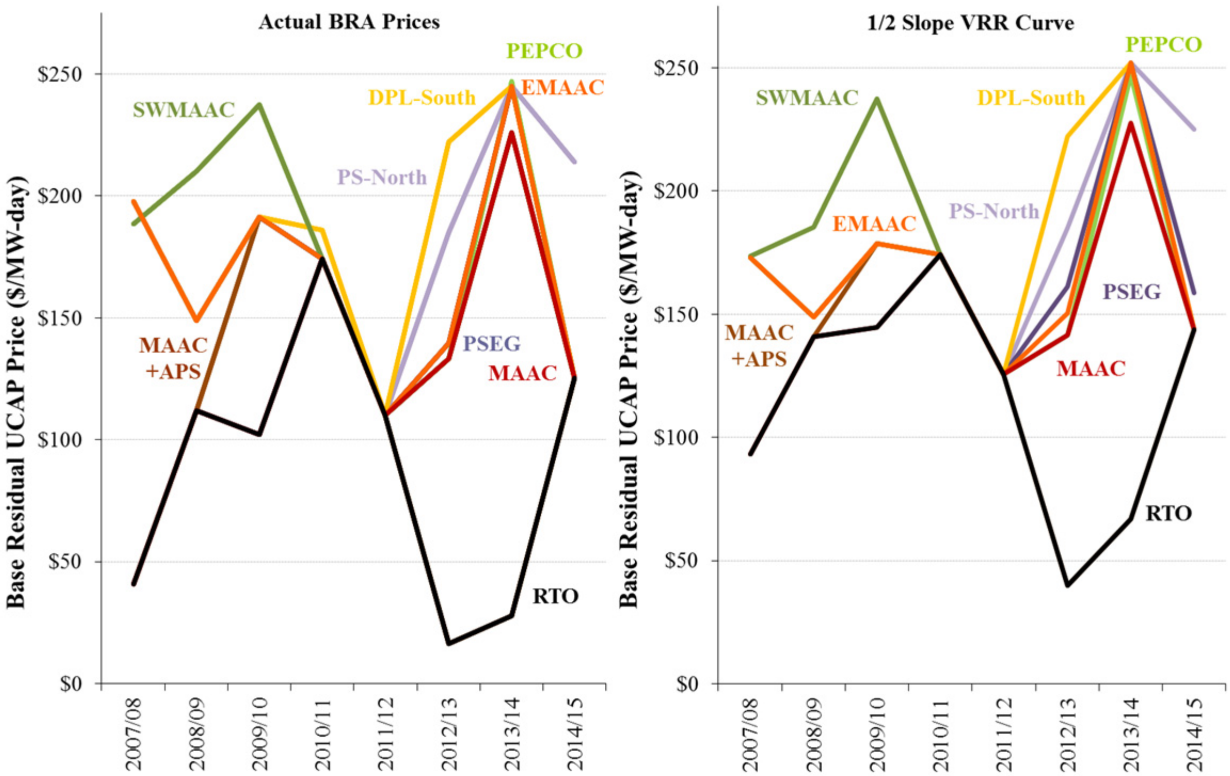
or more than 2.5 times larger. However, overall, the reduction in price volatility due to the VRR curve slope is somewhat less than we would have expected. The more moderate impact is not as surprising, however, when considering the causes of price changes we have identified and discussed in Sections II. It appears that the slope of the VRR curve, while beneficial in reducing price volatility, has not been sufficiently flat to fundamentally reduce the impacts of other uncertainty factors, such as changes in CETL values or whether individual LDAs are modeled.

Members of the generation owner, transmission owner, and other supplier sectors stated in our interviews that the VRR curve is too steep and, as a result, yields high price uncertainty. However, members of the end use customer sector and some state commissioners regulating FRR entities have placed substantial emphasis on the quantity uncertainty that the sloped VRR curve is creating. In response to these stakeholder comments, we also assess the extent to which a flatter VRR curve could reduce price uncertainty.

Figure 22 shows actual BRA prices (left chart) compared to simulation results under a more gradual VRR curve with half the slope of the existing curve (right chart). The simulations show that some additional reductions in price volatility could have been achieved under a more gradual VRR slope. For example, actual MAAC prices between 2011/12 and 2012/13 decreased by \$79/MW-day, while under the price decrease using a more gradual VRR curve was reduced to \$38/MW-day or less than half. Other LDAs, however, would have seen little benefits from a flatter VRR curve. The simulations indicates that while a more gradual VRR curve would somewhat reduce price volatility in RPM, the impact would only be modest.

Given these results and our analysis of the drivers behind BRA price changes presented in Section II, we conclude that it will be more beneficial to pursue other available options to reduce price volatility in RPM. As discussed, some of the factors that have driven price volatility are related to previous design issues that have since been corrected, including problems with not modeling LDAs that would have price separated and the exclusion of large amount of ILR supplies in the first five auctions. Other drivers of uncertainty include uncertainty and volatility in administratively-determined parameters, such as the load forecast and CETL and the potential for not modeling LDAs that may price separate in the future. We examine the potential for reducing price volatility introduced by these factors further in Section VI.

Figure 22
Actual BRA Prices (left) and Prices with a Gradual VRR Curve (right)



Sources and Notes:
Left chart shows actual BRA prices.
Right chart shows a scenario analysis under a VRR curve with ½ the slope of the actual historical curve.

2. Reduced VRR Curve Slope in Small LDAs

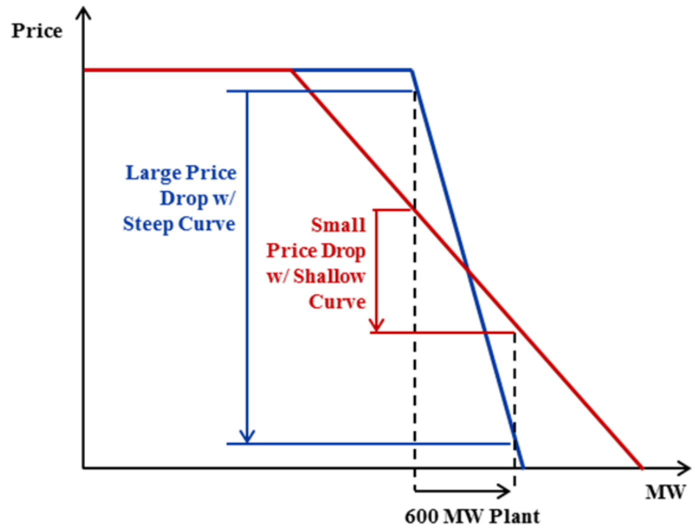
While it appears that a more gradual slope in the RTO overall may not be the most beneficial approach to reducing price volatility, we considered whether it may be beneficial in the smallest LDAs. This approach is used in New York, which has relatively more gradual VRR curve slopes in the smaller capacity zones covering New York City and Long Island than in the greater NYISO region.

It makes intuitive sense that a flatter slope would provide more stability in small LDAs. It might also help mitigate the impacts of individual generating plants, which could substantially reduce capacity prices in small LDAs for many years. In SWMAAC or PSEG for example, the impact of a single 600 MW plant corresponds to a price difference between zero and Net CONE along the VRR curve. In even smaller LDAs such as DPL-South, PSEG-North and PEPCO, the impact of a 600 MW plant would be the difference between the price cap and the price floor.[125] Figure 23 shows schematically how the addition of one large plant can substantially reduce prices, while under a more gradual VRR curve slope the price impact of a single large plant would be less.

[125] See the quantity difference between points a, *b*, and *c* in the 2014/15 BRA planning parameters, PJM (2011b).

This indicates that in a stand-alone small system, a more gradual VRR slope would mitigate such large price impacts. However, the implications of such a change are more nuanced in a multi-area capacity market such as RPM.

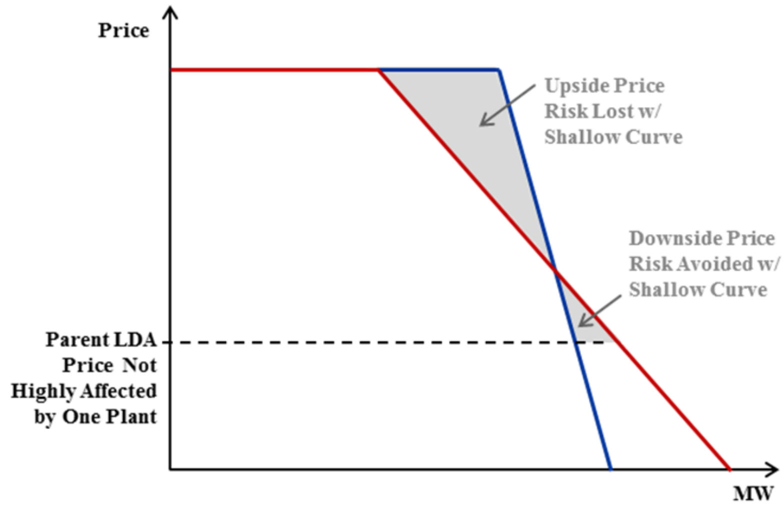
Figure 23
Price Impact of a 600 MW Plant with VRR Curves of Different Slopes
(In a Small Stand-Alone LDA *without* a Parent LDA)



In a market with a nested LDA structure like PJM, price impacts in small LDAs cannot be examined in isolation from prices in their larger parent LDA or unconstrained RTO. As depicted in Figure 24, price impacts in small LDAs are limited on the low end by the prices of their parent LDA. That is, the price of a small LDA cannot drop below the price of the parent LDA. For this reason, the downside price impact of a large plant addition in a small LDA is already limited, because the larger parent LDA price will not be substantially impacted by the addition of a single plant. The remaining avoided downside price risk is shown as the small shaded triangle in Figure 24. The figure also shows that the "upside price risk" that would be lost by applying a flatter VRR curve to small LDA would be much larger than the downside price risk mitigation, as shown in the larger shaded triangle.

The upside price risk lost under such a change is much larger than the downside price risk gained unless the parent LDA price is much lower than the small LDA price. In fact, as a result of this asymmetry, reducing the slope of the VRR curve in small LDAs would reduce the amount of capacity procured at high prices and, thus, also reduce incentives to add resources to the LDA.

Figure 24
Upside and Downside Price Risk Impact of a Shallow VRR curve
(In a Small LDA *with* a Parent LDA)



E. *SUMMARY OF* VRR CURVE RECOMMENDATIONS

As discussed above, we recommend that PJM and its stakeholders consider and more fully evaluate the following recommendations regarding the slope, cap, and forward period of the VRR curve design.

1. ***Increase the Cap of the VRR Curve to Improve Performance*** — we recommend that PJM and its stakeholders consider raising point *a* equal to point *b* plus 0.5×CONE, which would result in a higher cap and a steeper and more stable upward slope between points *a* and *b* compared to the current VRR curve. It should also be clarified that the value of Net CONE (for purpose of defining points a, b and c of the VRR curve) cannot be less than zero.
2. ***Otherwise maintain the Slope of VRR Curve***, including within LDAs.
    a. *VRR Curve for Unconstrained RTO* — We recommend maintaining the VRR curve at its current value (other than the modest change in slope between points *a* and *b*, due to the increase cap of the VRR curve). The current slope has reduced the price volatility relative to a vertical curve. An even more gradual slope would not result in significant further reduction in price volatility, but would create greater uncertainty in procured quantity relative to the reliability target.
    b. *VRR Curve in Small LDAs* — We recommend keeping the current slopes of the VRR curves the same even within small LDAs. Imposing a more gradual slope in constrained LDAs would reduce upside price risk without substantially impacting downside price risk (unless the parent LDA price were substantially lower), thereby reducing investment incentives.

VI. ANALYSIS OF MARKET DESIGN ELEMENTS

Our analysis of individual market design elements addresses six groups of design elements and administratively-determined RPM parameters. First, we analyze transmission-related factors and opportunities to reduce their impact on RPM price uncertainty. Second, we offer recommendations to improve the transparency of load forecasts and the load forecasting process. Third, we discuss the comparability of DR and generating resources and associated DR performance concerns. Fourth, we address the desirability and design of the 2.5% short-term resource procurement target. Fifth, we discuss concerns related to market monitoring and mitigation. And, finally, we explore options for expanding the NEPA or facilitating long-term procurement.

A. TRANSMISSION-RELATED FACTORS

This section assesses how transmission-related factors affect RPM and identifies opportunities to reduce their effects on the uncertainty and volatility of RPM prices—while still accurately representing transmission limits, maintaining reliability, and providing accurate price signals. We examine options for: (1) making the CETL parameter more transparent, more predictable, and less volatile in order to reduce volatility and improve the predictability of auction clearing prices in LDAs; (2) improving how transmission constraints are represented in RPM auctions; (3) reducing the need for RMR contracts that address transmission constraints into LDAs; and (4) improving coordination between the transmission planning process and RPM.

1. Transparency and Stability of the Capacity Emergency Transfer Limit

The capacity emergency transfer limit (CETL) parameter expresses the first contingency total transfer capability into each LDA.[126] The capacity emergency transfer objective (CETO) is the transfer capability into the LDA that would be required to maintain a 1-event-in-25-year conditional loss of load expectation for the LDA, assuming perfect availability of such transmission capability and resources outside the LDA.[127] These parameters are used for several purposes: (1) to determine whether to plan transmission enhancements to maintain reliability (*i.e.*, when CETL < CETO); (2) to determine whether to model an LDA in the RPM auctions (*i.e.*, when CETL < 1.15 × CETO); and, most relevant to this discussion, (3) to set the import limits into an LDA as modeled in the RPM auctions.[128]

The CETL parameter determines how much lower-cost capacity an LDA may import from outside while still observing transmission constraints. Because CETL can be large relative to the size of an LDA and the slope of the LDA's VRR curve, its value can have a major effect on auction prices. As discussed in Section II, CETL changes have been a major contributor to the observed volatility and unpredictability of auction prices. This is because CETL can change

---

[126] See PJM (2011i), pp. 53-54.

[127] Section III.G contains additional discussion of the 1-in-25 reliability standard for LDAs. See PJM (2011i), pp. 53-54.

[128] See PJM (2011i), pp. 27-28 and Attachment C; PJM (2011d), pp. 10-13.

significantly from one auction to the next due to planned transmission upgrades, deferrals of planned upgrades, generation plant retirements, or shifts in the load distribution within an LDA.

We first document changes in historical CETL values, including how and why they have changed over time. We then examine options that could make CETL determination more transparent, more predictable, and more stable.

a. Historical Changes in CETL and Their Effects on RPM Auctions

Table 23 lists the CETL values that applied to the various LDAs in each of the past base residual auctions as well as the 2012/13 incremental auctions.[129] The year-to-year changes in CETL have been substantial and in many years the magnitude of increases or decreases has been comparable to the addition or retirement of several large generating plants. Table 23 shows, for example, that the 2013/14 CETL for MAAC and EMAAC decreased by almost 2,000 MW, or more than the impact of three large CC plants. As discussed in Section II, these CETL reductions were a major contributor to LDA prices in 2013/14 that were higher than in the previous or subsequent BRA.

The following year, in 2014/15, CETL values reverted close to their levels two years earlier when the MAAC and EMAAC CETLs were more than 1,000 MW higher. These CETL increases were a major contributor to LDA price reductions in the 2014/15 auction. These impacts are larger in the small LDAs, including PEPCO, which experienced a CETL increase of 12.5% of the reliability requirement between the 2013/14 and 2014/15 BRAs, equivalent to almost twice the width of the sloped portion of the VRR curve.[130]

b. Causes of CETL Uncertainty

Table 23 shows that CETL values have changed substantially over time, which contributed to significant changes in auction prices, as discussed in Section II. The specific causes of the largest CETL changes are summarized in Table 24. Some of the largest CETL changes were due to major planned transmission projects and the subsequent modification of the projects' online dates. For example, the Susquehanna-Roseland backbone transmission project was planned to be in service starting with the 2012/13 delivery year, but the project has been substantially delayed due to environmental permitting difficulties.[131] The transmission line is now expected to be online starting in 2015/16.[132] When Susquehanna-Roseland was first modeled in RPM, it coincided with a relatively small CETL increase of 275 MW in EMAAC; when it was subsequently delayed, it caused a CETL reduction of 1,455 MW between the 2012/13 BRA and the first incremental auction for that delivery year, or a drop of 1,984 MW between the BRAs for the 2012/13 and 2013/14 delivery years.

---

129 Prior to 2012/13, CETL values were not updated in the incremental auctions, see PJM (2011d), p. 60.

130 The quantity difference between points a and c on the VRR curve for PEPCO in 2014/15 was 621 MW, while the change in CETL between 2013/14 and 2014/15 was 1,123 MW or 1.8 times higher. See PJM (2010a, 2011b).

131 See PJM (2011l).

132 *Id.*

Table 23
Historical CETL Values and Changes

Year	MAAC+APS	MAAC	EMAAC	SWMAAC	PSEG	DPL-S	PS-N	PEPCO
Capacity Emergency Transfer Limit (MW)								
2007/08	--	--	5,845	5,699	--	--	--	--
2008/09	--	--	7,930	5,610	--	--	--	--
2009/10	4,941	--	8,505	6,391	--	--	--	--
2010/11	--	6,645	--	6,667	--	1,447	--	--
2011/12	--	--	8,804	--	--	1,857	--	--
2012/13	--	6,377	9,079	7,400	6,290	1,746	2,755	--
1st IA	--	*6,377*	*7,624*	*7,400*	*6,077*	*1,746*	*2,675*	--
2nd IA	--	*6,098*	*7,624*	*6,950*	*6,077*	*1,746*	*2,675*	--
2013/14	--	4,460	7,095	6,725	5,868	2,123	2,570	4,483
2014/15	--	5,694	8,189	7,719	5,721	1,925	2,372	5,606
CETL Change from Previous BRA (MW)								
2008/09	--	--	2,085	(89)	--	--	--	--
2009/10	--	--	575	781	--	--	--	--
2010/11	--	--	--	276	--	--	--	--
2011/12	--	--	299	--	--	410	--	--
2012/13	--	(268)	275	733	--	(111)	--	--
1st IA	--	*0*	*(1,455)*	*0*	*(213)*	*0*	*(80)*	--
2nd IA	--	*(279)*	*(1,455)*	*(450)*	*(213)*	*0*	*(80)*	--
2013/14	--	(1,917)	(1,984)	(675)	(422)	377	(185)	--
2014/15	--	1,234	1,094	994	(148)	(198)	(198)	1,123
CETL Change as Percent of LDA Reliability Requirement								
2008/09	--	--	5.5%	-0.5%	--	--	--	--
2009/10	--	--	1.5%	4.7%	--	--	--	--
2010/11	--	--	--	1.6%	--	--	--	--
2011/12	--	--	0.7%	--	--	13.0%	--	--
2012/13	--	-0.4%	0.7%	4.3%	--	-3.7%	--	--
1st IA	--	0.0%	-3.7%	0.0%	-1.6%	0.0%	-1.3%	--
2nd IA	--	-0.4%	-3.8%	-2.7%	-1.7%	0.0%	-1.3%	--
2013/14	--	-2.6%	-4.9%	-3.8%	-3.1%	12.6%	-2.9%	--
2014/15	--	1.7%	2.7%	5.7%	-1.1%	-6.6%	-3.2%	12.5%

Sources and Notes:

BRA and IA parameters, see PJM (2007a, 2009b-d, 2010a, 2010h, 2011b, and 2011j).

2011/12 CETL was calculated for EMAAC and DPL-S although those LDAs were not modeled in RPM.

Prior to 2012/13, CETL was not updated between incremental auctions; see PJM (2011d), p. 60.

