The Brattle Group

Review of PJM's Reliability Pricing Model (RPM)

June 30, 2008

Johannes Pfeifenberger
Samuel Newell
Robert Earle
Attila Hajos
Mariko Geronimo

Prepared for

PJM Interconnection, L.L.C.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

I. PURPOSE AND SUMMARY

A. PURPOSE OF THIS STUDY

The Brattle Group has been commissioned by PJM Interconnection L.L.C. ("PJM") to review the performance of its Reliability Pricing Model ("RPM") and assess whether RPM is addressing the infrastructure investment needs that it was intended to address. Specifically, the scope of our assignment was to:

(1) assess the overall effectiveness of RPM in encouraging and sustaining infrastructure investments to maintain resource adequacy consistent with reliability requirements;

(2) review the key RPM design elements for their effectiveness in achieving RPM goals;

(3) review RPM interactions with related PJM market design elements to identify potentially adverse incentives or barriers to entry; and

(4) recommend possible modifications to the RPM.

To assess the overall effectiveness of RPM in encouraging and sustaining infrastructure investments, we analyzed the pricing and investment response achieved in the first five base residual auctions ("BRAs" or "base auctions"). We then reviewed key RPM design elements and assessed whether RPM rules may adversely affect RPM participation. This review of design elements included an evaluation and updated probabilistic simulation of the shape of the Variable Resource Requirement ("VRR") curve, the Net Cost of New Entry ("Net CONE") reference price, including the net energy and ancillary service ("E&AS") offset methodology; and the three-year forward commitment period. Our analysis also included a review of Locational Deliverability Area ("LDA") definitions and the procedures to establish new LDAs.

To determine whether RPM interactions with other PJM market design elements might create adverse incentives or barriers to entry, we assessed (1) incentives and potential barriers for existing resources to participate in RPM; (2) demand resource participation rules; (3) the generation interconnection queue process; (4) generation and demand response performance requirements and non-compliance penalties; (5) capital expenditure and project investment provisions for upgrades to existing generating resources; (6) and the relationship between the design and auction outcomes of RPM and other PJM markets.

Our report does not specifically address whether market mitigation processes are effective—a point that is and has been addressed by PJM's Market Monitoring Unit ("MMU"). Nor do we specifically address the desirability of forward capacity markets in comparison to fundamentally different market designs, such as energy-only markets.

To undertake this effort we analyzed RPM auction results. We also reviewed the available RPM documentation, the original filings on RPM and the RPM settlement before the Federal Energy Regulatory Commission ("FERC"), comments filed by market participants, and materials presented by market participants at RPM stakeholder and working group meetings. We interviewed a range of market participants and conferred with the staff of PJM and PJM's

Market Monitoring Unit. We also analyzed the forward capacity market design in New England and followed the ongoing capacity market design discussions in California.

The remainder of this report is organized as follows. We first summarize RPM results to date and our recommendations on RPM design elements and interactions with other PJM market design features. Section II provides an overview of RPM's objectives and design. Section III discusses RPM auction results in detail, focusing on the quantity and types of resources that have been added or retained under RPM. This section also provides an outlook on RPM-eligible resources that are available to make commitments in future RPM auctions. Section IV of this report presents our analysis of VRR design and forward commitment parameters, including an assessment of CONE values, and an updated 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. In Section V, we analyze a number of RPM and PJM market design features and identify aspects of these designs that likely create adverse incentives, barriers to entry, or inefficiencies. We also present recommendations on possible modifications to these design elements for consideration and further evaluation by PJM and its shareholders. Section VI presents our conclusions.

B. SUMMARY OF RPM RESULTS TO DATE

RPM introduced a capacity market design based on three-year forward-looking, annual obligations for locational capacity under which supply offers are cleared against a downward sloping demand curve (the VRR curve). RPM is designed to improve price stability, enhance reliability, and force existing resources to compete with a potentially large supply of new resources.

The first base auction took place in April 2007 and procured capacity for the 2007/08 delivery year. Since then, four more base auctions have been conducted. The most recent one, the May 2008 auction for the 2011/12 delivery year, was the first to procure capacity under a full three-year forward commitment.

Despite this very compressed time frame, the five base auctions conducted to date have been successful in achieving the stated reliability and economic objectives of RPM. We have a number of concerns and recommendations for possible improvement of various RPM design parameters. However, we also find that since RPM was implemented: (1) at least 4,600 MW of capacity has been retained that otherwise would have retired; (2) almost 10,000 MW of incremental capacity has been committed; and (3) the volume of generation interconnection requests has grown to make an additional 33,000 MW of new generation projects eligible to participate in future RPM auctions.

More specifically, the following incremental commitments—which amount to over 14,500 MW of resources that likely would not have been available in the absence of RPM—have been made under RPM to date:

- 4,248 MW of generation additions of various types, including 3,069 MW of new gas, coal, and renewable generation committed through RPM auctions, 580 MW of new generation committed to meet Fixed Resource Requirement ("FRR") obligations, and

599 MW of reactivated generating units that were previously retired; excluding renewables and FRR capacity for which RPM likely was not a primary driver, 3,274 MW of commitments from new generating units are reasonably attributable to RPM;

- Over 2,900 MW of uprates to existing generating capacity, which exceed derates by more than 1,260 MW;
- Close to 1,800 MW of demand resources ("DR") in addition to approximately 1,400 MW of interruptible load for reliability ("ILR") resources;
- Decreases in net exports of almost 2,200 MW (not counting almost 3,200 MW of committed imports from generating units in the Duquesne service area); and
- Withdrawn requests to deactivate 1,170 MW of existing resources and an additional 3,500 MW of planned retirements that were cancelled or deferred due to RPM; moreover, RPM helps retain over 20,000 MW of other existing resources that likely would *not* be financially viable in the absence of capacity payments.

In addition to these RPM-related incremental resource commitments, market participants competed with an additional 6,000 MW of resources that did not clear in the recent auction for the 2011/12 delivery year. This substantial amount of *uncleared* capacity included approximately 500 MW of uncleared new generating units, almost 300 MW of uncleared DR resources, and 670 MW of uncleared import offers. The remainder represented uncleared offers from existing generating units.

As a result of the more than 14,500 MW of new or retained resources committed under RPM to date and the help of planned transmission upgrades, target reserve margins have been achieved both on a PJM system-wide and Locational Deliverability Area (LDA)-internal basis. On a Regional Transmission Organization ("RTO") wide basis, committed capacity consistently exceeds target reliability levels by at least one percent in each year through the 2011/12 delivery year. Importantly, capacity margins have markedly improved within LDAs. The increase in generation, demand response, and transmission capacity committed to serve Southwestern MAAC ("SWMAAC") and Eastern MAAC ("EMAAC") LDAs has integrated these regions into the RTO-wide capacity market and improved reserve margins within these regions from levels that were one percent to two percent *below* target to RTO-wide levels of one percent to two percent *above* target reliability levels. A significant portion of improved LDA reliability is associated with planned new transmission facilities that were projected to be operational for the 2010/11 and 2011/12 delivery years.

To attract and retain these resources and improve reliability levels, customers have paid capacity prices that are consistent with resource adequacy conditions and the administratively-determined marginal cost of capacity for the RTO—the Net CONE of approximately $170/MW-day. RTO-wide capacity prices have increased from levels below Net CONE as reserve margins declined from above-target levels until the most recent auction. In contrast, LDA-internal capacity prices have decreased from levels above Net CONE through the 2009/10 delivery year to the RTO-wide level of $174/MW-day for the 2010/11 delivery year and $110/MW-day for the 2011/12 delivery year as reserve margins increased from below-target levels. If Duquesne had not withdrawn its load from PJM, however, or generation in the Duquesne zone had chosen not to offer its capacity into RPM, the 2011/12 clearing prices would have been approximately $150/MW-day.

The first four base auctions attracted new capacity primarily in the form of additional demand response, reduced net exports, and cancelled or delayed retirements. While almost 2,000 MW of new generation was committed in the first four auctions, it accounted only for a relatively small portion of the overall resources that were added or retained. In contrast, the most recent auction for the 2011/12 delivery year not only experienced a more significant increase in total supply offers, but it also *more than doubled* the amount of new generating resources committed in the four previous auctions combined.

The positive impact of RPM already extends beyond the 2011/12 delivery year. RPM has stimulated the development of an unprecedented amount of potential new resources, which include approximately 33,000 MW of effective capacity from new generation projects in PJM's interconnection queue that that are already eligible to offer into future RPM auctions.[1] The vast majority of these proposed generation projects did not exist before 2006, the year in which RPM was approved and finalized.

The impacts RPM has had on new and existing resources show that capacity price signals are important for facilitating the most cost-effective entry, investment, and retirement decisions. RPM capacity prices have also been important for stimulating demand-side investments that can effectively compete with supply-side resources.

C. Summary of Recommendations

Despite the success of RPM in attracting resources and achieving reliability targets, we offer several recommendations that, if more fully developed and implemented, could enhance the effectiveness of the RPM market design. We recommend maintaining the basic design elements, including the sloped VRR curve, the three-year forward time frame, and the one-year commitment periods. Our recommendations would modify rather than fundamentally change the basic design elements of RPM. Specifically, we recommend that PJM and its stakeholder community consider and further evaluate the following options:

1. Implement changes to certain market rules and design elements that would increase the pool of resources able to offer capacity into RPM by: (1) reducing capacity that is "excused" from RPM, in particular the excluded excess capacity of FRR entities; (2) streamlining the generation interconnection process; and (3) adopting various measures that allow energy efficiency and price-responsive demand resources to be reflected in RPM on a more timely basis. These changes would increase the future supply of capacity resources.
2. Revise the deficiency and unavailability penalty provisions of RPM. Current penalties faced by generating capacity resources seem overly punitive, while penalties

[1] 28,000 MW of these proposed generation projects are from non-renewable sources. The difference reflects the derated capacity of renewable sources.

faced by demand resources seem too lenient. We recommend changes to the penalty structure that would reduce the risks faced by suppliers, while maintaining performance incentives for all resource types.

3. Improve processes to maintain and cost-effectively provide reliability within LDAs by: (1) defining LDAs electrically based on proximity to major transmission constraints; (2) modifying or eliminating the pre-auction screening of LDAs; (3) reevaluating the current reliability criterion applied to LDAs; (4) adjusting for LDA capacity shortfalls due to delays in planned transmission projects; and (5) offering to resources within LDAs an option to “lock- in” capacity prices for three to five years.

4. Redesign incremental auctions so that they are more liquid, more able to address decreases in load and changes in LDA import capabilities, and more consistent with the base auctions by: (1) creating a single type of incremental auction; (2) adding into incremental auctions the portion of the VRR curve that did not clear in the base auction, updated for changes in load forecasts; and (3) integrating ILR resources into the incremental auctions.

5. Reevaluate RPM’s project investment cost provisions and evaluate potential modifications to how capital expenditures (cap-ex) may be included in suppliers’ offers, including: (1) allowing cap-ex adders to offer caps only in the first delivery year in which the particular capital addition is operational; (2) reevaluating investment recovery periods, particularly for major capital expenditures; and (3) allowing exemptions from offer caps for existing resources, based on a showing by a supplier that a higher offer cap is justified.

6. Evaluate how reliability targets and Net CONE values are selected to anchor the VRR curve by: (1) reviewing the reliability targets; (2) improving administrative updates to Net CONE, including an update to gross CONE and the use of forward-looking offsets for energy and ancillary service margins with ex post true-ups; and (3) refining the empirical adjustment option to update Net CONE.

More specific recommendations for PJM’s consideration and further evaluation are developed and discussed in Sections IV and V of this report.

II. RPM OVERVIEW: DESIGN AND PURPOSE

A. RPM BACKGROUND

On June 1, 2007, PJM's Capacity Credit Market ("CCM"), which had been the in place since 1999, was replaced with the current capacity market design, the RPM. The CCM was a voluntary balancing mechanism that allowed Load Serving Entities ("LSEs") to satisfy their installed capacity requirements on a daily, monthly, and multi-monthly basis. The CCM transacted less than 10 percent 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 below both the cost of adding new capacity and the cost of retaining some of the region's existing capacity. 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. 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 instead of vertical demand curves. The sloped demand curve 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 and qualifying transmission upgrades to satisfy LSEs' unforced capacity 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 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 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 it its December 22, 2006 order.

Attachment DD of PJM's Open Access Transmission Tariff and PJM's Manual 18 describes 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 available online.[3] Additional materials, discussion documents, and agendas documenting the ongoing efforts to refine various aspects of RPM are posted for the RPM stakeholder meetings[4] and by the RPM Working Group.[5] Design overviews and detailed assessments of RPM auction results and performance to date have also been published by PJM's Market Monitoring Unit.[6]

The results from the RPM auctions conducted to date have been posted by PJM and analyzed by the PJM MMU.[7] RPM design and auction results have also been reviewed in reports prepared for market participants, including the American Public Power Association ("APPA")[8] and, in response to the APPA review, on behalf of the PJM Power Providers Group ("P3 Group").[9] The results for all five RPM auctions conducted to date are analyzed in more detail in Section III of our report.

---

2 PJM's Open Access Transmission Tariff is posted under http://www.pjm.com/documents/agreements.html and PJM's "M-18: Capacity Market Manual" is available at http://www.pjm.com/contributions/pjm-manuals/manuals.html.

3 Detailed RPM overview and descriptions are available http://www.pjm.com/markets/rpm/rpm.html. RPM training materials are posted at and http://www.pjm.com/services/training/train-materials.html. Information about each delivery year, including modeling information, planning parameters, and auction results are available at http://www.pjm.com/markets/rpm/operations.html.

4 RPM Stakeholder meeting agendas and materials are available at http://www.pjm.com/committees/stakeholders/rpm/rpm.html.

5 RPM Working Group meeting agendas and materials are available at http://www.pjm.com/committees/working-groups/rpmwg/rpmwg.html.

6 For an MMU overview of RPM capacity market design and a comparison to the previous CCM design, see Chapter 5 of the 2007 State of the Market Report, available at http://www.pjm.com/markets/market-monitor/som.html. Assessments of the individual RPM auctions and related market monitoring materials are posted by the MMU at http://www.pjm.com/markets/market-monitor/messages.html.

7 PJM's auction results are posted at http://www.pjm.com/markets/rpm/operations.html; the MMU analyses of RPM auctions are available at http://www.pjm.com/markets/market-monitor/messages.html.

8 James F. Wilson, *Raising the Stakes on Capacity Incentives: PJM's Reliability Pricing Model (RPM),* LECG Inc., March 14, 2008. This paper and PJM's response to it are posted at http://www.pjm.com/documents/reports.html.

9 Robert B. Stoddard, *Reliability at Stake: Resource Adequacy Designs and the Success of PJM's Reliability Pricing Model*, CRA International, May 5, 2008 (posted at http://www.p3powergroup.com/sitecontent.cfm?page=pressdetail&id=344.) The P3 Group paper specifically addresses several critiques of the RPM design and auction outcomes raised by Wilson in the APPA-sponsored RPM review.

B. SUMMARY OF RPM DESIGN

The RPM design is based on annual auctions for locational capacity in which offers for the supply of three-year forward capacity are cleared against a downward sloping demand curve. 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.

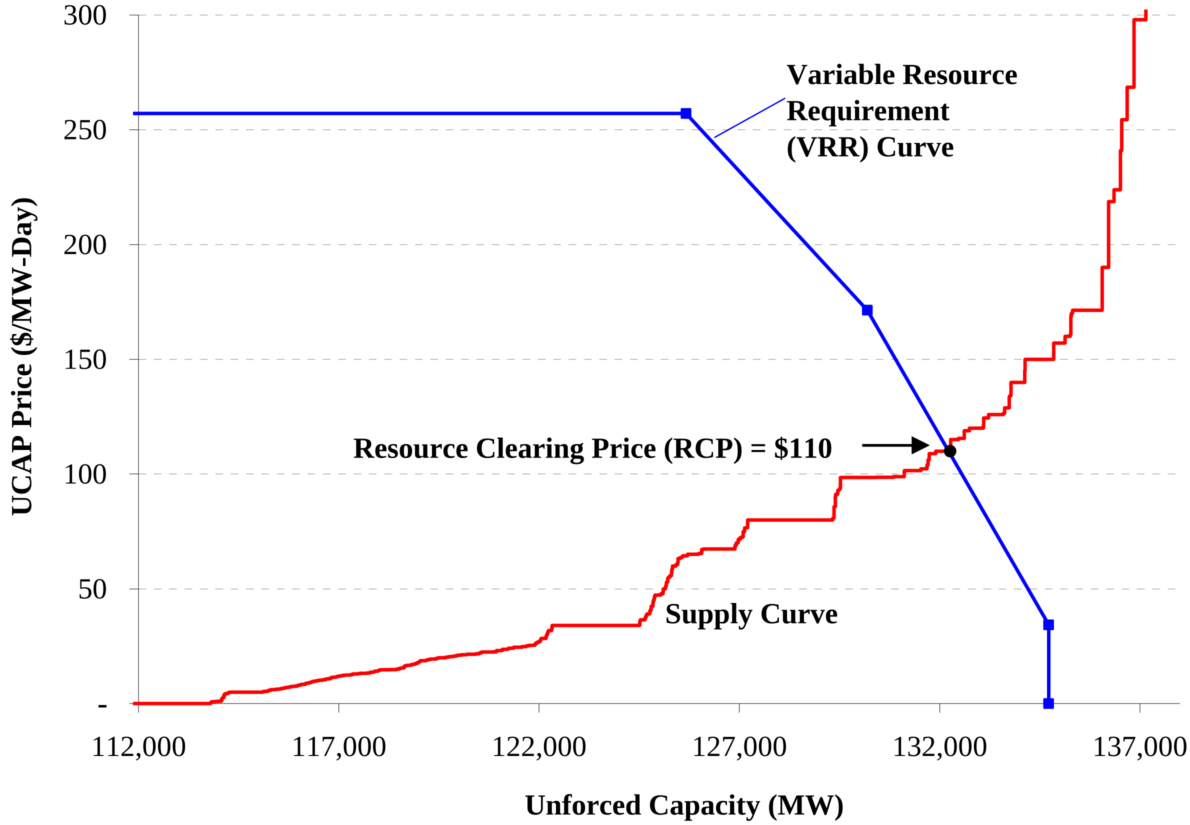
The key design parameters of RPM are:

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

Downward Sloping Demand Curve. The VRR curve is anchored at a price and quantity that reflects the Net CONE and target reserve margins 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 1 shows the capacity supply curve, VRR curve, and auction clearing price and quantity for the most recent RPM auction, which procured capacity for the 2011/12 delivery year.

Figure 1
Capacity Supply and Demand in the 2011/12 Base Auction



This VRR curve yields a capacity price equal to Net CONE at the target reserve margin plus 1 percent. For lower supply levels, capacity prices increase linearly to reserve margins that are 3 percent below target reserve margins, at which point the capacity price is capped at 150 percent of Net CONE. From a price equal to Net CONE at target reserve margins plus 1 percent, the capacity prices also decline linearly until reserve margins reach target reserves plus 5 percent, at which the capacity price is equal to 20 percent of Net CONE. For higher reserve margins, capacity prices drop to zero.

As noted in the FERC order approving the RPM design,[10] 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.

---

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

- 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 the estimated levelized cost that a new entrant needs to recover in power markets—including energy, ancillary service, and the RPM capacity market—in order to recover its investment costs. To date, CONE values have been administratively determined through a study which chose the most efficient and competitive new technology based on its estimated levelized costs. The PJM Tariff allows for periodic review and adjustment of the CONE parameter. The adjustments may either be administrative (like the original determination) or empirically based on actual market outcomes.

Energy and Ancillary Services Revenue Offset. The E&AS offset represents the 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 (six-year average during the RPM Transition Period) of historical profits for the reference technology.

Locational Deliverability Areas. 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. Potentially constrained areas are identified through PJM's Regional Transmission Expansion Planning ("RTEP") process. LDAs were gradually phased in over the course of the first several RPM auctions. Currently there are 23 LDAs defined in RPM.

Base Residual and Incremental Auctions. RPM implementation resulted in a series of four initial capacity auctions that, over the course of only nine months, were designed to transition RPM to its full three-year forward commitment: the first auction was conducted in April 2007 for the delivery year starting June 1, 2007 (the 2007/08 delivery year); the second auction took place in July 2007 for the 2008/09 delivery year; the third auction was held in October 2007 for the 2009/10 delivery year; and the fourth auction was conducted in January 2008 for the 2010/11 delivery year. A fifth auction, the first conducted a full three years ahead of suppliers' delivery commitments, took place in May 2008 for the delivery year starting June 1, 2011 (the 2011/12 delivery year).

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 up to three "Incremental Auctions"—23 months, 13 months, and 4 months before each delivery year. The first and third incremental auction allow suppliers to procure replacement capacity for commitments they can no longer fulfill, and the second incremental auction allows PJM to procure more capacity if the peak load forecast for the delivery year has increased since the base auction was conducted.

Participation by Demand-Side Resources and New Transmission Upgrades. In contrast to the previous capacity market, RPM enables participation by demand-side resources and new transmission projects. Capacity provided by these resources is treated equivalently to generating capacity. Demand-side resources may participate in the RPM auctions as Demand Resources (DR) or as Interruptible Load for Reliability (ILR) via a certification process. Eligible transmission projects, called Qualifying Transmission Upgrades ("QTUs"), can participate to increase import capability into a constrained LDA.

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, and will be committed regardless of the market price. The main purpose of the base auctions is to purchase capacity needs not met by self-supplied resources.

Market Power 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.

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

Performance Metrics. 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.

Differences Between the Current RPM Design and the Original RPM Proposal. The RPM settlement process resulted in a capacity market design that was based on the original RPM proposal filed by PJM. During the course of settlement negotiations, several design elements of the original proposal were modified, including the following:

- The RPM Settlement adopted a VRR curve with a different shape such that the price was lower at nearly all capacity levels.
- The forward commitment period was reduced from the originally proposed four to three years.

- The phase-in schedule for LDAs was lengthened to include the first three delivery years.
- The RPM Settlement did not incorporate a seasonal pricing of capacity that was initially proposed.
- The RPM Settlement eliminated the operational reliability requirements that were intended to ensure that generating capacity resources have sufficient operational flexibility to maintain reliability.
- After the RPM Transition Period, E&AS offset calculations were based on the three most recent years, not the originally proposed average of six years. The E&AS offset for the reference technology was calculated using the "Peak-Hour Dispatch" methodology, not the "Perfect Dispatch" methodology proposed in the original filing. The former method respects operational limitations of generating units, while the latter does not.
- The New Entry Price Adjustment, which allows a lock-in of capacity prices for up to three years under certain conditions, was introduced in Settlement.
- The Settlement added performance metrics to assess resource availability during peak periods.
- The Settlement added a new provision that allows the MMU to reject offers by planned capacity resources that are found to be uncompetitive.

III. RESULTS OF RPM AUCTIONS TO DATE

As noted earlier, PJM conducted its first base residual auction in April 2007 for the 2007/08 delivery year, which started June 1, 2007. Since that April 2007 auction, PJM has conducted four additional base auctions, the latest in May 2008 for the 2011/12 delivery year. Despite this very compressed time frame, these five auctions have produced significant commitments to retain and add new capacity resources on a PJM system-wide and LDA basis.

While we have a number of concerns and recommendations for possible improvement of various RPM design parameters, which we present in Sections IV and V of this report, we find that the five base residual auctions conducted to date have been quite successful in achieving the stated reliability and economic objectives of RPM. These auctions have attracted and retained about 14,500 MW of resources that likely would not have been made available to PJM otherwise, including new capacity of various types, uprates and other investments in existing capacity, a reduction in net exports, and unprecedented growth in demand response. As a result, target reserve margins have been achieved even as load has grown. Reliability requirements within LDAs also have been achieved through a combination of capacity retentions, new resources, and planned transmission upgrades. RPM has stimulated an unprecedented amount of potential new resources, which include approximately 33,000 MW of effective capacity from new generation projects in PJM's interconnection queue that have not already been committed through past auctions, but are eligible to offer into future RPM auctions.[11] The vast majority of these proposed generation projects did not exist before 2006, the year during which RPM was approved and finalized.

A. SUMMARY OF RPM RESULTS

Cleared Reserve Margins. The first five base residual auctions have produced a convergence of installed reserve margins toward the target reliability level, with new resources and retained existing capacity sufficient to meet load at both the LDA and RTO-wide level. As Figure 2 shows, the capacity cleared in the first base auction (conducted in April 2007 for the 2007/08 delivery year) was below target in the SWMAAC and EMAAC LDAs, while the rest of the RTO was several percentage points above its reliability target. These initial results reflect in large part the level of resources online before RPM. By the fourth auction (conducted in January 2008 for the 2010/11 delivery year), the LDAs were no longer constrained and, at only one percent above target reserve margins, the entire RTO was closer to its target reliability requirements.

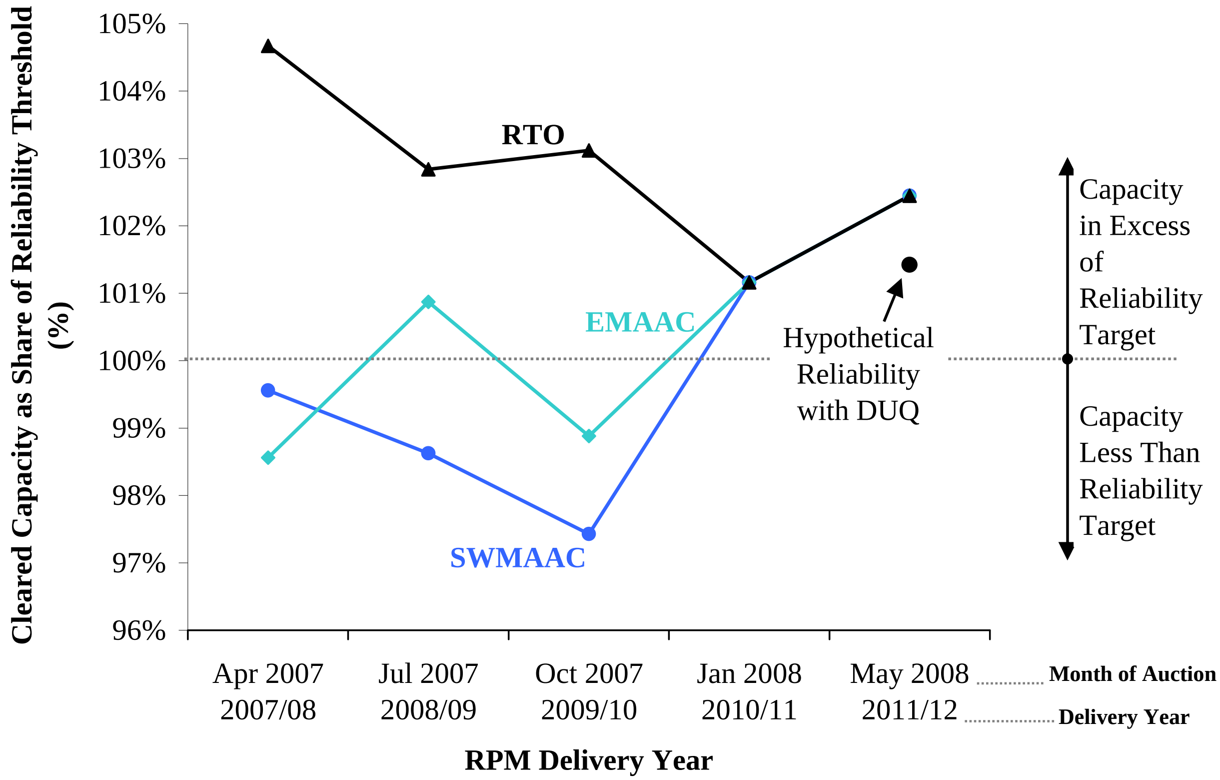
Reserve margins subsequently increased to slightly more than two percent above target in the fifth, most recent auction (conducted in May 2008 for the 2011/12 delivery year), but this increase in reserve margin resulted largely from the combination of Duquesne's departure from PJM, which removed approximately 3,000 MW of PJM load, and the choice by generation owners in the Duquesne service area to continue to offer their resources into RPM. If Duquesne had not withdrawn from PJM, or if the generating resources in Duquesne's service area had not

---

[11] Note that less than 5,000 MW of that capacity is accounted for by the effective capacity of renewable projects, for which RPM and the resulting capacity prices may not be a primary consideration.

chosen to continue to make all of their capacity available to PJM, reserve margins would have be approximately one percent above target.

Figure 2
RPM Cleared Capacity Relative to Reliability Target
(Reliability Target = 100%)



Source: *Brattle* analysis of PJM data. Excludes FRR capacity obligations and commitments.

As discussed in more detail below, RPM attracted and retained a substantial amount of resources in the RTO, including in the LDAs. However, a portion of the improvement in EMAAC and SWMAAC is associated with planned new transmission facilities that were projected to be operational in the 2010/11 and 2011/12 delivery years. These transmission facilities increase the import capability by over 1,198 MW into SWMAAC and 2,959 MW into EMAAC by the 2011/12 base auction. With new capacity resources and these projected increases of import capability, the LDAs became unconstrained and did not need to be modeled separately in the most recent base auction for the 2011/12 delivery year.[12]

Auction Clearing Prices. Auction clearing prices have largely followed the pattern set by reserve margins and moved toward the price required to sustain new entry (i.e., Net CONE).

[12] As we discuss further in Section V.F. of this report, delays in the construction of these planned transmission facilities may still create reliability challenges within these LDAs. We recommend refinements to the current RPM design to address this issue.

RTO-wide capacity clearing prices as well as pries for EMAAC and SWMAAC and their movement over time are show in Figure 3.[13] Prices in the LDAs were relatively high initially, reflecting initial capacity shortages. The highest price occurred in SWMAAC in 2009/10 when reserve margins were lowest and several thousand megawatts of existing capacity were offered at price levels that reflected the cost of required investments in emissions controls.[14] SWMAAC prices then decreased in the 2010/11 auction when new DR, planned increases in LDA import capability, and lower offers from existing generating plants eliminated the need to procure higher-cost capacity within the LDA. Due to planned increases in LDA import capabilities, LDAs were not modeled separately in the 2011/12 auction.[15]

While LDA prices exceeded RTO-wide auction clearing prices, the higher clearing prices were partly offset by credits for the value of capacity transfer rights (CTRs) for imports from the rest of PJM. This resulted in a net load price that is below the LDA clearing price, as indicated by the dotted lines in Figure 3.

RTO-wide prices were relatively low in the first auction, reflecting high initial reserve margins that existed prior to RPM due to new capacity bought online during the late 1990s and early in this decade. RTO prices subsequently rose in the following three auctions as reserve margins declined. By the auction for the 2010/11 delivery year (conducted in January 2008), a single clearing price of $174/MW-day was achieved for almost all of PJM (except the small DPL-south region within EMAAC), which was equal to the Net CONE value PJM used in that auction. The price then decreased to only $110/MW-day in the most recent auction for the 2011/12 delivery year due to offers from a substantial amount of new resources and the loss of Duquesne's load. As shown in Figure 3, had Duquesne not withdrawn its load from PJM—or had generation in the Duquesne service area chosen not to offer its capacity into PJM—the 2011/12 auction clearing price would have been approximately $150/MW-day.

The RTO-wide and LDA-specific clearing prices for each of the five base auctions conducted since April 2007 are also shown in Table 1. As these data show, RTO-wide capacity prices have generally been below the administratively determined net cost of new capacity (Net CONE), which is consistent with the fact that RTO-wide reserve margins, as shown in Figure 2, slightly exceeded target levels throughout this period. The clearing prices within the LDAs have been above the estimated net cost of new capacity for the delivery years in which auction results show reserve margins below reliability requirements.