Table 24
Summary of Major CETL Changes and Their Causes

Year	Location or Auction		Causes of Major CETL Changes
2008/09	*EMAAC*	-	2,085 MW increase in EMAAC coincides with the modeling of key expected transmission upgrades in the LDA including transformers, capacitors, line segments, and other transmission elements.
2009/10	*EMAAC and SWMAAC*	-	575 and 781 MW increases in MAAC and SWMAAC coincides with several key expected transmission upgrades in these LDAs.
2012/13	*BRA in EMAAC*	-	Addition of Susquehanna-Roseland transmission line coincides with a relatively small CETL increase of 275 MW in EMAAC.
	1st IA in EMAAC	-	Delay of Susquehanna-Roseland transmission line causes CETL reductions of 1,455 MW in EMAAC and smaller reductions in PSEG and PSEG-North.
2013/14	*MAAC and SWMAAC*	-	1,917 MW decrease in MAAC and 675 MW decrease in SWMAAC attributed primarily to load increase in the northern Virginia area of Dominion from expected large data center loads.
	EMAAC	-	1,984 MW decrease in EMAAC attributed primarily to the deferred online date of the Susquehanna-Roseland 500 kV line.
2014/15	*MAAC, SWMAAC, and PEPCO*	-	Approximate 1,000 MW increases in MAAC, SWMAC, and PEPCO are attributed to the addition of Brambleton 500 kV substation and 500/230 kV transformer in Dominion.
	EMAAC	-	1,094 MW increase in EMAAC attributed to a 350 MW size reduction in the O66 generation project and a shift in the EMAAC load distribution profile.

Sources and Notes:
BRA and IA parameters, see PJM (2007a, 2009b-d, 2010a,h, 2011b,j).
Causes of CETL changes from planning parameters reports and communication with PJM staff, PJM (2010i, 2011k).

Other large changes to CETL have not been related to major backbone transmission upgrades but have, instead, been related to smaller transmission projects or modeling changes. In 2014/15, the 1,000 MW CETL increases into MAAC, SWMAAC and PEPCO was caused by adding a new substation and transformer, illustrating the sensitivity of CETL values to even relatively modest transmission projects. Similarly, the 1,917 MW decrease in MAAC and the 675 MW decrease in SWMAAC for 2013/14, and the 1,095 MW increase in EMAAC for 2014/15 demonstrate the considerable sensitivity of CETL to changes in the distribution of load and generation within LDAs.

c. Impacts on and Perceptions of Market Participants

Many of these substantial CETL changes —and their impacts on market prices —came largely as a surprise to market participants when they were published shortly before each auction. The unexpected and unpredictable nature of such sizeable changes has reduced market confidence in the stability of RPM pricing. We attribute the uncertainty that market participants experienced to three causes:

- *CETL Impacts on Market Fundamentals* — In some cases, changes in market prices were caused by underlying market fundamentals and need to be reflected in market prices to achieve efficient outcomes. This is also the case for CETL increases caused by major transmission upgrades, or even large CETL decreases associated with the delay of the Susquehanna-Roseland transmission line.

- *Lack of CETL Forward View and Modeling Transparency* — Market participants lack visibility into CETL determination and CETL's likely future values. This lack of visibility relates to: (a) insufficient information about how CETL will change under changes to market fundamentals including load, supply, and transmission changes; and (b) lack of transparency around how easily constraining transmission elements could be relieved and the benefit from relieving binding constraints.
- *Modeling Sensitivity* — CETL determinations appear to be very sensitive to modeling inputs, including potentially large impacts from small transmission upgrades and small modeling changes regarding the distribution of peak loads and of capacity resources online.

CETL changes that are driven by market fundamentals need to be reflected in market prices, even if they may adversely affect unhedged suppliers or loads. However, changes and uncertainties that are driven by the lack of transparency or modeling sensitivity may have a detrimental effect on the market confidence and should be mitigated, if possible.

d. Recommendations

In response to these concerns, our recommendation is that PJM and stakeholders investigate options to increase CETL transparency and stability. However, we understand that this is not an easy task for a number of reasons. The modeling used to estimate CETL is complex, time intensive, and necessarily involves many data sources and judgments. Further, any changes to CETL determinations must also consider the impacts on the transmission planning process, which uses CETL to identify reliability-related transmission upgrades.

Because we understand that there will not be an "easy fix," we present our recommendation as a single broad objective: to *increase CETL transparency and stability*. We also offer a list of five options that may be explored for achieving that objective. At a high level, the options we present for increasing transparency involve increasing transparency into CETL calculations, its determinants, and expected future changes to CETL. The options we present for increasing CETL stability involve preventing CETL from being limited by easily-solved constraints and avoiding excessive changes to transmission plans.

Options to Increase CETL Transparency: Increasing transparency into CETL determinations and likely future CETL values could reduce unpredictability (without necessarily reducing variability) and avoid surprises just prior to RPM auctions. First, it is important to improve stakeholders' understanding of CETL calculations, CETL determinants, and expected future CETL changes. Sharing CETL load flow cases, calculations, and lists of limiting elements with transmission owners and other market participants could also provide opportunities for stakeholder feedback and sometimes remedial action, as discussed further below. To those ends, we recommend that PJM and stakeholders consider the following:

- ***Provide CETL Forecasts*** — We recommend that PJM consider providing CETL forecasts consistent with RTEP planning studies. The CETL values used for RPM are currently determined by PJM's transmission planning group each January, four months before each base residual auction. Stakeholders would benefit from seeing indicative forward-looking CETL estimates for each modeled LDA that account for planned transmission enhancements and other changes in system conditions. PJM could provide such estimates based on the transmission planning studies it already produces, including the 10-year outlook, 5-year outlook, and the 4-year "retool" study published 3 to 6 months before the BRA parameters are finalized each January. We recommend that PJM quantify CETL values for each of the LDAs modeled in RPM auctions (including, if known, future newly-constrained LDAs) for each of these transmission planning cases to provide market participants with preliminary 4, 5 and 10 year outlooks. If practical, PJM could also provide, for example, sensitivity analyses showing the effects on CETL of removing at-risk generators.

- ***Make Models Available*** — We recommend that PJM consider making the modeling cases and other data and assumptions related to CETL calculations available to market participants. Providing this information would enable market participants to conduct their own sensitivity analyses to understand how CETL might change. Our understanding is that PJM would be authorized to release the model and associated data to market participants that have CEII clearance, consistent with current practice for sharing transmission planning power flow cases. The only data that could not be shared would be the unit-specific EFORd data used in PJM's analysis.

Options to Increase CETL Stability: Although CETL must change when new transmission is planned and other system conditions change, it should be possible to increase the stability of the parameter. One area for improvement is to prevent easily-resolved constraints from limiting CETL. Allowing easily-resolved constraints to limit CETL is inefficient if a low-cost upgrade could substantially increase CETL, and it makes CETL unstable because an upgrade could be made at any time. Another area for improvement is to avoid excessive changes to transmission plans. PJM might be able to address these sources of instability through the following options:

- ***Identify Successive Limiting Elements*** — PJM should consider identifying successive limiting elements and the CETL impacts of relieving those constraints. Along with its release of CETL determinations, PJM already indicates which transmission facilities are the limiting elements. PJM could provide additional analysis to indicate how much CETL would increase if that constraint were relieved, and what the next limiting element would be, and repeat that process for several successive limiting elements. This would provide insight into CETL stability and help market participants identify cost-effective transmission upgrades.

- ***Facilitate Cost-Effective Upgrades*** — PJM could consider facilitating opportunities for cost-effective transmission upgrades through RTEP and market-based responses. Providing the information described above with the 5-year transmission plan and 4-year update would allow market participants to identify cost-effective transmission upgrades. These upgrades could be made either through the RTEP process or through market-based Qualified Transmission Upgrades ("QTUs") and Customer-Funded Upgrades.[133] If easily-solved constraints were upgraded through RTEP or through QTUs or Customer-Funded Upgrades, it would stabilize CETL and prevent it from being inefficiently limited by easily-resolved constraints.

[133] Customer-Funded Upgrades receive Incremental Capacity Transfer Rights ("ICTRs"). We have not specifically examined the effectiveness of the QTU mechanisms.

- ***Develop RTEP Deadband*** — We recommend that PJM and stakeholders consider creating a "deadband" within which transmission plans would not change, as the Regional Planning Process Task Force (RPPTF) has already been discussing.[134] This concept is discussed in greater detail below.

One of the current criteria for reliability planning is to add transmission when the resource adequacy requirement cannot be met by projected generation (ignoring potential new entry) and existing transmission alone. When this condition is expected, CETO (the transmission "objective") will exceed CETL (the transmission limit), which triggers planning for transmission upgrades to address the deficiency. However, if load forecasts or other system conditions subsequently change and CETO drops below available CETL, PJM will delay or cancel the planned transmission upgrades.

This response to short-term changes in system conditions imposes substantial uncertainties by delaying projects in the midst of permitting and other development efforts. The resulting impacts on market participants can be large, as shown by the delay of the Potomac-Appalachian Transmission Highline ("PATH"), which was previously planned to come into service by June, 2015, but was delayed in February for an indeterminate period.[135] The line would likely have increased CETL into MAAC by approximately 2,700 MW.[136]

Our understanding is that the primary reason that PATH was delayed was a substantial decrease in load forecasts related to the economic downturn, but it is not clear for how long the need for the project will be delayed. Such uncertainty in the online date of new transmission projects will also create substantial uncertainty for potential generation developers that will be unwilling to invest in projects that may or may not be needed depending on when and whether a transmission upgrade will come into service.

PJM could reduce this uncertainty by creating a "deadband" within which transmission plans would not change.[137] Basing transmission plans on the current strict threshold of CETO/CETL > 1.0 is problematic because it allows small changes to the load forecast, CETL, or projected installed generation make the difference between a major transmission project being needed in one year but not needed the next. The CETO/CETL ratio of 1.0 also means that these major projects are planned in RTEP as soon as there is a 50% likelihood that the project will be needed based on the current load forecast. To introduce more stability in the planning process, PJM could wait to plan a project until the CETO/CETL ratio exceeds, for example, 1.02 (instead of 1.0), or until the load forecast indicates a 60% likelihood that the project will be needed. Once an enhancement is planned, PJM could adhere to the plan even if the ratio subsequently drops slightly below the current trigger point, for example, until the ratio drops below 0.95, or until the load forecast indicates only a 25% chance that the project will be needed.

---

[134] See PJM (2011o), p. 9.

[135] See PJM (2011m, 2011n).

[136] Based on the difference in MAAC CETL between Scenario 19 (which did not include the PATH upgrade) and Scenario 20 (which did include the PATH upgrade) in the PJM 2013/14 price scenario analysis. See PJM (2010j)

[137] See PJM (2011o), p. 9.

Such a deadband would reduce the uncertainty in future CETL changes, which would improve the stability and predictability of RPM prices. An additional benefit of using a planning threshold slightly above the current 1.0 threshold is that it would allow for market-based opportunities to meet resource adequacy needs (*e.g.*, through QTUs, Customer-Funded Upgrades, or non-transmission alternatives), instead of pre-empting market-based solutions as soon as the ratio exceeds 1.0. Yet a 1.02 trigger likely would still be low enough to avoid serious reliability shortfalls in any given delivery year even if the market does not produce a solution.

While we do not propose specific values for the deadband boundaries, we propose two reasonable approaches for developing these numbers. As mentioned, one would be to base the high and low thresholds on the weather-normalized load forecast uncertainty. Under this approach a transmission project would not be planned unless it were, for example, 60% certain that it would be needed to meet the reliability requirement and would not be unplanned unless the chance that it would be needed to meet the reliability requirement dropped to 25%. A second approach would be to tie the deadband to the width of the VRR curve, such that small deviations from the target procurement level within the bounds anticipated under RPM would not be sufficient to trigger a transmission upgrade.

2. Modeling Transmission in RPM

One of the primary driving factors behind implementing RPM was the need to represent the locational value of capacity and reflect location-specific capacity shortages. Prior to the implementation of RPM, the Capacity Credit Market was not location-specific and could not address resource adequacy shortfalls in eastern PJM.[138] RPM was designed as a market-based *locational* capacity mechanism to provide efficient economic incentives for incremental capacity development in the locations where it is needed the most. To ensure that efficient economic incentives are produced by RPM, transmission capabilities must be represented accurately. We have generally found transmission representation under RPM to be implemented effectively, although we have identified refinements that could make RPM more robust to potential future locational modeling needs.

a. Determining Which LDAs to Model in Auctions

Partially in response to our 2008 report and effective for 2012/13 delivery year, PJM has revised LDA modeling rules such that more LDAs will be modeled in RPM auctions.[139] These new rules expanded the conditions under which LDAs will be modeled to include: (1) MAAC, SWMAAC, and EMAAC which will always be modeled; (2) LDAs with CETO ≤ 1.15 CETL; (3) LDAs that have price separated in any of the three previous BRAs; and (4) any LDAs that PJM expects may price separate.[140] These changes have been a beneficial addition in that they recognize that LDAs may price separate for economic reasons and may price separate in the future even if they have not price separated in the past.

[138] See PJM (2005), pp. 5-6.

[139] See PJM (2008f), pp. 50-53; Pfeifenberger and Newell (2008), pp. 104-109; PJM (2011d), pp. 11-12.

[140] See PJM (2011d), pp. 11-12.

Environmental regulations may introduce new locational resource adequacy challenges. We have seen, as discussed in Sections II and III.E, that RPM has so far proven robust in procuring the target capacity procurement despite the EPA HAP regulation expected to come into force during the 2014/15 delivery year. Sufficient capacity has been procured in all modeled LDAs. However, we have also observed that some zones that are not currently modeled as constrained LDAs have had a disproportionately large fraction of uncleared resources. In one currently unmodeled zone, the capacity of cleared resources for the 2014/15 delivery year dropped by 16% compared to the prior delivery year. Whether this particular reduction in committed resources creates locational resource adequacy concerns cannot be determined without also examining CETL for this zone, which has not been calculated. It is possible, however, that such a large reduction in LDA-internal resources could constrain the LDA even though it is not yet modeled in RPM.

While generators in PJM have the flexibility to avoid reporting their retirement until 90 days prior to the effective date, this does not mean that the *potential* for those retirements cannot be foreseen prior to the submission of deactivation requests.[141] There are both proactive and reactive ways to prevent potential resource adequacy and economic efficiency problems associated with zones that have not been modeled in RPM. In a proactive approach, PJM would more actively analyze which zones have a large fraction of capacity resources at risk for needing costly environmental upgrades. We understand that some analyses of this type have already begun in the context of the RTEP process.[142] Any area with a substantial amount of such resources that, if they were retired, would reduce the LDA below the 1.15 CETL/CETO threshold ratio could be modeled in RPM. A reactive approach would identify zones with substantial quantity of generating resources that have not cleared the prior BRA and, if the retirement of these resources would create a constrained LDA, model those zones in the remaining incremental auctions for that delivery year and the BRAs for subsequent delivery years.[143] Both of these approaches would provide safeguards against developing reliability problems develop in unmodeled LDAs.

b. Defining LDAs Based on Transmission Topology

As discussed in our 2008 report, it is important to recognize that transmission system capability may not in all cases be accurately represented by the traditional boundaries of transmission owners' service areas.[144] One example of how transmission constraints may not exactly conform to boundaries is the non-contiguous portion of APS, which is geographically entirely surrounded by the MAAC LDA, but modeled with the rest of APS as part of the unconstrained RTO under RPM.[145] Some stakeholders have suggested other LDAs that they believe should be modeled in

[141] Deactivation requests must be submitted to PJM at least 90 days prior to the proposed deactivation request, see PJM (2011p), p. 336.

[142] For example, see PJM (2011p) and PJM (2011z).

[143] It may even be possible to determine endogenously as part of the auction clearing process whether an LDA would be constrained based on the clearing of resources within the LDA.

[144] See Pfeifenberger and Newell, et al (2008), pp. 103-109.

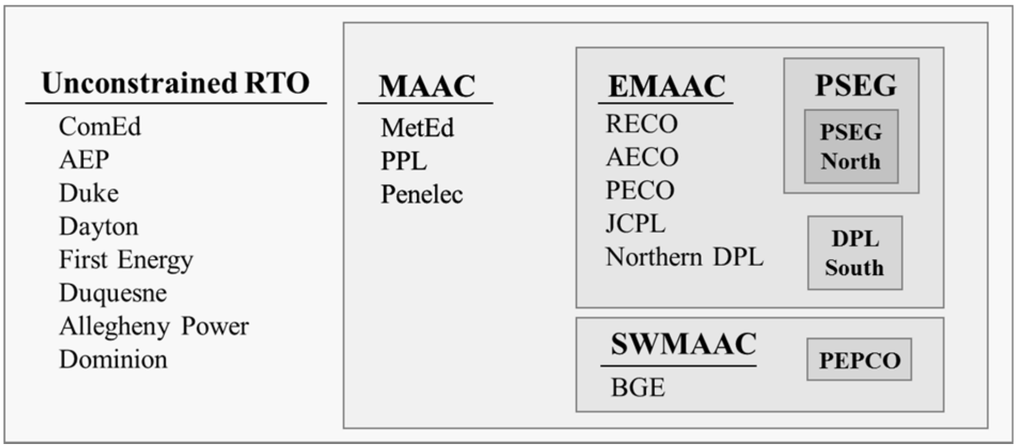
[145] The non-contiguous portion of APS discussed here is in the middle of Pennsylvania surrounded by PENELEC and PPL zones, both of which are in the MAAC LDA. See PJM (2011s).

RPM, including the AP-South region, although we note that PJM already has a process by which stakeholders may identify such regions for consideration as new LDAs under RTEP.[146]

c. More Flexible Ways to Represent Transmission in RPM Auctions

RPM currently models transmission constraints using a nested LDA structure. Each LDA can import capacity from one "parent" LDA, and no LDAs are modeled with export constraints. Figure 25 is a schematic diagram showing this nested LDA structure. All modeled LDAs are shown in boxes with names in bold font. The names of transmission zones that are not currently modeled as LDAs are shown in regular font.

Figure 25
Nested Zonal Locational Deliverability Areas and Utility Service Areas



Sources and Notes:
Modeled LDAs are shown as squares with names in bold; other transmission zones are not currently modeled.
LDA definitions and structure from PJM (2011d), pp. 10-11.

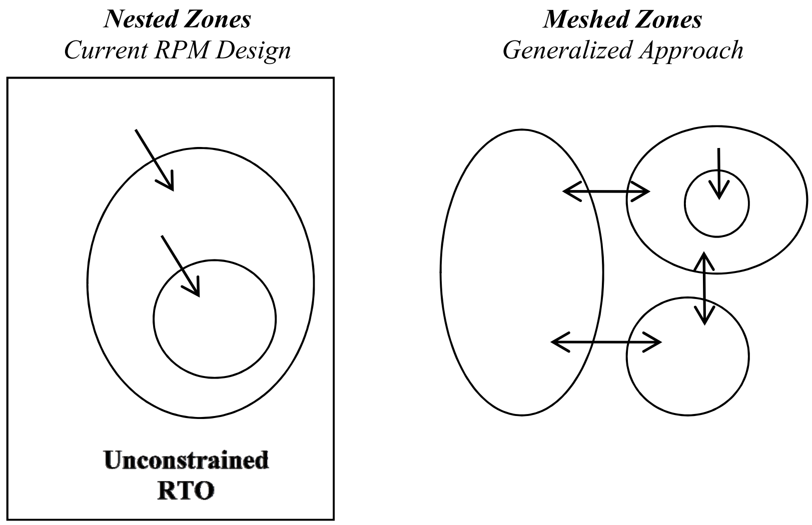
This nested, import-constrained LDA structure has limitations in that it is not possible to represent all types of transmission constraints under this system. For example, this approach is not able to model: (1) export-constrained LDAs (including LDAs that may be either import-constrained or export-constrained); or (2) more complex transfer capability relationships in which import capability may be available from LDAs other than just the parent LDA. An example where this nested LDA structure may not work well is illustrated by the planned MAPP transmission project. Under the current structure, imports into the DPL-South zone must follow the path: RTO → MAAC → EMAAC → DPL-South. However, with the MAPP project, DPL-South would be able to import capacity from either of two directions, one along the path currently modeled through EMAAC, and another path introduced by the MAPP line: Dominion → PEPCO → DPL-South. The MAPP project would also directly connect PEPCO to Dominion, which would create an alternative import path for PEPCO.

More general LDA capacity transfer relationships of the sort described here could be better represented based on a "meshed" LDA framework as depicted schematically in Figure 26. The figure contrasts the current RPM approach (left panel), which is limited to nested import-constrained zones, to a more general meshed approach which *could* account for export

[146] See PJM (2011d), p. 12.

constraints, path-dependent constraints, and the potential for multiple import interfaces into some LDAs (right panel).

Figure 26
Nested Import-Constrained Approach vs. Meshed Approach to LDA Modeling



It may not be critical to develop a more general approach to LDA modeling in the near term. However, as the excess capacity in the unconstrained RTO is reduced over time (*e.g.*, through environmental retirements), we expect that more LDAs will need to be modeled. As the number of LDAs increases, the current nested LDA structure may break down. In an extreme example, if all 25 LDAs needed to be modeled, a more general approach to modeling LDAs would certainly be necessary. The more general meshed zone framework is similar to what ISO-NE has proposed under new market rules, which will involve modeling all capacity zones in each Forward Capacity Auction (FCA).[147]

d. Summary of Recommendations for Transmission Modeling

With respect to transmission modeling in RPM, we have identified several potential refinements that PJM and stakeholders should consider in order to increase the likelihood that future resource adequacy needs and transmission constraints are accurately reflected in the RPM design.

- ***Model LDAs with Units at Risk for Retirement*** — To increase the likelihood that LDAs are modeled when needed for reliability and economic efficiency, we recommend identifying locations where a substantial number of units may retire.
  - ***Proactively Model LDAs based on Upcoming Environmental Regulations*** — We recommend that PJM and stakeholders continue ongoing efforts to identify units that may retire in response to new environmental rules. This could be done based on public data on emissions controls, stakeholder-submitted data on

[147] Additional complications and difficulties with a meshed zonal approach were also encountered in ISO-NE, but these were primarily related to difficulties in having a meshed zonal approach in combination with a descending-clock auction. PJM's sealed bid auction would not experience similar difficulties. See ISO-NE (2010), Section III.

individual plants, or IMM data from the 2014/15 BRA or other auctions. If the simultaneous retirement of the identified resources were to put a particular LDA below the 1.15 CETL/CETO threshold, PJM could consider proactively modeling that LDA in upcoming BRAs and incremental auctions.

  - ***Reactively Model LDAs based on BRA Results*** — We recommend that PJM examine post-BRA clearing results to identify LDAs that would drop below the 1.15 CETL/CETO threshold if uncleared resources were to retire. Specifically, we recommend that these LDAs be modeled in the remaining incremental auctions for that delivery year and BRAs for subsequent delivery years to avoid inefficient retirements and ensure procurement of sufficient resources.

- ***Define LDAs Based on Transmission Capability*** — While we have not specifically examined which LDA boundaries might need to be redefined, we reiterate our general recommendation from 2008 that LDAs are most appropriately and accurately defined electrically based on transmission constraints rather than by transmission provider territories. If electrically-defined LDAs would substantially differ from the current LDA definitions, PJM and stakeholders could consider revising these boundaries.

- ***Model Export-Constrained and Meshed Zones*** — We recommend that PJM and stakeholders consider generalizing the LDA concept beyond import constrained and nested LDAs. A more generalized "meshed" approach would be flexible enough to account for the potential for: (1) export-constrained zones; and (2) multiple import or export interfaces between individual LDAs that may not be accurately represented through nested LDA relationships.

3. Reducing Reliance on Reliability-Must-Run Contracts

a. Background and Concerns

Reliability must run (RMR) contracts are out-of-market backstop contracts used to prevent reliability problems that could occur when certain generating units retire. After a generator proposes to retire, PJM conducts a retirement study to determine whether reliability violations would occur. If reliability violations are identified, PJM may deny the deactivation request and offer to compensate the generation owner for keeping the generating unit online by signing an RMR contract. Such RMR contracts, while often necessary, are generally undesirable because they can be costly and will distort energy and capacity market prices.

In some markets, large out-of-market payments have also been indicators of problems in the market design. For example, the need to rely on several RMR agreements to ensure locational reliability under the prior capacity construct was one of the motivating factors for abandoning that design and implementing RPM.[148] Some stakeholders have indicated their concerns about the more recently-signed RMR contracts for Cromby 2, Eddystone 2, and Hudson 1, stating that

[148] See PJM (2005), pp. 5-6.

these contracts may indicate a deficiency in the RPM design, which was supposed to avoid such RMR backstop solutions.[149]

As we will discuss further in the context of coordinating RPM and RTEP, when evaluating whether a reliability concern can be addressed through RPM, one must distinguish between reliability concerns based on (1) localized transmission security, and (2) resource adequacy. Capacity markets are designed to address resource adequacy concerns. Thus, where a generation retirement would create highly localized transmission security violations, capacity markets are not well-suited to identify replacement capacity since adding resources in other locations within the same LDA would not resolve the problem. In this case, RMR contracts may temporarily be the only available solution if there is insufficient time to develop more cost-effective transmission or location-specific generation solutions. These types of transmission security violations do not indicate problems with RPM as they are generally unavoidable at the time of a specific generation retirement and could not have been prevented through additional capacity procurement from any other resources within the LDA. Our understanding is that the Cromby and Eddystone RMRs address such a transmission security violation. The Hudson RMR was also triggered by N-1-1 transmission security criteria violations, although the violations were far from Hudson and could presumably have been solved by adding generic resource within the LDA.[150]

If the retirement-related challenge creates a resource adequacy concern within an LDA, however, RMR contracts will generally not be an efficient solution to address the concern. A preferable solution would be to let the at-risk generation be replaced with other capacity resources procured within the LDA through RPM mechanisms, such as incremental auctions. Identifying the LDA-wide need and fostering such competition of resources within each LDA is precisely what RPM is intended to do. RPM offers a market-based alternative to RMR contracts that would address LDA-wide resource needs as long as the LDA reliability requirement is identified in the capacity auctions. However, there are several circumstances under which an LDA's reliability requirement might be understated in the auctions, causing RPM to under-procure sufficient market-based capacity resources in the LDA, potentially necessitating inefficient RMR contracts:

(1) If post-auction retirement studies include a stricter reliability standard than is included in the LDA reliability requirement for the auction, then retirement requests can result in inefficient RMR contracts. For example, if the binding constraint on LDA-wide need is an N-1-1 violation, it is considered a "transmission security" issue that is not considered in the LDA resource adequacy requirement for RPM purposes, *even if the violations could be addressed by any resource in the LDA*. The LDA reliability requirement is currently based on only an N-1 First Contingency Total Transfer Capability (FCTTC) analysis. Our understanding is that not recognizing the full LDA-wide resource need in the auction is what led to the Hudson RMR.

(2) CETL used in the auction could be higher than the transfer capabilities that are recalculated after the auction, for example, when resources that did not clear in the

[149] See, for example, MW Daily (2011). For additional documentation on these RMR contracts, see PJM (2011t), pp. 86-89.

[150] See Map 4.6 "PECO Zone: Upgrades Required by Eddystone and Cromby Retirements" and Map 4.7 "2012 Overloads — Hudson Unit 1 Retirement" in the RTEP [complete cite].

auction request deactivation. Such deactivation requests could reduce CETL by causing the pattern of electrical flows to change, thereby affecting the flows on the limiting transmission element.

(3) The CETO calculation assumes that all existing units will be available unless they have submitted a deactivation request. If this assumption overstates generation availability in an LDA (*e.g.*, because units that did not clear in previous auctions may be forced to retire), CETO will have been understated for the purpose of determining the auction parameters. Understating CETO can prevent the LDA from being modeled in the auction, thus not providing needed price signals and increasing the likelihood of having to rely on out-of-market RMR contracts for units that could have been committed through RPM if the LDA had been modeled.

b. Recommendations

To avoid these potential problems which could lead to inefficient RMR contracts, we recommend that PJM and stakeholders consider the following options. The first three options are presented in the order of potential problems discussed above:

- ***Set LDA Reliability Requirements Consistent with Certain Transmission Security Criteria That Would Be Used in Retirement Studies*** — We recommend that PJM determine whether any of the N-2 "transmission security" criteria that might lead to RMR contracts when existing generation seeks to retire could be addressed by any capacity within the same LDA (this will not be true of highly localized transmission security violations). Such criteria should be included in the LDA resource adequacy requirement used in RPM auctions so that the resource need is reflected in market prices and enough capacity can be procured within the LDA through RPM.
- ***Perform CETL Calculations Consistent with Auction Results*** — We recommend that PJM and stakeholders consider revising CETL calculations to account for resources that will likely not clear or have actually not cleared in RPM auctions. Because the determination of which units will not clear in RPM and, ultimately, may decide to retire cannot be foreseen perfectly at the time of the CETL calculation, this would be a difficult standard to achieve. Some options that could be considered, however, include:
  - Using information from prior auctions to anticipate potential retirements by removing units that have not cleared in recent RPM auctions. This may also affect CETL updates for incremental auctions by removing resources that did not clear in the BRA from the CETL analyses . If the retirement of uncleared units reduces CETL, it would allow needed resources to be procured in the incremental auctions and avoid reliance on RMR contracts.
  - When calculating CETL, LDA-internal capacity is ramped down and replaced with imports until the maximum capacity import limit is reached. These internal capacity resources could be dispatched down in descending order of the last BRA's offer prices (indicating the likely order of non-clearing units). This type of dispatch order might more accurately reflect the distribution of ultimately-available resources, resulting in more accurate estimates of future flows on critical transmission elements that determine LDA-wide needs.

- Another option would be to use bid data available to the IMM just prior to each auction to calculate CETL. In this case, CETL would be calculated based on an exclusion of any units that are offering into the BRA at high levels (as approved by the market monitor).
- It may also be possible to update CETL dynamically within the auction clearing process by making CETL dependent on whether certain large, key units fail to clear. This would require an analysis prior to the auction to estimate how CETL would change if certain key units were to become unavailable.

- ***Model LDAs More Proactively*** — Consistent with our recommendation in Section VI.A.2, some RMRs could be prevented by more actively identifying generation at risk for retirement and by modeling LDAs proactively when their CETL/CETO ratio is at risk to drop below the 1.15 threshold under a scenario in which some or all of the "at-risk" generation retires.
- ***Rely on Incremental Auctions to Avoid RMR Contracts*** — If reliability concerns caused by the announced retirement of a generating plant can be addressed by any type of capacity resource within the LDA, PJM could attempt to procure replacement capacity prior to the delivery year through the next incremental auction. An RMR contract would still be signed only if such resource procurement through an incremental auction is not possible.

4. Coordinating RPM and RTEP

a. Background and Concerns

Coordinating capacity markets and transmission planning is inherently difficult. Planning efforts for transmission and capacity resources are conducted by different entities and they occur at different times given the difference in project development timelines. In PJM, transmission planning is conducted on a five- to ten-year forward basis by PJM and its transmission owners, while planning efforts for capacity resources are conducted by competitive market participants through RPM participation, which is on a three-year forward basis. An additional difference is that the cost of transmission investments are recovered mostly through cost-of-service regulated tariffs, whereas the costs of capacity resources are recovered primarily in a market environment.

The two processes are inextricably linked, however, being dependent on each other and also sometimes representing alternative solutions to the same reliability concern. To coordinate these processes as effectively as possible, it is important to distinguish between transmission upgrades planned for two types of reliability concerns: (1) reliability concerns related to transmission security criteria, and (2) reliability concerns related to locational resource adequacy. For many transmission security needs, generation and DR alternatives do not exist. However, for locational resource adequacy needs, generation and DR alternatives do exist and the very purpose of RPM is to ensure efficient market-based incentives for them to be developed in the needed location.

We are concerned that the way the transmission planning framework for locational "reliability" addresses resource adequacy concerns can preempt market-based solutions under RPM. RTEP triggers transmission upgrades when the 5-year outlook projects a CETO/CETL ratio greater than 1.0. Because CETO is calculated as the locational resource adequacy requirement minus the expected amount of locational capacity resources, it includes an assumption about which capacity resources will be available within an LDA.[151] At that time, capacity market results are still unknown, which means that resource availability within the LDA, including any generation and DR additions and retirements, must be assumed. The CETO/CETL criterion will then require a transmission upgrade that could pre-empt a LDA-internal resource adequacy solution that may otherwise have been developed under RPM. Once the CETO/CETL criterion is triggered in transmission planning, there is little opportunity for new generation or DR to meet the identified resource need even if doing so would be less expensive than the planned transmission upgrade. Ideally, generation and DR solutions would be allowed to compete with transmission, and a market-based solution to LDA-level resource adequacy needs (as opposed to more location-specific transmission security issues) would be identified and committed through RPM.

b. Recommendations

We understand that PJM is currently reviewing its RTEP process and recommend that PJM explore the possibility of adding an additional economic planning component to RTEP. The additional economic criterion we propose here for evaluating resource adequacy-driven "reliability" projects would have a fundamentally different purpose from the current mechanism for identifying "market efficiency" upgrades under RTEP.[152] The current economic upgrades process is intended to allow for the development of transmission projects that are not needed for reliability purposes but that are desirable for purely economic reasons. The additional economic criterion that we propose here would be a threshold applied to the approval of reliability-driven transmission projects for which there are LDA-internal capacity alternatives. Such a transmission project would only be approved if the transmission solution is found to be less expensive than the expected cost of LDA-internal capacity alternatives. We have not conducted a comprehensive review of how such criteria could be structured within RTEP, but recommend that PJM and its stakeholders further evaluate these options as part of the ongoing RTEP review process:

- ***Consider Economic Criteria in RTEP for Reliability Projects*** — We recommend that PJM and stakeholders consider adding economic criteria to the evaluation of transmission projects that are planned primarily to meet locational resource adequacy requirements as represented by the CETO/CETL ratio. An economic criterion could, for example, require that such a transmission project would be pursued only if were cost-effective compared to generic LDA-internal generation additions that could similarly address the identified reliability concern (*e.g.*, the addition of a combustion turbine at a cost equal to Net CONE). We have not conducted a comprehensive review of how such criteria could be structured within RTEP, but recommend that PJM and its stakeholders further evaluate these options as part of the ongoing RTEP review process.

[151] See PJM (2011i), p. 53.

[152] See PJM (2011i), Sections 1.3.2, 1.5.2, 2.6 and Attachment E.

B. LOAD FORECASTING

1. Background

Stakeholders representing load and some of the state commissions raised concerns over the accuracy, economic efficiency, and transparency of reliability targets and load forecasts. Their concerns with reliability targets have been discussed in Section III.G of this report. This section addresses whether the load forecasting process could be improved to support greater transparency, predictability, and market confidence.

2. Analysis

It is invariably the case that future peak loads are uncertain and cannot be forecasted with great accuracy. Moreover, both actual future loads as well as the load forecasts themselves will change with economic market conditions and other factors. Just as it is not possible to forecast economic growth with great accuracy, it will not be possible to forecast future peak loads with any more certainty. In fact, uncertainty over future economic growth will magnify uncertainty in load forecasts. The drop in loads and load forecast in response to the unanticipated poor economic conditions over the last several years presents a good example of this type of uncertainty.

That load forecasts are uncertain also means that load forecasts for future delivery years will necessarily change over time as new forecasts are developed based on updated economic and other data. This uncertainty in load forecasts will consequently be one of the administratively-determined parameters that contribute significantly to uncertainty in capacity costs and RPM payments. Changes in load forecasts affect RPM payments through several mechanisms: (1) the total amount of capacity that needs to be procured on a system-wide and LDA basis; (2) the price at which that capacity clears; and (3) the extent to which prices within individual LDAs will separate from RTO-wide levels. For example, the 2014 system-wide summer coincident peak load forecast updated earlier this year was approximately 4,200 MW (approximately 2.8%) lower than the 2014 load forecast made in early 2010.[153] While the new forecast will be a more accurate estimate of likely future peak loads, the adjustment necessarily has significant implications for RPM. At an RPM clearing price of $130/MW-day for the 2014/15 delivery year, this change reduced RPM capacity payments by approximately $200 million per year due to the lower quantity procured, even before considering the impact in reducing the clearing prices.

Load forecasts will additionally affect RPM through CETL determinations and the transmission planning process. The transmission planning process identifies reliability violations and new transmission facilities needed to address these violations, but the process also delays previously-planned transmission facilities if updated load forecasts no longer result in reliability violations. For the purpose of transmission planning and RPM-related CETL determination, it is also necessary to estimate how the total load for a load zone is distributed within each zone. Changes

[153] From 145,829 MW and 149,998 MW 2014 summer coincident peak load forecast without ATSI or DEOK from the 2010 and 2011 load forecast reports, respectively. See PJM (2010c), p. 29 and PJM (2011e), p. 30.

in the estimated distribution of load within a zone can be as consequential as changes in the total load for that zone because of the impact of the load distribution on CETL calculations.

Given the size of the PJM market area, the largest organized power market in the world, and the associated magnitude of the dollar impacts related to even fairly modest changes in load forecasts, it is also increasingly important to assure to the greatest degree reasonable that:

1. Changes in load forecasts reflect to the largest degree possible the true changes in market fundamentals and a consensus of expectations regarding economic conditions three years into the future;

2. Both system planners and market participants are aware of inherent load forecasting uncertainties and are informed about the likely magnitude of this uncertainty; and

3. The load forecasting process utilizes best available practices and forecasting models that are transparent, understood, and accepted by market participants.

This requires that the load forecasting process is designed to minimize the likelihood of errors introduced by the load forecast development and review process. To avoid excessive uncertainty in RPM clearing prices and total annual payments, it would also beneficial to reduce fluctuations in load forecasts that are solely due to unavoidable statistical uncertainty of the underlying forecasting models.

3. Recommendations

PJM is fully aware of these factors and is already engaged in a review to improve its load forecasting model, involving stakeholder input through the Load Analysis Subcommittee (LAS) and Planning Committee. We do not offer specific recommendations about these current efforts to improve the PJM load *forecasting model* itself. However, in light of stakeholder concerns and the importance of load forecasting for RPM, we offer the following recommendations regarding PJM's *forecasting process* for further consideration, individually or in combination:

- ***Improve Stakeholder understanding of updated load-forecasts***. We recommend that PJM consider expanding the documentation and narrative explanation of its updated load forecasts. Each time an official new load forecast is issued, PJM would provide to stakeholders: (1) documentation of the changes in load forecasts and model input data from the prior forecast; (2) a full analysis and narrative explanation of the reasons for the observed changes in load forecasts (*e.g.*, changes in model coefficients or changes historical and forecast dependent variables such as economic growth); and (3) documentation of changes (if any) in how load forecasts are distributed within load zones for transmission planning and RPM-related CETL determinations. It may also be possible to provide this information for stakeholder review of a preliminary load forecast that could then be finalized with stakeholder feedback.

- ***Provide Estimates of Forecasting Uncertainty***. We recommend that PJM consider providing statistical estimates of the uncertainty of its weather-normalized long-term load forecasts. Uncertainty could be expressed as confidence intervals (*e.g.*, a 50%, 75% and 90% confidence band) for weather-normalized load forecasts for each of the next 10 years, including an estimate of the portion of the uncertainty caused by the uncertainty of key explanatory variables such as economic growth. (Because planning reserve margins are based on peak load forecasts for normal weather, weather-related load uncertainties used for transmission planning and reliability studies, such as forecasts of 50/50 and 90/10 loads, should be quantified separately.)

- ***Continue existing efforts to refine the load forecasting model***. We recognize PJM's current effort, through the LAS, to improve its load forecasting model, and we recommend continuation of this effort. This ongoing effort might additionally explore assessing the extent to which different model specifications and independent variables (*e.g.*, different data sources of economic growth forecasts) might be able to improve the model's multi-year forecasting error as an objective distinct from current effort to improve the model's backcasting accuracy. Within the current effort, we also recommend that PJM explore available options that might be able to reduce changes in load forecasts due to statistical uncertainty without suppressing changes in load forecasts due to changes in market fundamentals. (Documenting changes in load forecasts due to changes in economic forecasts and changes in model coefficients may be helpful in that regard).