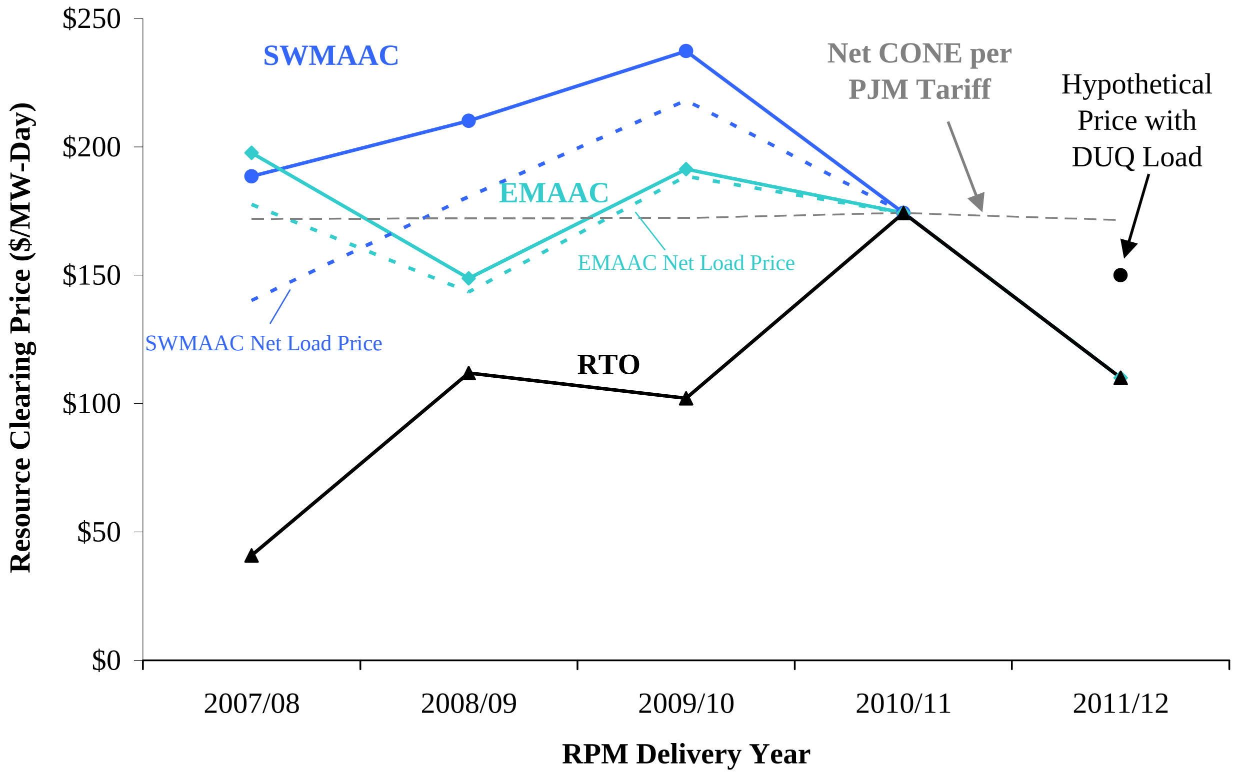
---

13 Note that only the two most persistent LDAs, EMAAC and SWMAAC, are shown in Figures 2 and 3. In the 2009/10 base auction EMAAC became unconstrained and cleared as part of the larger MAAC+APS LDA. In the 2010/11 base auction, DPL-South, an EMAAC subarea, became constrained and cleared at $186.1/MW-day, which is not shown in Figures 2 and 3.

14 See discussion of SWMAAC prices and RPM capital expenditure provisions in Section V of this report.

15 We address LDA definition and import capability issues more fully in Section V of this report.

Figure 3
RPM Resource Clearing Prices by LDA and Delivery Year



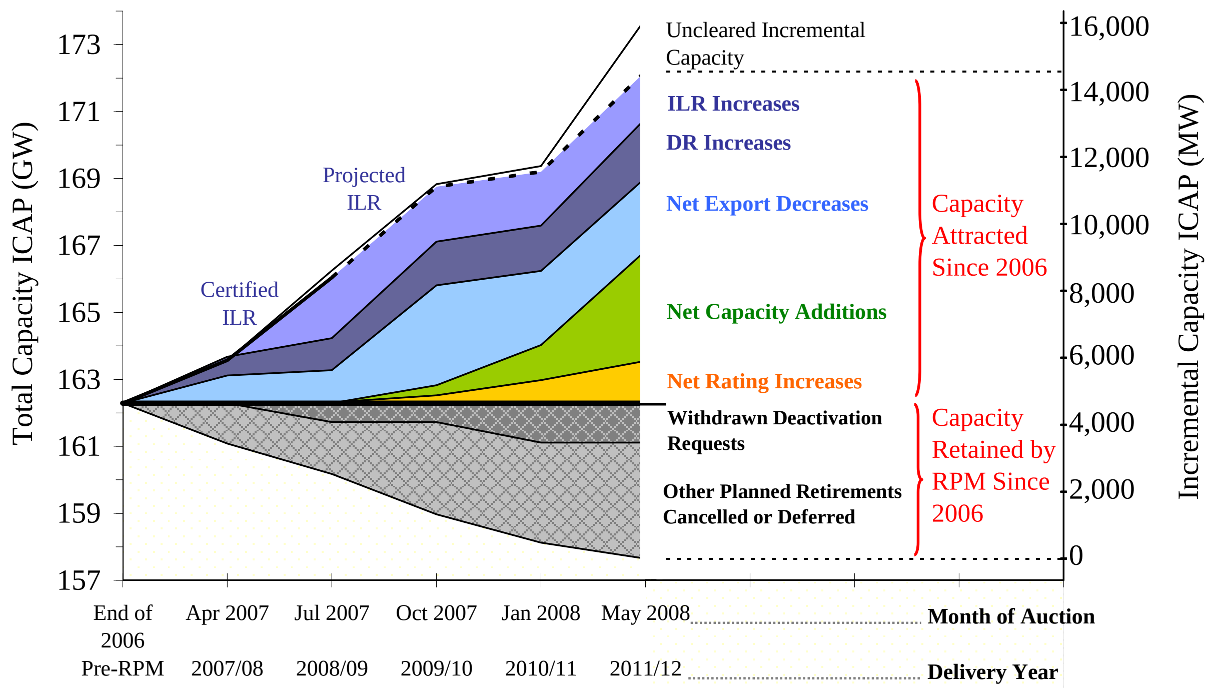
Source: *Brattle* analysis of PJM data.

Table 1
Summary of RPM Clearing Prices

	Price, by Delivery Year ($/UCAP MW-Day)				
	2007/08	2008/09	2009/10	2010/11	2011/12
Resource Clearing Price					
RTO	40.8	111.9	102.0	174.3	110.0
EMAAC	197.7	148.8	191.3		
SWMAAC	188.5	210.1	237.3	174.3	
MAAC+APS			191.3		
MAAC				174.3	
DPL-SOUTH				186.1	
Net CONE per PJM Tariff					
RTO	171.9	172.3	172.3	174.3	171.4

Added and Retained Capacity Resources. Approximately 14,500 MW of committed resources have been added or retained in PJM since 2006, the year before RPM was implemented. As shown in Figure 4, these resources include approximately 9,900 MW of added new resources and approximately 4,600 MW of retained existing capacity that likely would have been retired in the absence of RPM. The largest category of additional resources was capacity additions from new generating units (here shown net of retirements), followed by new DR and ILR resources, reductions in net exports, and "uprates" of existing capacity (also shown net of "derates"). In addition to the 14,500 MW of added and retained resources committed in these auctions, Figure 4 also shows that over 1,500 MW of capacity from new generation resources, new or existing demand resources, and imports were offered but did not clear in the most recent auction.

Figure 4
Committed Additional Resources and RPM Retained Capacity in PJM

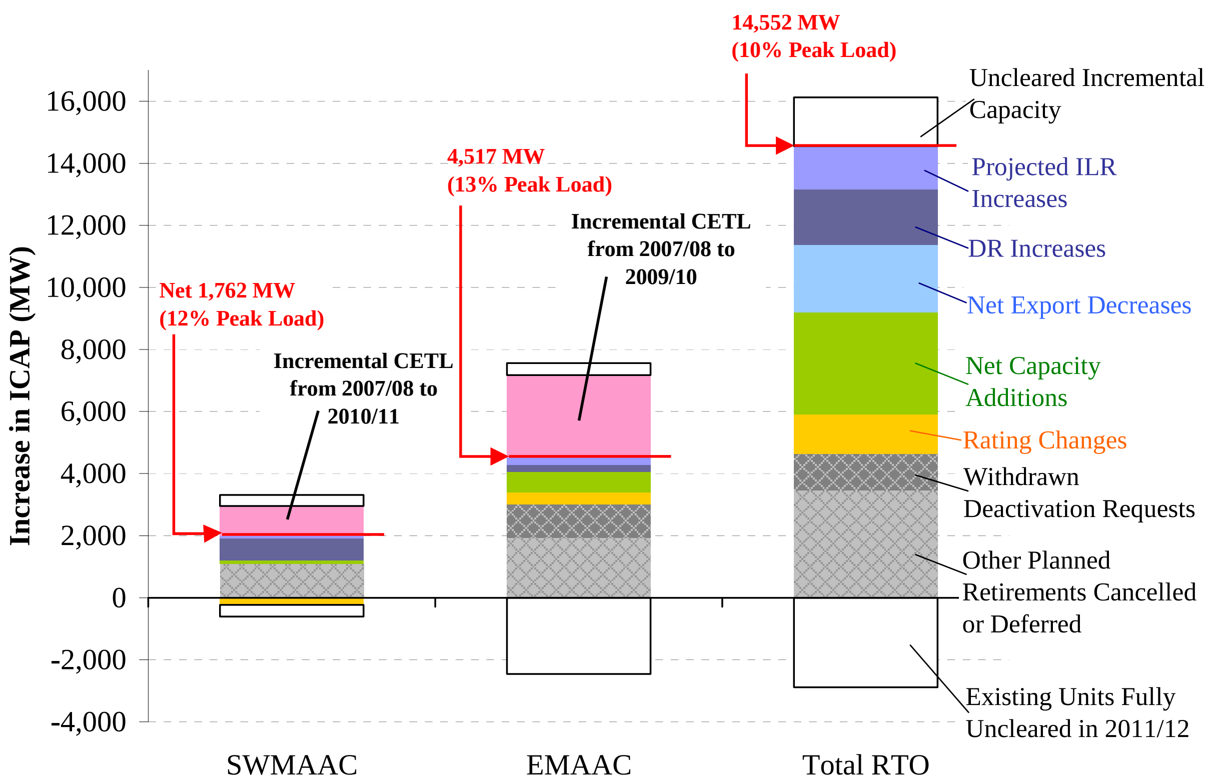


Source: *Brattle* analysis of PJM data, market participant interviews.
Note: Excludes new units, reactivations, imports, and demand response that do not clear.
Note: The 2011/12 PJM total load-serving obligation was reduced by approximately 3,000 MW due to Duquesne's change of RTO membership from PJM to Midwest ISO.

As shown in Figure 4, new generation capacity was not added in significant amounts prior to the 2009/10 delivery year. The most significant commitment of new generating capacity occurred for 2011/12, the first year for which the base auction was conducted a full three years prior to delivery. The first auctions attracted less new generation capacity because they were part of the "transition period" in which auctions were held less than three years ahead of delivery, which likely was insufficient lead time to attract new generation. However, even these early auctions did attract and retain a significant amount of resources. The cumulative amount of new DR/ILR attracted for the 2007/08 and 2008/09 delivery years was about 2,800 MW, while net exports decreased by 1,000 MW, and more than 2,100 MW of capacity that had planned to retire were retained.

As shown in Figure 5, substantial resources were attracted and retained within PJM's LDAs, SWMAAC and EMAAC, though new generation accounts for a more modest share of resources committed to date. In particular, the total amount of new demand-side resources (DR and ILR) and deferred retirements is substantially higher than in the rest of the RTO. As a result, despite the lower relative share of new generation, the total resources added or retained within LDAs exceed RTO-wide levels: they amount to 12 percent and 13 percent of peak load in SWMAAC and EMAAC, versus only 10 percent for the RTO as a whole.

Figure 5
Added Resources and RPM-Retained Capacity in PJM, EMAAC, and SWMAAC
(End of 2006 through 2011/12 Delivery Year)



Source: *Brattle* analysis of PJM data, market participant interviews.

Figure 5 also shows increases in LDA import capability—as measured by the Capacity Emergency Transfer Limit (CETL)—and the amount of uncleared new and existing capacity. Given the magnitude of increased import capability and existing resources that did not clear in the most recent base auction, both EMAAC and SWMAAC could be vulnerable to reoccurring reliability challenges if the planned transmission upgrades that are assumed to increase CETL were delayed and some the uncleared existing capacity were to retire. On the other hand, as further discussed in Section III.C., the existence of uncleared capacity from existing and new resources within these LDAs also means that resources are available to help address LDA reliability challenges should the planned transmission upgrades be delayed.

Figures 4 and 5 show existing capacity retained by RPM but do not specifically assess whether the net additions of new resources are reasonably attributable to RPM. That question is addressed with a more detailed discussion of each resource category in the following subsections.

B. ADDED AND RETAINED CAPACITY REASONABLY ATTRIBUTABLE TO RPM

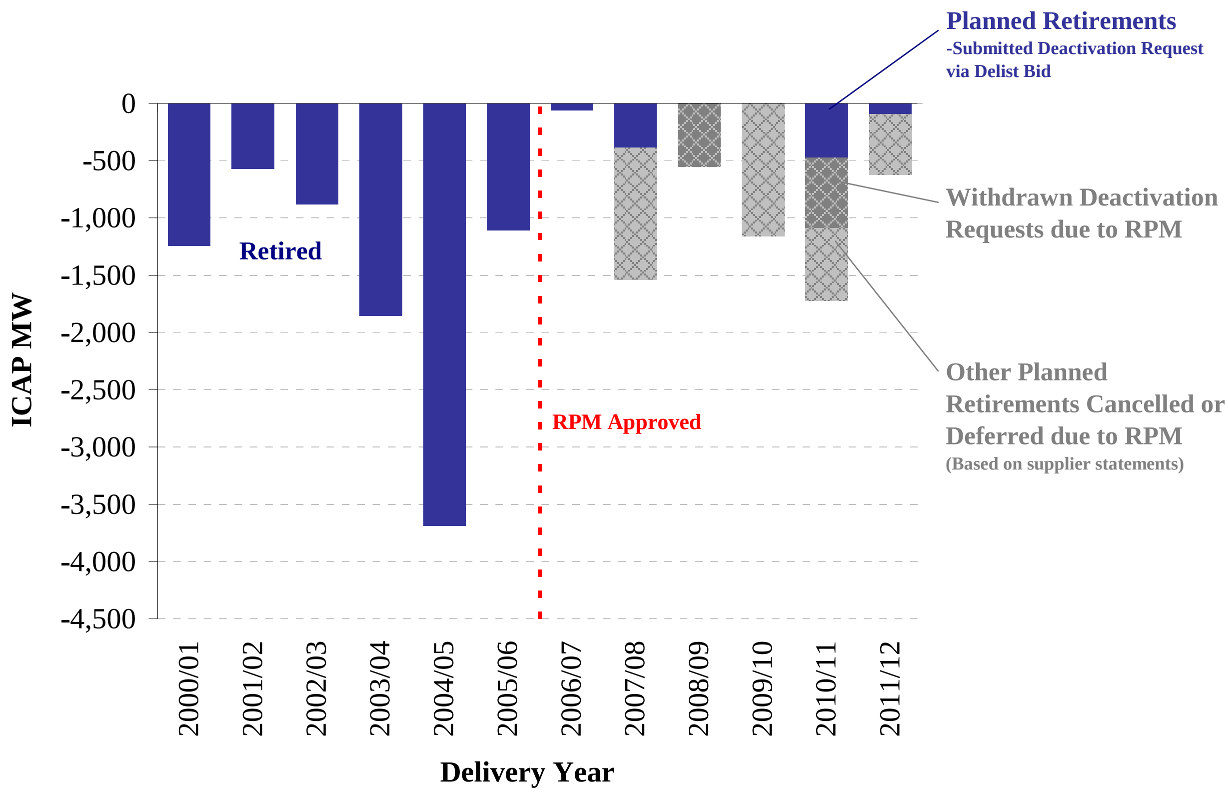
The capacity additions shown in Figures 4 and 5 represent total additions net of retirements (as well as changes in exports net of imports). RPM likely was not a primary driver for some of these capacity increases, nor was it likely the reason for retirements and exports. Accounting for the likely reason behind the observed changes, we still estimate that almost 14,500 MW of added and retained capacity are reasonably attributable to RPM. Our estimate exceeds the *net* resources added or retained for some of the resource categories shown in Figures 4 and 5, but is lower for other categories based on our assessment that some capacity would likely have been added even without RPM, such as renewable generation. Note, however, that our analysis of whether a change in committed resources reasonably can be "attributed" to RPM is in part based on a qualitative assessment of major factors in the retention or incremental commitment of resources. Our assessment of whether the observed changes are associated with RPM is not a formal "proof of causality," as that would require an assessment of the market design that would have been used "but for" RPM, which would be inherently speculative. The fact remains, however, that since RPM was implemented, (1) at least 4,600 MW of capacity has been retained that otherwise would have retired; (2) almost 10,000 MW of incremental capacity has been committed; and (3) the volume of generation interconnection requests has grown to make an additional 33,000 MW of new generation projects eligible to participate in future RPM auctions.

The following discussion analyzes in more detail each of the resource categories shown in Figures 4 and 5.

1. Deferred Retirements

We find that RPM induced at least 4,600 MW of capacity that had planned to retire to defer retirement. It also helps retain over 20,000 MW of existing resources that likely would not be financially viable in the absence of capacity payments. As shown in Figure 6, prior to RPM, the rate of retirements was approximately 1,000 MW annually, ranging from approximately 500 MW to over 3,500 MW per year. After RPM was approved, the retirement rate (shown by the blue bars) dropped markedly to a range between zero and few hundred megawatts annually. The gray bars in Figure 6 show how much capacity likely would have been retired without RPM, based on available information pertaining to withdrawn deactivation requests and other information on cancelled or deferred retirements.

Figure 6
PJM Retirements: Actual, Planned, and Deferred due to RPM
2000/01 Delivery Year through 2011/12 Delivery Year



Source: *Brattle* analysis of PJM data, market participant interviews, and retirement data compiled by Ventyx Energy, The Velocity Suite.

Quantifying RPM-induced deferrals of unit retirements is a challenging exercise because most generation owners do not announce their retirement plans until they submit a deactivation request to PJM. Many retirement plans and deferrals of those plans are likely to go unnoticed. Determining whether known retirement deferrals can reasonably be attributable to RPM is additionally challenging because generation owners do not always announce the reasons for their plans.

We estimated deferred retirements attributable to RPM by first identifying deferrals and then assessing whether the deferrals could be attributed to RPM. We identified units that deferred retirement using two sources: (a) deactivation requests that had already been submitted to PJM and which subsequently were withdrawn; and (b) market participants' statements regarding deferred retirements for which deactivation requests had not yet been submitted. These deferred retirements were attributed to RPM only if (1) the units associated with withdrawn deactivation requests (and stated deferred retirement plans) were revenue deficient without RPM; and (2) the units actually cleared in the base residual auctions, including at the lower market prices in the most recent auction for the 2011/12 delivery year; and (3) the applicable units did not withdraw their deactivation requests because they were required by PJM to stay online for local reliability reasons. Revenue deficiency was identified using the MMU's confidential unit-level offer cap data, which reflects the units' going-forward costs that are avoidable through mothballing.[16] On the basis of this analysis, the total amount of retained capacity attributed to RPM is 1,170 MW of withdrawn deactivation requests and 3,471 MW of additional deferred retirement plans, as shown in the gray bars of Figures 4, 5, and 6. The derivation of these results is shown in further detail in rows [1] through [10] of Table 2.

Table 2
Retirements Deferred in 2007 and 2008

Category		**Included in Figures 4 and 5?**	**ICAP MW**
Withdrawn deactivation requests			
Owner statements explicitly refer to RPM as cause	*[1]*	YES	461
Owner statements cite required investments likely not done without RPM	*[2]*	YES	608
No owner statements available, but revenue deficiency & no reliability concerns	*[3]*	YES	101
Deferred for reliability	*[4]*		0
No data on deferred retirement decision; no revenue deficiency	*[5]*		475
Total deferred retirements attributed to RPM ([1]+[2]+[3])			**1,170**
Other delayed retirements			
Owner statements explicitly refer to RPM as cause	*[6]*	YES	1,796
Owner statements cite required investments likely not done without RPM	*[7]*	YES	1,237
No owner statements available, but revenue deficiency & no reliability concerns	*[8]*	YES	438
Deferred for reliability	*[9]*		0
No data on deferred retirement decision; no revenue deficiency	*[10]*		262
Total deferred retirements attributed to RPM ([6]+[7]+[8])			**3,471**
Additional units at-risk for retirement due to revenue deficiency			
Average revenue deficiency >$10 & <$110.00/MW-day*	*[11]*		24,264
Average revenue deficiency >$110.00/MW-day* (these units are at-risk even with RPM)	*[12]*		3,474
Additional capacity at-risk for retirement without RPM			**24,264**
Total deferred retirements attributed to RPM, as shown in Fig.s 4 and 5			**4,641**
Additional capacity at-risk for retirement without RPM			**24,264**

Source: *Brattle* analysis of PJM data; Market participant interviews.
*RTO RCP in the 2011/12 Base Residual Auction.

This estimate of 4,641 MW of resources retained by RPM is conservative because of the limited information available on retirement plans. As shown in rows [11] and [12] of Table 2, substantially more resources could potentially be at-risk for retirement due to revenue deficiency in the absence of RPM. There are over 24,000 MW of existing generating units that submitted

[16] In addition to offer caps based on going-forward costs, suppliers of exiting capacity resources may also choose to have their offer caps calculated based on their opportunity cost, which is a documented price they can receive in a market outside of PJM. Starting with the third incremental auction for the 2009/10 delivery year, suppliers will also have the option to select 110 percent of the base auction clearing price as their offer caps for third incremental auctions.

offers at prices above zero and for which the MMU-mitigated offer prices are above $10/MW-day but below the $110/MW-day clearing price of the most recent auction.[17] Approximately 10,000 MW of these resources have a mitigated offer price above $50/MW-day and an additional 3,500 MW of existing generating units have mitigated offer prices above the $110/MW-day clearing price. While it is uncertain how many of these resources would retire without RPM, it is clear that many of these resources could be at risk of retirement because of significant revenue deficiency without RPM. In any case, several thousand megawatts of capacity would still be at risk of retirement in the absence of RPM.

This analysis of at-risk capacity resources is shown in more detail for PJM as a whole and individual LDAs in Figures 7, 8, and 9. We start with the mitigated offer curve for all units for which average revenue deficiencies in base auctions to date exceeded $10 per MW-day, as shown by the right-most curve in each figure. Then we removed the units that were previously identified as having withdrawn their deactivation requests or otherwise deferred their retirement decisions. This leaves only the *additional* resources at risk for retirement due to revenue deficiencies in the absence of RPM.

Figure 7 shows this analysis for the RTO as a whole. This pattern also exists at the LDA level. As shown in Figure 8 for EMAAC and Figure 9 for SWMAAC, several thousand megawatts of additional capacity is arguably at risk for retirement in each of the LDAs without the revenues provided by RPM.[18]

The substantial amount of capacity represented by units that might either be retired or revenue-deficient in the absence of RPM highlights the importance of capacity prices for existing resources. As discussed, RPM already has successfully deferred the retirement of over 4,500 MW of existing resources, most of which were needed to maintain reliability within LDAs. RPM also helps to retain more than 20,000 MW of other existing resources that would face revenue deficiencies in the absence of capacity prices. The uniform treatment of existing and new resources in terms of capacity payments also addresses the fact that "existing" and "new" resources—which include uprates, investments that avoid derates, reactivations, repowering options, and plants built in stages—cannot be distinguished meaningfully over time. Conversely, every "new" resource becomes an "existing" resource after its initial operating year. The pricing of uniform products in competitive markets does not distinguish between products produced by existing or new production facilities.

As these revenue deficiency data and the following discussions document, capacity prices play a number of important roles. The impacts RPM has had on new and existing resources show that capacity price signals are important for facilitating the most cost-effective entry, investment, and retirement decisions by suppliers. Capacity prices are similarly important for facilitating efficient consumption and investment by customers. As RPM results to date already show,

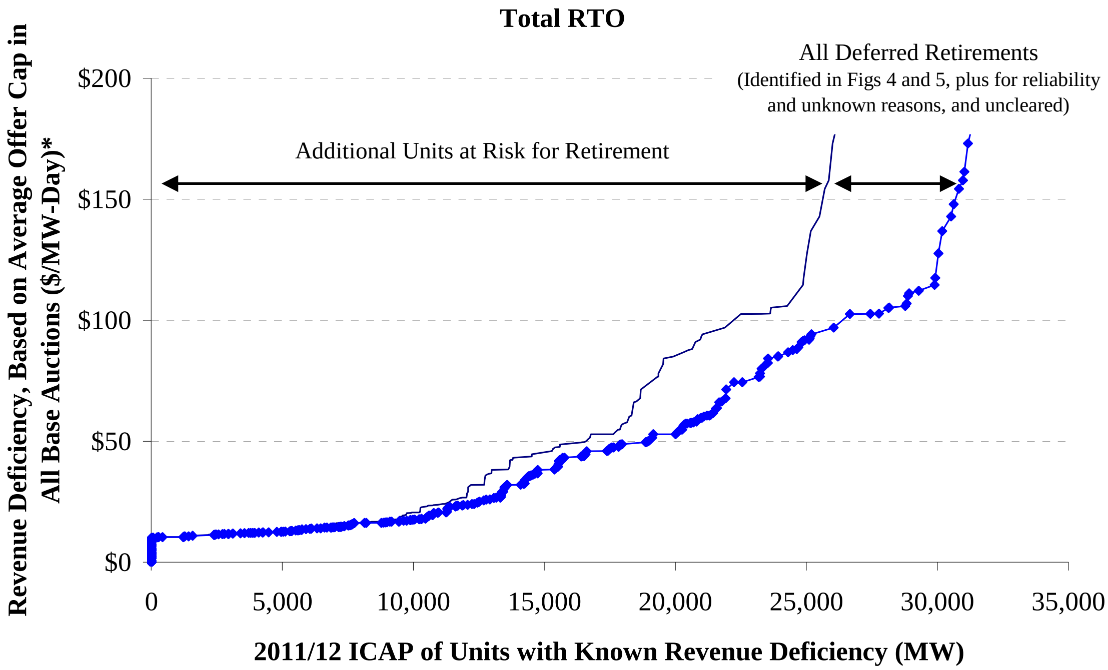
---

17 Mitigated offer prices are calculated as the weighted average from all five base auctions.

18 Note that a significantly larger portion of resources has been identified as deferred retirements in EMAAC, compared to SWMAAC and the RTO as a whole. This reflects in part the fact that we were able to gather more retirement information for units in EMAAC.

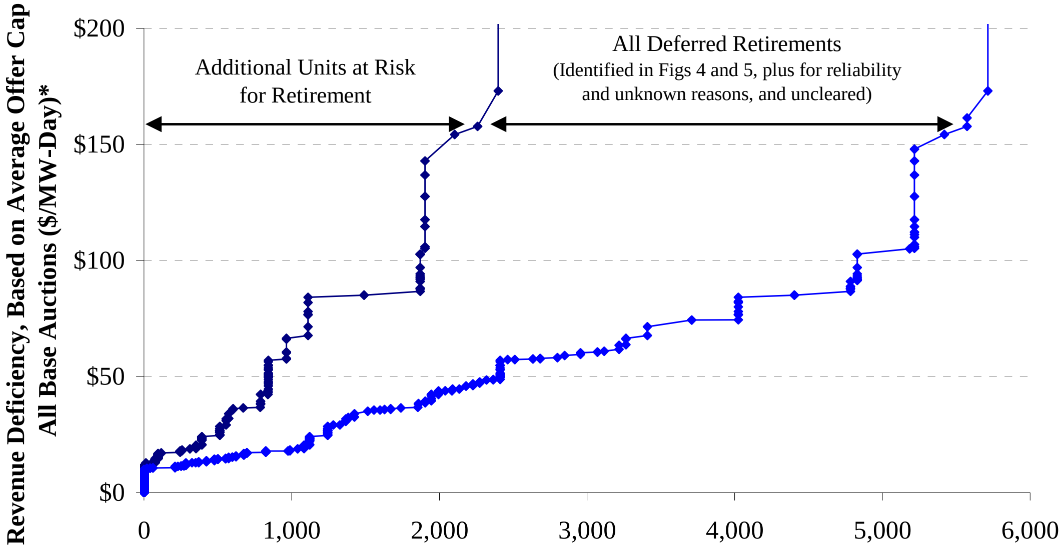
capacity prices have been important for stimulating demand-side investments and ensure that they can effectively compete with supply-side resources.

Figure 7
Resources at Risk for Retirement due to Revenue Deficiency



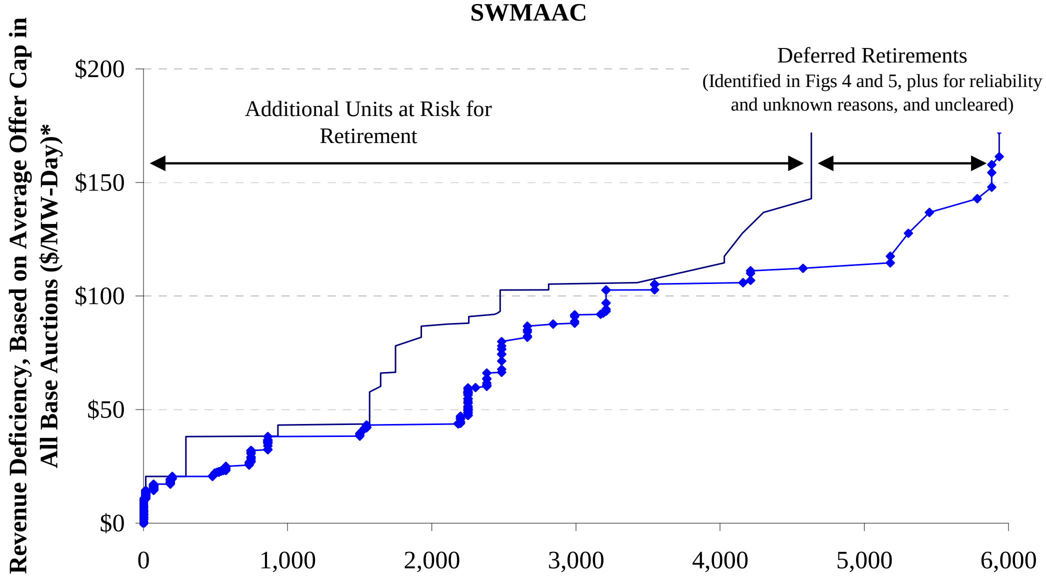
Source: *Brattle* analysis of PJM data.
*Graph omits capacity with average revenue deficiencies <=$10/MW-day, plus capacity (~1,824 MW) with average revenue deficiencies above $200/MW-Day.

Figure 8
Resources at Risk for Retirement due to Revenue Deficiency
EMAAC



Source: *Brattle* analysis of PJM data.
*Graph omits capacity with average revenue deficiencies <=$10/MW-day, plus a small amount of capacity (~600 MW) with average revenue deficiencies above $200/MW-Day.

Figure 9
Resources at Risk for Retirement due to Revenue Deficiency
SWMAAC



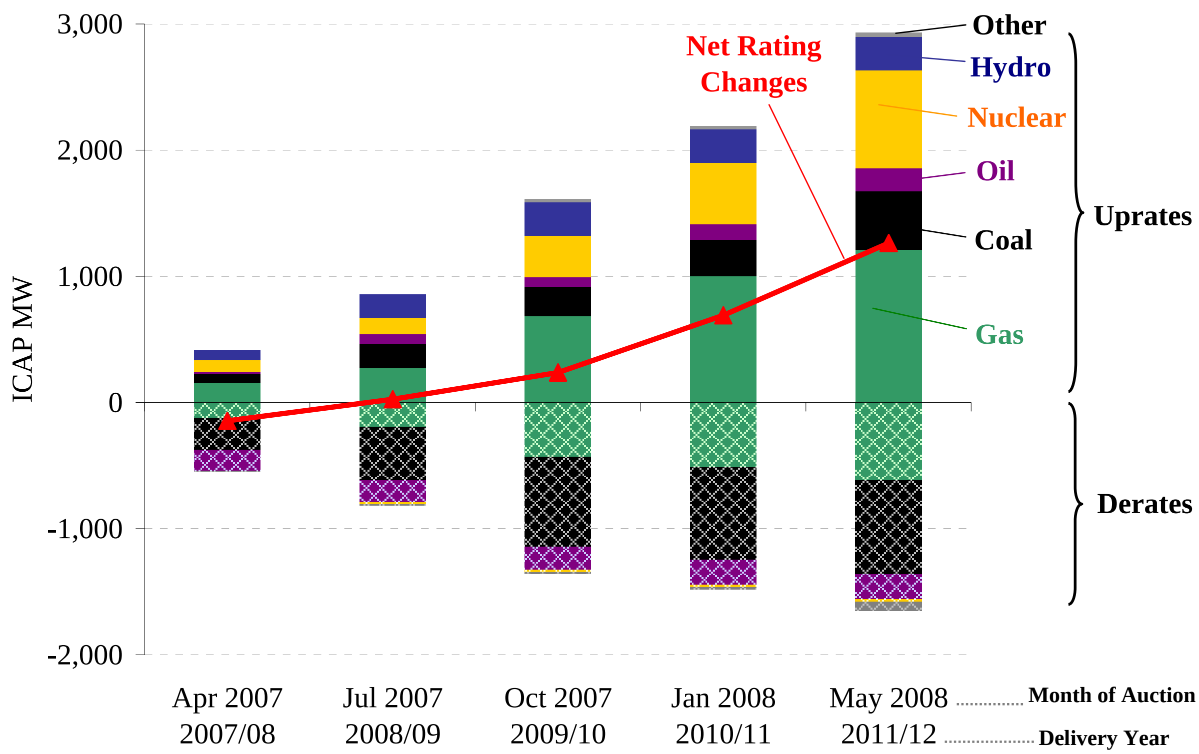
Source: *Brattle* analysis of PJM data.
*Graph omits capacity with average revenue deficiencies <=$10/MW-day, plus a small amount of capacity (~80 MW) with average revenue deficiencies above $200/MW-Day.

2. Net Rating Increases of Existing Generation

Since RPM was implemented, 2,932 MW of capacity was added through enhancements to existing units ("uprates"), while 1,668 MW was lost to derates, for a net rating increase of 1,264 MW. The cumulative rating increases and decreases, which do not reflect capacity additions from new generating units, are shown in Figure 10. The figure also shows that rating increases occurred for all types of capacity, especially for gas-fired, nuclear, and coal plants. Rating decreases affected coal, gas, and oil.

In our interviews of market participants, many suppliers stated they have been investing in their existing fleet, although we do not have specific information about which of the identified uprates are specifically attributable to RPM. We also do not have information about the extent to which derates—which have been applied to coal, natural gas, and oil-fired generation—are attributable to RPM. Not knowing exactly for how many of these uprates RPM was a primary factor and allowing for the possibility that some of the derates may be related to RPM (e.g., as the result of environmental investments facilitated by RPM), we only attribute to RPM the *net* rating increase of 1,264 MW. This may be conservative, because many of the rating decreases to existing units may have happened *despite* of RPM.

Figure 10
Cumulative Net Rating Changes of Existing Generation During RPM
(Excludes Capacity Additions from New Units)



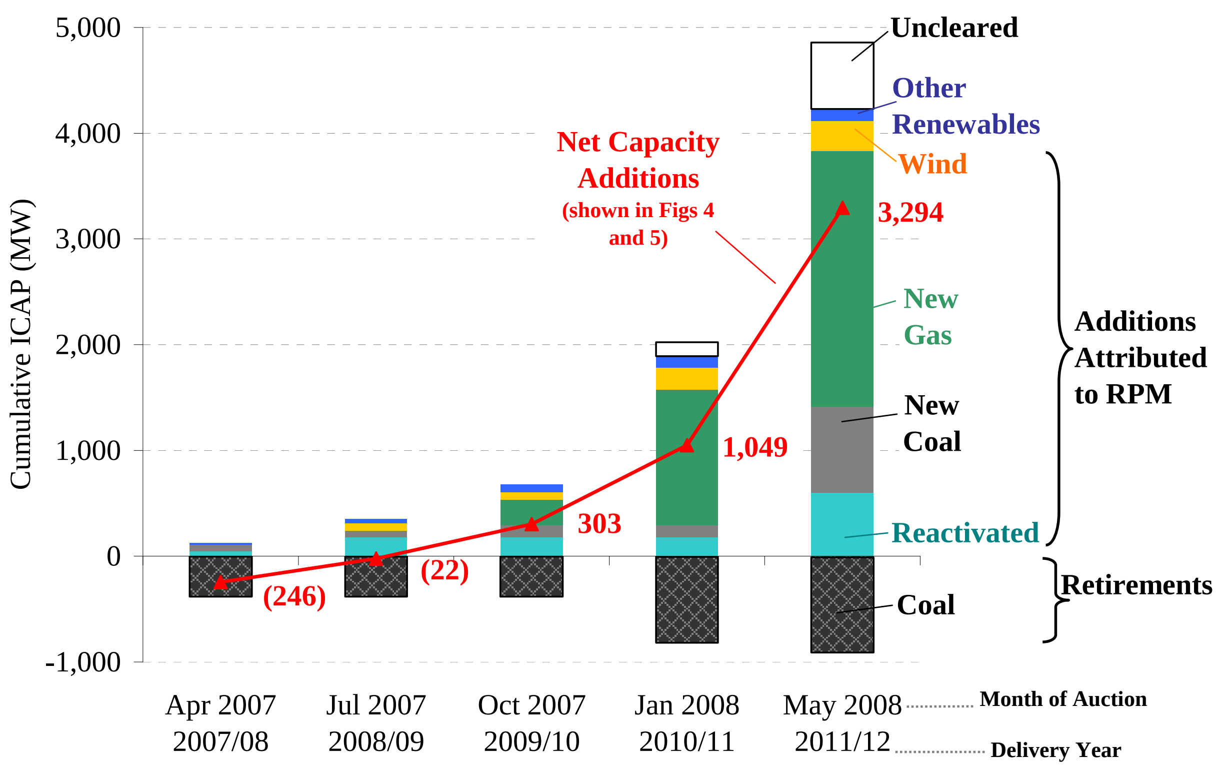
Source: *Brattle* analysis of PJM RPM data.

3. Capacity Additions (New Generating Units)

Following an intensive period of generation construction in the late 1990s and earlier this decade, little capacity has been added or was under construction in recent years. In the presence of further demand growth, this lack of new generation had caused significant reliability concerns, particularly within import-constrained load areas. These concerns ultimately led to the development and implementation of RPM.

Since RPM was proposed and implemented, however, there has been a noticeable resurgence in the development of new generating capacity. While much of the proposed new generation projects are still in permitting stages, 4,248 MW of capacity additions have either cleared in the base auction or been designated as FRR resources since the first auction took place in April 2007. This includes 3,069 MW of new units committed through RPM auctions, 580 MW of new generation committed to meet FRR obligations, and 599 MW of reactivated generating units that were previously retired. As Figure 11 shows, the 3,649 MW of new generation offered into auctions and FRR obligations that have been committed through the 2011/12 delivery year consist of a mix of new natural gas, coal and renewable generating capacity. The 4,248 MW in total capacity additions are offset by 957 MW of planned retirements (which are planned in spite of RPM), resulting in *net* additions of 3,294 MW as shown in Figures 4, 5, and 11.

Figure 11
Cumulative Additions of New Generating Units During RPM
(Excludes Uprates to Existing Units)



Source: *Brattle* analysis of PJM RPM data.
Note: A small amount of new oil (~21 MW), retired oil (~46 MW), and retired gas (~11 MW) is included in the totals but not shown.

The majority of new additions have been gas-fired (both combustion turbines and combined cycles), but a new merchant coal plant as well as several hundred megawatts of renewable generation have also been committed. The addition of the merchant coal plant is significant because it indicates that the RPM design may also be a significant factor in supporting the entry of competitive base load generating capacity.

In determining the amount of capacity additions that are reasonably attributable to RPM, renewables, FRR commitments, and retirements are excluded. It is reasonable to assume that renewable portfolio standards (RPS) are the primary driver for renewable generation though RPM-related capacity revenues will offset some of the cost of the 394 MW of committed renewable generation. We also exclude 580 MW of capacity additions by FRR entities because, as explained in Section V.A., these incremental resources currently are not able to obtain RPM payments. Similarly, the 957 MW of planned retirements are not attributed to RPM, as all or most of these retirements likely would have occurred at the lower revenues offered in a market design without RPM. Considering the large revenue deficiencies experienced even by existing generation in the absence of RPM (as shown in Table 2 and Figures 7 through 9), we believe the remaining capacity additions reasonably can be attributed to RPM. These RPM-committed resources—composed of new natural-gas and coal-fired capacity as well as reactivations of previously-retired capacity—amount to 3,274 MW of additional capacity. These attributions, as well as the 3,294 MW of overall capacity additions net of all retirements are also shown in Table 3 at the end of this subsection.

4. Decreases in Net Exports

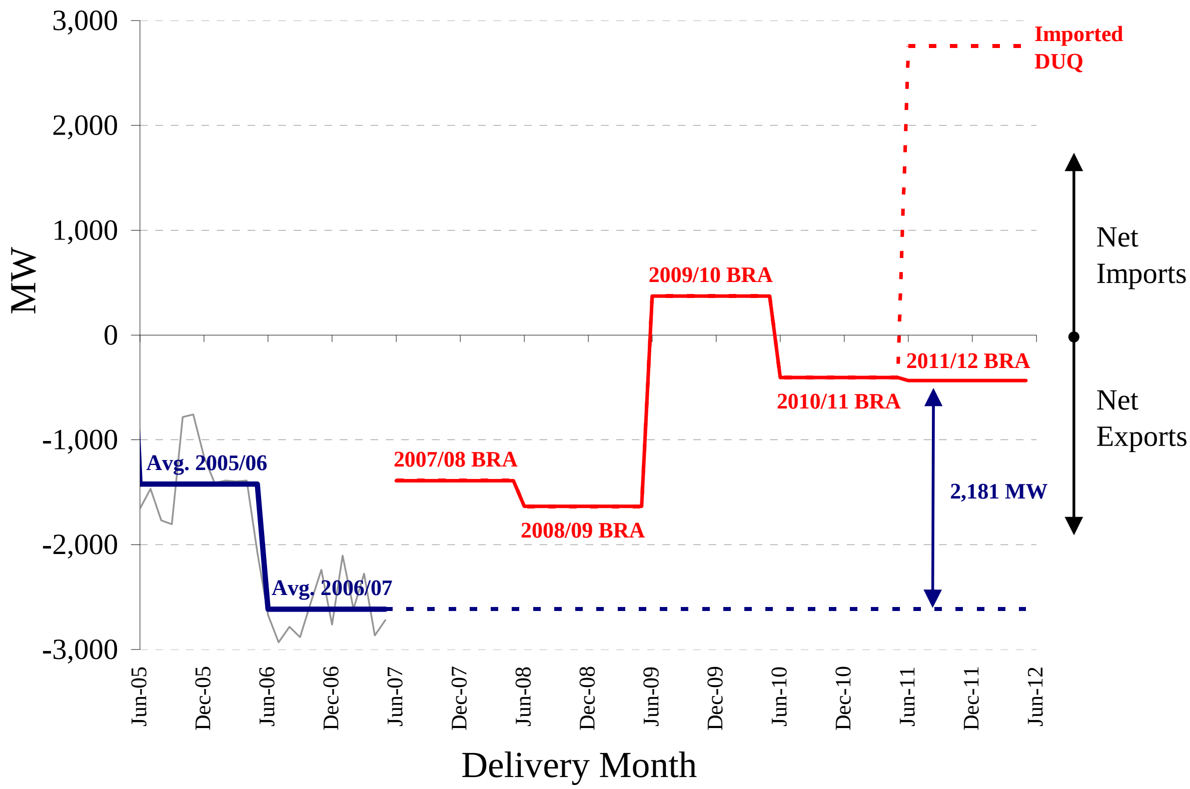
PJM has recently been a net exporter of capacity. Net exports for the 2006/07 delivery year prior to the commencement of RPM auctions were approximately 2,600 MW on average. Net exports have decreased substantially from that level under RPM.

As Figure 12 shows, net exports immediately decreased to approximately 1,500 MW in the first two auctions, then became negative, (i.e., net imports) in the 2009/10 auction. Net exports returned to a level of approximately 400 MW in the 2010/11 auction. The most recent 2011/12 auction changed the definition of exports and imports because generation in the Duquesne zone became labeled as "external;" when Duquesne departed PJM but, remarkably, generation resources in the Duquesne service area chose to continue to commit their capacity to PJM by offering it into RPM. As a result, net imports increased to almost 3,000 MW as shown by the dotted line of Figure 12. Compared to net exports of 2,600 MW during the year prior to implementation of RPM, this constitutes a swing (i.e., decrease in net exports) of over 5,000 MW.

The solid line in Figure 12 shows net exports on a "Duquesne-adjusted" basis, representing imports that would have been recorded had the generating capacity in the Duquesne service area still been considered internal to PJM. This is a very conservative representation of the net export patterns because, with Duquesne's departure from PJM, the generation in Duquesne's service area is no longer under an obligation to offer its capacity into RPM. Nevertheless, the decline in net exports since the 2006/07 delivery year resulted in a net capacity savings of 2,181 MW relative to the pre-RPM level. Figure 12 also shows that this decline in net exports since RPM was implemented would be approximately 1,200 MW if the 2005/06 delivery year was used as a baseline.

Overall, these reductions in net exports reflect the fact that capacity is a fungible product that can be exported and imported in response to market opportunities. Our review of public and confidential data confirmed that most of the exports from PJM internal generation units were reduced because of the prices available through RPM. There were some offsetting increases in exports, but those occurred mostly in spite of RPM—leading to a net decline of exports that understates RPM-related impacts. This review of unit-specific import and export data indicates that RPM likely is associated with a decrease in net exports of at least between 1,400 and 3,400 MW.

Figure 12
PJM Net Imports of Capacity



Source: *Brattle* analysis of PJM data. Annual RPM numbers exclude uncleared imports.

Our review of capacity export data was able to identify approximately 2,200 MW of decreases in unit-specific exports since RPM was implemented. Of these reductions in net exports under RPM, the largest share was from the Homer City Generation Station. Prior to RPM, Homer City exported approximately 900 MW of its capacity to New York. With the sales contract ending prior to the 2009/10 delivery year, the owner chose to switch to PJM due to the RPM price signal, as publicly stated in the company’s 2007 10-K filing with the Securities and Exchange

Commission.[19] Similarly, the owners of another large unit that stopped exporting explained in our interviews that they chose to commit their capacity to PJM in response to the RPM price signal. Overall, we were able to identify at least 1,400 MW of decreased unit-specific exports that are specifically attributable to RPM.

Since the 2006/07 delivery year, there have been approximately 1,200 MW of additional exports from PJM-internal units. However, our examination suggests that most of these exports would have occurred irrespective of RPM. The largest generation station to begin exporting after the inception of RPM was Marcus Hook (a.k.a. Phillips Island). The owner of Marcus Hook has a contract to sell 685 MW into Long Island across the newly constructed Neptune HVDC transmission line starting in 2010.[20] Since capacity prices on Long Island have been higher than in PJM, this loss of PJM capacity was likely unavoidable upon the completion of the new HVDC line, unless RPM prices had been much higher. The second largest generation station to begin exporting from PJM also occurred in spite of RPM when a vertically-integrated utility in the Midwest ISO purchased the unit in order to meet its increased need for capacity. Overall, we conclude that 1,241 MW of increased unit-specific exports likely occurred irrespective of RPM. However, as we also discuss further in Section V.A. of this report, some of the capacity that has been exported since the inception of RPM appears to have been done in response to RPM-related provisions.

Based on this review of import and export pattern, we conclude that no less than 1,400 MW of reduced net exports likely occurred because of RPM. Our review of export data also indicates that 1,241 MW of new exports would likely have happened irrespective of RPM. If these unavoidable additional exports are added to the 2,181 MW decrease in net exports relative to the 2006/07 base line, it suggests that RPM-related decreases of net exports may have been as high as 3,422 MW. Within this 1,400 to 3,400 MW range and ignoring the fact that RPM was able to retain commitments from generating resources in the Duquesne service area, the 2,181 MW decrease shown in Figure 12 is a conservative estimate of reduced net imports that can reasonably be attributed to RPM.

5. Increased DR and ILR

Commitment of demand-side resources has increased significant under RPM. New DR has been developed by utilities under state initiatives and by curtailment service providers, who have seized the opportunity to sell load reductions as supply resources. Capacity revenues account for the majority of anticipated revenues for DR, especially given RPM's more robust prices in comparison to the prior capacity construct. RPM has thus far facilitated in the commitment of more than 1,700 MW of new DR, and we estimate that it has produced approximately 3,000 MW of combined capacity from committed DR and ILR programs.

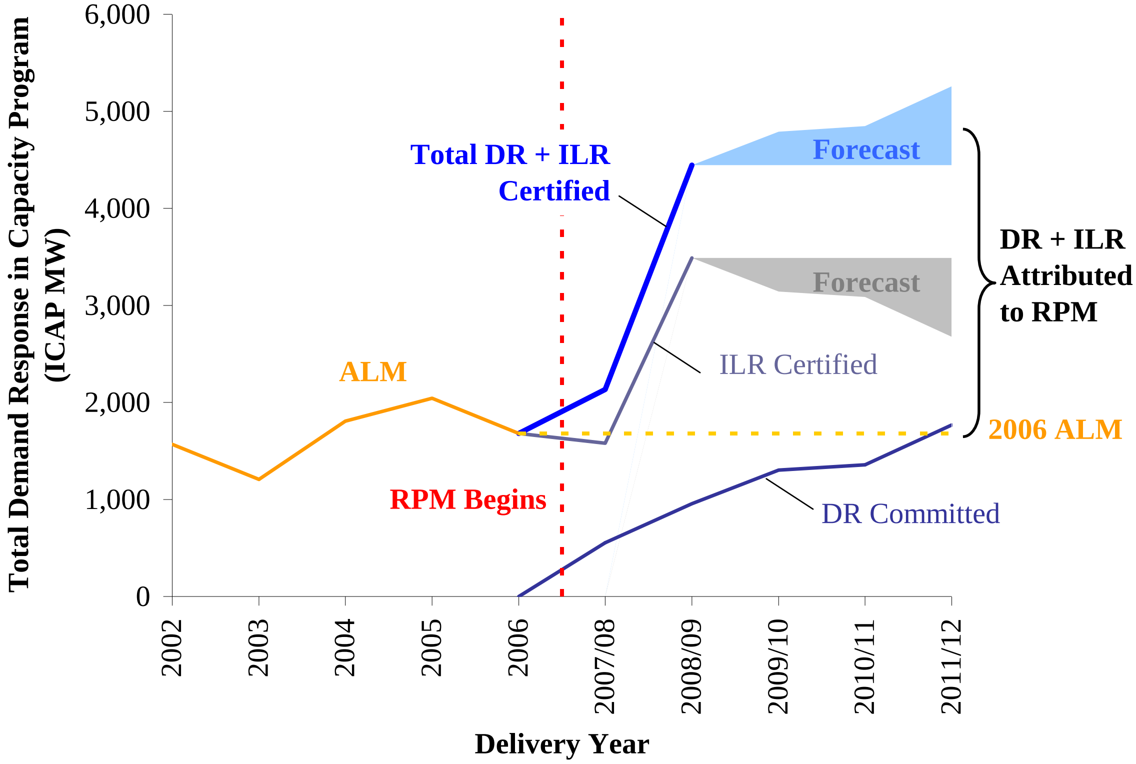
---

19 EME Homer City Generation L.P. SEC Form 10-K for the year ending December 31, 2007, p. 51-52. Available at http://ir.edisoninvestor.com/phoenix.zhtml?c=85474&p=irol-sec.

20 The Long Island Power Authority holds a 20-year power supply contract with Marcus Hook. The contract will expire in 2030. Source: "Request for Proposals: To Provide Power Supply Management Services to the Long Island Power Authority", Issued October 17, 2007 (http://www.lipower.org/company/papers/rfp/ps.html#Calendar).

Prior to the RPM, demand-side resources participated in the PJM capacity market through PJM's Active Load Management (ALM) program. Under RPM, demand resources may participate either as DR by making offers in base auctions or as ILR, which registers shortly before the delivery year and gets paid the Net Load price for that delivery year. We measured RPM's success in attracting new demand-side resources by comparing the RPM-committed DR and ILR capacity with the historical levels of ALM, as shown in Figure 13 but recognize that a portion of this increase will be associated with demand-side initiatives, such as state regulatory initiatives in eastern PJM, that have been motivated either directly by RPM or by the same market factors that resulted in the implementation of RPM.

Figure 13
Demand-side Participation in PJM Capacity Programs

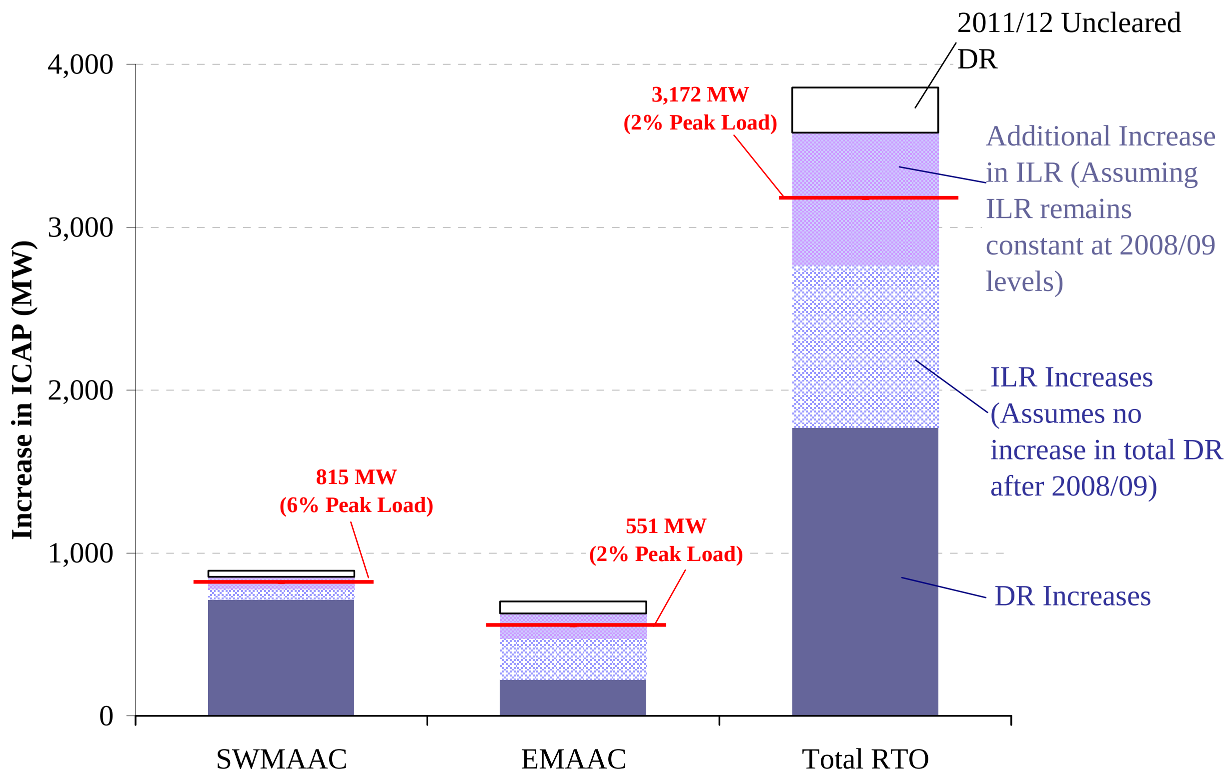


Source: *Brattle* analysis of PJM data.
*Forecast ILR range is estimated using (1) constant total DR + ILR capacity, and (2) constant certified ILR.

As shown in Figure 13, between 2002 and 2006, ALM participation fluctuated within a range from 1,207 MW to 2,042 MW. The first RPM auction for the 2007/08 delivery year produced a combined amount of DR and ILR only slightly above the upper end of the historic range. However, the base auction for the 2008/09 delivery year produced a substantial increase, with 956 MW of DR cleared in the base auction plus 3,489 MW of ILR registering in early 2008. DR offered and cleared continued to increase steadily in the following base auctions, with 1,769 MW of DR cleared for the 2011/12 delivery year. ILR has not yet registered for delivery years beyond 2008/09, so the amount of ILR that will be available in future delivery years can only be estimated. A conservative approach is to assume no additional growth in the total amount of DR and ILR beyond the 2008/09 delivery year, which would imply a decline in ILR as the already known levels of committed DR increase. Alternatively, one could assume that ILR will remain at the 2008/09 level, which would imply further increases in the total amount of DR and ILR capacity through 2011/12. Figure 13 shows the range covered by these two forecasting methods as a shaded area. The average of the two estimates—reflecting an increase of approximately 3,000 MW in DR and ILR capacity over 2006 ALM capacity levels and indicated by the bracket on the right—has been used in Figures 4 and 5 to show the incremental commitment made since RPM was implemented.

Figure 14 shows increases in demand-side resources from 2006 level for PJM as a whole as well as within the two major LDAs, EMAAC and SWMAAC. The light blue slice on top of these bars represents the range associated with the two approaches to forecast ILR for future delivery years as discussed above. The average of that range is indicated by the red lines, which also represent the estimated increase in DR and ILR resources from pre-RPM levels (as shown in Figures 4 and 5). These incremental levels of DR and ILR additions are reasonably attributable to RPM.

Figure 14
Added Demand Resource Capacity in PJM, EMAAC, and SWMAAC
(End of 2006 through 2011/12 Delivery Year)



Source: *Brattle* analysis of PJM data, market participant interviews.

Figure 14 also shows that SWMAAC has the greatest percentage increase in DR and ILR resources, when expressed as a fraction of the area's peak load. With the addition of approximately 800 MW (six percent of peak load) to the pre-RPM level of approximately 190 MW of demand-side resources (representing 1.3 percent of peak load), this growth in DR and ILR is impressive compared to other parts of PJM as well as to the rest of the country. Moreover, a significant portion of this increase occurred in the compressed period between 2006 and the recent certification of ILR for the 2008/09 delivery year, when SWMAAC still suffered from projected capacity shortages and RPM capacity clearing prices were relatively high. Demand-side resources were able to respond quickly to these price signals and commit with significantly less lead time than new generation.

As shown in Figure 13, it is also encouraging that significantly more DR cleared in the recent base residual auction for 2011/12 than in prior auctions in spite of the lower market clearing prices. Nevertheless, it is possible that these prices will cause less ILR to register for the 2011/12 delivery year than we estimated. More than half of our estimated ILR capacity for the 2011/12 delivery year is in the LDAs, where 2011/12 capacity prices are significantly lower than in 2008/09.

6. Incremental Auction Results

As noted in Section II, each base residual auction is followed by three incremental auctions. To date, only one incremental auction has been held: the third incremental auction for the 2008/09 delivery year held in January 2008 to allow suppliers to procure replacement capacity. A second incremental auction was scheduled in April 2008 for the 2009/10 delivery year but not executed because the load forecast for the 2009/10 delivery year had not increased.

In third incremental auctions, market participants submit buy bids for replacement capacity to cover EFORd degradation, ICAP derates, or resource cancellations or delays. These buy bids are used to construct demand curves for the RTO and each LDA. The supply curves consist of individual offers, which are made up of any eligible and previously uncommitted resources, such as EFORd improvements, rating increases, capacity uncleared or excused in previous auctions, or new resources. Approximately 55 percent of the supply curve for the 2008/09 third incremental auction was from EFORd improvements, 43 percent from resources which did not clear in the 2008/09 base auction, and about two percent new resources which were also offered in the 2009/10 base auction.

Total demand in the third incremental auction for the 2008/09 delivery year was about 2,252 MW (in UCAP terms), just under the total supply offered of 2,339 MW. About half of the capacity offered was from EMAAC resources, while EMAAC demand was only about 191 MW.

In this third incremental auction, the RTO and EMAAC cleared at the intersections of the supply and demand curves. This resulted in an unconstrained EMAAC region and a clearing price for both EMAAC and the rest of the unconstrained RTO of \$10/MW-day. In contrast, within SWMAAC the two curves did not intersect, and the clearing price was determined by a vertical extension of the supply curve at the total amount of offered capacity. SWMAAC saw incremental supply of only 21 MW, coupled with about 238 MW in demand. This shortage of supply in SWMAAC resulted in a relatively high clearing price of \$223.85/MW-day. This price was about \$14/MW-day higher than the 2008/09 base auction price of \$210.11/MW-day.

The supply-demand imbalances reflected in these results suggest that liquidity in incremental auctions can be very limited. Our recommendations on improving LDA price signals and incremental auction price stability are discussed in Sections V.E. and V.F.

7. Summary: Capacity Additions and Retentions Reasonably Attributable to RPM

Based on the above analyses and qualitative discussions of different types of existing and new resources, we conclude that over 14,500 MW of capacity retentions and additions are reasonably attributable to RPM. This includes over 4,600 MW of retained existing resources and almost 10,000 MW of incremental capacity commitments in the form of new generating units, rating increases to existing units, additional demand-side resources, and decreased net exports. Table 3 summarizes these RPM-related improvements to PJM resource adequacy.

Table 3
Summary of Capacity Attracted and Retained since 2006

Resource Category	**Incremental Capacity through 2011/12 Delivery Year (ICAP)**	
	Capacity Shown in Figure 4 *[1]*	Capacity Reasonably Attributable to RPM *[2]*
Withdrawn Deactivation Requests	**1,170**	**1,170**
Other Planned Retirements Cancelled or Deferred	**3,471**	**3,471**
Net Rating Increases	**1,264**	**1,264**
Uprates	2,932	
Derates	-1,668	
Net Capacity Additions	**3,294**	
Non-Renewable New Capacity Participating in Auctions	2,675	2,675
Non-Renewable New Capacity in FRR Plans	580	0
Renewables	394	0
Reactivations	599	599
Retirements	-957	0
Net Export Decreases	**2,181**	**2,181**
DR Increases	**1,769**	**1,769**
ILR Increases	**1,403**	**1,403**
Total	**14,552**	**14,533**

Source: *Brattle* analysis of PJM data.

As Table 3 shows, RPM-related retentions and incremental commitments of capacity resources include: (1) over 4,600 MW of retained existing capacity that would very likely have been retired without RPM-based capacity revenues; (2) over 1,200 MW of net rating increases; (3) over 2,600 MW of new generating resources and approximately 600 MW of capacity reactivations; (3) almost 2,200 MW of reduced net exports; and (4) over 3,100 MW of demand side resources, consisting of more than 1,700 MW of DR and over 1,400 MW of incremental ILR. As discussed in more detail earlier, our estimate of the resource impact attributable to RPM differs slightly from the capacity additions shown in Figures 4 and 5 due to capacity increases and decreases that are unrelated to PJM.

C. Uncleared Capacity in RPM Base Auctions

The most recently-conducted base residual auction for the 2011/12 delivery year resulted in lower market clearing prices with over 6,000 MW of capacity offers that did not clear in the auction. A portion of the uncleared capacity was due to the fact that PJM's load decreased by approximately 3,000 MW because of Duquesne's departure from PJM. But even if Duquesne had remained with PJM, over 4,000 MW of capacity offers would not have cleared in the recent auction. Some of the uncleared capacity has already been presented in various figures discussed above.

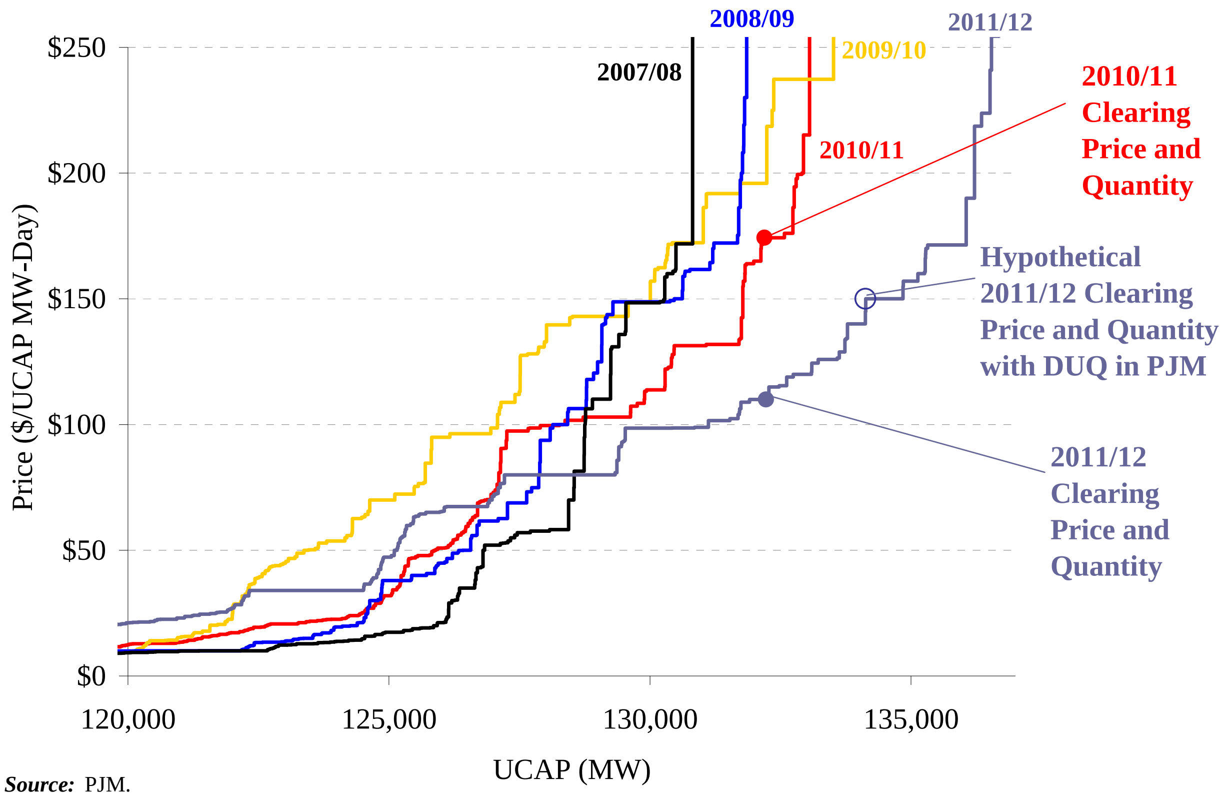
Figure 15 shows the RTO-wide supply curves from all five base residual auctions to date, including the clearing prices and clearing quantities for the two most recent auctions.[21] As the figure shows, additional resources have shifted the supply curve for the 2011/12 delivery year markedly to the right, which resulted in lower capacity prices and significantly larger amounts of uncleared capacity, even if Duquesne had not left PJM. This significant amount of uncleared capacity—and the fact that the auction cleared in a less steeply sloped portion of the supply curve—also points to a significant increase in competition between existing and a variety of new capacity resources compared to previous auctions in which little capacity remained uncleared. New generation units with relatively high offers that did not clear may be delayed or cancelled. Fully uncleared existing generating units—which accounted for almost 2,900 MW of capacity offers—are provided a price signal that the resources may be uneconomic, which could lead to their retirement unless RPM prices are expected to increase again or their going-forward costs decrease below their recent offers.[22]

---

[21] The first three auctions cleared with constrained LDAs and without a single total RTO-level market clearing price and quantity.