- ***Consider Sharing Semi-Annual Preliminary Updates to PJM's Load Forecast***. We recommend that PJM consider releasing preliminary updates to its previous load forecast and associated preliminary changes to RPM parameters (*i.e.*, target RTO-wide and LDA-specific procurement levels). These preliminary updates would be solely informational and not be used for any planning or market operations purposes. We believe the release of such preliminary updates would increase transparency and reduce uncertainty because it would: (1) allow trends and changes in RPM parameters to become visible earlier to market participants; (2) increase stakeholder understanding and acceptance of the forecasting process and how it affects RPM; and (3) provide a better sense of changes in market fundamentals and forward-looking forecasting uncertainty.

- ***Collect UDC load forecasts as additional reference points***. We recommend that PJM and stakeholders consider collecting (if necessary on a confidential basis) any long-term load forecasts that are routinely prepared and updated by individual utility distribution companies and/or load serving entities. These UDC and LSE load forecasts would provide a reference point to PJM's own forecasts of the individual zones' peak loads. Comparing the level of these forecasts and how they change over time would serve as an additional tool to validate PJM's own forecasts, confirm observed trends and changes, and provide an additional safeguard against inadvertent errors in the forecasting process.

- ***Possibly Retain Academic Advisors to the PJM Load Forecasting Team***. We recommend that PJM explore the benefits of retaining two or three academic advisors available as a standing resource to the PJM load forecasting group. These advisors would be able to contribute significant theoretical and applied experience in the field of econometric forecasting, be available to PJM's load forecasting group as a resource, assist PJM in obtaining and maintaining a "best available practices" standard for both the forecasting process and the econometric model itself, and evaluate the soundness of proposed changes to the forecasting process and forecasting model.

We recognize that the full development and implementation of any of the above recommendations would likely require additional resources dedicated to PJM's load forecasting function. However, given the importance and monetary implications of PJM's load forecasting functions in terms of RPM and transmission planning, the incremental cost of these resource requirements will likely be small compared to the benefits. The benefits also include increased transparency, improved forecasting data and processes, and the economic benefits of being able to reflect a better understanding of long-term load forecasting uncertainty in PJM transmission planning and stakeholder investment decisions.

C. Comparability of Capacity Resource Types

One of the original objectives of RPM was to allow different capacity resource types to compete in meeting PJM's resource adequacy requirements. To ensure that resource adequacy is achieved at the lowest cost, it is important to ensure that all resources capable of providing capacity can participate in RPM and that resources providing comparable capacity receive comparable treatment.

We find that PJM's incorporation of multiple types of demand resources (DR) is one of RPM's greatest successes. The successful integration of DR also helps to achieve resource adequacy at a lower cost. PJM has already addressed the two most important original design issues that arose as the amount of DR increased: (1) starting with the 2012/13 delivery year, it fully integrated DR into RPM by eliminating the ILR option; and (2) starting with the 2014/15 delivery year, it established differentiated DR products recognizing that DR that allows for only limited dispatch and has only seasonal availability has less capacity value than year-round availability of unlimited resources.

However, some stakeholders have emphasized that with DR approaching 10% of RPM-cleared capacity, including two new, untested products, the comparability of DR to other resource types should be reassessed. We thus evaluate: (1) the new multi-product construct to accommodate different types of DR resources; (2) existing mechanisms to verify and enforce that resources committed in RPM will perform as promised; (3) the determination of the (UCAP) capacity value for DR; and (4) potential future directions to recognize the capacity value of other non-traditional resources.

We find that PJM's existing design largely addresses stakeholder concerns. However, we recommend some refinements to further improve the efficiency of RPM and to ensure that all resources can perform as claimed. Our primary recommendation is to consider expanding the resource registration process just before each delivery year to include audits of random samples of contracts and the nature of loads that will be reduced. Annual DR resources must be able to respond in all seasons and not be constrained by contractual limitations on the number of calls. Extended Summer resources must also be unconstrained in the number of calls. This will allow PJM to confirm that resources can respond as frequently as claimed. Such verification and potential deficiency penalties will provide strong incentives to DR providers to make their offers and commitments consistent with ultimate capabilities. However, since only a small fraction of DR committed in the 2014/15 auction cleared as Annual or Extended Summer DR, this mostly addresses a potential concern about commitments made in future auctions.

1. Multiple Products to Accommodate Different Types of DR

In response to the rapid growth of DR in RPM, PJM recently conducted a demand response saturation analysis[154] that assessed the impact of Limited DR replacing year-round (annual) generation capacity at a relatively large scale.[155] The primary concern was that extensive reliance on Limited DR—which can be curtailed no more than ten times a year, for only up to six hours during each event, and only during the summer months—could lead to reliability problems. As DR displaces larger amounts of generation capacity, it could be needed to curtail more often, for longer durations, or during months when Limited DR is not obligated to curtail. This was not a concern at low levels of DR penetration because the chance that a DR resource would be called more often than its capacity obligation allows was very small. PJM's DR saturation analysis indicated that reliability problems were likely if PJM continued to rely on Limited DR at higher levels of penetration.[156]

There were several options available to address this concern. One was to redefine the obligations of DR from a limited (10x6) capacity resource to an annual resource by requiring them to be ready and available during the entire delivery year, just like generation capacity committed under RPM.[157] Another option was to retain the Limited DR resource type while adding a new, unlimited DR resource type. PJM opted for a hybrid approach to resolve the identified reliability risks by adding two new DR resource types starting with the 2014/2015 delivery year: Annual DR and Extended Summer DR. Although these products can be called upon more often than the Limited DR, neither of the two new products must be available at all times. Extended Summer DR is required to be available every day during a six-month extended summer period, May through October (compared to up to 10 times from June through September for Limited DR) and must be able to maintain load curtailments for up to 10 hours per event (compared to up to 6 hours for Limited DR). Annual DR must be available every day of the delivery year except during PJM-approved maintenance outages. The duration of events during which it must respond is limited to 12 hours from May through October, and to 15 hours from November through April. Annual resources include the newly-defined Annual DR and other annual resource types which are generally required to be available at all times, such as generation, but also energy efficiency. Extended Summer resources include all Annual resources and the newly-

---

154 PJM Interconnection, L.L.C., Exhibit 1 of the Tariff filing to FERC in Docket No. ER11-2288-000, submitted on December 2, 2010 and approved by FERC on January 31, 2011.

155 Prior to the 2014/15 delivery year, the RPM design recognized only one type of DR that had limited obligations both in terms of the frequency, duration, and the timing of events during which it was required to respond. In the remainder of this section we refer to this resource type as "Limited DR".

156 PJM's analysis found that, at a 90% confidence level, the penetration of Limited (10x6) DR should not exceed 4.7% of peak load, in order to ensure that PJM would not need these resources more often, or request longer curtailments, than their obligation. An earlier analysis conducted by PJM found that reliability would not be affected at DR penetration below 7.5% of peak load, however that study was conducted using less sophisticated tools and analytical methods.

157 This approach is favored by PJM's Independent Market Monitor, arguing that "the potential benefit of an unlimited demand-side product will not be realized without the elimination of the current flawed DR product." See Monitoring Analytics LLC, *2010 State of the Market Report for PJM*, page 118. This approach has also been implemented in other markets. For example, in ISO New England's Forward Capacity Market, demand resources must provide an annual capacity product (although they can combine with complementary resources).

defined Extended Summer DR (*i.e.*, all resources that must be available at least as often as Extended Summer DR).

The new design ensures that an adequate amount of Annual and Extended Summer resources is procured in RPM by setting a minimum amount of these two types of capacity that must be procured for the RTO and each LDA in each base auction.[158] The auction clearing mechanism treats the two new minimum capacity constraints in a similar manner as it treats transmission constraints (*i.e.*, to clear a minimum amount of local capacity). DR that qualifies as two or more of the DR types may submit separate but coupled offers for each DR type.[159] The auction clearing algorithm selects the offer that yields the least-cost overall capacity procurement. It will choose resources out of merit order if any of the minimum capacity constraints is binding. Prices may rise to clear additional Annual or Extended Summer DR, if needed, and those higher prices will be awarded for Annual and Extended Summer resources, but not for Limited DR. The price adders for Annual and Extended Summer resources reflect the additional value of unforced capacity required to meet the minimum capacity requirements. As a result of the recent market design change, price separation in RPM can now occur not just by location but also by resource type.[160]

PJM held its first BRA under the new design in May 2011 for the 2014/2015 delivery year. The auctions appear to be working as planned. In the auction, more than half (9,253 MW) of all DR resources submitted linked offers as Annual DR with an unlimited number of calls. Only 511 MW of Annual DR offers cleared, and 1,441 MW of Extended Summer, and 12,166 MW of Limited DR.

Overall, we conclude that the recently implemented change to the RPM market design was a reasonable and effective solution to a valid concern. However, the introduction of multiple capacity products for DR raises the question whether other kinds of resources should be allowed to be classified by product type. In this context we offer the following recommendations:

---

158 The minimum amounts of Extended Summer resources are derived from the Reliability Requirement (reduced by the 2.5% Short-Term Resource Procurement Target) minus the maximum reliable amount of Limited DR. The maximum reliable amount of Limited DR is determined in a probabilistic analysis that identifies the level of DR where the probability that PJM will require 10 or more interruptions is less than 10% and the chance that it would require interruptions longer than six hours is relatively low. A similar analysis is used to establish the minimum amount of Annual resources and maximum reliable amount of Extended Summer resources. The maximum amount is the level of DR penetration at which the annual LOLE is 10% higher than the LOLE of a reference scenario with DR penetration of zero.

159 In other words, a single resource may have up to three linked offers, one each for Limited, Extended Summer, and Annual DR, but only one of those offers may clear in the auction.

160 PJM's Independent Market Monitor disagrees with some aspects of the new design, namely the introduction of the Extended Summer DR product and the retention of Limited DR, which it views as a "flawed" capacity product. The IMM argued that reliance on Limited DR may compromise reliability and the overall capacity market design, and the addition of new DR products adds unnecessary complexity and creates an illiquid market for these products. Protest of the Independent Market Monitor for PJM, filed with FERC in Docket No. Docket No. ER11-2288-000 on December 20, 2010.

- ***Reclassifying Energy Efficiency based on capability.*** Energy efficiency is currently considered an annual product,[161] even though it is providing load reductions during a limited period.[162] We recommend that PJM consider classifying energy efficiency based on the periods when it can actually perform. For example, while energy efficient lighting would be an Annual resource, more energy efficient air conditioners could be classified as Extended Summer rather than Annual resources.

- ***Allow for Seasonal Generation.*** Generation capacity with seasonal (summer-only) availability cannot participate in RPM, because generators must offer an annual product. We recommend that PJM consider allowing such generation to participate as Limited resources. PJM could also consider allowing all generation that is submitting offers as Annual resources to also submit lower-priced linked bids as Limited capacity, reflecting the lower costs of committing the unit for the summer only.

2. Assurances of DR Performance

Forward capacity markets need to have mechanisms in place to ensure that committed resources, both existing and planned at the time of the BRA, will be available during the delivery year to fulfill their capacity obligations. Existing generating resources may face the risk of costly environmental retrofits or other major unexpected capital expenditures to stay online. Planned generation or demand-side resources face the risk of unexpected cost increases or delays. Untested products face the additional risk that actual circumstances during which they have to respond may be very different from what is currently expected. In this section, we focus on DR performance because of its high recent growth, but also to address stakeholder concerns about whether DR capacity is comparable to generation. More specifically, our primary focus is to explore whether existing measures will ensure that: (1) CSPs have sufficient incentive to submit realistically achievable DR plans; and (2) CSPs face sufficient verification and penalties if they were to misrepresent limited resources as unlimited resources.

PJM already has several stages of verification—including qualification, tracking development, registration, and performance and testing—and penalty and incentive mechanisms in place. There are several stages to validate the quality of new capacity resources and to assess the likelihood that they will be able to perform as expected during the delivery year. These stages include qualification of resources for the BRA, tracking the whether committed resources achieve various milestones prior to the delivery year, and penalizing resources for under-performance during the delivery year. We reviewed the milestones that planned resources in RPM must meet to avoid penalties due to non-compliance with their capacity obligations.

Table 1 Table 25 below summarizes each of these milestones for planned DR, actions taken by PJM at each milestone, as well as potential enhancements to the current process, as discussed below.

---

161 PJM Tariff, Attachment DD, Section 2.1B.

162 The performance hours for energy efficiency are between hour ending 15 Eastern Prevailing Time (EPT) and the hour ending 18 EPT from June 1 through August 31, excluding weekends and federal holidays. See Section 1.20A and Schedule 6 of the PJM Reliability Assurance Agreement.

a. Qualification

All resources must meet the qualification requirements for the BRA no later than approximately two weeks before the auction. For planned DR, this process consists of a review of the resource provider's DR plan and the posting of credit. A DR plan consists of basic information about the project, such as the aggregator's plan to procure customers, project milestones, and the nominated DR value, including the underlying assumptions used to derive it. Since these resources do not exist at the time of the auction, the evaluation of DR plans must be based on the credibility of the plan. It is important to ensure the process of reviewing DR plans is effective. However, we did not identify any potential enhancements for this stage of verification.

b. Tracking the Development of New Resources

The next stage is the tracking of new resources committed in RPM, which takes place between the BRA and the start of the delivery year. PJM may verify that a planned DR adheres to its DR plan at any time, but there is no pre-determined schedule of required progress reports. Furthermore, there appear to be no penalties for not following the DR plan. In contrast, ISO New England requires regular quarterly updates, and planned resources experiencing delays risk losing their posted credit and their capacity obligation if the planned online date moves beyond the start of the delivery year due to the delay.[163] We recommend introducing ***periodic update requirements from planned resources*** (*e.g.*, just before each incremental auction) as this would provide a clear indication whether planned resources are on track to be completed by the start of the delivery year.

c. Registration in Emergency Load Response Program

Registration in PJM's Emergency Load Response Program is the final step before the delivery year. It must be completed and approved before the start of the delivery year to avoid deficiency penalties. As part of the registration process, customer-specific data (*e.g.*, peak load contribution) must be provided to PJM. The registration process is largely an administrative step and does not involve any verification by PJM of the resource's ability to perform.[164] Since at this step planned resources must be at their final stage of development—with actual end-users and contracts in place—we recommend that PJM ***consider verifying that the CSP has the physical or contractual capability to curtail as often and seasonally as required***. For example, we believe that air conditioning load and event-limited contracts should not be able to register as Annual DR (given that no curtailments can be provided outside the air conditioning season), except perhaps as a discounted part of a larger, sufficiently balanced portfolio. Although DR resources are required to test during the delivery year, those tests do not check how frequently a resource would be able to curtail if called frequently or across seasons.

This is the most important enhancement we recommend. Adding such verification (and the threat of deficiency penalties) would provide additional incentives to CSPs to make sure their programs meet required capabilities. A comprehensive audit of all DR contracts may be too burdensome, but PJM could select a random sample for contractual audits (*e.g.*, a CSP's

163 ISO New England Market Rule 1, Section III.13.3.4.

164 Although PJM does not currently verify resources ability to perform in the registration process, EDCs and LSEs review DR programs to ensure that the customer physically exists and is not double counted.

portfolio of resources in a single zone). PJM could address audit failures by applying penalties (*e.g.*, deficiency penalties to the CSP's entire PJM-wide portfolio) and/or referring the CSP to FERC.

Table 25
Verification of Planned DR

Activity	Timing	Assurances & Verification in Place	Potential Enhancements
Qualification of New Resources	At least 15 days prior to an RPM auction	**Review of DR Plan (**project description; customer recruiting plan & milestones; MW value of DR; key assumptions) **Verification of RPM Credit Limit** **"Provisional approval"** of DR MODs (assigns nominated value to individual resources) if above requirements are met	None identified.
Tracking	Anytime between BRA and delivery year	**Verify adherence to the schedule in the DR plan** at PJM's discretion at any time including, but not limited to, 30 days prior to each IA; mostly relies on suppliers to develop planned resources and manage deficiencies by procuring replacement capacity (else risk penalties).	Consider requiring CSPs to periodically report their progress against DR plans.
Registration in Emergency Load Response Program	January through May prior to delivery year	Requires submittal of some customer-specific information Must be in "Approved" status prior to start of DY to avoid commitment shortfall & Deficiency Charge	**Introduce random audits of contracts and physical loads** to verify zonal resource portfolio abilities to curtail as frequently and seasonally as represented (esp. for Annual and Extended Summer), with appropriately punitive penalties to incent CSPs to represent accurately.
Performance & Testing	During delivery year	**Penalty/credit** for under-performance during emergencies (Load Management Events) **Penalty** for failing tests, but CSPs initiate tests; can test repeatedly and submit the best results. Tests show MW but not ability to respond frequently or seasonally.	**Conduct random testing initiated by PJM**; limit CSPs' ability to selectively pick test results; extend duration of tests to multiple hours, *e.g.*, 6; provide energy payments during tests.

d. Performance Assessment and Testing during the Delivery year

The pre-auction validation process is followed by performance assessment and testing during the delivery year. Under normal, expected conditions, there may not be many actual load management events called in the delivery year. This limits PJM's ability to discover how DR resources (or portfolios) would perform under unexpectedly tight market conditions (*e.g.*, due to an extended heat wave and major plant outages) when their capacity is most needed and calls are more frequent. To prevent CSPs from overstating their capabilities, we recommend a more rigorous verification process prior to (and possibly also during) the delivery year as discussed above.

Performance verification during the delivery years is also important. In case there are no dispatch events at all, testing is important for verifying that CSPs can produce the total committed number of MW in each zone in a single call. The current testing process works as follows: DR providers are required to conduct a one-hour simultaneous test of all their resources in a zone if PJM does not otherwise initiate an actual load management event in that zone. They are allowed to choose the timing of the test, as long as it falls within the hours of the summer period when the resources are obligated to respond, and notify PJM 48 hours in advance. If less than one quarter of the resources fail a test, the provider is allowed to retest the subset of resources that failed. There is no current limit on the number of tests that may be conducted, and the provider can submit the single most favorable of all the test results.

The fact that CSPs may conduct an unlimited number of tests and submit only the results for the test of their choosing raises the concern that those tests results may not reflect the resource's actual ability to respond on a consistent basis. Therefore, we recommend that PJM ***consider adding random PJM-initiated tests to the current testing procedures, and limit CSPs' ability to selectively pick the test results***. Furthermore, we recommend ***extending the duration of the tests to a multi-hour period***, consistent with the fact these resource are required to respond for a period of several consecutive hours.

e. Comparability of Penalty Mechanisms

Performance needs to be supported by penalties for under-performance. Such penalties should ensure that suppliers have the incentive to make resources available and guarantee their performance during the delivery year. Comparability of obligations and penalties across resource type also ensures that the different resource types compete on a level playing field.

PJM has two general types of penalties. A supplier is subject to a *deficiency penalty* if it is unable to provide all or part of its committed capacity in time for and during the delivery year. *Performance penalties* apply when the supplier's committed resources do not perform adequately when called upon. Performance can be measured by various metrics during peak periods, testing, or other PJM-initiated events. Table 26 below compares penalties applicable to DR to those applicable to generation resources.

The penalties in Table 26 are grouped into the following categories: deficiency, availability, test failure, and other. Each penalty is decomposed into two components: (1) basis for penalty (for failing to meet a certain obligation, usually not providing the committed UCAP MW); and (2) the penalty rate, which is the rate at which an unfulfilled obligation is penalized (usually in terms of $/MW-day or $/event).[165] The Daily Deficiency Charge, which is the higher of 120% of the resource clearing price or the resource clearing price plus $20/MW-day, is the penalty rate for failing to meet several obligations, including capacity deficiencies, peak-season maintenance, and resource tests.

[165] Some charges can turn into a credit if the resource over-performs; thus they penalize under-performance while incentivize good performance.