[22] Partially uncleared existing units, which accounted for approximately 1,700 MW of capacity offers in the recent base auction, are not at immediate risk for retirement because a portion of the capacity from these units is still committed.

Figure 15
Supplier Offer Curves in Base Auctions



Source: PJM.
Note: Y-axis is truncated and omits offers above $250/MW-day.

The total amounts of cleared and uncleared capacity in each of the five base auctions conducted to date are summarized in Table 4 for PJM as a whole as well as EMAAC and SWMAAC. The table, which excludes capacity committed by FRR entities, shows that over 6,000 MW of capacity offers did not clear in the recent auction for the 2011/12 delivery year, which significantly exceeded the 1,200 MW to 2,400 MW of uncleared capacity in the first four auctions. A significant portion of this increase in uncleared capacity is related to the fact that a substantial amount of new generation as well as additional DR were offered in the most recent auction. As shown in the table, almost 500 MW of new generation and close to 300 MW of DR did not clear in the recent auction. Additionally, the recent auction also resulted in 670 MW of import offers that did not clear.

Table 4
Summary of Cleared and Uncleared Resources in RPM Base Auctions
(Excludes FRR capacity)

	Capacity, by Delivery Year (ICAP MW)				
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**
TOTAL RTO					
Total Cleared	**136,982**	**136,358**	**139,454**	**139,253**	**139,121**
Cleared Existing Generation	135,008	133,900	136,502	136,029	130,414
Cleared New Generation	142	224	325	475	2,337
Cleared Demand Response	124	519	864	908	1,319
Cleared Imports	1,709	1,715	1,762	1,842	5,050
Total Uncleared Capacity	**1,507**	**2,411**	**1,456**	**1,212**	**6,044**
Fully Uncleared Existing Generation	382	891	98	531	2,883
Partially Uncleared Existing Generation	1,125	1,303	1,124	512	1,718
Uncleared New Generation	0	0	151	132	496
Uncleared Demand Response	0	173	43	28	278
Uncleared Imports	0	43	41	8	669
Total Uncleared Capacity (excluding partially uncleared existing generation)	382	1,107	332	700	4,326
EMAAC					
Total Cleared	**32,895**	**32,234**	**33,632**	**32,469**	**30,893**
Cleared Existing Generation	32,786	31,939	33,170	32,157	30,123
Cleared New Generation	65	131	101	17	546
Cleared Demand Response	43	163	361	296	223
Cleared Imports	0	0	0	0	0
Total Uncleared	**30**	**1,221**	**34**	**655**	**3,082**
Fully Uncleared Existing Generation	0	762	0	381	2,458
Partially Uncleared Existing Generation	30	290	30	129	375
Uncleared New Generation	0	0	0	132	176
Uncleared Demand Response	0	169	4	12	73
Uncleared Imports	0	0	0	0	0
Total Uncleared Capacity (excluding partially uncleared existing generation)	0	931	4	526	2,708
SWMAAC					
Total Cleared	**11,230**	**11,548**	**10,932**	**11,750**	**11,619**
Cleared Existing Generation	11,211	11,249	10,587	11,248	10,802
Cleared New Generation	0	0	0	0	101
Cleared Demand Response	19	299	345	502	716
Cleared Imports	0	0	0	0	0
Total Uncleared	**0**	**5**	**480**	**104**	**929**
Fully Uncleared Existing Generation	0	0	52	104	379
Partially Uncleared Existing Generation	0	0	428	0	192
Uncleared New Generation	0	0	0	0	320
Uncleared Demand Response	0	5	0	0	37
Uncleared Imports	0	0	0	0	0
Total Uncleared Capacity (excluding partially uncleared existing generation)	0	5	52	104	737

Source: PJM.

Despite the success of attracting significant quantities of new resources, which led to a substantial increase in uncleared capacity, Table 4 also shows that uncleared capacity from existing generating units could lead to new reliability challenges within EMAAC and SWMAAC if planned transmission upgrades were delayed and uncleared existing generating units were to retire. For example, more than half of the total uncleared capacity in the 2011/12 auction occurred in EMAAC, most of which was comprised of the full output of existing generation units (2,458 MW). The EMAAC LDA was not binding since the 2009/10 auction, based on the expectation that planned transmission upgrades would increase the import capability by approximately 2,700 MW prior to the 2009/10 delivery year. If the transmission upgrade is delayed and some of the fully uncleared existing generating units were to retire, reliability challenges could reemerge within the LDA.

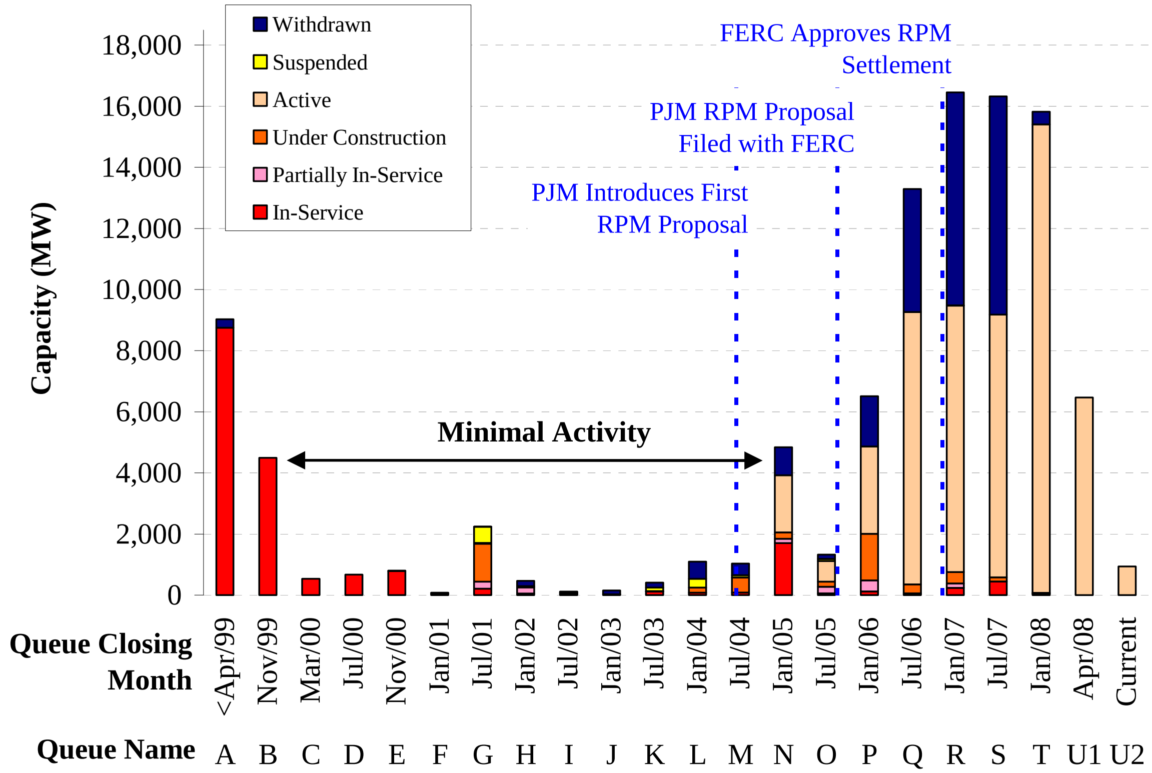
This challenge was already noted earlier in our discussion of Figure 5. If some of the uncleared existing units retired and the transmission upgrades were delayed or cancelled, EMAAC clearing prices in future base and incremental auctions would likely increase again as the LDA-internal reserve margins drop below reliability targets. Presumably, this prospect of higher future prices, however, would also serve to delay the retirement of existing units that did not clear in the most recent auction. In fact, the amount of uncleared capacity in EMAAC and SWMAAC is sizable enough to address all or most of the reliability challenges that could be caused by delays in the planned transmission upgrades. To address these challenges effectively, however, revisions to how RPM applies to LDAs may be warranted. These specific concerns and recommendations of how these concerns could be addressed are discussed further in Section V.

D. INCREASES IN PLANNED CAPACITY ELIGIBLE TO PARTICIPATE IN FUTURE RPM AUCTIONS

The impact of RPM reaches significantly beyond the additional or retained resources in excess of 14,500 MW that have been committed through the five base auctions since April 2007. Since RPM was proposed, approved, and implemented, substantial amounts of new generating capacity have been proposed and have begun development within the PJM footprint. As of May 2008, PJM's generation interconnection queues include approximately 33,000 MW of new resources that are eligible for participation in future RPM auctions and that have not yet been committed in the five base auctions conducted to date (including renewables at their effective capacities reflecting discounts for intermittency). Even excluding the effective capacity of renewable resources, for which RPM is likely not a major driver, there are approximately 28,000 MW of RPM-eligible resources that have not been committed in RPM auctions to date. Not all of this capacity will be constructed, but there has clearly been an enormous increase in development activities since RPM was proposed.

Figure 16 shows the size and status of PJM generation interconnection queues since the 1990s. The size of each bar shows the effective capacity and its status for each queue. The figure shows minimal activity with respect to the development of new generating capacity from 2000 through 2005. The generating projects that remained in the interconnection queues prior to 2000 have mostly been built. After the wave of construction beginning in the late 1990s, only trivial amounts of new generating capacity have sought interconnection with the PJM system. However, as Figure 16 also shows, interconnection activity has accelerated greatly since RPM was proposed, approved, and implemented. After RPM was first proposed, interconnection requests increased from trivial amounts to 4,000 to 6,000 MW for the six-month periods starting January 2005 and January 2006. After FERC first conditionally approved RPM in April 2006, over 13,000 MW of generating capacity were added into the interconnection queue starting July 2006, approximately 9,000 MW of which are still active. This pace has accelerated further after FERC approved the final RPM design in December 2006: approximately 16,000 MW were added in each of the interconnection queues starting January 2007, July 2007, and January 2008. Even the last completed queue, U1—which remained open for only three months rather than the six months used for previous queues—contains over 6,000 MW of active interconnection requests.

Figure 16
Additions to, and Status of, PJM Generation Interconnection Queues

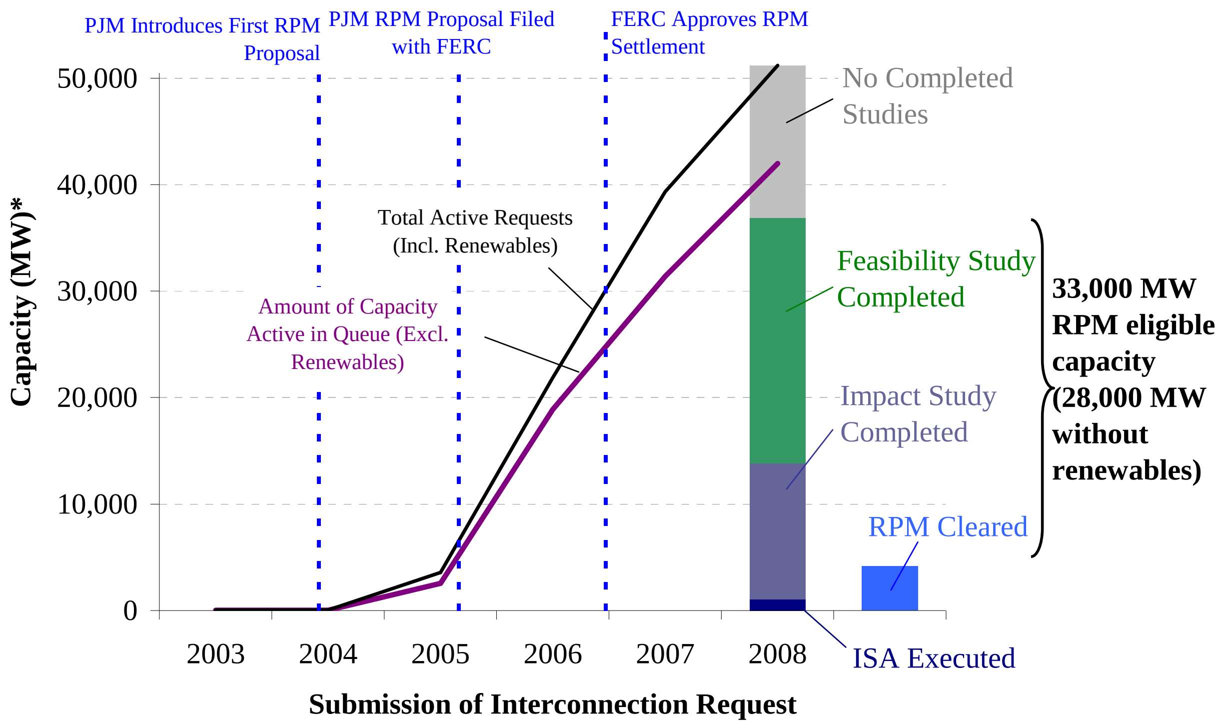


Source: *Brattle* analysis of PJM data. Queue data as of June 3, 2008.

Figure 17 below shows the status of all currently active interconnection requests and when those requests were added to the interconnection process. This documents that resources with an effective capacity of more than 50,000 MW currently have active interconnection requests. As indicated by the black line, there was negligible activity before 2005, and the vast majority of these generating resources have been added to the interconnection queues in 2006, 2007, and 2008. The purple line in Figure 17 shows the same pattern even when excluding renewable resources for which RPM is likely not a primary driver.

The stacked bar of Figure 17 documents the status of all currently active interconnection requests. It indicates that for approximately 15,000 MW of these resources, a system impact study has already been completed. For more than 20,000 MW of these resources, only a feasibility study has been completed to date. However, because completion of a feasibility study makes generating resources eligible to offer into RPM auctions, this brings the total effective capacity of proposed resources that are eligible to offer into RPM auctions to approximately 37,000 MW. Excluding the new resources that have already been committed in one of the five RPM base auctions to date leaves approximately 33,000 MW of uncommitted new resources that are eligible to offer into future RPM auctions. Approximately 28,000 MW of this capacity is from non-renewable resources for which RPM-based capacity payment are likely a major driver.

Figure 17
Active Generation Interconnection Request in PJM Queue
By Year and Milestone as of April, 2008



Source: *Brattle* analysis of PJM data. Queue data as of June 3, 2008.
*Only the effective capacity component of each proposed facility is included (e.g., wind is derated to 20% of its rated capacity). Excludes projects suspended, withdrawn, under construction, or in-service.

Table 5 shows the location of the currently active interconnection requests. It shows that new generating projects are planned throughout the PJM footprint, including in each of the LDAs. In each of these local areas as well as in the remainder of the RTO, the capacity of active resources in PJM's interconnection queues that are already eligible to offer into RPM auctions is equal to between 20 percent and 29 percent of the area's peak load forecast for the 2007/08 delivery year. This means, at an annual load growth of approximately 1.6 percent,[23] the RPM-eligible capacity in the interconnection queue that is located within each of these areas would be sufficient to satisfy at least 10 years worth of load growth.

[23] PJM 2007 Load Forecast Report, January, 2007, Page 27. See http://www.pjm.com/planning/res-adequacy/downloads/2007-load-report.pdf.

Table 5
Planned Projects Eligible for RPM Participation

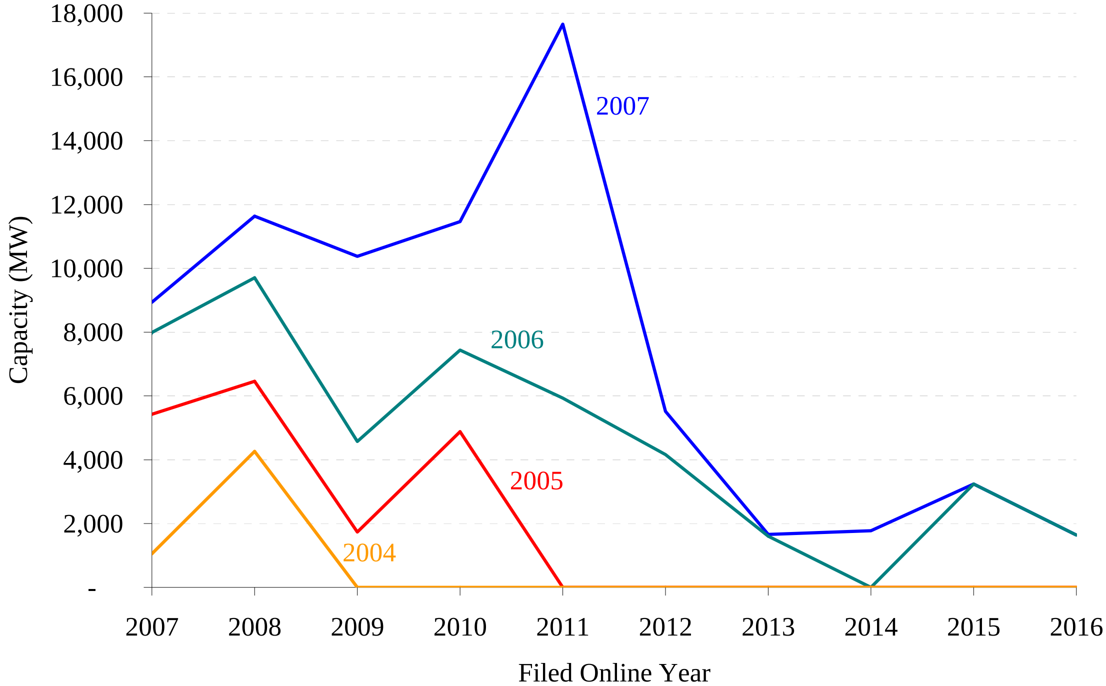
LDA	2007/08 Peak Load Forecast	Total Queue		Projects Already Eligible for RPM		
	(MW)	*(MW)*	*(% of Peak)*	*(MW)*	*(% of Total Queue)*	*(% of Peak)*
SWMAAC	13,817	3,645	26%	3,425	94%	25%
EMAAC	31,891	15,400	48%	6,361	41%	20%
MAAC+APS	66,648	30,741	46%	19,084	62%	29%
Rest of RTO	70,773	23,651	33%	17,788	75%	25%
Total	137,421	54,392	40%	36,871	68%	27%

Source: *Brattle* analysis of PJM data. Queue data as of June 3, 2008.
Note: Queue quantities include renewables; wind is derated to capacity value.

The significant increase in active interconnection requests has also been documented in the MMU's State of the Market (SOM) Reports of the last several years. Figure 18 assembles these data from the 2004 through 2007 SOM Reports, showing active generating projects in PJM's interconnection queues by filed online date as of the end of each year.[24] The trends illustrated in Figure 18 are evidence that the total capacity in the interconnection queue has expanded substantially in 2006 and 2007. The figure also shows that at the end of 2007, almost 18,000 MW had a filed online date for the 2011 calendar year. Only resources with an online date of May 2011 or earlier could offer into the most recent base residual auctions for the 2011/12 delivery year (starting June 1, 2011). This means that many resources with active interconnection requests likely are targeted to offer into the next several base auctions for the 2012/13 delivery year and beyond. These data suggest that most of RPM-related impacts on the entry of new capacity will be observed in future auctions.

[24] Note that the capacity shown in Figure 18 is based on the installed capacity of individual resources, which does not derate intermittent renewable resources. The queue data we present in other figures and tables is the installed capacity of conventional resources but the derated capacity of intermittent renewable resources.

Figure 18
Capacity of Active Generation Projects in Interconnection Queue
(as of December 31, 2004 through 2007, By Online Date)

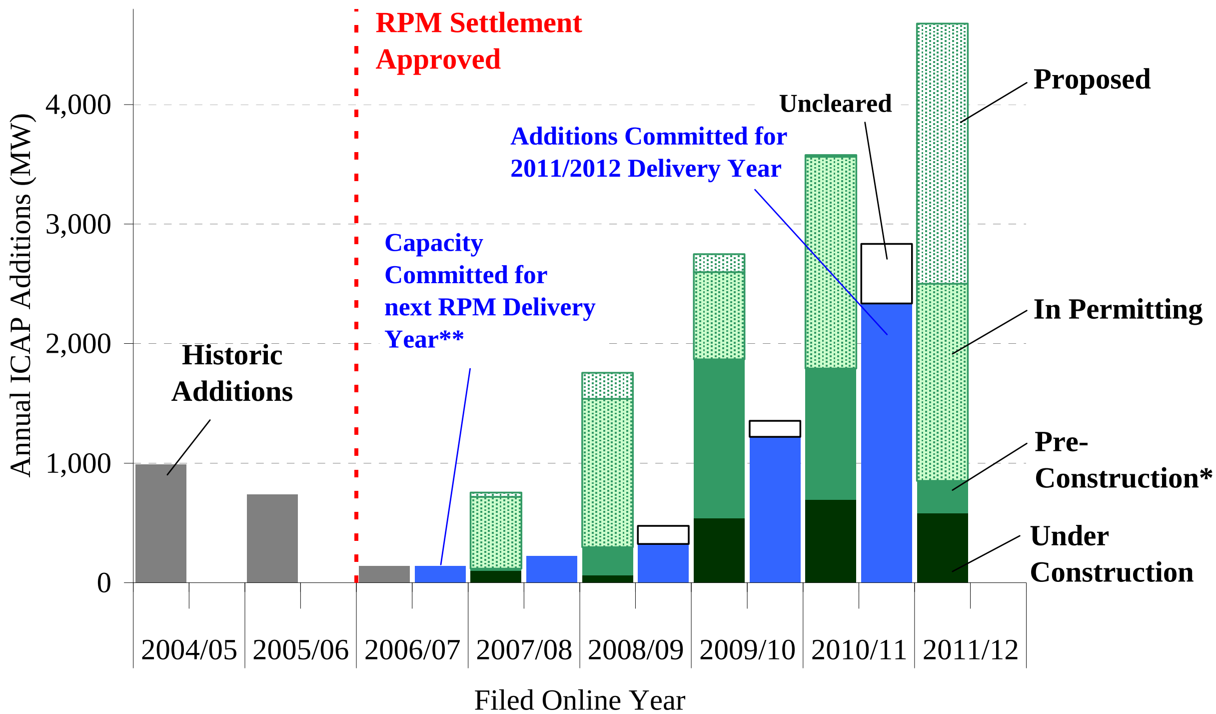


Source: 2005-2007 PJM State of the Market Reports.

Because some of the projects in PJM's interconnection queue may be speculative or have only a low probability of ever becoming operational, we have also analyzed planned capacity additions from a third-party data source that tracks permitting status, pre-construction activities, and construction of proposed generating projects. The result of this analysis is shown in Figure 19.

The green bars in Figure 19 show by filed online date how much of the planned capacity (1) is currently under construction, (2) is pursuing pre-construction activities (which includes units with permits that are arranging fuel supply and/or are undertaking site preparation activities); (3) is in the permitting process; and (4) is proposed without yet having started the permitting process. The blue bars show how much capacity has been committed in the various RPM base auctions, assuming that resources committed for a particular delivery year would become operational during the prior year. This comparison of planned capacity (green bars) with the capacity that has been committed in RPM auctions to date (blue bars) also confirms that plant development activities have accelerated greatly after the approval of RPM and that the level of this development activity substantially exceeds the new capacity that has been committed in RPM auctions to date.

Figure 19
Annual Capacity Additions in PJM based on Third-Party Projections
(as of April, 2008)



Source: *Brattle* analysis of data compiled by Ventyx Energy, The Velocity Suite as of April, 2008.
*Pre-construction includes units with permits or site preparation activities.
**Assumes RPM-committed capacity comes online before the delivery year.

IV. ANALYSIS OF VRR CURVE AND RPM FORWARD COMMITMENTS

The variable resource requirement (VRR) curve represents the administratively-determined demand for capacity in the RPM base auctions. The VRR curve was designed to reduce price volatility and incentive for withholding associated with the prior vertical demand curve and to yield reserve margins that, on average, are consistent with the target reserve margin. The extent to which the VRR curve actually achieves these objectives depends on how the curve is defined. The VRR curve is drawn with the amount of unforced capacity as the horizontal dimension and the price of capacity along the vertical dimension. The three key parameters defining the VRR curve are its slope and shape, its horizontal position corresponding to reserve margin targets, and its vertical position linked to the Net Cost of New Entry (Net CONE). All three of these parameters affect auction clearing prices and quantities of procured capacity.

After providing more background about the design of the VRR curve, we first evaluate the reserve margin targets used to define the horizontal position of the VRR curve and recommend that PJM consider re-evaluating the targets. We also evaluate Net CONE, which determines the VRR curve's vertical position. We find that RPM's existing mechanisms to update Net CONE over time are promising, but can be improved with some adjustments. We recommend that PJM consider improving the energy and ancillary service (E&AS) offset used to determine Net CONE and phasing in empirical adjustments.

We then analyze the shape and basic design parameters of the VRR curve using an updated and expanded version of the probabilistic simulation model previously developed by Professor Benjamin Hobbs for this purpose. Based on this updated probabilistic analysis we find that (1) the settlement-based VRR curve performs reasonably well relative to the originally-filed VRR curve (though at somewhat lower reliability levels); and (2) both sloped VRR curves perform better than a vertical demand curve.

Finally, we assess the reasonableness of the RPM design in terms of its three-year forward timeframe and one-year delivery period. We find that a three-year forward commitment is likely sufficient and more effective than longer-term forward commitments. In combination with the sloped VRR curve, the single-year delivery period should also offer sufficient price stability and predictability to form the basis for long-term investment decisions, at least on an RTO-wide basis. However, as we discuss further below, the same price stability does not exist within LDAs—which could be addressed by making multi-year pricing options broadly available to new resources serving these local areas.

A. BACKGROUND

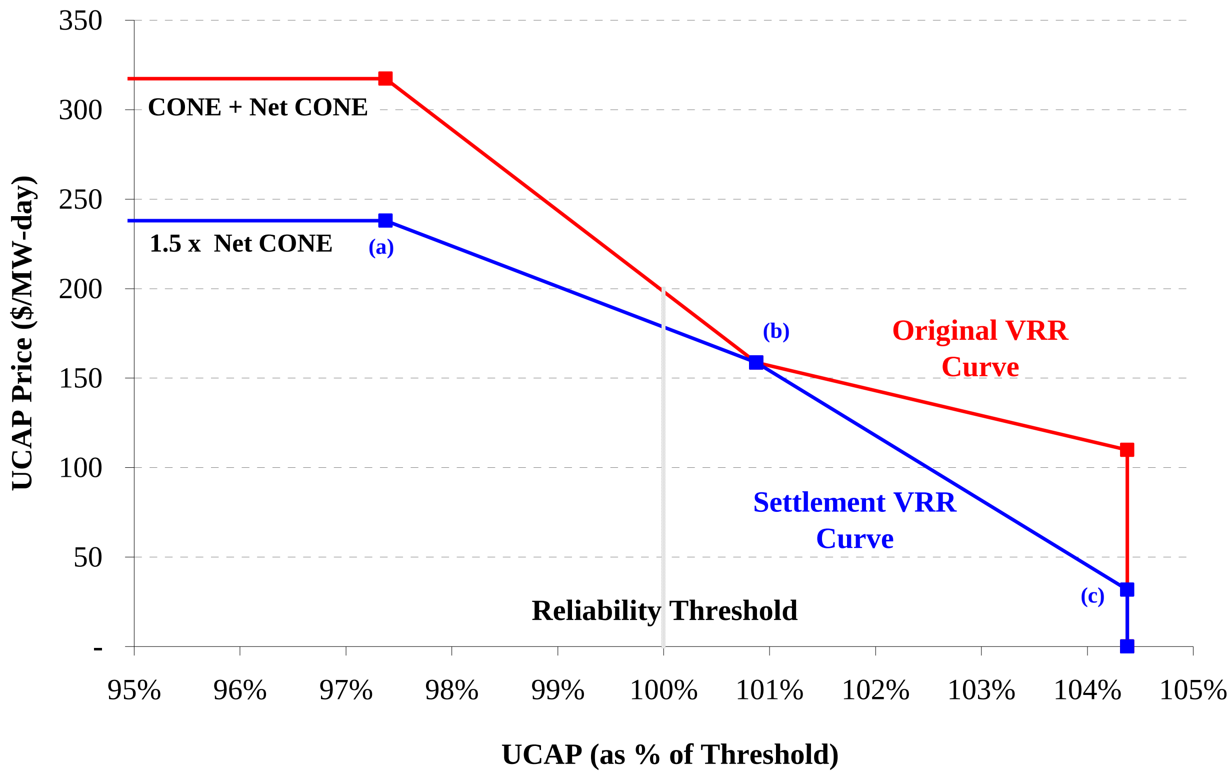
As noted earlier, the downward-sloping demand curve is meant to offer a number of advantages over a system that simply attempts to procure enough capacity to satisfy a target reserve margin (i.e., a vertical demand curve). The downward-sloping VRR curve reduces capacity price volatility and provides a better indication of the incremental and decremental value of capacity at different planning reserve margins. The sloped VRR curve also mitigates the potential exercise of market power by reducing the incentive for supplies to withhold capacity when aggregate supply is near the target reserve margin.

The Originally-filed VRR Curve. PJM originally proposed in its RPM filing a curve based on an initial analysis by Prof. Hobbs that sought to achieve reserve margins at or above the target level most of the time while limiting customer costs and cost uncertainty. As shown in Figure 20 below, the curve had two distinct segments with different slopes joined at an "anchor" point, where the capacity procured would exceed the reliability target by one percentage point. The price at that anchor point was set equal to the Net CONE, so that the market would support new entry (shown as point "b") at the desired level of reserves. For reserve levels above the anchor point, the curve decreased linearly to reach just under 70 percent of Net CONE at a capacity level that yields a reserve margin of about five percentage points above the target reserve margin (or about four percentage points above the anchor point). At that point, the curve fell vertically to zero to limit further overcommitment of capacity. For reserve margins below the anchor point, the VRR curve increased linearly to reach CONE plus Net CONE at a reserve margin that is approximately three percentage points below the target (or about four percentage points below the anchor point). At that point, the curve was capped (flattened horizontally) at CONE plus Net CONE, which is the same as two times CONE less energy and ancillary service margins.

The Settlement-based VRR Curve. The original VRR curve was subsequently modified through settlement discussions. The settlement process resulted in a slightly different curve with a lower cap and different slopes around the anchor point, shown in Figure 20. Prof. Hobbs also evaluated the settlement curve through probabilistic simulations and found that this curve performed well and produced results that were similar to the original curve. This curve has been approved by FERC and used within the RPM framework to determine market clearing prices and clearing quantities of capacity resources.

Again, the anchor point (point "b" in Figure 20) is based on a price equal to Net CONE and a reserve margin that is approximately one percentage point above the target reserve margin (shown in Figure 20 as 100 percent of UCAP Threshold). The curve drops from a price equal to 20 percent of Net CONE (point "c" in Figure 20) to a price of zero at a reserve margin of about 5 percentage points above target and is capped at 1.5 times Net CONE at a reserve margin of approximately 3 percentage points below target (point "a" in Figure 20).

Figure 20
PJM Variable Resource Requirement Curves



Reliability Threshold = Reliability Requirement - Forecast RTO/Zonal ILR Obligation

The shape of the settlement-based VRR curve is defined more precisely in Table 6 below, with several adjustments in addition to the conceptual shape discussed above. First, Net CONE is calculated as the difference between the CONE for a reference technology and the estimated E&AS offset for that technology based on historical data for the three-year period preceding the base auction.[25] Second, as discussed further in Section V.D., the quantity of capacity procured through the VRR curve is adjusted by subtracting the quantity of interruptible load for reliability ("ILR") that is forecasted to be available during the delivery year in addition to the capacity resources procured in RPM auctions. Finally, VRR capacity prices are expressed in unforced capacity ("UCAP"), which simply means that the price on a $/MW-day basis is paid to the capacity that can be expected to be available on average, which requires that the anchor point of the VRR curve be adjusted for anticipated system-wide forced outage rates ("EFORd").

[25] In the first three BRAs, a six-year period was used to calculate the E&AS Offset.

Table 6
Definition of Points on VRR Curve

Point	Price (UCAP Price)	Quantity (UCAP MW)
a	$\frac{[1.5(CONE - E\&AS)]}{1 - Pool\ Wide\ EFORd}$	$\left[\mathrm{Rel\,Req}\frac{(100\% + IRM - 3\%)}{(100\% + IRM)}\right] - \text{Forecast ILR Obligations}$
b	$\frac{[1.0(CONE - E\&AS)]}{1 - Pool\ Wide\ EFORd}$	$\left[\mathrm{Rel\,Req}\frac{(100\% + IRM + 1\%)}{(100\% + IRM)}\right] - \text{Forecast ILR Obligation}$
c	$\frac{[0.2(CONE - E\&AS)]}{1 - Pool\ Wide\ EFORd}$	$\left[\mathrm{Rel\,Req}\frac{(100\% + IRM + 5\%)}{(100\% + IRM)}\right] - \text{Forecast ILR Obligation}$

Determination of CONE. Thus far, the reference technology used to determine CONE has been a combustion turbine,[26] but PJM's consultant has also considered other technologies, including combined cycle units in the proposed CONE update study.[27] The CONE estimate includes "plant-proper" capital costs and estimates of the fixed annual operations and maintenance ("Fixed O&M") expenses. The "plant-proper" estimate reflects an engineering, procurement, and construction ("EPC") turnkey proposal.

CONE for the reference technology represents the levelized annual revenue that would provide an adequate return on and of capital and cover annual fixed O&M expenses. CONE was estimated using an after-tax discounted cash flow ("ATDCF") economic model based on the assumptions shown in Table 7.

Table 7
CONE Financial Assumptions

Project Evaluation	*(Years)*	20
Equity Share	*(%)*	50%
Debt Share	*(%)*	50%
Internal Rate of Return	*(%)*	12%
Loan Term	*(Years)*	20
Loan Interest Rate	*(%)*	7%
MACRS Depreciation Schedule	*(Years)*	15

26 Specifically, the reference technology is a combustion turbine plant with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 MMBtu/MWh.

27 Affidavit of Raymond M. Pasteris on Behalf of PJM Interconnection L.L.C., Docket No. ER08-516-000 *et al.*, filed on January 30, 2008

On January 31, 2008, PJM filed a proposal to update the CONE parameter. PJM stressed that in light of significant recent capital cost increases in construction costs, the CONE used in prior RPM auctions has become outdated. Specifically, PJM requested that FERC approve the CONE increase for the 2011/12 base auction that was scheduled to be held in May, 2008. However, because the PJM Tariff required PJM to submit CONE updates to stakeholders by September 1, 2007, FERC rejected the proposal. FERC argued that PJM did not allow stakeholders the four-month period to review CONE adjustment, as set out in the RPM tariff, in order to allow RPM buyers to hedge against higher prices that may result from the CONE adjustment.

Net Energy and Ancillary Services (E&AS) Revenue Offset. To calculate Net CONE, the administratively determined CONE value is reduced by the E&AS offsets earned by the reference technology. This offset is defined as the "margin" or revenues in excess of variable production costs that the reference technology would be expected to earn in the energy and ancillary service markets. For the first three delivery years, the E&AS offset was based on a historical average of the six years preceding the relevant base auction. Starting with the auction for the 2010/11 delivery year, the E&AS offsets have been based on the historical average for the three years prior to the base auction. E&AS offsets are calculated using the "Peak-Hour Dispatch" method and a set of assumptions regarding heat rates, costs, and fuel prices.[28] Under the "Peak-Hour Dispatch" method, the reference resource may be dispatched 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.

Empirical CONE Adjustments. As an alternative to the administrative determination of CONE, the PJM Tariff also allows for automatic adjustments based on "empirical CONE" data calculated from the previous three years of base residual auction results. These automatic CONE adjustments based on empirical data are allowed when three conditions are satisfied: (a) there was a *Net Demand for New Resources* during the most recent three-year evaluation period; (b) the cleared capacity in the most recent year was outside a so-called *Equilibrium Zone* on the VRR curve; and (c) the surplus or deficit of capacity is increasing beyond the equilibrium zone.

Net Demand for New Resources is deemed to occur if surplus generating capacity that existed three years ago was not sufficient to cover the increase in load generation capacity retirements and a decrease in import transmission capacity during the three-year period. [29] This effectively

---

[28] The E&AS calculations assume a heat rate of 10,500 BTU/MWh, variable O&M expenses of $5/MWh, $2,254/MW-year ancillary service revenues, and use actual fuel and hourly electricity prices.

[29] This condition is satisfied if the following formula yields a positive value:
Forecast Pool Requirement – Adjusted Load Growth in Years 1 to 3 + Generation Retirements in Years 1 to 3 – Surplus Resources in Year 1 + (CETL in Year 1 – CETL in Year 3),
where the *Forecast Pool Requirement-Adjusted Load Growth in Years 1 to 3* is given by the forecast growth in peak load multiplied by the forecast pool requirement, which is the amount of UCAP needed to satisfy the reliability target, or approximately 1.07, and *Surplus Resources in Year 1* represents the

reduces the likelihood that prices from auctions for which no new capacity is needed are used to establish the price of new capacity.

The second condition states that the total amount of capacity cleared in the base auction in the most recent year must lie outside the so-called *Equilibrium Zone*, which corresponds to capacity levels between the target reserve margin level and two percent above the target level. This ensures that CONE is adjusted only when actual CONE, as reflected in the clearing prices, is significantly different from the CONE parameter used in the VRR curve. Based on the slope of the VRR curve, this effectively implies that the *Equilibrium Zone* allows CONE to be adjusted only if the most recent clearing price is at least 12.5 percent above or 20 percent below Net CONE.

The third condition limits automatic adjustments to those cases when the severity of CONE misalignment has been getting worse during the three-year period. CONE may only be decreased if the amount of surplus capacity in the most recent year exceeds the amount three years ago. The criteria for increasing CONE are slightly less stringent in order to avoid compromising reliability. CONE may be increased unless it was empirically increased for the preceding base auction. In that case, CONE is adjusted only if the cleared amount of capacity three years ago was greater than the cleared amount of capacity in the most recent year. That is, empirical adjustments to CONE may, in general, only occur if the shortage or surplus of capacity, relative to the equilibrium zone, has been increasing during the three-year period.

If all three conditions are satisfied, CONE adjustments are determined by the following formula:[30]

CONE Adjustment = MIN [0.5 x ABS(Empirical CONE – CONE), 0.1 x CONE]

The "Empirical CONE" in this formula is calculated as the load-weighted average of the sum of (a) the average resource clearing price from the three most recent base auction results; and (b) the average of the E&AS offsets that were used in the VRR curve for each of those years. The CONE adjustment is then half of the difference between the Empirical CONE and the currently effective CONE, and the magnitude of any adjustment is capped at 10 percent of CONE. Taking only half of the difference and capping that at 10 percent was designed to prevent excessive year-to-year shifts in the VRR curve.

The empirical CONE adjustment provisions were not in effect during the RPM Transition Period, and PJM did not apply the automatic adjustment mechanism in the base auction for the 2011/12 delivery year held in May, 2008.[31]

---

difference between the total existing unforced generating capacity with a must-offer requirement and the capacity level corresponding to the kink on the VRR curve (approximately one percent above the target).

30 PJM Tariff, Attachment DD, Section 5.10.

31 Our understanding is that PJM has yet to resolve some details of its empirical adjustment process. The adjustments are supposed to be done by CONE area, of which there are three. However, the CETL data to be used in the equation for determining the Net Demand for New Resources does not exist by CONE area.

B. QUALITATIVE ANALYSIS OF VRR DESIGN

1. The Horizontal Position of the VRR Curve – Reliability Targets

Setting the anchor point of the VRR curve (point "b" in Figure 20) at a level just above the target reserve margin is consistent with the main objective of RPM, which is to achieve the target level of reliability most of the time. Assuming target reliability remains the same, the horizontal position of the VRR curve, defined by target reserve margins, therefore should remain the same even as market conditions change.

While this approach is consistent with RPM's stated objectives, those objectives may warrant being re-examined to consider the desirability of maintaining the same target level of reliability even when the cost of capacity changes substantially. Reliability targets might ultimately need to recognize the tradeoff between the value of reliability and the cost of capacity. If the cost of constructing new generating capacity is increasing substantially, as has been the case in recent years,[32] the market-determined cost of new capacity will increase as well. However, at a higher CONE, customers presumably would be willing to accept a slightly lower level of reliability. This tradeoff creates, at least theoretically, an optimal reserve margin that decreases as CONE increases. The anchor point of the VRR curve, corresponding to such an "optimal" reserve margin, would have to be shifted toward lower target reserve margins as CONE increases.

Based on these considerations, one could construct the demand curve so that it represents the marginal *value* of reliability. Such a demand curve would not need to be adjusted over time unless the value of reliability, which is generally measured as the value of lost load ("VOLL"), changed. The optimum level of reliability would be determined in each auction by the intersection of the demand curve with the supply curve, which means that the market would clear at the optimal level of reliability given the cost of capacity. It should be noted, however, that the analysis Prof. Hobbs filed in support of the RPM design showed that a VRR curve based on the value of lost load performed poorly in his probabilistic simulations. This was likely the case because the VOLL-based curve examined was steeper than the current VRR curve. In addition, a VOLL-based approach has not been considered practical because of a lack of reliable data on customers' actual willingness to pay to avoid losing load.

Nevertheless, PJM might want to examine this concept further as part of a broader re-evaluation of the level and application of current reliability criteria. A broader re-evaluation could consider questions such as:

CETL is meaningful for the EMAAC CONE area but it is meaningless for the other two CONE areas with non-contiguous zones.

32 Construction cost increases of 40 percent or more have been estimated for just the last few years. See, for example, Chupka and Gregory Basheda "Rising Utility Construction Costs: Sources and Impacts", Prepared by *The Brattle Group* for The Edison Foundation, September 2007. PJM's recent CONE estimates based on the cost of constructing natural gas-fired combustion turbines are consistent with these trends.

- What does loss of load of one day in 10 years ("1-in-10") mean in terms of the magnitude of unserved energy (i.e., lost MWh) within the current PJM footprint?
- Is the current 1-in-10 standard being applied consistently to small areas and large areas alike? For example, as the footprint of PJM has grown over time, has maintaining the 1-in-10 standard effectively increased reliability requirements (because losing, for example, one megawatt of load once in 10 years within the current PJM footprint provides more reliability than applying a one megawatt in 10 years standard to a smaller control area)?
- How should the RTO-wide reliability standard be applied to LDAs (a subject which is discussed further in Section V.F.)?
- Would a different target level of reliability provide a more optimal balance of the current cost of capacity versus the value of reliability?
- How should revised or dynamic reliability targets be incorporated into RPM?

2. The Vertical Position of the VRR Curve – Net CONE

RPM's base auctions can be expected to achieve the target level of reliability only if the vertical position of the VRR curve is consistent with a Net CONE that, on average over time, accurately reflects suppliers' costs of providing capacity resources. However, determining Net CONE—total CONE net of E&AS margins—is not straightforward and estimation errors will affect auction clearing prices and quantities, which could also affect RPM's overall cost and efficiency. Consequently, we further explore the implications of inaccurately estimating Net CONE, address concerns with administrative adjustments, and discuss the implementation of empirical adjustments.

Consequences of Inaccurately Estimating Net CONE. Using an inaccurate Net CONE to define the VRR curve has consequences for both reliability and customer costs. It is important to note that the reliability implications of understating or overstating Net CONE for the purpose of defining the vertical position of the VRR curve are partially mitigated by the downward-sloping nature of the demand curve. This allows prices to move in the direction of true Net CONE, but at reliability levels that are slightly higher or lower than intended. Understating Net CONE will result, temporarily, in capacity prices that are below the true Net CONE (but, because of the sloping supply curve, still above the estimated Net CONE). These temporary prices are also associated with reduced reserve margins. However, since these prices will likely fail to attract new capacity, reserve margins will decrease further until clearing prices reach levels consistent with the true Net CONE. In other words, understating Net CONE will lead to reduced levels of reliability, though the slope of the VRR curve mitigates that effect by allowing for clearing prices to rise to the true Net CONE.

Similarly, overstating Net CONE will temporarily lead to capacity clearing prices that are above the true Net CONE (but below the estimated Net CONE) at above-target reserve margins. In response to these prices, additional new capacity will be attracted such that reserve margins will increase further until clearing prices decline to be consistent with the true Net CONE. This mean that anchoring the VRR curve at estimated Net CONE levels above the true Net CONE will add additional costs in the form of higher reserve margins, and temporarily, higher auction clearing prices. These higher costs, however, are at least partly (if not fully) offset by the additional value of higher reliability and lower market prices for energy.

As discussed further in Section IV.C., our probabilistic analyses based on an updated Hobbs simulation model indicates that correct estimates of Net CONE would result in reserve margins that are on average 0.5 percent above target reliability requirements. If the estimate of Net CONE used to anchor the VRR Curve consistently understated Net CONE by approximately 17 percent, the simulations suggest that actual reserve margins would on average be 1.0 percentage point *below* target reliability requirements. Similarly, if the estimate used to anchor the VRR curve was consistently overstated by approximately 17 percent, average reserve margins would be 1.5 percentage points above target reliability requirements.

The recent base auction for the year 2011/12 was informative because the gross CONE value that was used, net of E&AS margins, to anchor the VRR curve was substantially below the gross CONE level that PJM believes is required to be consistent with the cost of constructing new generating capacity.[33] However, the auction cleared with a surplus of capacity at prices significantly below the Net CONE value at which the VRR Curve was anchored.[34] At least one developer decided not to participate in the 2011/12 auction because CONE was too low, and presumably more would have dropped out but for expectations that capacity prices would increase again in future auctions. Nevertheless, despite the much lower capacity prices, over 2,300 MW of new generation resources, over 400 MW of new DR, and over 3,000 MW of imports (including capacity from the former Duquesne zone) cleared in the auction. Only approximately 500 MW of new generation and close to 300 MW of DR did not clear at the relatively low auction clearing price.

Administrative Adjustments to Net CONE. Based on evidence of increasing construction costs, we know that the current *gross CONE* value specified in the PJM Tariff is significantly below actual construction costs. However, the recent auction indicate that despite the fact that construction costs have increased substantially in recent years, sufficient resources cleared to yield (1) a reserve margin in excess of the VRR Curve's anchor point and (2) prices that are below the Net CONE value on which the VRR Curve was based.

As discussed in more detail below, this result suggests that either (1) new resource owners are willing to commit at prices that are below their levelized total cost of entry during the initial year because they are confident that the RPM design will yield long-term results that compensate them for their total entry costs; (2) the administratively chosen reference technology that offers the lowest *total* cost of new entry (a combustion turbine) does not actually result in the lowest *net* cost of new entry; and/or (3) the resource owners' anticipated future energy and ancillary service margins are higher than the historical value currently used to determine Net CONE under

---

33 On January 30, 2008 PJM filed with FERC (in Docket No. ER08-516-000) a request to increase CONE by more than 40 percent to reflect recent construction cost increases. FERC rejected the request because it was filed after a September, 2007 deadline for modifying the CONE to be used in the 2011/12 auction.

34 One of the largest factors depressing prices was the loss of Duquesne load without losing a corresponding amount of generating capacity. But even without the loss of Duquesne load, the auction price would still have cleared below the Net CONE value that was used to anchor the VRR Curve.

the PJM tariff. In fact, since energy prices have been steadily increasing over the past several years, it is unlikely that the historical energy revenues will be an accurate predictor of future energy revenues. This suggests that, in conjunction with the adjustment to the gross CONE to reflect increased construction costs for the next auction, PJM should also consider (1) adjustments to the methodology to estimate Net CONE values based on projected E&AS offsets, and (2) reevaluate the chosen reference technology to verify that the chosen technology yields the lowest Net CONE value across a wide range of technology options.

PJM's current Net CONE and its recently requested update to gross CONE were estimated administratively. These estimates are uncertain for a number of reasons. First, an administrative process that identifies the technology with the lowest gross CONE, may not identify the reference technology with the lowest Net CONE. Second, even if the reference technology with the lowest Net CONE is selected, its estimated capital cost and fixed O&M costs are uncertain. Third, the financing and technology cost trend assumptions used to estimate the annual revenues that a plant owner would require initially to earn a satisfactory return on and of capital over the life of the asset may not correspond to developers' expectations.[35] And finally, the E&AS offset can only be estimated. It is impossible to determine all of these components accurately and fully consistent with developers' expectations.

To the extent that PJM continues to rely on administrative adjustments when empirical adjustments based on auction clearing prices cannot yet be applied, we recommend that PJM consider possible refinements to its administrative process of estimating Net CONE. First, the reference technology should be selected from a wide range of available technologies based on careful estimates of Net CONE values.[36] Because both gross CONE and E&AS offset can vary significantly across different regions (e.g., in LDAs), the reference technology may differ across the RTO footprint as well. For example, although high-efficiency combined cycle ("CC") plants are more expensive to build (*i.e.*, have a higher total CONE) than combustion turbines ("CT"), their higher efficiency results in higher energy margins that might more than offset the higher

---

[35] The expected trend of technology costs will determine how capital is recovered over time. For example, if the cost of new capacity is expected to be constant in nominal terms (e.g., because of technological progress), a levelized nominal cost rate (which yield charges that remain the same over time) would apply. If the cost of new capacity is expected to increase with inflation, a levelized real cost rate (which yields lower initial charges that increase over time) would be more appropriate. (In the RPM filings, the levelized *nominal* cost of new capacity was estimated at $72,000/MW-year; in comparison the levelized *real* cost of new capacity was estimated at $61,000/MW-year.) Other cost trends would yield other annual charge rates.

[36] PJM's recent filing to update CONE evaluated three types of peaking plant configurations: (1) a 170 MW GE Frame 7FA; (2) a 100 MW GE LMS-1000 aero-derivative CT; and (3) a Siemens FlexPlant10 combined cycle plant. The Frame 7FA configuration was chosen as the option with the lowest CONE value (Affidavit of Raymond M. Pasteris and Report by Pasteris Energy Inc. on behalf of PJM in Docket No. ER08-516-000, January 30, 2008). However, additional information showed that the Frame 7FA option also was the most economic peaker plant configuration in terms of Net CONE (Supplemental Affidavit of Raymond M. Pasteris on behalf of PJM in Docket No. ER08-516-000, March 20, 2008).

costs.[37] This possibility is documented, for example, in Section 3 of PJM's *2007 State of the Market Report* ("2007 SOM Report"), which estimated that during 2007 combined cycle plants located in EMAAC and SWMAAC had a significantly lower *net* cost than combustion turbines once E&AS revenues were deducted from their total costs. Table 8 is based on data presented in the *2007 SOM Report* and calculates net costs for the different technologies, including coal-fired plants. This illustration shows that a CT has the lowest Net CONE value at an RTO-wide level, but that this may not be the case within LDAs. For example, the estimated net cost of a combustion turbine in EMAAC was $148/MW-day, while the net cost for a combined cycle plant was only $105/MW-day.[38] It should be noted, however, that because CCs have larger and more variable E&AS revenues than CTs, using CCs as the reference technology would require more careful determination of the E&AS offset, including the fact that E&AS profits might decrease over time as the addition of more CC plants may reduce the spread between power and fuel prices.[39]

Table 8
Estimated Net Costs of New Generating Technologies

2007	EMAAC			SWMAAC			RTO		
	CT	CC	Coal	CT	CC	Coal	CT	CC	Coal
RT Energy Margin*	$34,539	$102,276	$301,722	$57,715	$132,416	$342,136	$18,335	$61,271	$219,633
Synchronized	$0	$0	$0	$0	$0	$0	$0	$0	$0
Regulation	$0	$0	$1,172	$0	$0	$1,172	$0	$0	$1,172
Reactive	$2,154	$3,094	$2,350	$2,154	$3,094	$2,350	$2,154	$3,094	$2,350
Total Net E&AS Revenue ($/MW-year)	**$36,693**	**$105,370**	**$305,244**	**$59,869**	**$135,510**	**$345,658**	**$20,489**	**$64,365**	**$223,155**
Levelized Cost ($/MW-year)	**$90,656**	**$143,600**	**$359,750**	**$90,656**	**$143,600**	**$359,750**	**$90,656**	**$143,600**	**$359,750**
Cost Not Covered by E&AS Revenues ($/MW-year)	**$53,963**	**$38,231**	**$54,506**	**$30,788**	**$8,091**	**$14,092**	**$70,167**	**$79,235**	**$136,595**
Net Cost of Entry ($/MW-day)	**$148**	**$105**	**$149**	**$84**	**$22**	**$39**	**$192**	**$217**	**$374**

Source: PJM 2007 State of the Market Report.

* Energy margins for Eastern MAAC were calculated as the average of energy margins in the Atlantic Electric, Delmarva Power & Light, Jersey Central Power & Light, PECO, Public Service Enterprise Group and Rockland Electric Company zones. Energy margins for Southwestern MAAC were calculated as the average of energy margins in the Baltimore Gas & Electric and Potomac Electric Power Company zones.

The E&AS offset used for administrative adjustments is difficult to forecast accurately and consistent with developers' expectations. This is because anticipated E&AS revenues will vary with market conditions that are not consistent with PJM's use of historical E&AS offsets. Using averages of historical E&AS offsets to determine Net CONE and the VRR curve can thus create uneconomic and inaccurate price signals. Moreover, our probabilistic analysis with the updated Hobbs model shows that strict reliance on historical averages could potentially lead to "resonances" with substantial price volatility that can undermine investment incentives. It also

37 Even DR could theoretically be the lowest-cost resource, but since DR costs are highly non-uniform and difficult to determine, it may be difficult to use DR as the reference technology for administrative Net CONE determination.

38 These net costs reflect the sharp recent increases in total construction costs, but are only illustrative. Accurate estimates of Net CONE would need to be developed based on a forward-looking perspective as discussed below.

39 This spread is generally referred to as the "spark spread", which is expressed relative to natural gas prices as a function of the "market heat rate" set by the efficiency of the marginal generating plant.

needs to be considered that historic E&AS offsets within constrained LDAs can significantly exceed anticipated future E&AS offsets, which may reflect reduced congestion premiums caused by the construction of new generation in 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. One approach 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. However, 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. A workable alternative approach could be to make adjustments to historical E&AS averages by considering market heat rates and changes in observed forward prices for natural gas.[40] Such adjustments might provide a significant improvement over simple historical averages, though the possibility of considerable estimation errors would remain.

These remaining uncertainties could be addressed through an ex post true-up for actual E&AS margins earned by the chosen reference technology. Such an ex post true-up would largely mitigate the uneconomic price signals caused by historical averages or inaccurately estimated E&AS offsets that might diverge significantly from the developers' anticipated E&AS margins. While such a true-up of E&AS offsets based on actual market conditions might decrease revenue predictability for a pure capacity product, such as emergency-only demand response, it could increase predictability and stability of total revenues for technologies that rely on the combination of capacity and E&AS margins to recover their investment costs.[41]

We consequently recommend that PJM consider revising the CONE and E&AS framework to: (1) determine gross CONE for the reference technology with the lowest Net CONE value; (2) determine the E&AS offset to gross CONE based on estimated future E&AS margins for the reference technology; and (3) consider introducing an ex post true-up for actual E&AS margins earned by the reference technology during the delivery year. These recommended improvements to administratively determined Net CONE values would apply only to the extent that PJM continues to rely on administrative rather than empirical adjustments. Ultimately, empirical adjustments would appear to be a promising approach to setting Net CONE at levels consistent with market expectations of the most economic technologies, their costs, and E&AS offsets.

---

[40] For currently constrained LDAs in which E&AS offsets are highly dependent on the construction of new generation or transmission facilities, it also may be advisable to rely on broader regional E&AS offsets that are more likely to reflect future market conditions within the LDA.

[41] A possible extension to the true-up would be to change reference technologies based on actual E&AS offsets. For example, if the E&AS offset for CCs is high enough to reduce its Net CONE below that of a CT, the combined cycle's Net CONE could be used to true-up Net CONE. Although this would reduce the likelihood of having the wrong reference technology, it would provide loads an option to pay based on the lowest-cost technology ex post, an option that developers do not have; hence, it would understate Net CONE.

PJM's recent filing provided evidence that the cost of new generation (i.e., gross CONE) has increased by more than 40 percent since CONE was originally determined in 2006.[42] This evidence is consistent with other studies.[43] However, the substantial amounts of cleared new capacity at comparatively low prices in the most recent auction suggests that, perhaps, *Net* CONE has not increased significantly despite the higher construction costs. It is possible that the effects of construction cost increases on supply have been substantially offset by the availability of alternative technologies including demand response, by higher anticipated future E&AS offsets, or by differences in financing and technology cost trend assumptions.[44] We thus recommend that PJM further evaluate the extent to which a significant administrative upward adjustment to *Net* CONE is necessary despite the documented substantial increase in total construction costs. Any updated estimates of developers' anticipated E&AS margins, however, would need to be consistent with updated estimates of developers' gross CONE value.

Empirical Adjustments to Net CONE. The RPM framework allows for empirical adjustments using auction clearing prices, based on the concept that market expectations for the true Net CONE are reflected in the supply offers and clearing prices obtained from the RPM auctions. If the Net CONE value used to anchor the VRR curve is too low, the clearing price can be expected, on average, to be above that Net CONE value, and *vice versa*. Hence, adjusting Net CONE based on the clearing price obtained in recent auctions should move it in the right direction, possibly without the need for an administrative determination of Net CONE based on the construction costs for a reference technology, capital and financing costs, and corresponding E&AS offsets.

It has been suggested that an alternative approach to empirical Net CONE adjustments could be based on the offers of new resources rather than the auction clearing prices, as proposed by some of the RPM stakeholders.[45] Such an offer-based Net CONE would replace the initial, administratively determined value of Net CONE. To mitigate market manipulation, the offers would be screened by PJM or its Market Monitoring Unit, and only the qualified offers would be used to determine the degree of CONE adjustment. It was argued that such an adjustment would yield a "truly" empirical CONE, since it would reflect the level at which prospective new entrants are willing to proceed with a project. We are concerned, however, that this alternative approach is not as promising as using auction clearing prices, for several reasons. First, administering such an adjustment mechanism would involve market monitoring challenges and

---

42 FERC Docket No. ER08-516-000, filed on January 30, 2008.

43 Chupka and Basheda, "Rising Utility Construction Costs: Sources and Impacts," Prepared by *The Brattle Group* for The Edison Foundation, September 2007.

44 Financing and technology cost trend assumptions having a material impact on CONE because they underlie the capital charge rate used to translate the capital cost into a developer's annual revenue target. Although we have not reviewed the reasonableness of PJM's assumptions, developers may have different assumptions than those used by PJM.

45 Initial Comments of the PPL Parties and the PSEG Companies in Opposition to the Proposed Settlement, Exhibit B-1, Affidavit of Roy J. Shanker, Docket No. ER05-1410-000 *et al.*

could potentially lead to market power abuses, since offers would directly impact the demand curve. This would potentially introduce circularity in which the VRR curve that is used to set the market clearing price is moved by the same supply offers that the auction process is supposed to select. Second, offer data for new capacity is sometimes thin, especially in small LDAs. Third, it is unclear whether the scope of "new capacity" considered should include only combustion turbines or also other generation technologies, demand response, uprates to existing capacity, or capital investments to retain existing capacity. And fourth, it is unclear whether the average, median, minimum, or some other statistic of all offers would provide the best measure of the cost of *economic* new capacity. Using clearing prices from recent auctions that required the addition of new capacity instead of the offers themselves has the advantage of incorporating only the marginal cost of capacity that was needed to clear the market. This should be the relevant measure of the cost of new entry, no matter what type of capacity is determining the market clearing price.

The current tariff allows empirical adjustments to CONE based on the clearing price from the three previous base residual auctions if certain criteria are satisfied. As discussed, the adjustment is only for half the difference between the existing CONE value and the empirically determined CONE value and the rate of adjustment is limited annually to 10 percent of CONE. This should prevent rapid adjustments of the VRR curve that would increase rather than mitigate price volatility. We have identified several concerns with the current method.

First, the empirical adjustments approach is poorly specified and the RPM tariff and other available documentation leave open a number of questions regarding implementation details. Second, the empirical CONE process determines the total CONE by "adding back" the historical E&AS offsets used to determine Net CONE to the level set by market clearing prices. However, since the purpose of the process is to derive an empirical estimate of the Net CONE value that anchors the VRR curve, we recommend that the market clearing price data be used to estimate directly an empirical Net CONE (rather than estimate an empirical gross CONE). These estimates of Net CONE would be derived directly from the RPM forward-prices for capacity and, consequently, would more likely reflect reasonable estimates of developers' anticipated future costs and E&AS revenues. Because such an empirical determination of Net CONE would be based on market data that reflects expected future market conditions, an ex post true-up would not be necessary. In fact, ex post true-ups would not even be practical since empirical adjustments are not based on a particular reference technology. Finally, the current framework should be improved to address more explicitly how the transition from administratively-determined to empirical Net CONE would be accomplished. For example, there is not an explicitly defined process for making administrative adjustments when Net CONE already contains empirical adjustments.

Overall, it is important to determine Net CONE accurately and update it over time as costs change, through a combination of administrative and empirical adjustments. This means that the clearing price from a single auction cannot be used as a definitive indicator of Net CONE. An individual auction can be influenced by idiosyncratic factors such as the departure of Duquesne load, the addition of single large generating units or transmission lines, or developers' plans that might not be responsive to market conditions in the short term. For this reason, empirical adjustments to Net CONE should be made only after several years of post-transition-period market clearing prices have become available.

It is also important that the VRR curve not be adjusted too rapidly over time or it will increase price volatility, which the sloped curve was meant to reduce. Adjusting the VRR curve only gradually over time is also supported by the VOLL concept, which would imply a static VRR curve, as discussed above. Hence, we recommend that PJM continue to limit the rate at which Net CONE can be adjusted empirically. PJM should also consider applying similar limits to changes in administratively-determined Net CONE. Over time, PJM could refine these limits if they tend to under-adjust (or over-adjust) and adjustments do not tend to attenuate over time.

3. Summary of Recommendations

Based on the concerns discussed above, we recommend that PJM and its stakeholders consider and more fully evaluate the following:

- Reevaluate reliability targets, which set the horizontal position of the demand curve, to determine: (1) whether the same target level of reliability should be maintained as the cost of capacity increases; (2) whether the 1-in-10 standard is being applied appropriately; and (3) how the RTO-wide reliability standard should be applied to LDAs (discussed further in Section V.F.).
- Refine the process for *administrative updates* of Net CONE values and evaluate: (1) whether it appropriately selects the reference technology with the lowest net cost (rather than total cost) of capacity in each region; (2) whether E&AS revenue offsets should be updated based on forward-looking market information, such as forward prices for natural gas; (3) whether a true-up of administratively determined E&AS offsets is desirable to mitigate distorted capacity prices due to E&AS estimation errors; and (4) whether restrictions to the magnitude of Net CONE changes based on administrative adjustments should be introduced similar to the restrictions that already apply to empirical adjustments.
- Clarify and refine the process for *empirical adjustments* to the VRR curve by (1) clarifying the existing provisions; (2) considering directly adjusting Net CONE (rather than gross CONE); and (3) specifying more explicitly how the transition from administratively-determined to empirical Net CONE would be accomplished.

C. PROBABILISTIC ASSESSMENT OF VRR DESIGN (HOBBS MODEL)

1. Background: The Hobbs Simulation Model

As part of PJM's analyses of the originally-filed and settlement-based VRR designs, PJM's witness, Professor Benjamin Hobbs, developed a simulation model (the "Hobbs model") for the probabilistic assessment of the costs and benefits of alternative VRR curves. The Hobbs model is a dynamic, agent-based, economic simulation model that conducts a probabilistic simulation of generation investments over time in response to incentives in the energy, ancillary services, and capacity markets.[46] Under this simulation framework, load grows according to a stochastic process and with random shocks due to weather. The model simulates, in annual steps, investment decisions in response to RPM capacity auctions occurring 3 or 4 years before delivery based upon recently observed (simulated) capacity market clearing prices, reserve margins, and revenues from the energy and ancillary service markets. Using a "utility function" approach that reflects investor risk aversion, a risk-adjusted forecast of generator profits is derived to determine the amount of supply that investors add to the market, which determines a market clearing price through interaction with the VRR curve.

In these simulations, generators' profits (technically, "gross margins") from energy and ancillary markets are modeled as the sum of a fixed E&AS payment plus a variable component ("scarcity rents") which is a function of the reserve margin. As reserve margins increase, generators' scarcity rents disappear and E&AS profits are close to the fixed energy and ancillary service payments assumed in the model. On the other hand, as reserve margins decrease, E&AS profits increase rapidly. This also means decreasing E&AS prices may reduce customers' total costs even as capacity payments increase with increasing reserve margins.

The modeling effort generally simulated 25 "samples" of 100 years each to evaluate the long-run behavior of the VRR design under a particular scenario, as opposed to capturing only short-run dynamics.[47]

2. Updated Hobbs Simulations

To work with the Hobbs model for the purpose of this report, we first replicated the Hobbs model, which was originally implemented in Excel, in a more flexible software package (Matlab). This allowed us to more easily update the model, change assumptions, and perform sensitivities on the model. The replicated model in Matlab reproduces exactly the analyses and results previously presented by Prof. Hobbs, including his assessment of (1) the originally-filed VRR curve based on a four-year forward period; and (2) the settlement-based VRR curve based on a three-year forward period.