Table 26
Comparison of RPM Penalties for Generators and DR & ILR

		Penalty Rate		
Penalty	**Basis for Penalty**	**Generators**	**DR**	**ILR**
Deficiency Penalties				
Capacity Resource Deficiency Charge	Daily shortfall between committed and actual capacity	Wtd Avg RCP[1]+ Max[0.2×Wtd Avg RCP; $20/MW-day] *(Daily Deficiency Rate)*		N/A
Availability Penalties				
Peak Season Maintenance Compliance Penalty Charge	UCAP shortfall due to unapproved maintenance or planned outages during peak season	Wtd Avg RCP + Max(0.2 Wtd Avg RCP; $20/MW-day) *(Daily Deficiency Rate)*	N/A	
Peak-Hour Period Availability Charge/Credit[2]	Daily Net[3] Peak-Hour Period Capacity Shortfall (max. to a cap that gradually increases from 0.5 × UCAP to1 × UCAP by the third consecutive year of limited availability)	Wtd Avg RCP	N/A	
DR and ILR Compliance Penalty Charge/Credit	Under-compliance (positive difference between committed MW and actual load reduction) during Load Management events[4]	N/A	*On-peak periods*: Min [(1/(# of events); 0.5] × Wtd Avg Annual Revenue Rate[5] *Off-peak periods*: 1/52 × Wtd Avg Annual Revenue Rate	
Test Failure Penalties				
Test Failure Charge	Shortfall between committed and tested capacity	Wtd Avg RCP + Max(0.2 Wtd Avg RCP; $20/MW-day) *(Daily Deficiency Rate)*		
Other Penalties				
Emergency Procedures Charges	Failure to comply with PJM instructions during emergencies	Number of days in the DY x Daily Deficiency Rate x Under-compliance MW		
RPM Must-Offer Requirement Failure Penalty	Failure of existing generators to offer into a BRA	Not allowed to participated in any incremental auction or be used to satisfy any LSE's UCAP obligation; further action by IMM	N/A	

<u>Notes:</u>
[1] Weighted average Resource Clearing Price of a portfolio in an LDA across all RPM auctions.
[2] The amount collected in Peak-Hour Period Availability penalties is credited to resource providers with negative net capacity shortfalls, subject to cap of Net Peak-Hour Period Capacity Shortfall times their weighted average RCP in the LDA.
[3] The netting of Peak-Hour Period Capacity shortfall is performed across committed units by seller (*i.e.*, single eRPM account) in an LDA. Uncommitted capacity by the same seller may be used to offset shortfalls by committed capacity (provided uncommitted capacity is in the same LDA).
[4] Performance is assessed on a portfolio-basis by each seller in a given zone.
[5] Annual Revenue Rate is the RCP from the RPM auction where the resource was committed.

We conclude that penalty rates for DR and generation are comparable, with only a few exceptions noted below. They are now more comparable than in the early RPM design when, for example, when DR was not subject to test failure penalties and ILR was not subject to deficiency penalties due to its timing.[166] Some penalties, namely the peak-hour availability and peak-season maintenance compliance penalties apply only to generators. The rationale could be that DR is an idiosyncratic resource with availability that may be difficult to measure.

3. UCAP Value of DR Products

In order for DR resources to participate in RPM, they must be assigned an unforced capacity (UCAP) value. However, the traditional availability metrics used to calculate UCAP for generation are not necessarily applicable to DR because the nature of loads underlying DR is much more varied than the capacity of generation technologies. Therefore, the UCAP value of DR must be measured differently. The current method used in RPM is to multiply the nominated value of DR by the Forecast Pool Requirement ("FPR") and the DR Factor.[167] The FPR grosses up the nominated value of DR for reserves (in UCAP terms) based on the rationale that if DR commits to be curtailed then PJM will not need to procure reserves for the underlying load — as if the load reduction were a reduction in the peak load forecast whose magnitude is perfectly correlated with system load. The DR Factor is based on the Effective Load Carrying Capability ("ELLC") of the resource and accounts for the fact that the resource may not always be available to serve PJM's capacity needs.

The current method of calculating UCAP value for DR seems slightly inaccurate in different ways for each type of DR. A more accurate method would result in a UCAP value that better reflects the reduced capacity need as a result of the load curtailment. The method of calculating the UCAP value of DR should take into account the type of load curtailment that the resource is committed to provide. DR that commits to curtail load *by a given amount* under the Guaranteed Load Drop (GLD) option is very similar to generation, and therefore it should be assigned a comparable capacity value, without any need for adjustment using the current DR Factor and FPR Factor.

However, DR that commits to curtail load *to a pre-determined level* under the Firm Service Level ("FSL") option provides greater value and should be assigned a higher UCAP value accordingly. The following example illustrates this point. Suppose a customer whose load is perfectly correlated with the system load has a 100 MW coincidental peak load forecast (all figures are assumed to be at the bus-bar level, already grossed up from the metered load for transmission losses). PJM will need to procure 108 MW of UCAP for this customer, assuming a typical FPR value of 108%. However, if the customer agrees to curtail its load to 90 MW whenever PJM calls on it under the FSL DR option, only 90 MW of UCAP is needed to serve the customer. Since this reduces the capacity need by 18 MW, the DR should be assigned a capacity value of 18 MW, ignoring unavailability. However, if the customer is not under supervisory control or is not able to curtail under all circumstances, the full 18 MW may be excessive. For example, if a customer's *forecasted* load were reduced to 90 MW, without a guaranteed curtailment to that level, then the value of that load reduction would be 10.8 MW (change in load forecast multiplied by an FPR of 8%). Thus, even in that worst case, FSL-type DR should be assigned a UCAP value that continues to be grossed up by the FPR Factor, but without the

[166] Penalties will become even more comparable after the ILR option is eliminated starting with the 2012/2013 delivery year.

[167] Nominated value of DR is determined by the resource owner, and is akin to ICAP for generation.

discount currently applied through the DR Factor. The assigned UCAP value could be even higher for FSL under firm supervisory control.

As a separate issue, PJM's current method of determining UCAP value of existing DR ignores past performance, in contrast with UCAP value of generation. For generation, a one-year average EFORd is used to calculate its UCAP value for each delivery year. If the resource under-performs in previous years, its EFORd and UCAP value will reflect that fact. Therefore, generators are implicitly penalized for past weak performance. It would be reasonable to add a comparable adjustment to the UCAP value of DR resources. Unlike generation, capacity of DR depends more on the CSP's ability to manage its portfolio that on the quality of the underlying resource. Therefore it is should be assumed that if a CSPs portfolio underperformed in the past, it is likely to underperform in the future. This assumption could be maintained until the CSP proves otherwise. If a shortfall occurs due to derated DR capacity, replacement capacity can be procured in the incremental auctions.

4. The Present Proceeding Affecting GLD Value and Participation

PJM and its Independent Market Monitor recently identified an issue regarding the Guaranteed Load Drop ("GLD") option used for measuring the performance of DR that chooses this method.[168] The key issue in this "double-counting" debate is how to measure compliance against the nominated (and committed) amount of DR and what should be the appropriate reference point or baseline. PJM has argued that allowing DR to measure its performance against a baseline that depends on recent load levels (effectively, the same baseline as the one used in the energy market) may provide an incentive for curtailment service providers to include assets in their portfolios with little ability to perform because over-performance by other assets in the portfolio will often allow the portfolio to perform at the expected level.[169] PJM analysis has indicated that this issue could result in the commitment of a large number of low-quality DR which could lead to future reliability problems. For example, during super-peak hours high-quality DR resources may be able to perform (*i.e.*, curtail to their peak load contribution, or "PLC") but not over-perform, while low-quality DR may under-perform. As a result, PJM may be, on aggregate, short on capacity when the amount of low-quality DR is relatively large. To address this, PJM has filed its proposal with FERC that would cap the baseline under the GLD option at each resource's PLC.

We are not commenting on the overall merits of PJM's proposal because it is being addressed in a separate proceeding, and we have not analyzed the need for PJM's proposal or its implications. However, we acknowledge stakeholder concerns that limiting DR contributions to reductions below a customer's PLC could impair the GLD option for some end users. End-users with a highly variable and unpredictable total load can often and legitimately experience unrestricted total load in excess of their PLC (which is based on peak loads during the year prior to the delivery year). Thus, they may not be allowed to fully take credit even for definitive actions to shed a portion of their load, such as

[168] PJM Filing to FERC in Docket No. ER11-3322-000 on April 7, 2011.

[169] DR performance is assessed on an aggregate basis for the provider's zonal portfolio. PJM explains that some of the over-performers are end-users that manage their super-peak loads and thus have low PLCs. They can provide additional reductions in non-super-peak hours, but not in the super-peak hours. Thus, they can over-perform (beyond their registered capacity) and cover for under-performers if events are only called outside of the super-peak hours.

interrupting a particular baseload process or turning on a backup generator. Such guaranteed load drop is valuable for RPM. If PJM's proposal is adopted, it will be important to fully preserve the GLD option in some manner.

Relatedly, some stakeholders have expressed concerns regarding the accuracy of PLC to measure each customer's contribution to the total capacity need. PLC is currently calculated by EDCs, usually based on the 5-CP method, which measures loads during the five highest zonal coincident peak hours during the summer before the delivery year. This method does not take into account the fact that capacity need arises outside the 5-CP hours, and some customers may find it relatively easy to avoid paying for any capacity by curtailing their load during just the super-peak hours that are likely to define the 5 CP. Therefore, we recommend that PJM ***consider working with the EDCs to refine their PLC methods***. Doing so would improve customers' incentive to more efficiently manage their load, and it would make PJM's proposed refinements to the GLD option less restrictive.

5. Future Directions

Future directions of RPM should include the incorporation of further resource types, in particular price responsive demand ("PRD") and advanced energy storage devices.

PJM recently presented its stakeholders with a proposal to integrate PRD into RPM. This proposal fits into a longer-term vision where PRD could play a more prominent role in electricity markets. In the long run, adding PRD will reduce the amount of generation capacity needed. By allowing LSEs to explicitly reduce their capacity obligations for expected PRD, capacity procurement costs also could be reduced. There have been competing PRD proposals, including one that PJM recently presented to its stakeholders.[170] The key (positive) elements of this proposal included PRD under supervisory control that commits to curtailments to a pre-determined level (Maximum Emergency Service Level) during PJM-declared emergencies, as well as a complementary scarcity pricing mechanism that would allow energy prices to rise above the current ($1,000/MWh) offer cap.[171] PJM and stakeholders should strive to complete the integration of PRD into RPM.

Another recent development has been the increased need for energy storage caused by the development of variable generation, especially wind. A range of advanced energy storage devices (such as, batteries, flywheels, thermal and compressed air energy storage, *etc.*) are currently under development. Although the primary driver behind the development of these devices is to provide additional ancillary services to balance the grid, these resources could also participate in RPM.

Energy storage devices have unique limitations that require a different methodology to calculate their capacity values. Storage devices may be able to provide two types of capacity products: (1) an annual product, for devices that can sustain their capacity value for at least 10 hours; and (2) a limited product for devices that can sustain their capacity value for at least 6 but less than 10

---

[170] PJM Staff Whitepaper, Price Responsive Demand, March 3, 2011.

[171] This is important because most loads have a higher reservation price, and low energy market offer caps would exclude them.

hours. We do not recommend adding any new capacity products for such a small category of potential capacity resources (compared to DR, for example) as that would make the RPM design more complex with questionable net benefits. Instead, to achieve the requirements of existing capacity products, multiple short-duration storage devices may need to be aggregated (*e.g.*, to reach 6 hours discharge capability) and mechanism would need to be developed to avoid recharging during dispatch periods.

6. Summary of Recommendations

We find that PJM's existing design mostly addresses identified stakeholder concerns, but we recommend that PJM and its stakeholders consider some refinements to further improve the efficiency of RPM and to ensure that all resources can perform as claimed.

With respect to the use of multiple capacity products to ***accommodate different resource types*** we recommend that PJM:

- Consider allowing other resource types with limited availability (*e.g.*, generation with seasonally-differentiated capabilities and costs) to make linked offers as Limited or Extended Summer resources.
- Consider re-classifying some seasonal resources (*e.g.*, energy efficient air conditioning) from Annual to Extended Summer.

With respect to the ***assurances of performance***, we recommend the following enhancements for PJM's consideration:

- ***Tracking***: continue to rely on suppliers to manage potential deficiencies to avoid penalties; however consider requiring Curtail Service Providers ("CSPs") to periodically report their progress against planned milestones to increase visibility into progress and avoid surprises.
- ***Registration***: Introduce random audits of contracts and physical loads to verify zonal resource portfolio abilities to curtail as frequently and seasonally as represented (especially for Annual and Extended Summer), with appropriately punitive penalties to incent CSPs to represent accurately. These audits should be conducted before the start of the delivery year (when all "planned" resources have become actual resources involving end-users with contracts to curtail) or any time during the delivery year. This enhancement is our most important recommendation regarding DR even though little DR has yet cleared as Annual or Extended Summer resources.
- ***Testing***: conduct random tests and limit DR providers' ability to selectively choose the most favorable of (multiple) tests that. Tests should be called by PJM, and the duration of each test should be longer than one hour.

We recommend that PJM also consider slightly modifying its ***methodology for determining DR UCAP values***, in the following manner:

- ***FPR and DR Factor***: Eliminate both the FPR and the DR Factor for GLD-type DR, counting guaranteed load reductions at its full value (just like generation); for FSL-type DR, eliminate the DR Factor and maintain the FPR gross-up (or more).
- ***Derating capacity values for weak performance***: Derate future UCAP value of any resource (or a CSP portfolio) that under-performs during the most recent delivery years. Such derates already apply to generators as their average EFORd is lowered by past under-performance.

- ***Measurement and verification***: PJM should consider working with the EDCs to improve their methodologies for assigning PLCs, for example, by considering more hours than just the top five hours of the previous year.

Other recommendations:

- ***Price Responsive Demand ("PRD")***: PJM and its stakeholders should integrate PRD into RPM by finalizing the proposal that PJM has already proposed.

D. 2.5% Short-Term Resource Procurement Target

1. Background

Substantial concerns have been raised by several stakeholders about the 2.5% short-term resource procurement target (STRPT). This 2.5% "holdback" is a quantity of capacity held back from the 3-year forward procurement. The amount is subtracted from the BRA VRR curve and therefore not procured in the base auction. Instead, that capacity is procured over the following three years, with 0.5% procured in the first incremental auction two years prior to the delivery year, 0.5% in the second incremental auction one year prior to the delivery year, and 1.5% in the third incremental auction, just prior to the delivery year.[172] Starting with the BRA for the 2014/15 delivery year, the holdback has been subtracted not only from the VRR curve, but also from the Minimum Annual and Minimum Extended Summer resource requirements.[173] The result of this approach is that the STRPT quantity held back is Annual capacity, which means the resources procured in the incremental auctions for the 2014/15 delivery year will be primarily for Annual capacity.[174]

The STRPT was first implemented for the 2012/13 delivery year at the same time that Interruptible Load for Reliability (ILR) was eliminated and DR resources were first required to bid and clear through the centralized auctions. Prior to the incorporation of DR into RPM auctions, demand-side resources were allowed to participate as ILR, which could register just prior to the delivery year but still receive the BRA price.[175] To account for that, the base auctions included a "holdback" for an amount of capacity equal to the forecast quantity of ILR for the delivery year (an amount that would not actually be known until the delivery year). When the ILR mechanism was eliminated, the STRPT replaced the ILR-related holdback and was introduced primarily to accommodate demand-side resources that had never before had to make three-year forward commitments.[176] Eliminating ILR and implementing the STRPT to

[172] Other adjustments to reliability requirements and locational import limits are also reflected in these incremental auctions, including the incremental uncleared portion of the VRR curve and adjustments due to changes in load forecasts, see PJM (2011d), pp. 20-21.

[173] See, for example, the calculation of the Extended Summer and Annual resource procurement targets as a function of the STRTP for the 2014/15 BRA, PJM (2011b).

[174] However non-annual capacity may also be procured because of market participant buy bids, through adjustments to the reliability requirement, or through the incremental portion of the VRR curve that is included in these auctions.

[175] See PJM (2011d), p. 29.

[176] See PJM (2008f), pp. 39-41.

accommodate DR and other short-lead time resources was consistent with our 2008 recommendation.[177]

Members of the end-user and other supplier sectors stated that they support maintaining, or possibly increasing, the size of the STRPT. These stakeholders stressed that the three-year forward period creates significant risks for DR suppliers and other short-term resources. They note that the small size of the holdback, along with historically overstated load forecasts, have been artificially inflating BRA prices while causing IA prices to clear at much lower levels.

Generation owners, almost all transmission owners, and the Independent Market Monitor voiced their concerns over the 2.5% holdback and suggested that it should be eliminated. Their primary argument for eliminating the holdback is their concern that it artificially reduces demand in the BRA, thereby suppressing BRA prices below competitive levels. A supporting argument is that most of the supply in the BRA is under must-offer obligations and also mitigated in terms of their offer prices. The combination of must-offer obligations and mitigated offer prices prevents those participants from offering their capacity in the later incremental auctions, even if incremental auction prices are expected to exceed the BRA prices. In addition, some generation and transmission owners have argued that the 2.5% holdback is not needed to accommodate short lead-time resources, as evidenced by the large quantities of DR that have offered 3-years forward in the BRA.

The IMM has run BRA scenario simulations showing that, assuming the supply curve remains unchanged, increasing BRA demand by removing the 2.5% holdback would have resulted in price increases of $14 to $79/MW-day in the 2013/14 BRA, depending on location.[178] As we noted in Section V, one must exercise caution when interpreting these simulation results because they make the unrealistic assumption that the BRA supply curve would have been identical in the absence of the holdback.[179]

2. Discussion

The primary argument for eliminating the 2.5% holdback is that it will artificially suppress BRA prices by shifting demand from the 3-year forward auction to the later incremental auctions. In evaluating this argument, we looked primarily for two pieces of evidence. First, we looked for a pattern of incremental auction prices that were higher than BRA prices, which would indicate that shifting demand from the BRAs to the incremental auctions was indeed artificially suppressing BRA prices. Evidence is still limited as there have only been two incremental auctions conducted since the introduction of the 2.5% STRTP, but the results from these auctions show that incremental auction prices were generally below BRA prices. In the first incremental auction for 2012/13, RTO prices were identical to BRA prices, MAAC prices were $117/MW-day below BRA prices, and EMAAC prices were $14/MW-day above BRA prices. The increase

177 See Pfeifenberger and Newell, *et al.* (2008), p. 101.

178 See Monitoring Analytics (2010a), p. 31.

179 We find it plausible to believe that, in the absence of the 2.5% holdback, some suppliers would have placed a higher value on clearing in the BRA given the lower likelihood of clearing in the IAs. In this case some suppliers may have offered into the BRA rather than waiting for the IAs or may have offered into the BRA at lower prices. For this reason, it is not clear how different the BRA supply curve might have been without a holdback.

in EMAAC prices was caused by the 1,455 MW increased local demand due to the delay in the Susquehanna-Roseland transmission line. The reduced prices in other LDAs are explained by reductions in demand due to decreased load forecast that exceeded the size of the holdback.[180] In the second incremental auction for 2012/13, prices were uniformly below BRA prices.[181] In other words, the opposite has been the case—BRA prices have been far above or persistently above incremental auction prices — although differences between the BRA and incremental auction prices are explained by factors other than the holdback.

Second, we examined the quantity of BRA supply that is either unmitigated in terms of its offer price or does not face a must-offer obligation. Unmitigated supply faces no offer price cap, like resources without a must-offer obligation, and can easily shift from the BRA to later incremental auctions if higher incremental auction prices are anticipated. These suppliers will therefore be able to rationally choose to sell into the auction with the highest expected prices, which will have an equilibrating effect on BRA and IA prices. In contrast, suppliers with must-offer obligations and offer price mitigation, do not have the flexibility to increase their offer BRA prices or shift their supplies to the incremental auctions. If the BRA clearing price is set within this mitigated portion of the BRA supply curve (without substantial quantities of unmitigated supply clearing inframarginally), this would artificially lower BRA prices.