As a next step, the model parameters were updated as shown in Table 9 below. The increase in peak demand reflects both load growth and growth in the scope of PJM's service territory.[48]

---

[46] 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 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.

[47] We found in our analyses (discussed below) that in some cases, where greater precision was needed for sensitivity runs, the sample size needed to be increased to 100 to achieve higher statistical significance.

[48] The absolute level of peak demand does not have an effect on model results because the model parameters are generally expressed in percentage terms rather than absolute quantities. The data is included here for completeness.

Table 9
Original and Updated Simulation Model Parameters

Parameter	Original Value	Updated Value
Developer CONE value ($/Installed MW-year)	61,000	72,000 *
VRR CONE value ($/Installed MW-year)	72,000	72,000 *
CT Marginal Cost ($/MWh)	79.47	73.58
EFORd (%)	7%	6.17%
Initial Peak Demand (MW)	63,957	144,644
Load Growth (%)	1.7%	1.4%

* Reflects CONE used to anchor the VRR curve in the first five auctions; PJM recently proposed that CONE be increased to approximately $105,000/MW.

Using these updated simulation parameters, we reevaluated the originally-filed VRR curve and the settlement-based VRR curve. The results for these analyses are shown in Table 10. As discussed further below, we also contrasted these sloped VRR curves with a vertical demand curve.

Table 10 reports a number of measures along which different VRR curves can be evaluated. The first two columns are measures of achieved reliability. The first column shows the percentage of years during which the *forecast* reserve margin exceeds the target reserve margin, which is 92 percent for the updated simulations of the originally-filed VRR curve. The second column shows the average percentage by which the *actual* reserve margin exceeds the target.[49] This is 1.0 percent with an average standard deviation of 4.7 percent. In other words, over the sample of twenty-five 100-year runs, the average standard deviation of the percentage by which the actual reserve margin exceeded the target was 4.7 percentage points. This number gives a sense of the variability of the actual reserve margins realized in a particular year relative to the average.[50]

The third column in the table shows generators' annual profits in $/kW/yr. It is important to understand that these profits are not accounting profits, but *economic* profits in excess of required returns on investment. That is, zero generator profit means that the investor has recovered both its variable costs (such as fuel) as well as its fixed costs, including the required return on and of investment. Positive generator profits therefore mean that further entry would be profitable and negative generator profits would signal that entry would not be profitable.

---

[49] Note that similar tables provided by Prof. Hobbs show the average percentage by which *forecast* reserve margins exceed the target. We report *actual* reserve margins to also provide a measure of year-to-year fluctuations in actual reserve margins. Also note that, as should be expected, the forecast reserve margins exceed the target for a greater fraction of years than the actual reserve margins, since the latter have more variability due to weather and other factors.

[50] This information is provided for each of the metrics shown in the various columns of the table, except the for the first column (which it is a measure over all of the 100 years rather than an average over the 100-year runs).

Columns 4 through 6 in Table 10 are measures of the cost to consumers. Column 4 reports the average scarcity revenues recouped by investors, while column 5 shows the average price paid for capacity in the auction. The final column shows the average of total annual consumer payments (for energy, including scarcity rents, and capacity) for peak load, as measured in $/kW/yr. Again, the figure in parentheses shows the average standard deviation, which, in the last column, measures the uncertainty of total consumer payments.

Table 10
Comparison of Simulation Results for Originally-filed and Settlement Curves
(Fixed E&AS Revenues)

Curve	% Yrs Forecast Reserve Exceeds Target Reserve	Average % By Which Actual Reserve Exceeds Target Reserve	Generation Profit $/kW/yr	Scarcity Revenue (Variable Portion of E/AS) $/kW/yr	Capacity Payment $/kW/yr	Consumer Payments for Scarcity + Capacity, divided by Peak Load $/Peak kW/yr
Originally filed curve, 4 year auction	92%	1.0%	17	29	49	87
Mean of standard deviations		(4.7%)	(59)	(57)	(8)	(61)
Originally filed curve, 3 year auction	91%	1.0%	15	28	49	86
Mean of standard deviations		(4.7%)	(55)	(53)	(9)	(57)
Settlement curve, 4 year auction	66%	0.5%	20	35	48	91
Mean of standard deviations		(4.8%)	(67)	(66)	(5)	(70)
Settlement curve, 3 year auction	66%	0.5%	19	34	47	90
Mean of standard deviations		(4.7%)	(65)	(64)	(6)	(68)

While these updated results differ somewhat from the original Hobbs simulations, they support the same qualitative conclusions: the settlement-based VRR curve performs reasonably well compared to the originally-filed VRR curve. First, as Table 10 shows, total consumer costs under both the originally-filed and settlement-based VRR curves are very similar—only slightly lower for the originally-filed VRR curve. Second, the settlement VRR curve results in an average reserve margin (0.5 percent above target) that is only slightly lower than the average reserve margin for the originally-filed VRR curve (1.0 percent above target). The lower reliability result for the settlement-based VRR curve is also evident in the fact that target reserve margins are exceeded 66 percent of the time, while the reserve margins under the originally-filed VRR curve exceeded target reserve margins 92 percent of the time.[51] In other words, while the variability of forecast reserve margins is the same for both VRR curves, the lower average reserve margins for the settlement-based VRR (0.5 percentage points) causes reserve margins to drop (slightly) below targets more often (approximately one third of the time). The main causes of this difference are (1) the lower cap of the settlement-based VRR curve (at only 1.5 times the administratively-determined Net CONE); and (2) the lower payments offered by the settlement curve at reserve margins below the VRR curve's anchor point (i.e., the lower slope of the

[51] Both of these numbers in our updated simulation analyses are below the 95 percent level (for the settlement curve) and 98 percent level (for the originally-filed curve) that were presented by Prof. Hobbs in his the original simulations. Note however, that the 0.5 percentage point difference in average reserve margins for the originally-filed and the settlement-based curves (1.0 percentage point above target vs. 0.5 percentage points above target) is less than the 0.6 to 0.69 percentage point difference in the original simulations (1.7 and 1.79 percentage points above target for the 3- and 4-year original curves vs. 1.1 percentage points above target for the 3-year settlement curve).

settlement curve between its anchor point and the cap, as shown in Figure 20 of Section IV.A. above).

We utilized the updated simulation framework to evaluate additional design considerations and sensitivities. These include:

- The impact of conducting auctions three years versus four years ahead of delivery;
- The impact of using historical averages of E&AS margins versus projected E&AS margins in determining net CONE;
- The implications of consistently understated or overstated estimates of CONE;
- The impact of risk aversion and alternative investment functions;
- The implications of temporary deviations between the CONE value used to define the VRR curve and the true CONE value faced by investors; and
- A comparison of the performance of sloped VRR curves compared to a vertical demand curve.

Three versus four-year forward commitments. As the results in Table 10 show, there is very little difference in the simulated performance of the RPM design between a three-year forward commitment and a four-year forward commitment under either the settlement-based or the originally-filed VRR curve. Moreover, for the other sensitivities discussed below, the choice of 3- or 4-year commitment period similarly had essentially no impact on results.

Historical Average versus Projected E&AS offsets. Under the Hobbs framework used in the original and settlement analyses, Net CONE is determined by subtracting from CONE a fixed offset that does not vary with market conditions and simulated E&AS margins over time. This is not quite consistent with the current PJM tariff, under which the offset is based on historical averages of E&AS margins. We explored updating the Hobbs model to use the average of historical simulated E&AS margins to determine Net CONE.

Under this approach, however, we found that 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.[52] 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.

To analyze the implications of Net CONE values that vary with E&AS revenues over time (while holding constant total CONE), we also simulated an E&AS offset that is consistent with *anticipated* (forward-looking rather than historic) market conditions.[53] Using this average projected (normalized) E&AS offset performed markedly better than the highly unstable simulations based on historic averages of actual E&AS margins. As shown in Table 11, determining Net CONE based on the projected normalized E&AS margins performed even better than the simulations undertaken by Prof. Hobbs using a fixed E&AS offset to determine Net CONE. More specifically, relying on projected E&AS margins (Table 11 below)—and assuming accurate projections of normalized future E&AS margins—offers improvements over the updated Hobbs simulations based on fixed E&AS revenues (Table 10 above) in terms of decreased costs, reduced price volatility (as measured by standard deviations), and higher reliability. For example, for the settlement-based VRR curve, the percentage of time during which forecast reserve margins exceed target reserve margins increased to 79 percent of the time (for predicted E&AS offsets) from 66 percent of the time (for fixed E&AS offsets).

Table 11
Simulation results for Original and Settlement VRR Curve with Net CONE Based on Projected Normalized E&AS Margins

Curve	% Yrs Forecast Reserve Exceeds Target Reserve	Average % By Which Actual Reserve Exceeds Target Reserve	Generation Profit $/kW/yr	Scarcity Revenue (Variable Portion of E/AS) $/kW/yr	Capacity Payment $/kW/yr	Consumer Payments for Scarcity + Capacity, divided by Peak Load $/Peak kW/yr
Originally filed curve, 3 year auction	98%	1.5%	12	24	50	83
Mean of standard deviations		(4.7%)	(46)	(45)	(6)	(47)
Settlement curve, 3 year auction	79%	0.8%	16	30	48	87
Mean of standard deviations		(4.7%)	(56)	(56)	(6)	(59)

Consistently Understated or Overstated Estimates of CONE. We have also analyzed the implication of consistently understated and consistently overstated estimates of CONE by simulating the performance of VRR curves for the extreme case in which the CONE value that is used to define the VRR curve is *consistently* above or below the correct CONE value by a significant amount for all simulated years and cases.

These simulations, which are summarized in Table 12, show that the settlement-based VRR curve is somewhat more sensitive to significant CONE estimation errors than the originally-filed

[52] In a more recent study, a cap of $40,000/MW on the E&AS offset avoided this type of instability. See Ming-Che Hu and Benjamin F. Hobbs, "Dynamic Analysis of Demand Curve Adjustments and Learning in Response to Generation Capacity Cost Dynamics in the PJM Capacity Market, Proceedings of the IEEE PES General Meeting, Pittsburgh, July 20–24, 2008.

[53] 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.

VRR curve. In particular, Table 12 shows that when the CONE value used to anchor the VRR curve is *consistently below* the actual CONE value, the settlement curve's performance deteriorates more quickly than under the originally-filed curve. The table shows that if the VRR curve is anchored at an assumed CONE value of $60,000 per MW-year, which approximately 17 percent *below* the true CONE of $72,000, the settlement VRR curve leads to higher increases in costs and larger declines in reliability than the originally-filed VRR curve. This is driven by the fact that, as reserve margins decline, the settlement curve's capacity prices increase more slowly and are capped at a lower level than for the originally-filed VRR curve. As a result of the lower capacity payments, less capacity is built under the settlement-based VRR curve if the true cost of new capacity is always higher than the CONE value that PJM uses to define the VRR curve.

Such consistent and significant errors in the estimation of CONE or Net CONE values may not be very likely in reality—particularly not over the long term. Nevertheless, these results highlight the importance of anchoring the VRR curve at reasonably accurate estimates of Net CONE such that market outcomes remain within the sloped portions of the VRR curve. Reliability challenges, higher costs, and higher volatility would likely materialize quickly if clearing prices for capacity reach the capped portions of the VRR curves because of understated Net CONE values. In fact, these simulations suggest that reliability, costs and uncertainty might all be improved by anchoring the VRR curve at a Net CONE value that is above the "true" Net CONE.

Table 12
Simulation Results for Consistently Under/Overstated VRR CONE
(True CONE remains at $72,000/MW-yr in all cases)

Curve	% Yrs Forecast Reserve Exceeds Target Reserve	Average % By Which Actual Reserve Exceeds Target Reserve	Generation Profit $/kW/yr	Scarcity Revenue (Variable Portion of E/AS) $/kW/yr	Capacity Payment $/kW/yr	Consumer Payments for Scarcity + Capacity, divided by Peak Load $/Peak kW/yr
Originally filed curve, 4 year auction						
VRR CONE: $60,000	49%	0.2%	23	38	47	93
Mean of standard deviations		(4.7%)	(71)	(70)	(9)	(75)
Originally filed curve, 4 year auction						
VRR CONE: $72,000	92%	1.0%	17	29	49	87
Mean of standard deviations		(4.7%)	(59)	(57)	(8)	(61)
Originally filed curve, 4 year auction						
VRR CONE: $84,000	98%	2.1%	12	22	53	83
Mean of standard deviations		(4.8%)	(46)	(44)	(8)	(48)
Settlement curve, 3 year auction						
VRR CONE: $60,000	15%	-1.0%	31	52	41	101
Mean of standard deviations		(4.7%)	(87)	(86)	(4)	(91)
Settlement curve, 3 year auction						
VRR CONE: $72,000	66%	0.5%	19	34	47	90
Mean of standard deviations		(4.7%)	(65)	(64)	(6)	(68)
Settlement curve, 3 year auction						
VRR CONE: $84,000	95%	1.5%	14	25	51	85
Mean of standard deviations		(4.7%)	(49)	(48)	(7)	(51)

Risk Aversion and Alternative Investment Function. We explored the degree to which the results are influenced by the risk aversion parameter in the assumed investors' utility function. To test the sensitivity of the results to the assumed risk aversion, we repeated the base-case simulations assuming investors were risk neutral. The results showed that the relative benefits of various VRR curves were not sensitive to risk aversion, and the earlier conclusions on the originally-filed and settlement VRR curves as well as the 3 versus 4 year commitment periods remained the same. The simulations without risk aversion result in slightly higher reliability and slightly lower costs compared to the simulation results with risk-averse investors. The reasons are, in effect, that risk-neutral investors do not require a higher return on investment to compensate for risks, and so more investment is made for a given level and variability of capacity prices and gross margins. In a simulation without risk (no weather-based variability in prices and smooth load growth), the results are the same for both risk-averse and risk-neutral behaving investors; the differences arise only when returns are variable.

We also tested an alternative investment function to determine the extent to which the simulation results depend on the specific utility function originally developed by Prof. Hobbs. Under the original function, investment in generation depends on a non-linear relationship of empirical factors including assumed investor risk aversion and historical profit levels. As a first step to implementing an alternative investment function, we simulated investment decisions based on perfect foresight of normalized future market conditions. Under that assumption, investors simply build exactly the economic level of capacity that is consistent with predicted (normalized) market conditions: just enough generation is added so that predicted capacity prices are equal to the net cost of that generation. Actual market prices and profits still vary around these predicted levels due to uncertainties such as deviations of actual peak load from predicted (normalized) peak load.

The results from this experiment did not significantly differ from those shown in Table 10—although, similar to the risk neutral simulations, costs and uncertainty were slightly lower, and reliability was slightly higher for both the originally-filed and settlement-based VRR curves. The originally-filed VRR curve continued to perform slightly better than the settlement-based VRR curve under this alternative investment function, with essentially no difference between three- and four-year forward periods.

Temporary Deviations between Estimated and Actual CONE under the Alternative Investment Function. Developers, of course, do not always accurately know what the optimal amount of capacity is for a variety of reasons including uncertainty about costs, uncertainty about future prices, imperfect forecasts of normal peak loads, the lack of coordination among developers, and uncertainties associated with actually building generating capacity. To address these real-world challenges, we added uncertainty to the alternative investment function discussed above: investors now misestimate the optimal level of capacity that should be built.[54] With this uncertain investment function framework as the basis, we also added uncertainty to the cost of new generation under which the true CONE varies over time based on positive and negative "shocks" to construction costs.[55]

---

[54] A normal distribution with a standard deviation of 1 percent was applied to the "optimal" level of capacity.

[55] CONE observed by developers varies with an annual draw from a normally distributed random variable with a standard deviation of 15 percent. Only changes between 1.5 and 2 standard deviations are used in order to have an effect on the CONE.

Given uncertain true CONE values, we explored and tested three methods for updating the Net CONE value used to anchor the VRR curves. The first method simply derives an estimate of CONE using the average of the capacity clearing price for the last three years. The second method also uses three year averages, but "mitigates" the magnitude of changes to estimated CONE by adjusting the anchor point of the VRR curves only halfway from the current anchor level to the new three year average of clearing prices. Third, we modeled a mechanism similar to the tariff-based empirical adjustments to CONE as discussed in Section IV.B. Under this mechanism, year-to-year changes are mitigated further with additional constraints that limit when the VRR anchor point can be updated, as also described in Section IV.B.

The result for one 100-year sample of the simulations is shown in Figure 21 below, using the settlement-based VRR curve and the tariff-based mechanism to adjust the CONE. The figure charts the true Net CONE faced by developers (blue line), the Net CONE value at which the VRR curve is anchored by PJM (red line), the resulting clearing price for capacity (green line), and the resulting difference between forecast (normalized) and target reserve margins (purple line). As illustrated, there are some periods in which the reserve margins tend to be below (or above) target margins when the VRR curve is anchored at values below (or above) the true Net CONE value. This, again, illustrates the importance of being able to anchor the VRR curve at a value that remains reasonably close to the true value of Net CONE.

Figure 21
Sample Path for Simulation of Uncertain CONE and Investor Expectations
(Tariff-based adjustment mechanism, settlement VRR curve)

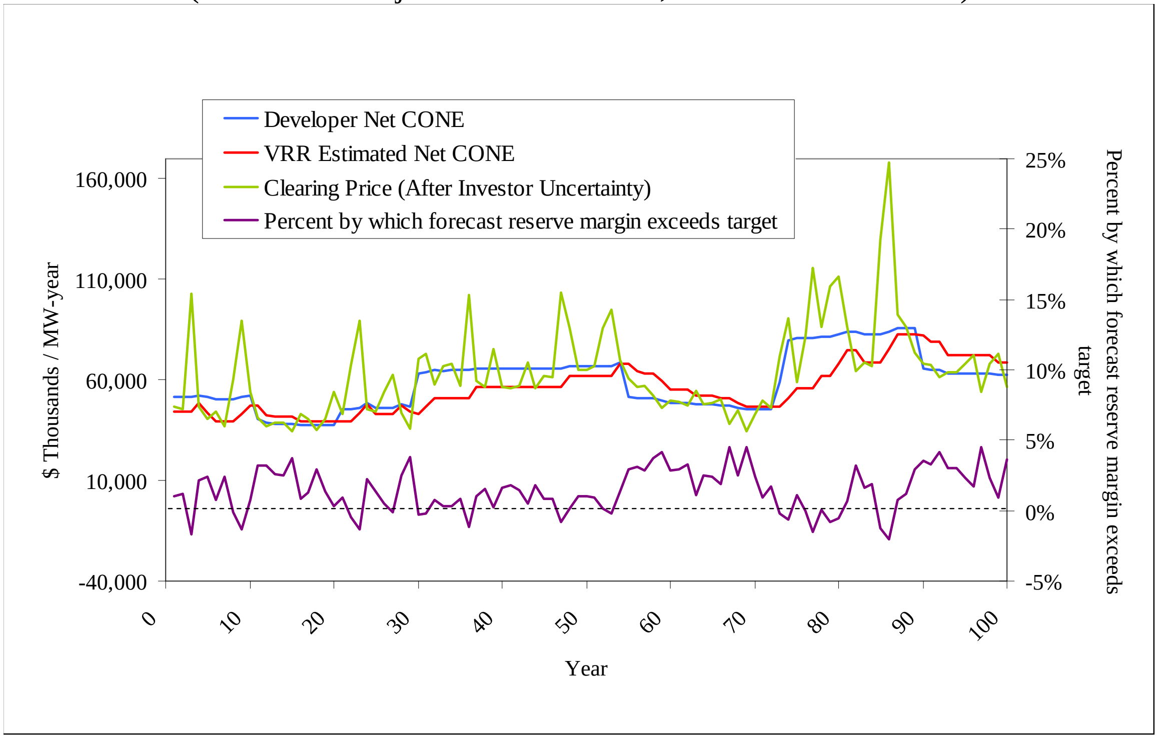


Table 13 reports the aggregate results for reliability and costs for the tariff-based CONE adjustment simulation (The two other methods to adjust CONE produced almost identical results.) These results show again that the settlement-based VRR curve performs reasonably well, though not quite as well as the originally-filed curve.

Table 13
Simulation of Uncertain CONE and Investor Expectations

Adjustment Mechanism and Curve	% Yrs Forecast Reserve Exceeds Target Reserve	Average % By Which Actual Reserve Exceeds Target Reserve	Generation Profit $/kW/yr	Scarcity Revenue (Variable Portion of E/AS) $/kW/yr	Capacity Payment $/kW/yr	Consumer Payments for Scarcity + Capacity, divided by Peak Load $/Peak kW/yr
Tariff-based adjustments						
Originally filed curve	87%	2.0%	10	19	47	78
Mean of standard deviations		(4.9%)	(38)	(27)	(21)	(60)
Settlement curve	80%	1.4%	9	22	47	84
Mean of standard deviations		(5.0%)	(39)	(32)	(18)	(67)

Comparison of Sloped VRR Curves to a Vertical Demand Curve. We also simulated costs and reliability outcomes under a vertical demand curve with updated model parameters based on the approach Prof. Hobbs used in the analyses he prepared in support of the original filing and the subsequent settlement. Our updated simulations reinforce Prof. Hobbs' original results that the sloped VRR curves outperform a vertical demand curve, both in terms of lowering overall costs to consumers and cost uncertainty, as well as in terms of maintaining reliability in the long run.

We also found that the original modeling approach produces simulated market clearing prices that are either at the capped value or at zero (but not at price levels in between). This will overstate the level of costs and uncertainty associated with a vertical demand curve. However, we found that a vertical demand curve continues to result in higher costs and cost uncertainty compared to sloped VRR curves even under more conservative alternative modeling approaches.[56] In addition, the Hobbs modeling framework does not capture important benefits of a sloped VRR curve. In addition to the benefits quantifiable through the probabilistic simulations, sloped VRR curves (1) help mitigate the potential exercise of market power by reducing the incentive for supplies to withhold capacity when aggregate supply is near the target reserve margin; and (2) recognize that incremental capacity above the target reserve margin provides additional reliability benefit, although at a declining rate. Neither the reduced incentive to exercise market power nor the value of reliability are reflected in these simulations.

3. Conclusions Based on Probabilistic Simulations

The overall conclusions from this probabilistic assessment of VRR design parameters are that the settlement-based VRR curve performs reasonably well, though not quite as well as the originally-filed VRR curve. The three-year and four-year commitment periods perform similarly

[56] We analyzed replacing the supply quantity determined in the Hobbs model (which essentially employs a vertical supply curve that intersects with the VRR curve) with a sloped supply curve, which significantly reduced but did not entirely eliminate the disadvantage of a vertical demand curve. This combination of a sloped supply curve with a vertical demand curve resulted in lower average reserve margins at slightly higher costs and higher cost uncertainty than the combination of a sloped supply curve with the sloped VRR curves.

under a wide variety of assumptions. Sensitivities including those on developer uncertainty, uncertainty in CONE values, and the precise shape of the assumed investment function do not fundamentally change these conclusions—although we found that the settlement-based VRR curve can perform poorly if the Net CONE value used to anchor the VRR curve is below the true Net CONE value. Our updated simulations using the framework developed by Prof. Hobbs continue to confirm that the sloped VRR curves outperform a vertical demand curve, both in terms of costs and cost uncertainty, as well as in terms of reliability.

D. RPM Forward Timeframe and Commitment Period

Some market participants have expressed concerns that a three-year forward timeframe and one-year delivery period might be too short. As discussed below, we do not share these concerns. The three-year forward timeframe appears long enough to allow a significant amount of resources to react to price signals to enter or delay before major irreversible financial commitments need to be made. Longer-term forward commitments would likely be less effective by increasing supplier risks and, ultimately, customer costs. The sloped design of the VRR curve should offer sufficient price stability and predictability to form the basis for long-term investment decisions, at least on an RTO-wide basis. However, that price stability is not created within LDAs.

1. Background

RPM establishes an organized market for buying and selling one-year capacity commitments on a three-year forward basis. PJM's original RPM proposal contained a four-year forward period, which was reduced to three years during the RPM settlement process. Incremental auctions conducted subsequently to the three-year forward base auctions have shorter forward periods, but very little capacity is currently transacted in the incremental auctions. The commitment period is only one delivery year, which means resources do not receive a guaranteed price beyond the single delivery year for which they are committed.

The New Entry Price Adjustment ("NEPA") provision of the RPM Tariff provides for a three-year price "lock-in," although no unit has yet qualified or opted for this option.[57] Developers may opt for NEPA only if the resource would reduce prices from a price level greater than 112.5 percent of Net CONE to a price less than 40 percent of Net CONE. If the resource owner then opts for NEPA, it must offer its capacity in the two subsequent base auctions at a price that is less than its offer price in the first year or 90 percent of the then-current Net CONE. Apart from NEPA, RPM does not offer a price "lock-in" for new resources, unlike ISO-NE's forward capacity market (FCM), in which all new resources may chose to lock-in a capacity price for up to five years.

It must be noted, however, that RPM's three-year forward timeframe and single-year commitment period does not preclude bilateral contracts for longer terms. However, load serving entities typically do not sign such longer-term contracts in restructured states in which

[57] See Attachment DD, Section 5.14c.

customers are not captive. As a result, the forward and commitment periods established by RPM are quite important.

2. RPM Forward Period

The length of the forward period affects the types of new capacity that can be offered into an auction as “potential” projects that could be brought online within three years if they clear the auction. For example, many combustion turbines, demand response resources, and rating increases, have sufficiently short lead times. Projects with longer development lead times that exceed the three-year forward period can still participate in RPM auctions, but they must have begun their development process before offering their capacity.

Some market participants have expressed concern that a three-year forward timeframe is too short and could inhibit the development of baseload resources with longer lead-times. We do not share that view. While baseload plants cannot generally be developed within three years, we nevertheless find that a three-year forward commitment is likely sufficient and more effective than longer-term forward commitments for a number of reasons.

First, it is not necessary to have a forward period that is long enough to accommodate all types of generation. Rather, the forward period needs to be long enough to allow a sufficient portion of capacity resources to be able to adjust their entry and exit decisions within the forward commitment window. This will stabilize capacity prices and reserve margins even if not all new resources can be built in three years.

The significant growth of demand-side resources (DR and ILR), uprates, retirement deferrals, and new generation that have been committed since RPM auctions started in April 2007 suggests that a significant amount of capacity resources can respond to market signals within the three-year forward timeframe.

In addition, many projects that require more than three years for the entire development process may require less than three years from the time of the first major irreversible financial commitment (e.g., at the beginning of construction) until commercial operation. This allows some projects at an earlier stage of development to offer into base residual auctions and delay or cancel construction if they do not clear in the auction. Considering that approximately 30,000 MW of RPM-eligible but still uncommitted generation projects have already completed their feasibility or system impact studies under PJM’s generation interconnection process (see discussion in Section III.C.), a very large resource pool is potentially available to offer into the next RPM auctions.

Of course, some projects—in particular baseload generation such as coal or nuclear power plants—will have had to make significant irreversible financial commitments before they are able to offer their capacity into a base residual auction. However, these baseload resources are not built for a single delivery year three years from the date of the auction. Rather, the development of these resources is (at least in part) based on the expectation that RPM will continue to exist and capacity payments will continue to be available if and when the resources become operational. Extending the forward timeframe, for example from three to four or five years, would not likely make much difference.

In fact, extending the forward period beyond three years would likely create additional risks and costs. It would increase risks to developers due to their exposure to changing market conditions. For example, the ultimate cost of a generation project four or five years before it becomes operational will be more uncertain than three years out. Similarly, demand-response suppliers would likely find it more difficult to commit to deliver capacity for longer forward periods because of increasing uncertainties about the types of services and contracts their customers might be willing to sign at that point. Extending the forward period would also increase the uncertainty of the load forecast used to determine capacity needs, which could lead to over-procurement.

Our probabilistic simulations based on the updated Hobbs model (see Section IV.B.) similarly found that extending for forward period would not offer additional benefits. These simulations indicate that a four-year forward timeframe would produce almost identical outcomes as the three-year forward timeframe: the same level of reliability at very similar (in fact, slightly higher) customer cost and cost uncertainty.

3. RPM Commitment Period

Some market participants have also expressed the concern that RPM's one-year commitment period provides insufficient price certainty to attract new generation resources. Baseload projects require many years of revenues to recover their large upfront capital costs. This raises the question of whether longer-term commitment periods would be needed, especially to attract large new baseload projects.

This concern appears to be overstated. At the RTO-wide level, RPM provides support for long-term investments through capacity prices that are comparably stable and predictable even without multi-year guarantees. RPM stabilizes prices around Net CONE through its three-year forward timeframe, its sloping VRR curve, and market power mitigation. The three-year forward timeframe prevents substantial supply-demand imbalances, which stabilizes prices. Moreover, the RPM design of consecutive annual auctions provides for a degree of self-correction. Whenever the clearing price rises, future auctions will attract additional capacity, resulting in lower future prices, and *vice versa*. Market monitoring will additionally mitigate pricing uncertainty that could be caused by the exercise of market power. Most importantly, however, capacity price uncertainty in RPM is mitigated by its downward-sloping VRR curve, which will cause prices to change only gradually as capacity supplies vary over time. We believe this is an important design feature that adds price stability relative to other market designs, such as the forward capacity market in New England, where new resources have the option to lock-in market clearing prices for up to five years. The downward sloping VRR curve avoids price volatility that can be associated with a vertical demand curve under which prices can collapse quickly with even a slight surplus of capacity. At least at the RTO-wide level, these factors allow PJM market participants to forecast the likely range of capacity prices with reasonable certainty for several years beyond the delivery year from the most recent auction. This relative stability and predictability of capacity prices should be sufficient to attract new generation resources, including baseload plants.

While RPM clearing prices have varied over time, these variations have been modest—in particular compared to the highly variable capacity prices under the previous CCM market design. Even with the significant one-time adjustment caused by the departure of the Duquesne from PJM, which removed approximately 3,000 MW of load without a corresponding decrease in generation for the 2011/12 delivery year, prices fell by only approximately 25 percent below the level they would have been otherwise.[58] Moreover, even this level of uncertainty can be "hedged" through long-term bilateral contracts. While RPM itself does not offer such multi-year price certainty, it will form the basis and significantly facilitate such longer-term arrangements on a bilateral basis.

At this point, we have found no indication that the lack of multi-year price guarantees has deterred new entry. To the contrary, the recent auction has seen the entry of new baseload capacity—a new 700 MW merchant coal plant cleared in the base auction for the 2011/12 delivery year.[59]

We are concerned, however, that the relative stability of prices that RPM creates at the RTO-wide level does not exist within LDAs. As we discuss further in Section V.F. of our report, for example, prices within LDAs are very sensitive to changes in transmission import capabilities. The addition of (or failure to add) new transmission can substantially shift supply-demand balances and unpredictably increase or collapse the difference between LDA-internal and RTO-wide prices. In smaller LDAs, even the addition of one large power plant can substantially reduce the LDA's price premium. In fact, the original price premiums in SWMAAC and EMAAC have disappeared in the most recent auctions, partly because planned transmission upgrades were assumed to be online by the 2009/10 and 2010/11 delivery years, respectively.

To address these pricing uncertainties within import-constrained LDAs, we recommend that PJM consider and further evaluate making a multi-year lock-in mechanism (or an auction product reflecting a multi-year commitment period) broadly available to new resources within LDAs. As we address more fully in Section V.F. of this report, PJM could modify NEPA to make it more broadly available to all new capacity in constrained LDAs.

4. Conclusions on Forward Commitment

We recommend that PJM consider and further evaluate making a multi-year lock-in mechanism (or an auction product reflecting a multi-year commitment period) broadly available to new resources within LDAs. On an RTO-wide basis, however, the single-year delivery period should offer sufficient price stability and predictability by virtue of the sloping VRR curve and other RPM design parameters. The RPM design based on a three-year forward timeframe is likely sufficient and more effective than longer-term forward commitments in attracting capacity to meet reliability requirements cost-effectively.

---

58 As shown in Figure 3, without Duquesne's departure the market clearing price would have been approximately $150/MW-day compared to the actual clearing price of $110/MW-day.

59 GenPower, LLC began construction of the Longview supercritical cycle pulverized coal-fired mine-mouth generating facility, located in Maidsville, West Virginia, in January 2007. Longview will sell power and capacity through a five-year, 300 MW bilateral power purchase agreement. The balance of the Project's generation will be sold on a merchant basis into PJM. (See http://www.genpower.net/index.php?act=1070).

V. ANALYSIS OF OTHER RPM AND PJM MARKET DESIGN FEATURES

RPM has an impressive record of attracting new resources and retaining existing resources. Resulting resource commitments not only satisfy reliability requirements on a PJM-wide basis, but also serve to significantly improve reliability within LDAs. Nevertheless, our review identified a number of concerns regarding the design of RPM. We have developed recommendations for consideration by PJM and its stakeholders that we believe would help to increase the effectiveness and efficiency of RPM.

Our concerns and recommendations are with specific design elements in the areas of:

- Excluded capacity
- Generation interconnection queue
- Penalties
- Demand response (DR and ILR)
- Incremental auctions
- Locational deliverability areas (LDAs)
- Capital expenditure and project investment provisions; and
- Non-dispatchable demand-side resources and load forecasting.