To analyze this issue, we examined the quantity of cleared unmitigated BRA supply, as summarized in Figure 27 for the 2014/15 BRA.[182] The figure shows the cleared unmitigated supply for Limited, Extended Summer, and Annual resources and compares this quantity to the size of the STRTP, which is the same for each product type. For the Limited Summer product, the figure shows that the quantity of cleared unmitigated resources is 3.3 times larger than the holdback, indicating that the holdback has not suppressed BRA prices. The same pattern exists at the LDA level as well. If BRA prices were artificially suppressed, we would expect these unmitigated suppliers to shift their supply into subsequent incremental auctions, which would then have the effect of increasing BRA prices and decreasing incremental auction prices. We would expect supply shifts of this type to continue until BRA and IA prices were approximately equal in expectation.

In contrast to the Limited Summer product, however, the holdback for Extended Summer and Annual products was 2.6 and 2.0 times larger than the quantity of cleared, unmitigated supply for these products. The reason for these lower quantities relates to the fact that DR resources

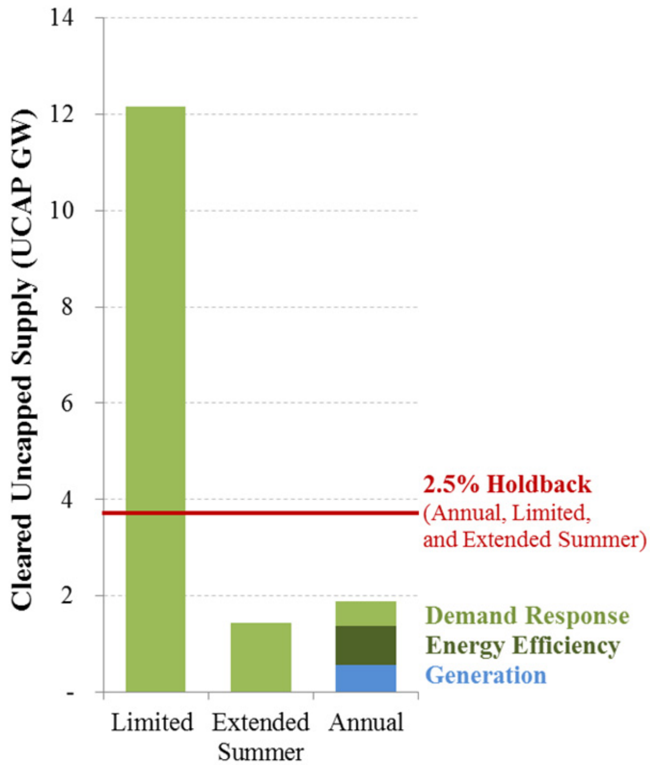
180 SWMAAC had an increase in demand of 409 MW due to increased load forecast and the STRTP. However, the LDA was unconstrained in the BRA and first IA, meaning that factors affecting MAAC prices were also the primary drivers of SWMAAC prices. See PJM (2009e, 2010g-h).

181 Note, however, that this is largely explained by demand reductions due to a decrease in load forecasts in every location, except PSEG-North and DPL-South. See PJM (2009e, 2011j).

182 We examined other BRAs as well, but found them less relevant to this analysis. Because such a large fraction of unmitigated supply consists of demand resources, we find only BRA data starting with 2013/14 to be informative as this was the first year that demand resources were unmitigated. Prior to 2013/14, "existing" demand resources were required to bid into the BRA at a mitigated price of zero. Examination of the 2013/14 BRA shows that the quantity of unmitigated cleared supply at 10,730 MW nevertheless greatly exceeded the 3,750 MW holdback. This result from the 2013/14 BRA is consistent with the evidence related to the limited product from the 2014/15 BRA, but does not inform the question of how the holdback interacts with Annual or Extended Summer resource requirements. PJM (2010a, 2011a).

account for most of the unmitigated supply, much of which cleared as Limited Summer supply. The much more modest amount of cleared unmitigated supply for Annual and Extended Summer products is problematic and indicates that the STRPT could possibly have lowered 2014/15 BRA prices for these products. Due to offer mitigation and must-offer obligations, suppliers would have had limited ability to shift their offers from the BRA to potentially higher-priced incremental auctions. However, this analysis is not conclusive since the cleared results already account for any shifting that may have occurred.

Figure 27
Cleared Unmitigated Supply in the 2014/15 BRA by Product Type



Sources and Notes: PJM (2011a-b).

This is a concern that should be addressed by concentrating the STRPT on Limited Summer products, which consists mostly of unmitigated short-term resources and in an amount that significantly exceeds the STRPT amount. Continuing to procure a portion of these resources closer to the delivery year will reduce the cost of providing these resources and, as we explained in our 2008 RPM Report, offer other benefits such as increasing liquidity in incremental auctions and providing PJM with more flexibility to adjust total capacity procurement in response to updated load forecasts.

3. Recommendations

Based on our analysis of stakeholder arguments and evidence to date related to the short-term resource procurement target, we make the following recommendations:

- ***Maintain the 2.5% STRPT for Total Resources*** — We recommend maintaining the short-term resource procurement target (STRPT) at its current level for the *total* system requirement.

- ***Eliminate STRPT for Extended Summer and all Annual Resources*** — We recommend eliminating the STRPT for the minimum amounts of Extended Summer and Annual resources to avoid distorting BRA prices for these products. We believe this modification will not substantially disadvantage short lead-time resources, because DR accounts for most short lead-time supplies, few of which have cleared as Annual or Extended Summer supplies. Eliminating STRPT for Annual Resources, which consist mostly of generation resources, will also add a safeguard to reduce the risk of resource adequacy challenges in the face of retirement pressures on existing coal plants from new EPA regulations. The full procurement of Annual Resources will reduce the risk that existing resources do not clear due to artificially suppressed BRA prices, which could lead to inefficient retirements of resources that may not be replaceable in the short term.

We also recommend that PJM continue to monitor that: (1) the amount of cleared unmitigated offers in each BRA and incremental auction exceeds the STRPT amount to avoid distorting auction prices as discussed above; (2) the quantity of supplies offered in the incremental auctions is sufficient to comfortably meet short-term procurement targets; and (3) prices and offer levels in incremental auctions are not substantially higher than in BRAs for reasons that appear unrelated to changes in market fundamentals.

E. Monitoring and Mitigation

1. Minimum Offer Price Rule

a. Background

In February of 2011, PJM filed with FERC a number of tariff modifications to update, simplify, and expand the applicability of its Minimum Offer Price Rule (MOPR).[183] PJM's filing was triggered partly by new long-term procurement efforts in New Jersey. The State of New Jersey had initiated a proceeding to solicit 2,000 MW of new in-state generation supply through long-term PPAs, whereby the winning projects would be required to bid into RPM as price takers. The PJM Power Providers Group ("P3") had subsequently filed a complaint stating that such out-of-market entry would artificially depress capacity prices, that the then-applicable MOPR would fail to prevent such entry or mitigate its effects, and that other changes were needed to the MOPR. PJM filed its MOPR proposal several days later, largely in agreement with P3, with a requested effective date in time for the Base Residual Auction earlier this year.

PJM's filing included the following major changes:

1. It eliminated the net short incentive test. This test was intended to narrow the application of MOPR only to entities with total capacity needs that exceeded the capacity that they owned, which would make them "net short" in the RPM market. Being net short creates an incentive to add capacity inefficiently in an effort to suppress the prices for the

---

[183] See PJM (2011h).

capacity they procured through RPM. This test would also have exempted generation suppliers such as those responding to New Jersey's solicitation because, unlike the ratepayers who would be contractually backing the capacity additions, the suppliers themselves would not be net short;

2. It eliminated the "impact test" that exempted any offers that reduce the auction clearing price by less than 20 to 30% (depending on the size of the LDA) since even a small amount of price suppression can harm competition;[184]
3. It modified the threshold and mitigation levels to be consistent with the Net CONE calculations used to determine the VRR curve (but the threshold was set at 90% of Net CONE for both combustion turbines and combined-cycle plants); and
4. It proposed to extend the amount of time that a planned resource would be subject to MOPR from one to three delivery years, counting only years when the unit would have cleared in RPM absent the MOPR.

PJM also proposed an exemption based on state mandates that address projected capacity shortfalls and several related changes.

The FERC's order, issued in April, 2011, accepted most of PJM's changes.[185] The order also rejected PJM's proposed three-year mitigation period and its proposal to review below-threshold sell offers through market participant filings under Section 206 of the Federal Power Act. PJM was required to submit a compliance filing specifying an offer review process conducted by the IMM first or, upon appeal, by PJM. Market participants would need to submit a Section 206 filing to FERC to request exemptions from the new rules, such as for reliability reasons). Since then, PJM has submitted its compliance filing and started working with stakeholders to develop the details of the offer review process.

In addition to accepting most of PJM's tariff changes, the order also clarified the Commission's views about the purpose and scope of the MOPR. For example, the MOPR Order rejected intervenor pleadings for exemptions for municipal utilities, cooperatives, and other entities that meet their customers' needs through resource planning.[186] It also rejected blanket exemptions for state initiatives lest captive customers pay above-market rates and wholesale market prices are depressed:

> … states are free to pursue their policy goals by financing new investments. We find only that such investments must submit bids into the capacity auction consistent with their competitive costs. Clarifying that the MOPR applies to new self-supply, however, does not prevent rate-based investments that are economic by market-based RPM standards from being designated as capacity resources. The MOPR, then, is both an appropriate and necessary mechanism to support market-driven investment in a way that does not expose captive customers to long-term investment risk.

[184] See PJM (2011h), p. 18.

[185] See FERC (2011a).

[186] See FERC (2011a), pp. 191-197.

> Nor are we persuaded, as intervenors argue, that permitting new self-supply to be rejected at its preferred offer price is too harsh and too costly for ratepayers. First, as noted above, the FRR option is available for those load serving entities that want to secure capacity outside of the RPM market. Second, permitting new self-supply investment to compete as a price-taker in RPM impermissibly shifts the investment costs of self-supply to competitive supply by suppressing market clearing prices, and will create an environment in which only such self-supply investment will occur. Failure to subject new self-supply to the MOPR, that is, permitting new self-supply to participate in RPM as a price-taker, would significantly impede competition from all types of private investment and shift long-term investment risk from private investors to captive customers.[187]

These statements appear to establish a standard in which RPM-based procurement and Net CONE determinations will take precedence over capacity procured through bilateral contracts and resource planning efforts by vertically-integrated utilities.

b. Concerns

We agree that capacity markets need to be protected from manipulation by both sellers and buyers. Without the MOPR or an equivalent mechanism, market prices would be vulnerable to manipulation by buyers. If buyers with a significant net-short position in RPM were able to flood the market with excess capacity to depress prices, other suppliers' confidence in the market would undoubtedly collapse. This would likely lead to the undesirable outcome that new supply would be able to enter only through similar uncompetitive arrangements with buyers. This would also cause an increasing proportion of existing plants to retire uneconomically unless they, too, were able to obtain long-term contracts. There would no longer be a market where capacity resources of all types would compete. Expanding the original MOPR was necessary in order to close the key loophole that allowed net buyers, including states, to avoid mitigation by contracting bilaterally with an entity with a net-long capacity position.

However, we are concerned that the new MOPR will inadvertently interfere with self-supply offers from generating resources that are competitive and do not involve manipulation. We are particularly concerned that the MOPR will lead to over-mitigation that will undermine bilateral markets and RPM participation by entities, such as public power companies, that meet their customers' needs primarily through long-term contracts or other self-supply options.

The MOPR does not attempt to detect manipulative intent or incentives for manipulation. It is triggered whenever an RPM offer from new gas-fired generation falls below the administratively-determined benchmark level for that technology (*i.e.*, 90% of Net CONE for a CT or CC in level-nominal terms). However, there will be many legitimate reasons why an RPM bid could be below the Net CONE benchmark and should not be mitigated. In fact, the wide range of offer prices for new generation observed in RPM auctions over the last few years suggests the existence of a large range of cost structures, market outlooks, and bidding strategies.[188] The threshold of 90% of Net CONE is also imperfect because the discrepancy

[187] See FERC (2011a), pp. 194-195.

[188] As discussed in Section IV.C, we have observed offers for new generation at many different levels including zero, any fraction of Net CONE, and levels higher than Net CONE.

between the administratively-determined historical E&AS offset used to calculate Net CONE and the actual E&AS margins that market participants may anticipate to earn could easily exceed 10% of Net CONE.

The IMM and PJM have attempted to recognize these factors in the review process by determining offer floors for each resource, such as low project-specific costs (*e.g.*, due to an existing site with low-cost infrastructure needs), low financing costs, or additional competitive sources of revenue. However, there will also be legitimate other reasons for low bids that would be difficult to verify. For example, a competitive merchant developer might offer below the benchmark level if: (1) the developer anticipates rising energy and ancillary service margins (relative to 3-year historical E&AS offset used in the benchmark Net CONE calculation), thus reducing the amount of payment needed from the capacity market; (2) the developer anticipates rising equipment costs, which will tend to increase capacity prices over time, thereby reducing the amount of revenue needed in the first year of entry; or (3) the developer has already sunk a portion of the development costs, having started the project early in anticipation of different market conditions or due to a development schedule of more than three years. Such reasons might be difficult to recognize or validate in the IMM's offer review. Unfortunately, the inability to validate some legitimate factors may prevent the IMM from relying on them to determine offer floors. In addition, even if these factors would be considered in the review process, uncertainties about the review process itself will increase risks (*i.e.*, the risk of over-mitigating RPM offers) for many new resources and load-serving entities.

Over-mitigation would be particularly problematic for resources developed as self-supply or through bilateral contracts. In addition to the factors described above, self-supply and bilateral resources will rationally offer into RPM as a price taker (*i.e.*, offer at or near zero) if the development of the resource has already been committed. Such a project's development is not contingent on the auction outcome, but the project must clear to count toward the buyer's resource requirement or contractual obligations. Mitigating offers from such a generating unit is problematic because it might prevent the resource from clearing, the prospect of which could create a prohibitive risk for the resource owner, the load serving entity, or both. One might argue that a resource that does not clear in RPM auctions at its mitigated offer level is uneconomic and should not be developed. However, this argument ignores the factors described above (*e.g.*, Net CONE as an imperfect threshold), as well as the possibility that the lack of perfect foresight will result in some resources being planned and contracts being signed at prices that, contrary to initial expectations, turn out to be above or below market in some cases and some years. It would be unrealistic to expect market participants to be able to forecast uncertain annual capacity prices precisely enough to ensure clearing at MOPR-mitigated threshold prices and to avoid having to pay twice for capacity: —once for the bilaterally-contracted (but uncleared) resource and again for RPM capacity to replace the uncleared mitigated resource.

In fact, the inability of any buyer or seller to perfectly anticipate annual market prices is a principal reason to sign long-term contracts. RPM should facilitate such bilateral contracts, not prevent them, and also complement or facilitate resource planning by load-serving entities. RPM should inform entities' planning efforts and decision making through transparent auction prices and allow them to utilize auctions to efficiently balance their portfolios on a year-by-year basis.

We fear that the risk of not clearing self-supplied resources in the RPM auctions due to MOPR mitigation and uncertainties in the review process will create a barrier to bilateral contracting and other self-supply options. This will make it more difficult and costly to hedge capacity prices and will likely force many load serving entities that rely on self-supply to opt out of RPM through the FRR option. More widespread use of the FRR option would reduce market efficiency and increase costs because it places limits on selling into RPM, as discussed in our 2008 RPM Report.

c. Recommendations

The MOPR is needed to protect against buyers' manipulation of capacity prices through subsidized excess capacity. We believe, however, that the current rules are inefficiently structured, will inefficiently mitigate legitimate resource additions, and will discourage bilateral contracting and self-supply.

The objective should be to protect the wholesale capacity market from intentional manipulation, not from inadvertent effects that normal contracting and investment decisions can have on RPM prices, even if those investments and contracts turn out to be poor decisions. Further, it is important to recognize that over-mitigation can harm the market as much as under-mitigation. Any test and intervention thus needs to balance the risk of false positives (over-mitigation) against the risk of false negatives (under-mitigation).

We recognize that MOPR is already discussed extensively in other forums, including FERC dockets. However, given its importance to RPM performance, we offer a number of recommendations for consideration by PJM and stakeholders in these ongoing discussions. Our recommendations would exempt from mitigation self-supply options that are either (1) based on non-discriminatory competitive bilateral procurement processes; or (2) undertaken by entities or under circumstances without the incentive to suppress RPM auction prices. These recommendations differ from proposals the FERC has already considered in its Order. More specifically, we recommend that PJM and its stakeholders ***consider the following exemptions to MOPR mitigation***:

- Exempt resources that have won a competitive, non-discriminatory RFP that is open to both new and existing resources. Clearly, new generating units that can enter the market through such a bidding process are competitive and economic and should not be mitigated. They should be able to clear in the RPM auction as price takers, as the IMM has proposed.[189]

- Exempt self-supply resources that are offered into RPM by vertically-integrated LSEs if the resource is the result of a deliberative planning process by the LSE and the LSE is not substantially net short in RPM.

- Exempt a resource if the owner—and its contractual counterparty, if relevant—are not substantially net short in RPM and, thus, would not benefit from suppression of RPM capacity prices. To qualify for such an exemption would require a verification process, such as: (1) the resource owner would have to show that it is not net short; (2) the resource owner would have to disclose all contracts with counterparties; and (3) the

[189] See Monitoring Analytics (2011), pp. 5-6.

contractual counterparties would need to make available documentation that they are not substantially net short.

Implementing such exemptions would require PJM and stakeholders to determine an appropriate threshold of an LSE's acceptable net short position. For example, a MOPR exemption could be granted if the net short position is small enough such that the benefit of market price suppression obtained on the net short position would likely be less than the above-market subsidy implied by the contract price or the self-supplied assets' cost.

2. Default Offer Cap of Zero for Existing Generators

a. *Background and Concerns*

The default offer cap for existing generators, which are under a must-offer obligation, is $0/MW-day.[190] To offer at a higher price, generators may submit data and documentation of their resource-specific costs based on either: (1) avoidable costs less projected net energy revenues; or (2) the documented opportunity costs of not exporting capacity into another market. An offer cap based on avoidable costs must be calculated assuming the unit will either mothball or retire if it fails to clear.[191] Alternately for generators in the unconstrained RTO and in an asset class deemed unlikely to be a price-setting resources, these units may opt to use a default ACR rate calculated and updated prior to each BRA.[192]

Some stakeholders have expressed the concern, and we agree, that a default offer cap of zero for existing generators is too low because it does not account for costs and risks of the forward capacity obligation, particularly considering their must-offer obligation. If a generator expects large enough operating margins in energy and ancillary services markets, then it would still prefer to operate rather than to mothball or retire even if it receives no capacity payment. However, the generator would not rationally choose to take on the obligations of an RPM commitment without at least some compensation. Fair and efficient compensation for this obligation may be small, but it will not be zero. At a minimum, it would reflect the risk of deficiency penalties and the costs associated with complying with the day-ahead must-offer obligation in the energy market.[193]

Deficiency penalty risks would be a function of the penalty rate of $20/MW-day applicable at very low capacity prices[194] and a measure of uncertainty regarding a plant's UCAP value including EFORd uncertainty and unanticipated unit derates or retirement.[195] The costs of complying with the must-offer obligation would likely be small or zero for large generators that

190 See PJM (2011d), p. 64-65.

191 See PJM (2011d), pp. 64-65; (2011q), Attachment DD, Sections 6.4, 6.7-8.

192 See for example the 2014/15 ACR data at PJM (2011r); see also PJM (2011q), Attachment DD, Section 6.7.

193 Explanations of penalty structures and the day-ahead must-offer requirement are available from PJM (2011d), p. 66 and Section 9.1.

194 Deficiency penalties are the greater of $20/MW-day and 20% of the capacity price; the $20/MW-day applies when capacity prices are very low, which is the only case in which (low) non-zero offer caps are likely to matter.