A. EXCLUDED CAPACITY

Under RPM, all existing capacity resources must offer their available capacity into the RPM capacity auctions unless the capacity resources involve: (1) capacity delisted because of export commitments; (2) capacity committed to satisfy the reliability requirements of load serving entities (LSEs) that have elected the Fixed Resource Requirement (FRR) alternative to the market clearing mechanism under RPM; and (3) capacity that is formally "excused" from participation in RPM auctions. The first category is excused because capacity that is exported is committed to non-PJM entities. The second category is excused because capacity committed to FRR entities can not also commit in the RPM auctions. And the third category, excused capacity includes capacity that is excluded by an RPM sales cap and certain capacity that cannot currently participate in RPM due to ownership, contractual, environmental, and retirement issues affecting the availability of the resource during part or all of a delivery year.

The current RPM rules regarding FRR and other excused capacity inefficiently exclude some of the available capacity and recommend that PJM consider making these resources available to RPM auctions by removing certain restrictions on FRR entities and addressing partial-year ownership of generating assets.

1. Background

Capacity "excused" from RPM auctions mostly involves three categories of exclusions: (a) capacity excluded by an RPM sales cap that is imposed on FRR entities; (b) capacity excluded because of environmental restrictions; and (c) capacity excluded because of partial-year ownership and availability.

FRR Exclusions. The RPM design allows LSEs to avoid direct participation in RPM auctions by electing the FRR alternative. LSEs under the FRR alternative must self-supply capacity to meet their reliability requirements through a fixed capacity obligation. This fixed obligation is akin to the capacity obligations under the prior capacity market design, although it now has a locational element. Some LSEs may find the FRR alternative more appealing because its fixed capacity obligation results in more planning and cost certainty compared to the variable obligation that is determined in the RPM auctions by means of the VRR curve. The FRR option does, however, impose significant additional limits on LSEs. For example, any election of the FRR option must be made for a five-year term, and the LSE must serve the entire load in the area where the FRR alternative applies. Since capacity committed under an FRR capacity plan is already dedicated to meeting reliability requirements, these resources are not required to be offered into RPM auctions. In addition, FRR entities with capacity in excess of their reliability requirement also must set aside a "buffer" for uncertainties in load growth and generation availability[60] and face a "sales cap" on how much of that excess capacity can be offered in RPM auctions. As we discuss below, however, these constraints on FRR entities' ability to make capacity in excess of their reliability requirements available in RPM auctions raises concerns about inefficient exclusion of resources. Table 14 shows that the capacity "excused" due to FRR sales caps amount to over 1,100 MW of installed capacity in 2011/12. The FRR buffer excludes an additional 240 MW.[61] In comparison to these FRR exclusions, the magnitude of all other RPM excused capacity has been small, in particular during the last base auction. (The total of "other RPM excused" capacity is shown Table 14 and a detailed breakdown is provided in Table 15).

---

[60] Capacity included in the FRR Threshold Quantity, as defined in section 1.82 of the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region.

[61] Note that the capacity associated with the FRR "buffer" is counted as capacity committed by FRR entities, not as "RPM excused" capacity.

Table 14
Potentially Inefficiently Excluded Capacity
(ICAP MW)

Category	Description	Delivery Year 2007/08	2008/09	2009/10	2010/11	2011/12
FRR Sales Cap Excused	FRR entities' excess capacity excluded by sales cap	43	357	553	745	1,180
FRR Buffer	Threshold above UCAP obligation +1%	241	238	235	228	236
Other RPM Excused*	Capacity that cannot be available to PJM for entire delivery year	415	365	569	247	103
Total		700	960	1,357	1,220	1,519
Total as % of PJM Internal Capacity		0.4%	0.6%	0.8%	0.7%	0.9%

* PJM's excused category also includes certain retirements that were not delisted in time for the base auction.

Environmental Exclusions. More than 300 MW was excluded in the first three auctions because of environmental restrictions. In one case, a plant's state operating permits set limits on pollutant emissions in a manner that restricted the owner's operational flexibility, and prevented it from offering its entire installed capacity into RPM. The owner has been negotiating with its state regulator to obtain an operating permit that would allow it to offer its entire capacity into RPM. The owner has since offered all of its capacity into the 2010/11 auction, which greatly reduced the PJM-wide capacity excused for environmental reasons. As shown in Table 15, exclusions for environmental reasons have decreased to less than 40 MW in the 2010/11 and 2011/12 auctions. Absent unexpected regulatory changes, environmental restrictions are no longer expected to exclude a significant amount of capacity from future RPM auctions.

Table 15
Other RPM Excused Capacity
(ICAP MW)

Category	Delivery Year 2007/2008	2008/2009	2009/2010	2010/2011	2011/2012
Behind-the-Meter (BTM)	14	18	4	0	0
Ownership Issues - Non-Utility Generators (NUGs)	25	30	87	194	64
Ownership Issues - Other Contract Matters	8	1	137	1	1
Environmental Issues	316	316	334	37	37
Other	52	0	8	15	1
Total	**415**	**365**	**569**	**247**	**103**

Source: PJM.

Partial-year Ownership and Availability Exclusions. RPM defines capacity as an annual product, and therefore any resource that is not available or cannot be offered for the entire delivery year is not eligible to participate. Often, contracts terminate in the middle of a delivery year and, at the time of RPM auctions, it cannot be known with a reasonable degree of certainty whether these contracts will be renewed. In the case of some non-utility generators, the actual owner is not known by PJM, and therefore there is no party to accept a capacity commitment for the remainder of the delivery year. As shown in Table 15 (rows 2 and 3), total capacity excused because of partial-year ownership or contract issues has increased over the first several auctions to more than 200 MW, followed by a decline in the last two auctions. These exclusions reflect the inability or unwillingness of suppliers to offer capacity into RPM from resources for which they lack a full-year contract that entitles them to the capacity rights from that resource.

Similarly, but not shown in Tables 14 and 15, capacity that is expected to retire during the delivery year is also excluded from RPM participation. Such capacity cannot be offered into RPM since it is unable to commit for the entire delivery year. Total capacity excluded because of pending retirements has been almost 300 MW in recent delivery years.

Total capacity excluded for other reasons, such as behind-the-meter ("BTM") generation or delayed capacity resources, is not significant and does not raise serious concerns.

2. Identified Concerns

We have identified two primary concerns related to excused capacity: (1) FRR rules limiting participation in RPM auctions; (2) incompatibility of RPM with partial-year ownership and availability.

FRR Rules. FRR entities are subjected to a "sales cap" on the total capacity that they may offer into RPM markets. Currently this sales cap is equal to the lesser of 25 percent of each FRR entity's UCAP obligation or 1,300 MW. Any capacity owned by an FRR entity in excess of the sum of its reliability requirements and sales cap amount, is excluded from RPM participation. The sales cap raises concerns because it inefficiently excludes resources from the capacity market. This will increase the capacity clearing price in RPM auctions in the short-term and, if the excluded capacity is exported, also lead to lower RTO-wide reliability. Even if this capacity is not exported, reliability may be affected. Unlike RPM- or FRR-committed capacity, FRR excused capacity is not subject to the must-offer requirement into the PJM day-ahead energy market, and therefore may not be available for meeting PJM's reliability objectives.

To date, three LSEs elected the FRR alternative, representing about 14 percent of PJM's peak load. Excluded FRR capacity due to the sales cap has been steadily increasing, exceeding 1,000 MW in the last auction. As these FRR entities build new generation or upgrades to existing units, this capacity is excluded from RPM auctions due to the imposed sales cap if their load obligation does not increase as quickly. We strongly recommend that PJM consider eliminating the sales cap to enable these resources to participate in RPM. We also recommend that the must-offer obligation, which applies to all other PJM resources, also be applied to any FRR capacity that is not needed to satisfy FRR entities' own reliability requirements and has not been committed elsewhere (e.g., through a bilateral transaction).

In addition to the sales cap, FRR entities' participation in RPM auctions is also limited by a requirement that FRR entities with capacity in excess of their reliability requirements also hold a minimum amount of capacity above their UCAP obligation before offering that excess capacity in RPM auctions. The threshold for this "buffer" is the lesser of three percent of the LSE's UCAP obligation or 450 MW. The primary rationale for this threshold is the uncertainty in load forecasts made more than three years prior to the delivery year, which are the basis for setting the FRR entities' UCAP obligations. Holding additional capacity decreases the likelihood of falling below the target reliability level if load grows more than expected. PJM determined that a two percent buffer would be appropriate, based on its analysis of historical errors in forecasting weather-normalized loads.[62] In addition, another one percent buffer is added to account for forward uncertainty related to capacity resource availability, for a total of three percent (or 450 MW, whichever is less). This three percent FRR buffer is greater than the RPM implicit buffer created by centering the VRR curve at one percent above the target reserve margin. RPM entities do not need as large a buffer because they and their suppliers have opportunities to cover any deficiencies in the incremental auctions held closer to the delivery year.

Managing uncertainty through RPM's incremental auctions is more efficient than the FRR "buffer" requirement. It is more efficient to commit the expected amount of capacity in advance and use markets to address incremental and decremental needs, rather than requiring individual loads or suppliers to hold large buffers to hedge against their own individual uncertainties. Hence, we recommend that PJM consider reducing the threshold amount of capacity that FRR entities must hold before offering excess capacity into the RPM auctions, and requiring them to cover any deficiencies bilaterally or in the incremental auctions. This approach would also provide enhanced reliability to the FRR entities that are holding a buffer of less than three percent. A buffer of less than three percent is already allowed for entities that own less than three percent excess capacity or are large enough that the threshold is set at 450 MW instead of three percent. Setting the threshold at one percent for all FRR entities (and including a requirement to procure additional resources, if needed, bilaterally or in incremental auctions) would add approximately 240 MW of expected supply to RPM auctions, as shown in Table 14.

Concerns might be raised that removing the FRR sales cap and threshold could increase participation in the FRR alternative and adversely impact liquidity and competitiveness of the RPM auctions. We do not expect this for a number of reasons: (1) current FRR rules restrict the FRR option to entities that serve all load in an FRR area; there are only a small number of such LSEs in the PJM footprint; (2) rules limiting switching between RPM and FRR make FRR less attractive (e.g., FRR election is for minimum of five years); (3) being an FRR entity may not be advantageous for an LSE that is net short on capacity, because it may not find RPM's price transparency in bilateral markets.

Partial-Year Ownership and Availability. Our second concern is that an increasing amount of capacity is excused from the RPM auctions because of partial-year ownership and availability rules. These resources may include units with annual run-time restrictions, agency contracts expiring, or units expected to retire during the delivery year. Although they are not formally disallowed from participating in RPM, the penalty structure strongly discourages it. Under the current penalty structure, resource owners would face negative net payments for the delivery year even if they were available during a portion of the year, such as the summer months. There is also some indication that when the contractual relationship between the owner of a non-utility generator and its marketing agent ends during the delivery year, the agent may be reluctant to offer the capacity into RPM because it risks facing deficiency charges if the contractual

[62] Supplemental Affidavit of Andrew L. Ott On Behalf Of PJM Interconnection, L.L.C. Conference On Technical Issues, Docket Nos. EL05-148 and ER05-1410, May 30, 2006.

relationship is not extended through the end of the delivery year. This risk is substantial, since the RPM forward commitment is made three years in advance of the delivery year and the penalties applied are quite high.

Our concern is that resources that are available during the summer peak season, when capacity is most needed, are valuable and should not be excluded or discouraged from RPM participation. We recommend that PJM explore mechanisms that help avoid excluding capacity from RPM participation due to partial-year ownership and availability. One option may be to allow participation of all capacity that is available during the summer peak load season. These resources could receive a reduced capacity payment, but one that is proportional to the value of their contribution to meeting reliability during the delivery year—which could be based on the proportion of loss of load expectation ("LOLE") for the summer peak months to total annual LOLE. This would likely add several hundred megawatts of supply to the RPM auctions.

3. Summary of Recommendations

Based on the concerns discussed above, we offer the following recommendations for further consideration by PJM and its stakeholders. Our recommendations would likely reduce the magnitude of excluded capacity, lower RPM clearing prices and increase system reliability in the short-term.

- The FRR sales cap should be removed, as it results in the uneconomic and inefficient exclusion of capacity. This alone would likely increase capacity available to RPM by close to 1,200 MW, which could serve to meaningfully reduce RPM market clearing prices while increasing system reliability.
- PJM should consider reducing the three percent threshold amount in excess of the FRR entities' capacity obligation to a level consistent with the procurement targets under the VRR curve, which is approximately one percent above target reserve margins. If additional capacity is required by FRR entities to satisfy the reliability requirements such as higher-than-anticipated load growth, FRR entities should be obligated to obtain the additional capacity before the delivery year. To do so, FRR entities should be allowed to participate and procure replacement capacity in the incremental RPM auctions or face penalties applicable to RPM participants.[63]
- PJM should explore mechanisms that help avoid excluding capacity from RPM participation due to partial-year ownership and availability. One option may be to allow participation of capacity available during the summer peak season as discussed above.

[63] We understand that under the current rules, PJM cannot impose an obligation on FRR entities to procure additional capacity in incremental auctions. We believe this issue would be resolved if RPM penalties were applied to FRR entities with capacity deficiencies.

B. GENERATION INTERCONNECTION QUEUE

In PJM, as in most other RTOs and individual transmission systems, all new generating capacity and every increase in existing generating capacity exceeding one megawatt must participate in the generation interconnection process. The interconnection process establishes the transmission upgrades that a generation developer or the relevant transmission owner must construct so that the generation resource can be placed in service and its output be delivered to the grid without impairing system reliability. Thus, the interconnection process can create barriers to participation in RPM to the extent that it creates hurdles to offering capacity or exposes committed capacity to the risk of penalties or unexpected costs. This section describes the elements of the interconnection process that are relevant to RPM, identifies specific concerns about delays and cost uncertainties caused by the process, and recommends potential improvements.

1. Background

The interconnection process has multiple stages, starting with a developer submitting an interconnection request. PJM places interconnection requests into queues that are ordered according to submission dates. PJM then evaluates each project in that order. This evaluation consists of three analytical steps:

(1) a Generator Interconnection Feasibility Study ("Feasibility Study");

(2) a System Impact Study; and

(3) a Generation Interconnection Facilities Study ("Facilities Study").

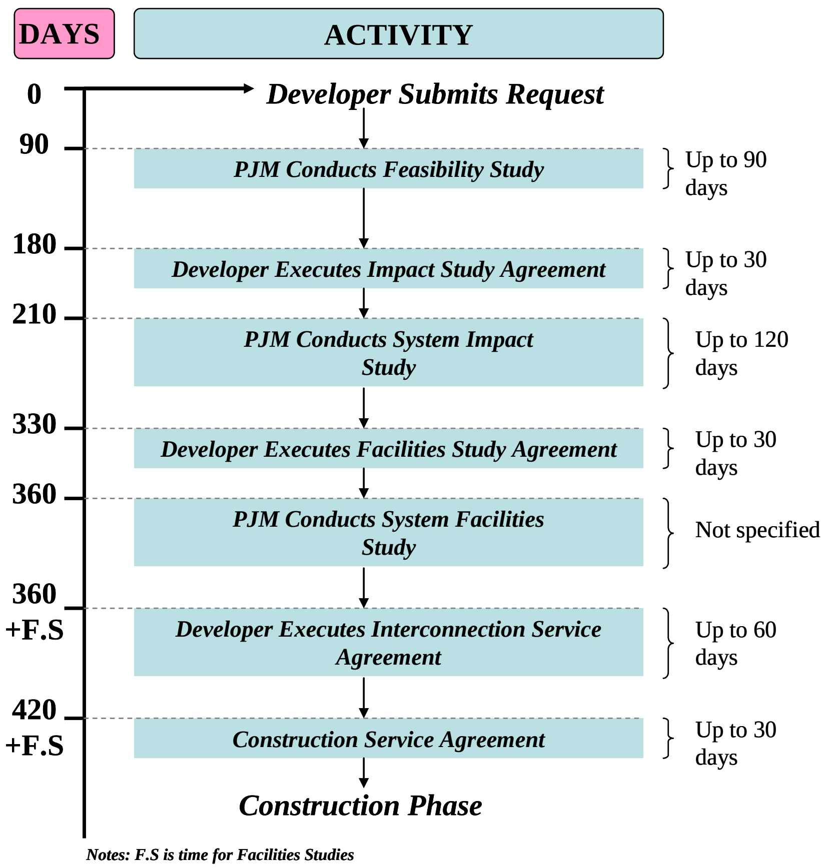
The process ends with a signed interconnection agreement between the developer and PJM, and the subsequent construction of required transmission upgrades.

The Feasibility Study is a preliminary, 30-day study that identifies what transmission upgrades, if any, may be required to reliably integrate the new generator's output into the PJM system. Each project is studied based on its position in the queue, with all projects at a higher position (i.e., earlier submission date) being assumed to be in service. The first project to overload a transmission facility, and all subsequent projects that add to the overload, are considered to trigger system upgrades. The Feasibility Study also estimates the scope, cost, and lead time for the construction of those upgrades, but it does not allocate cost responsibility among the projects that triggered upgrades (if any).

If the generator decides to continue the interconnection process, it can sign a System Impact Study Agreement to proceed to the next study phase, the System Impact Study. The System Impact Study is a comprehensive regional analysis and provides a more detailed assessment of interconnection requirements as well as cost allocation. Cost allocation is based on the relative flow impact a given project has on a system element requiring enhancement. If a project withdraws from the queue, the System Impact Study for each subsequent project in the queue is redone to reassess the need for the upgrade and to reallocate costs.

Upon completion of the System Impact Study, the applicant must decide whether or not to pursue the third and final study, the Facilities Study. The Facilities Study provides complete details of the requirements for interconnecting a new generation project to the PJM system. The study includes cost estimates by the transmission owners of attachment facilities and required network upgrades, and indicates any changes from the System Impact Study. If these terms are acceptable to the developer, the Interconnection Service Agreement is signed, after which construction of the interconnection facility can be started. Figure 22 below illustrates the process flow and the timeline of the PJM generator interconnection process, as specified in the PJM Tariff.

Figure 22
Process Flow and Timeline of the PJM Generator Interconnection Process[64]



Although the generation interconnection process is separate from RPM, there are important interactions between them:

- In order for planned generation to be eligible to offer into an RPM auction, the resource must have requested interconnection and reached certain milestones in the

64 Reflects the PJM generator interconnection process as of a June 2008. Several changes to the process have been proposed, and they are currently being evaluated by FERC.

process. The minimum requirement for participation in a base residual auction is an executed System Impact Study Agreement (which can be signed after the Feasibility Study is completed), and the minimum requirement for participation in incremental auctions is an executed Interconnection Service Agreement.[65]

- Interconnection studies provide planning cost estimates for required transmission upgrades that allow developers of planned resources to better formulate their offers in RPM auctions. Uncertainty in these cost estimates creates risk for the developers.
- A planned generation resource must complete its interconnection and begin commercial operation by the start of the delivery year for which it is committed.
- The interconnection process can also affect the capacity value of planned resources if only part of the requested capacity is deliverable without prohibitively expensive upgrades.

2. Identified Concerns

The interconnection process raises two concerns. First, delays during the interconnection process can prevent the resources from offering into a base auction, which will tend to increase market clearing prices. Similarly, if the resource is offered into an auction, the potentially long delays expose the supplier to potentially high replacement capacity costs or large penalties if interconnection delays prevent the resource from coming online in time to fulfill its RPM commitments. Second, the cost uncertainty related to required transmission upgrades can cause developers to have to pay more for transmission interconnections than was anticipated at the time they offered their capacity into the three-year forward auction. Given the challenges that currently exist with respect to the interconnection process, the combination of these factors will make participation in RPM more difficult and more risky for suppliers, which reduces the effectiveness of the RPM design.

Delays in the Interconnection Process. PJM has accumulated significant backlogs in its interconnection process. Following the surge of interconnection requests that have been made over the past three to four years in response to RPM and renewable resource requirements, PJM and most other transmission providers have fallen behind schedule on a majority of projects. This backlog has grown significantly over the last few years.

A project can be considered behind schedule if the time to complete the steps in the interconnection process exceeds guidelines specified in the PJM Tariff. Although the PJM Tariff does not specify firm deadlines, PJM must apply reasonable efforts to complete each interconnection study within the specified timeframe. Under normal circumstances developers of new capacity would likely expect that these milestone dates could be met. Table 16

---

[65] The minimum requirement to participate in RPM auctions during the RPM Transition Period was an executed Interconnection Service Agreement for the 2007/08 and 2008/09 base auctions and an executed Impact Study Agreement for 2009/10 and 2010/11 base auctions. In the RPM steady state, the minimum requirement to participate in a base auction changed from an executed Facilities Study Agreement in the original tariff to an executed System Impact Study Agreement, starting with the delivery year 2011/12.

summarizes the number and volume of interconnection requests that are behind schedule and the average number of days that projects fall behind the anticipated schedule at each analytical step. As shown in the table, over 41,000 MW of new capacity is backlogged at one of the three analytical study stages, and the average delay at each stage is six months or longer.

Table 16
Backlogged Projects in PJM Generator Interconnection Queues

	Number of Projects	Capacity in MW	Avg. Number of Days Late Beyond Required Completion Date
Backlogged Feasibility Studies*	35	9,450	307
Backlogged Impact Studies*	160	27,308	176
Backlogged Facility Studies**	16	4,573	225
Total Backlogged Studies	**211**	**41,331**	

Source: PJM.

*Feasibility and Impact Studies are required to be completed within 90 and 120 days, respectively, as defined in the PJM Tariff.

**Facility Studies have no required timeline in the PJM tariff, but PJM uses nine months as a threshold to indicate backlog.

It appears that the two primary reasons for the delays in the interconnection process are (1) the sheer volume of recent interconnection requests, and (2) the current method of processing those requests. The increase in the number of interconnection requests must at least in part be attributed to RPM, and hence is an indicator of RPM's success in encouraging participation by and competition among a large number of potential entrants. On the other hand, it raises the concern that the current interconnection process is not fully supportive of the RPM design.

The current interconnection process allows all potential projects, even very tentative ones, to enter the queue at negligible cost. Projects that are more likely to be developed, even those that have firmly committed to bring capacity online through RPM auctions, must "wait in line" behind all other projects that entered the queue before them. They are subject to significant delays and uncertainties while other projects are studied. They also face additional delays and uncertainty because they must be restudied whenever tentative projects withdraw from the queue. Restudy following other projects' withdrawal may result in further delays as well as shifts in cost responsibilities for required upgrades. This suggests a need to change the interconnection process so that PJM can accommodate a larger number of requests and prioritize those requests that commit to providing capacity through RPM.

PJM and its stakeholders have already proposed or implemented a number of improvements to the interconnection process, including:

- Processing of interconnection requests in clusters instead of individually;

- Limiting the number of primary interconnection points to one per request at the System Impact Study phase; and
- Reducing the length of individual interconnection queues from six to three months.

These proposed changes are likely to expand the volume of requests that PJM can accommodate in a timely fashion. Studying interconnection requests in clusters should also make the process more efficient, because individual projects in the queue would not have to wait until interconnection studies of earlier projects are completed. Similarly, limiting the number of primary interconnection points reduces the number of baseline cases that are included in the study of subsequently queued projects, thus reducing PJM's workload and speeding up the entire interconnection process. Shorter queue length should help avoid the "last-minute rush" to add interconnection requests to a queue just prior to the closing date, a problem PJM has experienced in recent years.

To prioritize requests that commit to provide capacity through RPM, additional refinements that PJM and its stakeholders could consider and more fully evaluate include:

- Develop a screening method to weed out speculative projects without judging the merits of each project. For example, the fees charged for each interconnection request could be increased and be determined as a function of the proposed project size. Current flat fees are perceived as an insignificant cost for larger projects, and hence may encourage the submission of multiple interconnection requests for what is essentially one proposed project.
- Consider introducing an expedited treatment for planned capacity resources that have cleared in a base residual auction. For example, it may be desirable to study all RPM-committed resources as a group and ahead of other projects in the queue. PJM should also evaluate if it could guarantee these resources interconnection (or deem them interconnected) by the start of the delivery year for which they are committed.
- PJM could consider pre-selecting and pre-approving electrical locations in its footprint where requests submitted for proposed projects would receive expedited treatment. The preferred locations could be chosen in areas where committed capacity falls short of the reliability requirement and at nodes that can accommodate interconnection of additional capacity without triggering the need for upgrades.

Delays in generation interconnections may also be caused by delays in the permitting and construction of the necessary transmission facilities by the transmission owners. This can impose significant risks on generation developers, who may be exposed to RPM non-performance penalties if interconnection facilities are not constructed in time to allow for the delivery of the generating plant's capacity. Considering these risks, we also recommend that PJM explore incentives for and binding contractual commitments from transmission owners that would mitigate interconnection-related risks to generation developers. If such incentives and commitments cannot be obtained from transmission owners, PJM may want to explore limiting generation developers' risks through mechanisms such as allowing the procurement of replacement capacity in the third incremental auction at a guaranteed price equal to the base auction price.

Interconnection Cost Uncertainty. Not all of the interconnection process uncertainty that developers face is caused by the backlog. There is also considerable uncertainty about the ultimate level of interconnection-related costs. While initial estimates are made available through the Feasibility Study, these cost estimates can change significantly as either the System Impact Study or the Facilities Study is completed and the Interconnection Service Agreement is signed. Moreover, under the current cost allocation method, every time an interconnection request is withdrawn from the queue, a restudy may be necessary for interconnection requests with higher queue positions, and costs of required transmission upgrades must be reallocated. PJM conducts the restudies through an iterative process. Every restudy must determine the first project that causes the reliability violation, determine required transmission upgrades, and reallocate cost responsibility among the remaining requests in the queue. As a result, withdrawn requests may not only slow the interconnection process but also result in considerable changes in interconnection costs for the remaining projects in the queue. Since a developer cannot foresee whether any interconnection request will be withdrawn or not, cost estimates reported in the interconnection studies are inherently uncertain.

Our review of a number of interconnection projects have shown that cost changes over the course of the interconnection process can be quite significant. For example,

- For a 60 MW wind project that started the interconnection process in August 2003, the Feasibility and System Impact studies were completed without identifying any interconnection-related costs. By the time the Facilities Study was completed, interconnection costs were estimated at almost $10 million. That estimate subsequently dropped to $300,000 by the time the Interconnection Service Agreement was signed. The project was able to come online in 2007.
- The Feasibility Study for a 140 MW oil-fired plant identified up to $22 million of interconnection cost responsibility. That estimate subsequently dropped to zero.
- The Feasibility Study for a 50 MW natural gas-fired plant did not identify any interconnection cost responsibility. However, the System Impact study later identified $4 million in interconnection costs.
- The Feasibility Study for a 120 MW upgrade to an existing natural gas-fired generating plant by Dominion Resources identified up to $170 million of interconnection cost responsibility. The System Impact study later estimated interconnection costs at just over $6 million.

There is anecdotal evidence that the combination of delays and cost uncertainty in the PJM interconnection process have already had adverse impacts on RPM participation. For example, in a recent complaint filed with FERC,[66] Dominion Resources Services, Inc. claimed that it reduced the amount of capacity it offered into the 2010/11 base auction because of delays in the interconnection process. Dominion has made a $30 million capital investment in a 120 MW capacity uprate at its Fairless facility, with an expected completion date in the fall of 2008.

[66] Complaint and Request for Fast-Track Processing of Dominion Resources Services, Inc. Against PJM Interconnection, LLC, Docket No. EL08-36-000, filed January 28, 2008.

Dominion claims that its investment decision was made in response to price signals observed in the auctions for delivery years 2007/08 through 2009/10. However, Dominion also claims that delays and cost uncertainty in the interconnection process prevented it from offering the entire amount of capacity it plans to build into the 2010/11 base auction, and it may not be able to offer in the full amount in the base auction for the 2011/12 delivery year either.

The original interconnection request for the Fairless capacity uprate was filed on January 26, 2007.[67] The Feasibility Study for the request was completed on June 21, 2007, three months late. The Feasibility Study did not provide a complete estimate of Dominion's cost responsibility for upgrades needed to eliminate overloads that were initially caused by prior queue requests. PJM was going to report Dominion's share of the cost responsibility in the System Impact Study, which was not completed until April, 2008. Dominion claims that without those estimates, it had an undefined exposure to the cost of required transmission upgrades, and it could not prudently offer its new capacity into the RPM auctions.

On March 12, 2008, PJM, Dominion, and other signatories filed a proposed offer of settlement[68] aimed at resolving the backlog related to queue request R81 and other related projects via an ad-hoc mechanism. They also agreed to establish a stakeholder process regarding interconnection studies and queuing. The group of issues identified for the stakeholder process includes (1) entry and exit from the queue, (2) "weeding out" speculative projects, and (3) establishing enforceable timetables for interconnection studies. The proposed settlement was approved by FERC on April 10, 2008.[69]

PJM and its stakeholders have proposed several changes to the current cost allocation methodology, including the following:

- Changing the method of cost allocation from the current approach of identifying incremental network enforcements project by project to finding an optimal solution of network fixes for the whole queue group;
- Allocating cost responsibility to all projects in the queue group that contribute to the reliability need, instead of identifying the first project causing the reliability violation, and allocating the costs only to that project and subsequent projects; and
- Eliminating cost allocations across different queue request groups, except for the transmission upgrades that exceed a certain cost threshold.

These proposed changes to the cost allocation methodology appear reasonable and would likely reduce cost uncertainty faced by developers, including cost uncertainty associated with need for restudy when projects drop out of the queue. These proposals would also reduce the risk to developers of significant cost allocations from transmission interconnection requests studied several queues earlier.

---

67 Queue position R81.

68 Dominion Resources Inc, v. PJM Interconnection L.L.C., Settlement Agreement and Offer of Settlement, Docket No. EL08-36-000.

69 FERC, Order Approving Contested Settlement, Docket No. EL08-36-000, issued April 10, 2008.

3. Summary of Recommendations

Developing a comprehensive plan to reform the interconnection process is beyond the scope of this report. However, we recommend that PJM and its stakeholders consider and more fully evaluate the following guidelines for reforming the generation interconnection process:

- Design an interconnection process that can handle a larger volume of interconnection requests.
- Consider introducing expedited treatment for planned capacity resources that are committed in an RPM capacity auction and subject to enforceable deadlines at each phase of the interconnection process. Expedited treatment could also be offered for resources at pre-selected locations that can accommodate interconnection of additional generation.
- Develop a cost allocation methodology that reduces cost uncertainty for required transmission upgrades.
- Consider developing incentives and contractual commitments for the timely construction of generation interconnection facilities by transmission owners or mitigate interconnection-related risks to generators.

C. PENALTIES

The RPM design specifies two types of penalties: "deficiency penalties" enforcing that resource suppliers provide their committed quantities throughout the delivery year[70] and "availability penalties" to ensure that the committed resources are available for dispatch during critical peak periods. These penalties are an important feature of RPM because they provide incentives for resource providers to align their procurement, investment, and operational decisions with their RPM commitments. Penalties need to be high enough to encourage resource providers to procure replacement capacity for unavoidable deficiencies without creating risks that discourage RPM participation or induce developers to incur unreasonable costs.

1. Background

Table 17 shows the key characteristics of each penalty incurred by non-compliance of RPM forward commitments.

[70] These deficiency penalties are also sometimes referred to as "commitment compliance" penalties by PJM.