195 See PJM (2011d), Section 9.1.

intend to operate year-round in the energy and ancillary service markets in any case, but may be higher for small or high-cost generators with very low capacity factors who might otherwise opt to reduce costs by shutting the plant down during off-peak seasons. While calculating a likely low, near-zero offer cap may be an onerous process if done on a unit-by-unit basis, it seems that this could be done effectively on a class-average basis. Such a default ACR rate for units that will operate regardless of the energy price could be posted by the IMM along with the ACR rates for units that would otherwise mothball or retire.[196]

b. *Recommendations*

We understand that PJM and stakeholder have previously discussed this topic. However, based on the above considerations, we recommend that PJM and stakeholders reconsider developing an above-zero default offer cap for units that could otherwise operate in the energy and ancillary services markets even without a capacity payment.

- **Above-Zero Default Offer Cap for Existing Generators** — We recommend increasing the minimum offer cap so that no resources are required to offer at zero, but instead may offer at a level that includes the incremental cost of capacity supply obligations to a resource that would operate with or without any capacity payments. This minimum offer cap may be quite low, but would include an estimate of: (1) the risk of deficiency penalties; and (2) the costs of complying with the energy must offer requirement.

It is important to note that such a minimum offer cap for existing generators would not create a price floor for RPM auctions because generators would be free to bid below the offer cap.

F. NEPA AND ALTERNATIVES FOR EXTENDING FORWARD-PRICE CERTAINTY

1. Background

The New Entry Price Adjustment ("NEPA") was originally included in RPM to mitigate the price impacts of lumpy resource additions in small LDAs. NEPA is intended to allow providers of new resources in LDAs to "lock in" prices for three years under certain special qualifying conditions indicating that the resource addition would severely reduce the LDA clearing price, thus making entry less likely. However, the price impact conditions for new entrants to qualify for NEPA are difficult to meet. Only a single resource has qualified for NEPA to date, while 29 new resources have requested (but not awarded) NEPA treatment.[197]

In its December 12, 2008 filing addressing many RPM issues, PJM cited our 2008 report and proposed to expand NEPA. PJM proposed to eliminate the stringent price impact test and make NEPA available to all new entrants in a modeled LDA.[198] It also proposed to expand the term of

---

[196] See for example PJM (2011r).

[197] Many units have requested NEPA treatment in multiple bids in different auctions; these resources are counted only one time in this number. From PJM (2011a).

[198] NEPA would be available to any new resource in "an LDA that has a separate VRR Curve, if the LDA clears with a locational price adder, or if the LDA would have had a locational price adder had the new entrant not cleared." See *PJM Interconnection, LLC*, Docket ER09-412-000, filed December 12, 2008, at pp. 53-55.

NEPA pricing from three to five delivery years, which it then proposed to increase to seven years in a subsequent settlement filing.[199] FERC issued an order on March 26, 2009 rejecting PJM's proposed expansion to NEPA, with the following explanation:

> The proposed relaxation of the pre-conditions and the extension of the lock-in period go beyond the intent of the original provision, intended only to address the issue of lumpy investments in a small LDA. PJM's proposal would further bifurcate capacity markets by giving new suppliers longer payments and assurances unavailable to existing suppliers providing the same service. Thus, it would result in further price discrimination between existing resources, including demand response, and new generation suppliers. We therefore reject the proposal to change the existing NEPA provisions.
>
> We also recognize that a longer commitment period may aid the developer in financing a project. However, as PJM notes, RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers, and we must therefore balance the benefits of the longer commitment period (to the extent it fosters new entry by making project financing easier or cheaper) against the possible uplift payments in excess of auction clearing prices that loads may have to bear due an extension of the NEPA term. In our view, no party has made the case that extending the NEPA term to five or seven years strikes a superior balance to the existing provisions.[200]

In a subsequent filing, PJM stated that NEPA did not provide assurance for qualified resources for even three years, since offers were subjected to having to clear the base auctions for the following two delivery years. PJM proposed modifications essentially guaranteeing that the amount of qualified capacity that cleared in the first year would also clear in the following two years. FERC accepted these revisions in an October 29, 2009 order.[201]

Since then, stakeholders have expressed increasing interest, both publicly and in our interviews, in expanding NEPA to support new investment. Many see expanding NEPA as a way to address the lack of multi-year forward-price certainty within RPM, the current lack of interest in long-term bilateral contracting, and the perceived effect this has on generation development. We discussed long-term contracting and issues extensively in Section III.C.

Recognizing stakeholder interest in NEPA, PJM requested in its February 2011 "MOPR" filing the need to establish a date certain for addressing NEPA in a future FERC filing. FERC set an October 1, 2011 filing date and PJM is currently undergoing a stakeholder process to address the issue. We hope our analysis will inform that process.

---

199 See *PJM* Interconnection*, LLC*, Docket ER05-1410-000 *et al.*, filed February 9, 2009, at pp. 20-21.

200 See 126 FERC ¶ 61,275, Order Accepting Tariff Provisions in part, Rejecting Tariff Provisions in Part, Accepting Report, and Requiring Compliance Filings, Issued March 26, 2009, at P149-150.

201 See 129 FERC ¶ 61,081, Order on Proposed Tariff Provisions, Issued October 29, 2009.

2. Analysis of Options for Extending Forward-Price Certainty

Driven by concerns about a lack of long-term contracting and capacity-price uncertainty, stakeholders have proposed several options for extending forward-price certainty. While each of these options would extend price certainty for market participants, some of them would also have problematic consequences. We analyze here the advantages and disadvantages of each of these proposed alternatives:

1. *Extending the RPM Forward Period* — Some generation and transmission owners proposed a five-year forward period, moving the BRA two years earlier relative to the delivery year.
2. *Expanding NEPA* — Some stakeholders argued for expanding NEPA by relaxing qualification criteria, offering the option to existing generation and generation outside the LDAs, and/or extending the price assurance period to five or ten years.
3. *Introducing Mandatory Long-Term Procurement by PJM* — PJM would procure a portion of capacity needs in annual auctions for delivery periods spanning multiple years.
4. *Voluntary Long-Term Auctions* — PJM would develop centralized, voluntary forward auctions for standardized multi-year capacity products. Alternatively, these products could be traded continuously through an over-the-counter trading platform.

As explained in more detail below, we recommend that PJM facilitate bilateral contracting through centralized, but voluntary, multi-year auctions or hedging products to increase longer-term liquidity and pricing transparency in the capacity market. This recommendation is consistent with PJM's existing proposal. Only if lack of long-term contracting can be shown to threaten system reliability should PJM consider implementing mandatory long-term procurement options. We do not recommend expanding NEPA as a generally-available multi-year pricing option.

a. Extending the RPM Forward Period

As we discussed in Section V, we recommended that PJM maintain the 3-year forward design of RPM. Increasing the forward period to four or five years would likely increase overall costs as it would increase risks to suppliers due to changing market conditions and permitting uncertainties. Probabilistic simulations with the Hobbs Model in our 2008 RPM Report similarly showed that a longer forward period would not offer additional benefits. Given the increase in commitment-related risks, we do not believe that extending the forward periods beyond three years would be a cost-effective option to provide increased long-term pricing certainty.

We reconfirm our 2008 recommendation to maintain the 3-year forward auction design. While increasing the forward procurement period would likely increase overall costs because of the increased commitment-related risks, we also find that the three-year forward procurement period offers significant advantages over shorter forward periods. First, as discussed in Section II.A.4, the BRA results from the first several auctions show that the supply curves were very steep when the forward period was less than three years. The flatter supply curves for the three-year forward auctions offer significant benefits in terms of mitigating price volatility and creating a more competitive market environment. The three-year out visibility of cleared and uncleared resources also provides a valuable indicator of likely retirements, which may prove to be critical in addressing challenges related to environmental compliance.

b. Expanding NEPA

As a mechanism to reduce the risk of investment in a volatile market, NEPA does not appear to provide an efficient solution. NEPA provides new resources with a multiple-year price based on an auction whose parameters and competing supply offers reflect single-year market fundamentals. This mismatch can be expected to distort the bidding behavior of candidate NEPA resources. Moreover, the current NEPA also excludes DR and existing resources—as FERC emphasized in its order rejecting PJM's proposal to expand NEPA.[202] A distortion of market prices and inefficient outcomes would be the likely result. For example, if prices in future auctions were anticipated to drop due to planned transmission, new NEPA-supported generation could clear at current auction prices and receive a high price for subsequent years despite the fact that long-term resources would not have been needed. The NEPA mechanism would not recognize if expanding DR or delaying the retirement of an existing generator could more efficiently meet the short-term need until the planned transmission project is in service. At the same time, suppliers bidding with the hope to lock in a multi-year price may bid below the level supported by market fundamentals in the current auction, thus depressing the annual auction price.

However, NEPA may still be helpful for mitigating the price impacts of adding large resources to small LDAs—the investment barrier NEPA was originally intended to address. Otherwise, adding a large unit to a small LDA can eliminate the LDA price premium in subsequent auctions (when the entire new resource is considered "existing"), especially if load growth is low relative to the size of the new unit. This effect of lumpy investments in small LDAs can deter developers from adding new generation at a minimally-efficient scale (*e.g.*, a new 2×1 7FA combined cycle plant) in locations where it is most valuable. NEPA mitigates this lumpiness problem by allowing the new entrant to continue being paid at the price at which it cleared initially. The mechanism could still distort annual prices as discussed in the prior paragraph, but it would continue to apply more narrowly. NEPA applies only in an LDA that has a substantial shortage and only to relatively large resources. As noted earlier, to date NEPA been applied only once.

c. Mandatory Long-Term Procurement by PJM

Due to the distortions in annual auction prices that an expanded NEPA would cause, as discussed above, we do not recommend expanding NEPA as a solution for the lack of long-term price stability offered by RPM. If long-term pricing certainty is needed within the RPM construct, a more efficient alternative to extend forward-price certainty would be for PJM to introduce long-term procurement for a portion of PJM resource needs. For example, PJM could procure each year 7% of capacity needs under 7-year contracts (*i.e.*, for delivery years 3 to 10 years in the future). Over time, this process would procure approximately half (49%) of all resource needs, with the other half being procured through the annual terms under the current BRA design. Developers would gain enough price certainty to finance their projects, and consumers would be less exposed to price volatility, due to the laddering of the long-term contracts over time.

However, implementing such a concept would require PJM to make important decisions about major long-term contract terms: (1) how much total capacity should be procured under such

---

[202] See 126 FERC ¶ 61,275, Order Accepting Tariff Provisions in part, Rejecting Tariff Provisions in Part, Accepting Report, and Requiring Compliance Filings, Issued March 26, 2009.

long-term contracts (*e.g.*, more or less than the 49% in the above example) and (2) what should be the contract term (*e.g.*, more or less than the 7 years in the above example). Procuring too much capacity under long-term commitments could significantly increase deficiency risks for suppliers, particularly suppliers of existing resources that could become unavailable over time. Because the added risk may offset some or all of the reduced financing risk for new plants or existing plants with major investment needs, procuring too much capacity through such long-term arrangements could increase total costs. Because prices and quantities are locked in, customers would also face an increased risk of being forced to pay for out-of-market resources. For these reasons, we believe decisions on how much capacity should be procured under long-term contracts and the determination of contract durations are best left to market participants. Market participants know their own risk profiles better than PJM, and they are free to enter contracts on their own terms bilaterally. Market participants will also be able to adjust contracting terms if market conditions and industry financing practices change over time.

We do not recommend that PJM expand the scope of RPM to procure capacity on a long-term basis at this point. As we discussed in Section III.C, it is not clear that a market failure currently exists that would need to be resolved through mandatory long-term contracting. Current market conditions do not support long-term contracts for new plants because new generation is not currently needed. If market failures preventing long-term contracting were to become evident in the future, PJM could consider introducing long-term procurement of capacity into the RPM design at that point. The signposts to look for would be: (1) generation investment lags even as market prices reach or exceed Net CONE; (2) structural problems related to default service procurement prevent LSEs from signing long-term contracts, and a review and revision of default service procurement is unlikely; and (3) it can be determined with sufficient confidence that longer-term contracts through RPM-based resource procurement will actually be needed to assure resource adequacy at reasonable costs.

As discussed in Section III.C, we believe that generation development and bilateral long-term contracting will increase as load grows and old generation retires. However, the MOPR design may need to be modified to avoid creating a barrier to bilateral contracting (as discussed in Section VI.E) and state default service procurement arrangements may have to be reformed, as discussed in Section III.C.

d. Voluntary Long-Term Auctions

At this point, we believe that PJM's best option to facilitate long-term contracting would to conduct *voluntary* long-term auctions. Compared to mandatory long-term procurement through RPM, this approach would leave long-term contracting decisions up to the suppliers and buyers, who best know their own risk preferences.

PJM's administration of a centralized, but voluntary, auction would also increase forward price transparency and liquidity to long-term contracting. Auction results would indicate the prices and quantities cleared, which would help market participants forecast and plan. Even when no capacity clears, PJM could report bid-ask spreads of uncleared capacity and other information that would also increase forward price transparency. A PJM-administered voluntary auction would also enhance liquidity by facilitating a forward market for capacity as a commodity, where suppliers and buyers would not need to be concerned about their counterparties' individual risks. As with all existing PJM auctions, PJM would take responsibility for specifying contract terms, validating the qualifications and creditworthiness of suppliers and buyers, and for backing up each counterparty (subject to penalties for defaulting parties).

Some of the market-design details that PJM and its stakeholders would have to develop include auction terms, qualification and credit requirements, LDA representation and other auction mechanics, market monitoring, and implications for the BRA.

> ***Term***: It would be necessary to define forward products, such as 3 years, 5 years, and/or 7 years forward, starting with the BRA delivery year or standardized single-year products for multiple years beyond the 3-year BRA horizon.
>
> ***Qualification and credit requirements***. Because the delivery period would encompass multiple years and extend further into the future than the BRA, the qualification and credit requirements would likely need to be more stringent.
>
> ***Market monitoring***. The voluntary nature of the auctions would likely eliminate the need to mitigate supplier market power. Suppliers would have to compete for the limited number of buy bids in the forward auction, against each other and against the heavily-mitigated BRA. However, there is still a danger that buyers could manipulate prices downward by introducing excess capacity at low prices.[203] It may still be necessary to apply MOPR, including the MOPR modifications we recommend in the prior section.
>
> ***Auction mechanics***: Presumably, the auction would produce a single clearing price for each LDA and RTO. Transmission constraints would probably not have to be modeled, although LSEs would have to consider likely BRA price differentials when deciding how much to bid for capacity in any particular location in the voluntary forward auctions. LDAs would ideally be consistent with the LDAs modeled in all BRAs conducted for delivery within the extended delivery period of the long-term product(s). When new LDAs are modeled, PJM would need rules to address long-term buyers' exposure to zonal price differentials. To facilitate such long-term commitments, PJM would need to make available forward views of key administrative parameters—for example, the 5- and 10-year outlooks for CETL that we recommended in Section VI.A.VI.A.1
>
> ***Implications for BRAs***: It would probably make sense to conduct the forward auctions prior to each BRA. The cleared long-term resources would then pass through the BRAs, with bilateral buyers offering their procured long-term resources as a price taker at the resource's physical location.

It may also be possible to increase forward price transparency through a continuously-clearing over-the-counter trading platform for standardized capacity products.

[203] For example, merely disallowing self-supply offers in the voluntary forward may not mitigate this threat since someone planning on offering capacity at a zero price could submit a buy bid of infinity and be sure of clearing both its sell offer and its buy bid.

3. Summary of Recommendations on NEPA and Forward Contracting

As discussed above, we offer the following recommendations:

- ***Avoid expanding NEPA.*** We do not recommend expanding NEPA as a means to provide price certainty that may promote new investment. Doing so would introduce inefficiencies and distortions by allowing some resources to be paid for multiple years based on a single-year auction. However, for the purposes of mitigating the adverse effects of lumpy investments in small LDAs, we recommend that PJM retain NEPA.
- ***Centralized, voluntary multi-year auctions.*** To facilitate long-term contracting and forward-price transparency, we recommend that PJM consider introducing voluntary long-term forward auctions, as described above. This recommendation complements recommendations in other sections that strive to reduce RPM price uncertainty by addressing the administrative factors that contribute to this uncertainty.
- ***No mandatory long-term procurement at this point.*** We cannot recommend introducing mandatory long-term procurement by PJM at this point. The need for such procurement is not yet clear, and it would be very difficult to determine the economically-efficient terms and amounts to procure under such mandatory long-term commitments. However, this issue can be revisited in the future if investment barriers (*e.g.*, structural barriers to long-term procurement by LSEs as default service providers) were to become evident and it can be determined with sufficient confidence that longer-term contracts through mandatory RPM-based resource procurement would be needed to assure resource adequacy at reasonable costs.

VII. CONCLUSIONS

Our analyses show that RPM is performing well. Despite concerns by some stakeholders, RPM has been successful in attracting and retaining cost-effective capacity sufficient to meet resource adequacy requirements. Resource adequacy requirements have been met or exceeded in both the RTO and, during the last four BRAs, in all of the individual LDAs at capacity prices generally below the net cost of new entry (Net CONE). Without considering new RTO members and FRR entities not participating in RPM auctions, RPM has been successful in attracting and retaining 28.4 GW of committed gross additions, consisting of 11.8 GW (ICAP) of demand-side resources, 6.9 GW of increased imports or decreased exports, 4.8 GW of new generation, 4.1 GW of generation upgrades, and 0.8 GW of reactivations. Net additions were 13.1 GW, considering 5.0 GW of retirements, 2.7 GW of derates, and 7.5 GW of resources withdrawn from auctions by FRR entities and other excused resources.

Year-to-year capacity price changes have been consistent with market fundamentals, reflecting changes in the supply and demand for capacity, as well as refinements to market design and changes in administratively-determined parameters. RPM has reduced costs by fostering competition among all types of new and existing capacity, including demand-side resources. It has also facilitated decisions regarding the economic tradeoffs between investment in environmental retrofits on aging coal plants or their retirement.

Stakeholders have raised a number of key concerns. We find, however, that several major criticisms of RPM are contradicted by the evidence available to date—most notably the arguments that RPM prices are too high, that RPM does not support investment in new generation of the right types in the right places, or that RPM cannot maintain reliability in the face of environmental retirements. Stakeholders expressed particular concerns about the volatility and unpredictability of RPM prices. Some of the observed price changes are consistent with changes in market fundamentals, which necessarily must be reflected in prices for the market to be efficient. Others are caused by the one-time implementation of various improvements to the initial RPM design, such as modeling more LDAs or the elimination of ILR. These impacts on prices reflect a non-recurring one-time adjustment, which is not a concern going forward.

However, price uncertainty remains high due to non-transparent and possibly excessive fluctuations in modeled transmission limits and other administratively-defined parameters in RPM. We thus recommend a number of refinements to make the determination of transmission limits and administrative parameters more stable and transparent. To increase forward-price transparency and facilitate long-term contracting, we also support the development of voluntary auctions or an over-the-counter trading platform for long-term capacity products.

We have identified several performance risks stemming from the RPM design that should be addressed to ensure that resource adequacy will be met going forward. To address these concerns, our main recommendations include the implementation of six safeguards that would mitigate the identified performance risks. Specifically, we recommend:

- Calibrating the E&AS offset methodology to E&AS margins actually earned by generation plants similar to the reference technology.
- Increasing the price cap of the VRR curve to mitigate under-procurement risks.
- Modeling constrained LDAs more proactively for locations where significant amounts of plant retirements are likely.
- Maintaining the 2.5% overall Short-Term Resource Procurement Target for the total resource requirement, but eliminating the "holdback" for Annual and Extended Summer resources.
- Introducing audits of demand-side resources to confirm their contractual and physical ability to respond as often and seasonally as claimed.
- And finally, establishing exemptions to the Minimum Offer Price Rule ("MOPR") to better support competitive entry through bilateral and self-supply arrangements.

BIBLIOGRAPHY

Caballero, R. J., and Pindyck, R.S. (1996). "Uncertainty, Investment, and Industry Evolution." *International Economic Review,* 37 (3).

Calpine (2010). „Calpine Completes Acquisition of Conectiv Energy Fleet: 19 Power Plants Provide Scale in PJM Region, Complement Clean Portfolio," July 1, 2010. Retrieved from http://phx.corporate-ir.net/External.File?t=2&item=g7rqBLVLuv81UAmrh20MpyIW7aGu4foPuZ7gq2Z+CcNjUvrB1b1zFU3HGs3J1Mx874Nx6hD0z7jS8tAiLeiYAQ==

Constellation Energy (2010). "Constellation Energy Signs Agreement to Acquire the 2,950 MW Boston Generating Gas Fleet in New England," August 9, 2010. Retrieved from http://ir.constellation.com/releasedetail.cfm?releaseid=497503

Constellation Energy (2011). *2010 Annual Report.* April 15, 2011. Retrieved from http://files.shareholder.com/downloads/CEG/1291436832x0x460644/70872692-8CCD-479A-8DD8-32CA988D726F/2010AR.pdf

Direct Energy (2011). "Direct Energy Corporate Fact Sheet." May 2011. Retrieved from http://www.directenergy.com/EN/About-Us/Documents/Corporate_Fact_Sheet_May_2011.pdf

Environmental Protection Angency (2011a). "Fact Sheet: Proposed Mercury and Air Toxics Standards," March 16, 2011. Retrieved from http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf

Environmental Protection Angency (2011b). *National Emission Standards for Hazardous Air Polutants from Coil- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units.* Proposed Rule. March 3, 2011. Retrieved from http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf

ERCOT, MISO, NYISO, PJM and SPP (2011). "Joint Comments of the Electric Reliability Council of Texas, The Midwest Independent Transmission System Operator, The New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool" in EPA-HQ-OAR-2009-0234, August 4, 2011, available at http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234-iso-rto.ashx.

Exelon and Constellation Energy (2011). "Exelon and Constellation Energy to Merge," News Release. April 28, 2011. Retrieved from http://www.exelonconstellationmerger.com/sites/default/files/NEWS_RELEASE.pdf

Federal Energy Regulatory Commission (2009) "Order on Proposed Revisions," Issued October 29, 2009. Docket No. ER09-1673-000. Retrieved from http://www.pjm.com/~/media/documents/ferc/2009-orders/20091029-er09-1673-000.ashx

Handy-Whitman Index (2010). "The Handy-Whitman Index of Public Utility Construction Costs," Whitman, Requardt and Associates, LLP, 2010.

Hobbs, Benjamin F. (2005). "Affidavit of Benjamin F. Hobbs on Behalf of PJM Interconnection, LLC." Filed before the Federal Energy Regulatory Commission. August 5, 2005. Docket Nos. ER05-1440-000, EL05-148-000. Retrieved from http://stoft.com/metaPage/lib/Hobbs-2005-08-PJM-ICAP-affidavit.pdf

Hobbs, Benjamin F., Ming-Che Hu, Javier G. Iñón, Steven E. Stoft, and Murty P. Bhavaraju. (2007). "A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model," *IEEE Transactions on Power Systems,* Vol. 22, No. 1. February 2007.

ISO New England Inc. (2010). "First Brief of ISO New England Inc.," filed before the Federal Energy Regulatory Commission, July 1, 2010. Retrieved from http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12378583

ISO New England Inc. (2011a). "Forward Capacity Market (FCA 5) Result Report." June 9, 2011. Retrieved from http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp15/fca15/fca_5_results_report.pdf

ISO New England Inc. (2011b). *2010 Annual Markets Report.* Internal Market Monitor. June 3, 2011. Retrieved from http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf

Kiesling, Lynne L. and Kleit, Andrew N. (2009). *Electricity Restructuring: The Texas Story*, The AEI Press, Washington, D.C.

Levitan & Associates, Inc. (2011). *LCAPP Agent's Report: Long-Term Capacity Agreement Pilot Program.* Prepared for the New Jersey Board of Public Utilities. March 21, 2011. Retrieved from http://www.nj.gov/bpu/pdf/energy/LCAPP%20Agent%20Report.pdf

Meade, Richard, and Seini O'Connor (2009) "Comparison of Long-Term Contracts and Vertical Integration in Decentralised Electricity Markets," Larsen Working Paper No. 26. October 2009. Retrieved from http://www.gis-larsen.org/fr/files/LARSEN_WP_26.pdf

Minton, B. A., and Schrand, C. (1999) "The Impact of Cash Flow Volatility on Discretionary Investment and the Costs of Debt and Equity Financing," *Journal of Financial Economics.* Vol. 54, pp. 423-460.

MegaWatt Daily (2011). "N.J. Rate Counsel Official Decries PJM Process," July 21, 2011.

Monitoring Analytics (2008) *Analysis of the 2011/2012 RPM Auction.* Independent Market Monitor for PJM. Revised October 1, 2008. Retrieved from http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf

Monitoring Analytics (2010a) *Analysis of the 2013/2014 Base Residual Auction: Revised and Updated.* Independent Market Monitor for PJM. September 20, 2010. Retrieved from http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf

Monitoring Analytics (2011a) *Reports.* Retrieved :ugust 23, 2011 from http://www.monitoringanalytics.com/reports/Reports/2011.shtml

Morningstar (2010). "Constellation Energy Group Inc. CEG Q4 2009 Earnings Call Transcript," Transcript Call Date February 22, 2010. Retrieved from http://www.morningstar.com/earnings/12366794-constellation-energy-group-inc-ceg-q4-2009.aspx

New Jersey Electric Distribution Companies (2011) "Comments of the New Jersey Electric Distribution Companies on Agent's March 21, 2011 Report," March 24, 2011. Retrieved from http://www.nj-lcapp.com/Documents/NJEDCs_ReportComments.pdf

Pasteris Energy (2011). Cost of New Entry Combined Cycle Power Plant Revenue Requirments for PJM Interconnection, LLC. Filed February 11, 2011. Retreived from http://www.pjm.com/~/media/documents/ferc/2011-filings/20110211-er11-2875-000.ashx

Pfeifenberger, Joannes, Samuel Newell, Robert Earle, Attila Hajos, and Mariko Geronimo (2008) *Review of PJM's Reliability Pricing Model (RPM).* June 30, 3008. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/documents/ferc/2008-filings/20080630-er05-1410-000.ashx

Pfeifenberger, Johannes, Kathleen Spees, and Adam Schumacher (2009). "A Comparison of PJM's RPM with Alternative Energy and Capacity Market Designs." Prepared for PJM Interconnection, Inc. September 2009. Retrieved from http://www.brattle.com/_documents/UploadLibrary/Upload807.pdf

PJM Interconnection, L.L.C. (2005) "Reliability Pricing Model Filing: Volume 1," before the Federal Energy Regulatory Commission. Filed August 31, 2005. Docket Nos. ER05-1440-000 and EL05-148-000.

PJM Interconnection, L.L.C. (2007a). "2007/2008 Base Residual Auction Results," May 31, 2007. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20070531-rpm-0708-bra-settlement.ashx

PJM Interconnection, L.L.C. (2007b). "2007/08 – 2009/10 Planning Period Parameters," October 29, 2007. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters.ashx

PJM Interconnection, L.L.C. (2008a). "2008/2009 Base Residual Auction Results," April 3, 2008. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2008-2009-base-residual-auction-results.ashx

PJM Interconnection, L.L.C. (2008b). “2010/2011 Base Residual Auction Results,” February 1, 2008. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20080201-2010-2011-settlement-sheet-l.ashx

PJM Interconnection, L.L.C. (2008c). “2011/2012 Base Residual Auction Results,” May 15, 2008. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20080515-2011-2012-bra-results-spreadsheet.ashx

PJM Interconnection, L.L.C. (2008d). *PJM Load Forecast Report.* January 2008, Revised May 2008. Retrieved from http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/~/media/documents/reports/2008-load-report.ashx

PJM Interconnection, L.L.C. (2008e). “2008/2009 Third Incremental Auction Report,” January 17, 2008. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/08-09-third-incremental-auction-report.ashx

PJM Interconnection, L.L.C. (2008f). RPM Revisions Filing before the Federal Energy Regulatory Commission. December 12, 2008. Docket No. ER09-412-000. Retrieved from http://www.pjm.com/~/media/documents/ferc/2008-filings/20081212-er09-xxx-000.ashx

PJM Interconnection, L.L.C. (2009a). “2009/2010 Base Residual Auction Results and Final Zonal Capacity Prices,” September 23, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2009-2010-base-residual-auction-results.ashx

PJM Interconnection, L.L.C. (2009b). “2010/2011 Planning Period Parameters,” December 2, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2010-2011-rpm-planning-parameters.ashx

PJM Interconnection, L.L.C. (2009c). “2011/2012 Planning Period Parameters,” December 2, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2011-2012-rpm-bra-planning-parameters.ashx

PJM Interconnection, L.L.C. (2009d). “2012/2013 Planning Period Parameters,” May 22, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-rpm-planning-parameters.ashx

PJM Interconnection, L.L.C. (2009e). “2012/2013 Base Residual Auction Results Document,” May 15, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-results-document-xls.ashx

PJM Interconnection, L.L.C. (2009f). *PJM Load Forecast Report.* January 2009. Retrieved from http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/~/media/documents/reports/2009-pjm-load-report.ashx

PJM Interconnection, L.L.C. (2009g). "Duquesne Settlement Information," July 20, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20090720-duquesne-settlement-information.ashx

PJM Interconnection, L.L.C. (2009h). "2009/2010 Third Incremental Auction Report," January 16, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20090116-third-incremental-auction-report-09-10.ashx

PJM Interconnection, L.L.C. (2009i) "2011/2012 First Incremental Auction Report," June 15, 2009. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2011-2012-first-incremental-auction-report.ashx

PJM Interconnection, L.L.C. (2010a). "2013/2014 Planning Period Parameters," May 17, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-planning-period-parameters.ashx

PJM Interconnection, L.L.C. (2010b). "2013/2014 Base Residual Auction Results," May 14, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-results.ashx

PJM Interconnection, L.L.C. (2010c) "2011/2012 & 2012/2013 ATSI FRR Integration Auction Results," May 26, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/atsi-frr-integration-auction-results.ashx

PJM Interconnection, L.L.C. (2010d) *Duke Integration White Paper, Version 4.0.* September 28, 2010. Retrieved from http://www.pjm.com/markets-and-operations/market-integration/~/media/markets-ops/duke-integration/duke-integration-white-paper.ashx

PJM Interconnection, L.L.C. (2010e) *PJM Load Forecast Report.* January 2010. Retrieved from http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/~/media/documents/reports/2010-load-forecast-report.ashx

PJM Interconnection, L.L.C. (2010f) "2010/2011 Third Incremental Auction Report," January 15, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2010-2011-third-incremental-auction-report.ashx

PJM Interconnection, L.L.C. (2010g) "2012/2013 First Incremental Auction Report," September 24, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-first-incremental-auction-report.ashx

PJM Interconnection, L.L.C. (2010h) "2012/2013 1st Incremental Auction Planning Parameters," October 18, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-1st-incremental-auction-planning-parameters.ashx

PJM Interconnection, L.L.C (2010i) *2013/2014 RPM Base Residual Auction Planning Period Parameters Report.* March 12, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/planning-period-parameters-report.ashx

PJM Interconnection, LLC. (2010j) "Scenario Analysis Results," November 1, 2010. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/scenario-analysis-results.ashx

PJM Interconnection, L.L.C. (2011a) Data Supplied for this Study over February-August, 2011.

PJM Interconnection, L.L.C. (2011b). "2014/2015 Planning Period Parameters," April 8, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/rpm-bra-planning-parameters-2014-2015.ashx

PJM Interconnection, L.L.C. (2011c). "2014/2015 Base Residual Auction Results," May 13, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-2015-base-residual-auction-results.ashx

PJM Interconnection, L.L.C. (2011d). *PJM Manual 18: PJM Capacity Market.* Revision 12, Effective May 25, 2011. Retrieved from http://www.pjm.com/~/media/documents/manuals/m18.ashx

PJM Interconnection, L.L.C. (2011e). "FirstEnergy's American Transmission Systems, Inc. And Cleveland Public Power Successfully Integrated into PJM," June 1, 2011. Retrieved from http://www.pjm.com/~/media/about-pjm/newsroom/2011-releases/20110601-atsi-and-cpp-successfullly-integrated-into-pjm.ashx

PJM Interconnection, L.L.C. (2011f). "2014/2015 RPM Base Residual Auction Results." Addendum released May 31, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-rpm-bra-results-report-addendum.ashx

PJM Interconnection, L.L.C. (2011g). *PJM Load Forecast Report.* January 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2011-2012-third-incremental-auction-report.ashx

PJM Interconnection, L.L.C. (2011h) “2011/2012 Third Incremental Auction Report,” May 11, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2010-2011-third-incremental-auction-report.ashx

PJM Interconnection, L.L.C. (2011i) *PJM Manual 14B: PJM Region Transmission Planning Process.* Revision 17, Effective April 13, 2011. Retrieved from http://www.pjm.com/~/media/documents/manuals/m14b.ashx

PJM Interconnection, L.L.C. (2011j) “2012/2013 2nd Incremental Auction Planning Parameters,” July 7, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-2013-2nd-incremental-auction-planning-parameters.ashx

PJM Interconnection, L.L.C. (2011k) *2014/2015 RPM Base Residual Auction Planning Period Parameters Report.* February 1, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110102-rpm-bra-planning-parameters-2014-2015.ashx

PJM Interconnection, L.L.C. (2011l) “Susquehanna-Roseland.” Retrieved July 22, 2011 from http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx

PJM Interconnection, L.L.C. (2011m) “Potomac-Appalachian Transmission Highlight (PATH).” Retrieved July 26, 2011 from http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx

PJM Interconnection, L.L.C. (2011n) “PJM Board Directs Delay in PATH Transmission Line,” February 28, 2011. Retrieved from http://pjm.com/~/media/about-pjm/newsroom/2011-releases/20110228-RTEP-announcement.ashx

PJM Interconnection, L.L.C. (2011o). “PJM Planning Process Strawman,” Presented by Steve Herling to the RPPTF. April 29, 2011. Retrieved from http://www.pjm.com/~/media/committees-groups/task-forces/rpptf/20110429/20110429-item-03-pjm-planning-process-strawman.ashx

PJM Interconnection, L.L.C. (2011p). “Coal Units at Risk for Retirement in PJM as a Result of the Proposed EPA Transport Rule and Hazardous Air Pollutant Rule: An Analysis of Operational and Physical Characteristics,” Presented by Paul M. Sotkiewicz and M. Gary Helm. June 24, 2011. Retrieved from http://www.pjm.com/~/media/committees-groups/task-forces/rpptf/20110624/20110624-at-risk-generation.ashx

PJM Interconnection, L.L.C. (2011q) *PJM Open Access Transmission Tariff.* Effective June 9, 2011. Retrieved from http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx

PJM Interconnection, L.L.C. (2011r) “PJM RPM Default Avoidable Cost Rates for the 2014/2015 Delivery Year,” January 20, 2011. Retrieved from http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/default-acr-values-for-the-2014-2015-dy.ashx

PJM Interconnection, L.L.C. (2011s) Transmission Zones Map. Retrieved July 28, 2011 from http://www.pjm.com/documents/~/media/about-pjm/pjm-zones.ashx

PJM Interconnection, L.L.C. (2011t) *PJM 2010 Regional Transmission Expansion Plan.* February 28, 2011. Retrieved from http://www.pjm.com/documents/reports/rtep-report.aspx

PJM Interconnection, L.L.C. (2011u) “Training Material,” Retrieved August 22, 2011 from http://www.pjm.com/training/training-material.aspx

PJM Interconnection, L.L.C. (2011v) “RPM Auction User Information,” Retrieved August 22, 2011 from http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

PJM Interconnection, L.L.C. (2011w) “Committees and Groups,” Retrieved August 22, 2011 from http://www.pjm.com/committees-and-groups.aspx

PJM Interconnection, L.L.C. (2011x) *PJM Manual 20: PJM Resource Adequacy Analysis.* Revision 4. Effective Date June 1, 2011. Retrieved from http://www.pjm.com/~/media/documents/manuals/m20.ashx

PJM Interconnection, L.L.C. (2011z). “Corrected Comments of PJM Interconnection, L.L.C.” in EPA-HQ-OAR-2009-0234, August 4, 2011, available at http://pjm.com/~/media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234comments.ashx.

Power Project Management (2008). 2008 Update of Cost of New Entry Combustion Turbine Power Plant Revenue Requirements for PJM Interconnection, LLC. Retreived from http://www.pjm-miso.com/documents/ferc/documents/2008/20081212-er09-xxx-000.pdf

U.S. Department of Labor (2011). Consumer Price Index. Retrieved Augues 1, 2011 from ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt

Ventyx (2011). Energy Velocity Suite. Data Downloaded over February-August, 2011.

Viscusi, W. Kip, John M. Vernon, and Joseph E.Harrington, Jr. (2000). *Economics of Regulation and Antitrust*, The MIT Press, Cambridge, Massachusetts, Third Edition.

Wiser, Ryan, and Mark Bolinger (2010) *2009 Wind Technologies Report.* U.S. Department of Energy,. Energy Efficiency and Renewable Energy. August 2010. Retrieved from http://www1.eere.energy.gov/windandhydro/pdfs/2009_wind_technologies_market_report.pdf

Wittenstein, Matthew, and Ezra Hausman (2011) *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement.* June 14, 2011. Retrieved from http://www.publicpower.org/files/PDFs/2011APPACapacityMarketsReport.pdf

LIST OF ACRONYMS

ALM	Active Load Management
APIR	Avoidable Project Investment Rate
APPA	American Public Power Association
APS	Allegheny Power Systems
ATSI	American Transmission Systems, Inc. (a FirstEnergy subsidiary)
ATWACC	After-Tax Weighted-Average Cost Of Capital
BRA	Base Residual Auction
CC	Combined Cycle
CCM	Capacity Credit Market
CETL	Capacity Emergency Transfer Limits
CETO	Capacity Emergency Transfer Objective
CONE	Cost of New Entry
CP	Coincident Peak
CPI	Consumer Price Index
CSP	Curtailment Service Providers
CT	Combustion Turbine
DEOK	Duke Energy Ohio/Kentucky
DPL	Delmarva Power and Light
DR	Demand Response
E&AS	Energy and Ancillary Service
EDC	Electric Distribution Company
EE	Energy Efficiency
EFORd	Equivalent Demand Forced Outage Rate
ELLC	Effective Load Carrying Capability
EMAAC	Eastern Mid-Atlantic Area Council
EPA	Environmental Protection Agency

EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operation and Maintenance
FPR	Forecast Pool Requirement
FRR	Fixed Resource Requirement
FSL	Firm Service Level
GHG	Greenhouse Gas
GLD	Guaranteed Load Drop
GSU	Generator Step-Up
GW	Gigawatt (= 1,000 MW)
HAP	Hazardous Air Pollutant
IA	Incremental Auction
ICAP	Installed Capacity
ICTR	Incremental Capacity Transfer Right
ILR	Interruptible Load for Reliability
IPSTF	Interconnection Process Senior Task Force
IMM	Independent Market Monitor
IRM	Installed Reserve Margin
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt Hours
LDA	Locational Deliverability Area
LOLE	Loss of Load Expectation
LSE	Load-Serving Entities
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MACT	Maximum Achievable Control Technology
MOPR	Minimum Offer Price Rule
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NEPA	New Entry Pricing Adjustment
NRG	NRG Energy, Inc.

NSR	New Source Review
NUG	Non-Utility Owned Generator
NYISO	New York ISO
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OFR	Owner-Furnished Equipment
OTC	Over the Counter
PATH	Potomac-Appalachian Transmission Highline
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, LLC
PLC	Peak Load Contribution
PPA	Power Purchase Agreement
PPM	Power Project Management
PRD	Price Responsive Demand
PSD	Prevention of Significant Deterioration
QTU	Qualifying Transmission Upgrade
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability-Must-Run
RPM	Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
STRPT	Short-Term Resource Procurement Target
SWMAAC	Southwestern Mid-Atlantic Area Council
TO	Transmission Owner
UCAP	Unforced Capacity
VOLL	Value of Lost Load
VRR	Variable Resource Requirement