Table 17
Summary of RPM Penalties for Non-Compliance

	Deficiency Penalties					Availability Penalties	
	Generation & DR Capacity Resource Deficiency Charge	**Generation Resource Rating Test Failure Charge**	**Peak Season Maintenance Compliance Charge**	**FRR Commitment Insufficiency Charge**	**FRR Capacity Resource Deficiency**	**Generating Unit Peak-Hour Period Availability Charge**	**DR and ILR Compliance Charge**
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Purpose	To enforce that registered UCAP meets committed UCAP (penalizes resource cancellations, retirements, delays, deratings, retirements, or degradation of EFORd)	To enforce that generation can achieve committed ICAP by testing at a time of its choosing	To enforce PJM approval of all maintenance outages (MO) and planned outages (PO) during the peak season	To enforce sufficient committed UCAP in the FRR capacity plans	To enforce that registered UCAP of committed units, on a portfolio basis, meets FRR obligation	To penalize for lower availability during top ~500 hours than average 5-year historic peak availability	To penalize for DR & ILR under-compliance of RPM-committed capacity when needed in load management (LM) events
Applicable Resource Types	Gen & DR	Gen	Gen	FRR entities	FRR entities	Gen	DR & ILR
Penalty Criteria	If [registered ICAP*(1-final DY EFORd), where EFORd is t-6 months before DY] < [committed ICAP*(1-Offered EFORd), where EFORd is up to t-3.5 years before DY]	Tested ICAP < committed ICAP	Unapproved maintenance or planned outages during the peak season	If committed UCAP < reliability requirement + any required threshold, for the commitment period	If total registered UCAP of committed units < FRR obligation	If EFORp<EFORd-5, subject to limitations [b], where EFORp is during DY and EFORd-5 is t-5 years to DY history Deficiency is netted for portfolio	UCAP dispatched < committed UCAP when needed in LM event Deficiency is netted for portfolio
Penalty Rate	**Auction:** max{2*Avg. RCP, Net CONE}	**Auction:** max{2*Avg. RCP, Net CONE} **FRR**: Net CONE	**Auction:** max{2*Avg. RCP, Net CONE} **FRR**: Net CONE	2*CONE, for each DY remaining in FRR term If penalty is triggered, FRR entity may no longer use FRR option	**FRR:** 2*CONE	**Auction:** Avg. RCP **FRR:** Net CONE Unit UCAP deficiency capped in first 2 years [c]	1/5*Annual Revenue Rate per event, capped at 1x (typically only 1-2 events per year)
Frequency of Assessment	Daily	Seasonally [a]	Daily, during unapproved MO or PO	Annual	Daily	Annual	After each PJM-initiated LM event
How Can the Penalty be Avoided or Reduced?	Specify replacement resources [d]	Specify replacement resources [d]	Get all peak season MOs and Pos approved, or specify replacement resources [d]	Submit viable FRR capacity plan	Specify replacement resources [d]	Specify replacement resources [d], over-compliance	Specify replacement resources [d], over-compliance

Notes:
Resource clearing price, or "RCP," in this summary is used generically, and may represent a weighted average resource clearing price among locational deliverability areas.
The Emergency Procedure Charge, a charge for not cooperating with PJM's emergency procedures, is not included in this summary.
Qualifying Transmission Upgrade penalties are also not addressed in this summary.
[a]: Hydro units are tested annually, and can test at any time during the DY; units out of service for entire testing window are allowed to test out-of-period.
[b]: Excludes deficiency days, "outside plant management control" events, and gas supply unavailability events for single-fueled natural gas units.
If there is insufficient outage history, then a class-average EFORd and the available outage history are used.
If the number of service hours is greater than 50 then the unit's EFORp (EFORd during peak hours) is used; if the number of service hours is less than 50 then the unit's registered delivery year EFORd is used.
[c]: The shortfall at the resource level is limited to 50% of committed UCAP. If the cap is reached, the cap is 75% in the next delivery year.
The cap is removed for the next delivery year if the 75% cap is reached. The 50% cap is reinstated if it is not reached in 3 contiguous delivery years.
[d]: The participant can buy excess capacity in the incremental auctions or bilaterally.

As shown in Table 17, two types of penalties are applicable to capacity resources under RPM: (1) deficiency penalties for failure to maintain committed UCAP or ICAP levels throughout the delivery year, and particularly during peak periods; and (2) availability penalties for under-performance during peak hours and actual emergency events during the delivery year. Because the applicability of this array of penalties can be confusing, we provide the following examples of common situations and the penalties that currently apply to resource suppliers:

- **A generator or DR that does not come online** in time for the delivery year and that is not replaced through incremental auctions or bilateral procurement of replacement capacity is penalized for each megawatt of UCAP deficiency and each day for which it is delayed. The deficient supplier must pay the greater of: (1) two times the weighted average resource clearing price it received in the LDA; and (2) Net CONE in the LDA. This means that the deficient supplier must pay back the daily capacity payment it receives and pay an additional amount that is at least as large as those capacity payments.

- **A generator with a degradation of its expected availability ("EFORd")** that is not replaced through incremental auctions or bilateral contracts for replacement capacity faces the same penalty as new resources that do not come online. For the resulting UCAP deficiency, the supplier must pay on a per-MW-day basis the greater of: (1) two times the weighted average resource clearing price it received in the LDA; and (2) Net CONE in the LDA. Degradation in expected EFORd occurs when the offered EFORd at the time of the auction (i.e., when UCAP commitments are determined) is less than the registered EFORd that is "locked in" six months prior to the delivery year (i.e., when the UCAP resource positions are finalized).

- **A generator that cannot prove its ICAP-committed capability at a time of its choosing** during two seasonal testing windows in the delivery year is similarly penalized at the greater of: (1) two times the weighted average resource clearing price received in the LDA; and (2) Net CONE in the LDA. The level of UCAP deficiency is determined based on the "best" test result submitted (i.e., the test that results in the highest ICAP capability).

- **A generator that schedules unapproved maintenance for planned outages during the peak season** (a 13-week period defined during June through September) must pay for the UCAP deficiency over the duration of the outage at the greater of two times the weighted average resource clearing price received in the LDA, and Net CONE in the LDA.

- **Generation with a degradation of actual availability during the top 500 hours** of the delivery year must pay the weighted average resource clearing price received in the LDA times the net portfolio deficiency, with resource-specific deficiencies capped at 50 percent of UCAP. The resource-specific UCAP deficiency is determined by comparing (1) the availability during the subset of peak hours when the unit is economic for energy or needed for operating reserves in the delivery year ("EFORp"), and excluding days with deficiency charges due to delays, retirement, or cancellation, to (2) the availability during the five years ending September 30 prior to the delivery year ("EFORd-5"). If the generator is a peaking unit with less than 50 service hours, then an EFORd based on outage data that covers the entire delivery year is used instead of EFORp when determining performance during the delivery year.

- **Generation with an improvement of actual availability during the top 500 hours** in the delivery year may receive a distribution of any deficiency charges collected for shortages, up to the weighted average resource clearing price received in the LDA for the additional UCAP.

- **A DR supplier that under-complies during individual load management events** in the delivery year must pay for each under-compliance event 20 percent of its Annual Revenue Rate ("ARR," which is the UCAP commitment valued at the resource clearing price for 365 days) times its UCAP deficiency in each event. Total under-compliance payments are capped at the ARR for the delivery year. If the demand resource over-complies, it is eligible to receive a portion of the deficiency charges collected from under-compliant resource providers.

The RPM penalty structure ensures that any given deficiency is not penalized twice. That is, if a market participant is deficient or underperforms, then that participant must pay either a deficiency penalty or an availability penalty, but not both penalties for the same MW of capacity. The participant also would not pay more than one type of deficiency penalty on the deficient amount. Any *additional* underperformance or deficiency, however, could be subject to one of the other penalties.

2. Identified Concerns

A well-designed penalty structure should discourage underperformance without imposing excessive penalty risks on responsible RPM participants. Excessive penalty risks could discourage suppliers from making forward commitments for resources that can reasonably be expected to be available during the delivery year and/or could encourage developers to incur excessive costs in efforts to mitigate the penalty risks. The difficulty of striking an appropriate balance is compounded by numerous interactions between penalties and other factors, such as the cost of replacement capacity, the risk associated with developing new capacity, and the varying quality of different resources. Penalties should not discourage resources with capacity value from participating.

Our review of the RPM penalty structure indicates a sensible overall design with at least three areas of concern:

- First, deficiency penalties appear to be excessive—potentially discouraging entry of new resources and creating unnecessarily high penalty risk for existing resources. They are more than large enough to encourage compliance with commitments and the procurement of replacement capacity for commitments that cannot be met.
- Second, availability penalties may be insufficient to penalize certain types of resources for being unavailable during peak hours.
- Third, some penalties are unnecessarily asymmetric across resource types. DR and ILR, in particular, face a more lenient penalty structure than generation resources. (DR and ILR are discussed further in Section V.D.)

Excessive Deficiency Penalties. The primary purpose of the deficiency penalties is to provide incentive for suppliers to ensure that their committed resources are online and operating properly at the start of and during the delivery year, and in the event this is not possible, to procure replacement capacity for any deficiencies. Hence, it makes sense for deficient suppliers to have to pay back their capacity revenues *and* make an additional payment, such that they have incentive to procure replacement capacity to cover any deficiencies. The current penalty (the higher of Net CONE or two times the clearing price) appears to be much larger than necessary to achieve these objectives.

At the high current level, the deficiency penalty imposes risks on participants that cannot easily be priced into their supply offers, which likely discourages participation in RPM. Penalty risk is not factored into the RPM auction offer caps, so suppliers potentially must bear the risk without being compensated for doing so. New resources, in particular, already face the risk of not coming online due to queue uncertainty, permitting risks, and state regulatory obstacles, and they may be discouraged from participating given the heavy deficiency penalty rate. Even if some of these risks can be priced into suppliers' offers (e.g., by incurring additional costs, such as the cost of supplier guarantees that would mitigate these risks), these added costs are likely to be incurred inefficiently.

To reliably encourage the procurement of capacity to replace commitment deficiencies, we believe the deficiency penalties should be set at a modest premium above the higher of: (1) the base auction clearing price; and (2) the clearing price associated with the third incremental auction conducted four months prior to the delivery year. A "penalty" factor of at least the clearing price is needed to "take back" the payments suppliers receive based on auction outcomes. An additional "premium" above that amount would be needed to provide an incentive to replace deficiencies, which means it needs to be larger than the sum of: (1) any capacity price increases (in bilateral markets) between the third incremental auction and the delivery year; and (2) any incremental transactions costs that would be incurred if replacement capacity needs to be arranged on a bilateral basis after the third incremental auction. We believe adding a 20 percent premium above the higher of the base or incremental auction clearing prices would be adequate for that purpose. With this penalty provision, the supplier would pay the 20 percent penalty in addition to paying back the capacity payments it has already received as a result of having been awarded such payments through the base auction. The 20 percent premium above the higher of the market clearing price of the auction in which the capacity was first committed and the third incremental auction clearing price would also apply to any capacity committed in the first, second, or third incremental auctions.

The following examples illustrate the impact of the current deficiency penalty rate versus the proposed deficiency penalty rate (daily deficiency rate or "DDR"). The first example is based on an auction resource clearing price (Base Auction RCP) capacity revenue rate that is low relative to replacement cost (i.e., Third Incremental Auction RCP). In the second example, the capacity revenue rate is high relative to replacement costs. Both examples assume the capacity was originally committed in the delivery year's base residual auction. The third example illustrates that the current penalty structure can lead to disproportionately high penalties that are entirely disconnected from the market value of the committed capacity.

Example 1:

Deficiency Quantity = 1 MW

Net CONE = $175/MW-day

Base Auction RCP = $100/MW-day

3rd Incremental Auction RCP = $250/MW-day

Current Penalty*	Proposed Penalty*
DDR = 2 x $100 = $200/MW-day	DDR = 1.2 x $250 = $300/MW-day
DDR < Cost of Replacement	DDR > Cost of Replacement
Supplier may not replace deficiency	Supplier replaces deficiency
(Supplier can not know ahead of time if replacement cost exceeds penalty)	(Supplier knows ahead of time that penalty exceeds replacement cost)

*Note in this and the following examples the supplier is receiving revenue at the auction clearing price. As a result, the "net penalties" beyond having to pay back the auction revenues are 100 percent of the clearing price (or Net CONE minus the clearing price, if that amount is higher) under the current design and 20 percent of the clearing price under our recommendation.

Example 2:

Deficiency Quantity = 1 MW

Net CONE = $175/MW-day

Base Auction RCP = $250/MW-day

3rd Incremental Auction RCP = $100/MW-day

Current Penalty*	Proposed Penalty*
DDR = 2 x $250 = $500/MW-day	DDR = 1.2 x $250 = $300/MW-day
DDR >> Cost of Replacement	DDR > Cost of Replacement
Supplier may replace deficiency	Supplier replaces deficiency
(Supplier can not know ahead of time if replacement cost exceeds penalty)	(Supplier knows ahead of time that penalty exceeds replacement cost)

Example 3:

Deficiency Quantity = 1 MW

Net CONE = $175/MW-day

Base Auction RCP = $50/MW-day

3rd Incremental Auction RCP = $50/MW-day

Current Penalty*	Proposed Penalty*
DDR = Net CONE = $175/MW-day	DDR = 1.2 x $50 = $60/MW-day
DDR >> Cost of Replacement	DDR > Cost of Replacement
Supplier may replace deficiency	Supplier replaces deficiency
(Supplier can not know ahead of time if replacement cost exceeds penalty)	(Supplier knows ahead of time that penalty exceeds replacement cost)

Availability Penalties. In order to avoid attracting and depending on low-quality resources, availability penalties should be sufficiently large to put all revenues at risk for capacity that is not made available. We are concerned that availability penalties currently imposed within the RPM framework are too lenient to achieve that objective. We are also concerned that availability penalties for demand resources are not sufficiently aligned with those of generation.

In particular, we are concerned that the 20 percent penalty per load management ("LM") event for non-performing demand resources does not put all of the resource's capacity revenues at stake, because there are typically only one or two load management events per year. As a result, with only one or two load management events per year, even entirely unresponsive demand resources would still receive up 60-80 percent of their capacity payments. Not only may this result in a windfall to demand response providers, but it would also likely degrade reliability by attracting low-quality resources that *cannot* respond when needed. Furthermore, availability penalties for DR should be comparable to availability penalties for generation, which—with our proposed changes—could lose its entire capacity payment for poor availability. To discourage the development of low quality demand resources and better align demand resource penalties with those of generation, we recommend that PJM consider and further evaluate the following measures:

- Require DR suppliers to return the fraction of their revenues corresponding to the fraction of annual LM events to which they did not respond. Thus a demand resource that responds to half of all LM events would lose half of its capacity payments, while an entirely unresponsive resource would lose 100 percent of its capacity payments. This would be comparable with generation availability penalties. DR that is entirely unresponsive due to a registered UCAP deficiency would still be subject to the recommended 120 percent deficiency charge discussed above.

- Subject demand resources to tests (or equivalent verification processes) and deficiency penalties if they fail. Unlike the testing requirements imposed on generators, RPM currently does not subject demand response to any testing.

We also believe that the current RPM penalty structure is unnecessarily lenient on generation with poor availability during peak hours. The 50 percent penalty cap on generators with poor EFORp works against the objectives of RPM by potentially forgiving poor performance during the very hours when reliability is most vulnerable. To avoid rewarding poor performance, we recommend that 100 percent of resources' capacity payments be at risk. At a minimum, the cap should be increased to reflect the fact that most (nearly 100 percent) of a resource's annual reliability value is concentrated in peak hours, and resource providers should be charged for that diminished value of their generating capacity if they are deficient during these crucial hours.

3. Summary of Recommendations

Based on the concerns discussed above, we have the following recommendations on RPM penalty provisions for further consideration and evaluation by PJM and its stakeholders:

- Reduce deficiency 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.
- Change the 20 percent multiplier on demand resource availability to reflect the actual number of load management events during the delivery year.
- Apply the testing and penalty provisions to demand response resources similar to the testing and penalty provisions that apply to generators.
- Remove the 50 percent penalty cap for generators with poor EFORp to make resources at risk for 100 percent of their capacity payments.

D. DEMAND RESPONSE (ILR AND DR)

Under RPM, demand resources ("DR") and interruptible load for reliability ("ILR") resources have increased from 1,679 MW in 2006 to 5,258 MW in 2011/12.[71] These demand-side resources are dispatchable by PJM under emergency conditions or based on economic criteria if simultaneously enrolled in an economic program. Based on the recent ILR certifications and auction results, DR and ILR resources account for approximately three percent of all capacity committed in the 2011/12 delivery year. DR and ILR account for almost half of new capacity added since 2006. They have a capacity value of approximately $200 million in the 2011/12

[71] Certified ILR after the 2009/10 delivery year has yet to be determined. Growth in demand resources through 2011/12 assumes no change in certified ILR after the 2009/10 delivery year.

delivery year[72] and have become a major contributor to reliability, both on a system-wide and locational basis.

Despite RPM's success in attracting a significant amount of new DR and ILR, the current RPM design can be improved by reducing inefficiencies in the utilization and pricing of these resources. RPM allows individual demand resources to provide capacity either as DR through base residual or incremental auctions or as ILR, which obtains auction-based prices simply by registering three months before the delivery year. Our concern is that all ILR receives these prices, no matter how much or how little ILR registers compared to the forecast level of ILR that was considered in the base auction. This approach could lead to inefficient pricing, inefficient procurement, and inefficient incentives that may not sufficiently encourage forward commitments by demand-side resources.

We recommend that PJM consider addressing these concerns by removing the ILR option and requiring all demand response resources to compete in the base or incremental auctions, along with other changes to incremental auctions as discussed in Section V.E. This would also guard against the potential risk of withholding DR from base and incremental auctions, which could lead to higher auction clearing prices. As discussed in Section V.H., we are also recommending that PJM consider allowing energy efficiency and price-responsive demand resources to participate in RPM more directly.

1. Background

Prior to RPM, demand response participated in the capacity market through PJM's Active Load Management ("ALM") program.[73] In order to receive capacity payments, demand response resources had to simultaneously enroll in PJM's Emergency Load Response Program (ELRP). The redundancy of both programs working in parallel during emergencies created a need to integrate ALM and ELRP into a single demand response program.

With RPM, the old ALM/ELRP construct is combined into PJM's ELRP Full Option. Through this Full Option, demand response can receive both capacity payments and emergency event-based energy payments during PJM-initiated events. PJM also designed an ELRP Capacity-Only Option in order to accommodate demand response that previously could not enroll in ELRP due to state restrictions on receiving emergency payments.[74] Under the Capacity-Only Option, demand response can receive capacity payments and is obligated to respond during PJM-initiated events, but it cannot receive emergency event-based energy payments.

To participate in RPM, providers of eligible demand-side resources must first decide whether to enroll in the Full Option or Capacity-Only Option of ELRP. Because both programs allow the

---

[72] Calculated using offered and FRR-committed DR, projected ILR assuming 2008/09 certified amount, and current ILR Credit Rate.

[73] ALM was only used to reduce an LSE's unforced capacity obligation, and was not offered directly into the CCM auctions.

[74] Both the Full Option and the Capacity-Only Option are designed for the same types of demand response programs as ALM: direct load control, firm service level, and guaranteed load drop.

same demand response types, the decision hinges solely on whether or not the resource is allowed to receive emergency energy payments. Once a resource enrolls in ELRP, it can participate in RPM in one of two ways, (1) as ILR if it is online three months before a delivery year, or (2) as planned or existing DR participating directly in the RPM auctions or FRR capacity plans.[75] All existing DR are qualified to switch to an ILR designation in the following delivery year, but not vice versa. DR must meet more stringent enrollment and credit requirements, must be capable of making a longer forward commitment, and must not be capacity-only resources.

The ILR/DR distinction reflects RPM participation and other operational rules, not a distinction in resource type. DR participates in the three-year forward auctions (or subsequent incremental auctions if it does not clear in the base auction). Participation rules for DR are similar to those applicable to generation. In contrast, ILR does not participate in the auction and does not commit until three months prior to the delivery year. Prior to each base auction, PJM attempts to forecast ILR participation during the delivery year, and the ILR forecast is deducted from the PJM load forecast used in creating the demand curve for the base auction. Irrespective of whether the realized ILR is higher or lower than the forecast, all certified ILR suppliers are paid the "net load price" determined by the base auctions.[76] In the first four base auctions, the net load price has been equal to or somewhat lower than the capacity clearing price.[77] (See Figure 2 in Section III.A.) If actual ILR resources for a given delivery year exceed the ILR forecast, the total cost to load increases because load must pay for all certified ILR in the delivery year.

In spite of ILR earning the slightly lower net load price in constrained LDAs, there are several reasons a demand-side resource might choose to participate as ILR instead of DR. Participating as ILR allows resources to avoid a three-year forward commitment and, instead, enter the market with short notice. This is valuable to demand resource providers who either cannot easily obtain forward commitments from end-users three years in advance, or who are not willing to make forward commitments without corresponding customer contracts. Without customer contracts, there is the risk that the DR supplier will not be able to provide the committed resources. Even if customers can be signed up three years in advance, there is a penalty risk if they discontinue or change their operations in a way that changes their baseline and affects their ability to achieve load reductions. A further disincentive for demand-side providers to commit DR three years in advance is created by PJM's $43/kw-yr credit requirement for participation in the base residual

---

75 Resources enrolled in either the Full Option or the Capacity-Only Option can participate as ILR. Resources enrolled in the Full Option also have the choice to participate directly in the RPM auction or FRR capacity plan. Resources enrolled in the Capacity-Only Option cannot participate as DR.

76 For delivery years in which no second incremental auction is conducted, the net load price is determined by the resource clearing price from the corresponding base auction, minus the value of capacity transfer rights into an LDA (per MW-day of peak load).

77 However, in the 2011/12 delivery year, the preliminary net load price slightly exceeds the capacity clearing price. This is the result of make-whole payments incurred during the clearing of the base auction; load must pay the offer price to the marginal resource, which increases the total load charges by approximately $.04/MW-day.

auction, which may be high for smaller DR providers. The ability of demand-side resources to avoid forward commitments through the auction process can result in pricing inefficiencies since the amount of demand-side resources that are anticipated to enter as ILR needs to be forecast for the base auction. Since the auction demand curve reflects the amount of ILR forecasted, auction clearing prices would be too low if less ILR enters the market than was forecasted; and prices would be too high if actual ILR amounts exceed forecasts.

2. Identified Concerns

The RPM construct for demand response participation is similar to that of ALM under the prior capacity market design. This has ensured a smooth transition for resources from ALM to DR or ILR under RPM. However, some features of the DR/ILR participation rules appear to be overly accommodating and work adversely to RPM's objectives. Specifically, allowing demand response resources to participate as ILR and still get paid at (nearly) the base auction price creates the following inefficiencies:

- ILR forecasting difficulties, which likely lead to inefficient capacity commitments and inaccurate prices.
- A mismatch between the value provided by ILR and the price received.

Forecasting Difficulties. The amount of ILR participation is difficult to forecast because it depends on both the growth of demand response over time and the unpredictable decisions of suppliers about whether to participate as DR or ILR. This is problematic because the ILR forecast is deducted from the load forecast to determine the demand for capacity in the base auction. Forecasts must therefore be conservative in order to preserve reliability, and PJM's current "forecasting" approach, based purely on historical data, is arguably conservative. However, under-forecasting ILR can result in higher prices and the forward commitment of capacity that would not otherwise have been needed. For example, in the base auction for the 2008/09 delivery year the RTO-wide ILR forecast in UCAP was 2,110 MW. Certified ILR for that delivery year was almost double the forecasted amount: about 3,600 MW. If this higher ILR level had been anticipated for the purpose of the base auction, resource clearing prices would have been lower.

We recommend that PJM consider addressing this problem by eliminating the DR/ILR distinction to encourage all demand response that is able to commit three years forward to participate as DR in the base auction. Demand response resources that are not willing or able to commit until closer to the delivery year could still sell as DR into the incremental auctions (with further modifications to the incremental auction process, as discussed in Section V.E.). This approach would also solve the "value mismatch" problem discussed below. Requiring participation in the auction process would also guard against the potential risk that market participants use the ILR option to withhold DR from base and incremental auctions, which could lead to higher auction clearing prices that ILR resources would also be able to receive.

In the incremental auctions, DR would compete with other supply resources to provide capacity to bidders for replacement capacity and to PJM. PJM would be procuring more capacity in incremental auctions than it does today, as described in Section V.E. Procuring more capacity in the incremental auctions would ensure an active market at the time of the incremental auctions and could be achieved in many ways, including by reducing peak load in the base auction parameters by an historic average level of DR (similar to the current deduction of the ILR "forecast"), and procuring that amount in the incremental auctions.[78]

Value Mismatch. The price paid to ILR resources that do not commit until three months before the delivery year is essentially the same as the price received by a resource that committed on a three-year forward basis. This three-year forward price, however, does not reflect the value of capacity three months before the start of the delivery year. The mismatch is most evident in the event of a decrease in load forecast, where additional resources might not be needed but loads are nevertheless required to purchase all ILR that is offered at the original base auction price. On the other hand, if load exceeds forecasts and/or there is high demand for replacement capacity just prior to the delivery year, the value of incremental capacity could be much higher than the base auction price that ILR would be paid. In either case, ILR is truly a three-*month* forward product and should receive payments that reflect the value of additional resources at that time.

Under our recommendation to eliminate ILR, a demand response resource that can only make a multi-month forward commitment could still offer into the third incremental auction (four months before the start of the delivery year) and receive the third incremental auction price.[79] The third incremental auction would appropriately price DR that enters at that time. Similarly, demand resources that can make a one-year forward commitment could offer into the second incremental auction, and those that can make a two-year forward commitment could offer into the first incremental auction. The incremental auctions could also be revised to accommodate demand response as described in Section V.E.

3. Summary of Recommendations

We recommend that PJM consider the following changes to its participation rules for demand response:

- Remove the ILR option to encourage participation of these demand-side resources in the base and incremental auctions, which will improve pricing and procurement efficiency.
- Modify the supply and demand in the incremental auctions as described in Section V.E. This will accommodate demand response in the incremental auctions, among other objectives.

---

78 Like the current approach, this modified approach could lead to inefficient outcomes if the amount of demand moved from the base auction to the incremental auctions were inconsistent with the costs and availability of resources that can commit on a three-year forward basis versus shorter-term. In that case, one would expect incremental auction prices to be consistently above or below the base auction prices. If such patterns are observed, PJM could adjust the amount of load cleared in base auctions.

79 Resources that cannot make a four-month forward commitment would be outside of the construct of the auctions. However, these resources can offer their capacity bilaterally to market suppliers needing replacement capacity on even shorter notice or during the delivery year.

E. INCREMENTAL AUCTIONS

Three incremental auctions are scheduled between the base auction and the delivery year to address incremental demand for capacity to replace existing commitments or to serve increases in load forecasts. However, the incremental auctions are not very liquid and do not accommodate many other types of supply-demand imbalances, including decreases in load forecasts and changes to CETL. They also exclude replacement bids from the second incremental auctions and capacity needed to reflect changes in load forecasts from the first and third incremental auctions. On the supply side, they exclude the demand-side resources that are allowed to bypass the auctions by registering as ILR.

We recommend that PJM consider and further evaluate measures to bring into the market all elements of supply and demand adjustments that might occur after the base auction. Our recommendations include procuring a portion of demand in the incremental auctions. We also describe how elements of the downward-sloping VRR curve could be included in the incremental auctions in order to recognize the value of incremental capacity and stabilize prices.

1. Background

Under RPM, almost all capacity committed for a particular delivery year is cleared in the base auction conducted three years prior to the delivery year. A small fraction of capacity can be committed in three subsequent incremental auctions, which occur closer to the delivery year: the first incremental auction, held 23 months before the start of the delivery year; the second incremental auction, held 13 months before the start of the delivery year; and the third incremental auction, held four months before the start of the delivery year.

The current purpose of the first and third incremental auctions is to allow suppliers to buy replacement capacity for capacity committed in prior auctions that has become deficient due to project cancellations, delays, deratings, or availability decreases (EFORd increases). Buying replacement capacity preserves the reliability of the system and protects the buyer from deficiency penalties. The purpose of the second incremental auction is to allow PJM to arrange procurement of additional capacity if its peak load forecast for the delivery year increases after the base auction. The second incremental auction is held only if the preliminary and final peak load forecasts differ significantly.

The incremental auctions differ from the base auction in several ways. First, the demand is not based on the VRR curve concept. The demand curve is formed by the submitted "buy" bids in the first and third incremental auctions, and a vertical demand curve in the second incremental auction. Second, supply in the incremental auctions is limited to capacity that offered into the base auction but did not clear, except for newly-available capacity, which can participate in incremental auctions without having participated in the base auction. As in the base auction, the resource clearing price is determined by the intersection of supply and demand curves, resulting in a price that is either the offer of the highest-cost resource cleared or the price on the demand curve that corresponds to the total amount of cleared capacity. Prices in the second incremental auction are capped at 12.5 percent above Net CONE (corresponding to the target capacity level on the VRR curve used in the base auction).

During the RPM Transition Period no first incremental auctions were held. The second incremental auction for the 2009/10 delivery year was scheduled for April, 2008, but was not held because the criterion for conducting that auction (increased load forecast) was not met. The only third incremental auction held so far was conducted in January 2008 for the 2008/09 delivery year, as described in Section III.B.6.

2. Identified Concerns

We have identified several concerns about RPM's incremental auction design:

- Incremental auctions do not address decreases in load forecasts after the base auction.
- Incremental auctions do not address changes in LDA import capability (CETL) relative to the assumptions in the base auction.
- Separating the procurement of replacement capacity (in the first and third incremental auctions) from procurement of additional capacity in response to increased load forecasts (in the second incremental auctions) is inefficient.
- The demand curves used in the incremental auctions are inconsistent with the concept of sloped demand embedded in the base auction.
- The incremental auctions have too little demand and supply to provide sufficient liquidity to efficiently address substantial changes in demand, transmission, or supply availability.

Each of these concerns—and several related concerns regarding ILR/DR and penalties—could likely be addressed by expanding the scope of the incremental auctions and by other refinements, as discussed below.

Decreases in Load Forecasts. The demand for base auctions is based on PJM's preliminary load forecasts conducted more than three years in advance. These forecasts are subsequently updated and finalized no later than 15 months before the start of the delivery year. If the final RTO unforced capacity obligation, based on the final RTO peak load forecast, exceeds the total amount of capacity cleared in the base auction (plus ILR forecast) by more than 100 MW, additional capacity is procured in the second incremental auction.

However, there is no similar provision for addressing *decreases* in the load forecast by "uncommitting" or "selling" capacity that was committed in the base auction. Once capacity is committed in the base auction, it cannot be uncommitted. This can result in load having to buy more capacity than is actually needed, especially, for example, if the success of conservation and other demand-side efforts surpasses expectations, or if the economy slows down. It also means that too much capacity is bought on average over time, since load forecasts that are made years in advance are inherently uncertain, and adjustments are made for the under-forecasts but not for the over-forecasts.

One solution would be to procure in the base auction only a portion (most, but not all) of the capacity needed to serve the preliminary forecast of peak load, and then buy the remainder in incremental auctions if needed. Doing so would require a substantial redesign of the auction processes, as described in more detail below. A less far-reaching alternative would be to "uncommit" capacity that is no longer needed (because of decreased load forecasts) and offered it to buyers of replacement capacity in the first and third incremental auctions.[80]

Changes in LDA Import Capability (CETL). Approximately three months before each base auction, PJM publishes CETL values for each LDA. CETL depends on the online date of planned transmission upgrades,[81] and it affects the base auction by reducing the amount of local generation capacity needed within the LDA. If CETL into a constrained LDA is increased to reflect an expected transmission upgrade, less local generation will be committed in the base auction. This results in the intended level of reliability within the LDA.

However, many transmission projects experience significant delays. In our interviews, several market participants expressed concerns about the timely construction of some of the transmission upgrades included in CETL values in recent base auctions. If the planned transmission upgrades are delayed, the CETL will have been overstated in the base auction. The LDA will consequently have a deficiency of committed local capacity. As discussed in Section V.F., this situation could be avoided by increasing CETL only when there is a reasonable expectation that transmission projects will be online as anticipated (e.g., after key permits have been received).

If transmission enhancements are not completed as anticipated by PJM at the time of the base auction, and the LDA becomes deficient, PJM would need to replace the missing imports in order to preserve reliability. This would require PJM to commit more LDA-internal resources. There is not currently a mechanism in place for PJM to do so through RPM. To address this deficiency, we recommend that PJM consider procuring such LDA-internal resources through incremental RPM auctions. PJM could periodically update CETL values between the base auction and the delivery year. If the import capability is expected to decrease in a constrained LDA relative to what was assumed in the base auction, PJM could commit more internal capacity (and uncommit LDA-external capacity) through its incremental auctions. In the event that CETL increases, PJM could similarly use incremental auctions to uncommit internal capacity and commit LDA-external capacity.

Separate Uses for Incremental Auctions. Excluding capacity replacement offers from the second incremental auction and excluding load-growth-related procurement bids from the first

---

80 This is currently done by ISO New England ("ISO-NE") in its Forward Capacity Market ("FCM"). Under the FCM, ISO-NE is allowed to sell excess capacity in the FCM "reconfiguration auctions"—the analogue of RPM's incremental auctions—if the forecasted capacity requirement decreases. ISO-NE's sell offers are expressed by an upward-sloping supply curve starting at an offer price of 0.25 x CONE and zero megawatt of offered capacity, up to an offer price of 0.75 x CONE and the full amount of surplus capacity. The potential buyers of this capacity are suppliers with commitments from the Forward Capacity Auction (FCA) – the analogue of the base auction in RPM – that are looking for replacement capacity to satisfy their obligations. However, New England's FCM utilizes a vertical demand curve. The sloping VRR curve in RPM implies that the amount of excess capacity that PJM would attempt to sell would be less than the reduction in load forecast.

81 CETL values reflect the N-1 emergency import limit into the LDA. The import limit is determined based on the existing transmission system plus key transmission upgrades that are planned within PJM's RTEP process to be in service by the start of the delivery year.

and third incremental auctions appears to be unnecessary, inefficient, and inconsistent with the VRR curve concept.

We recommend that PJM consider expanding the scope of each incremental auction to include both market participants' offers for replacement capacity and PJM's incremental procurement bids for reliability. This may raise concerns that PJM's procurement of incremental capacity to address increased load forecasts would be "in competition" with resource owners that submit buy bids in incremental auctions, which could increase the price of PJM-procured capacity. We do not share that concern. First, there is precedence in other markets. ISO-NE can submit buy bids and sell offers in its FCM reconfiguration auctions alongside resource owners submitting buy bids for replacement capacity. Second, a higher demand for capacity in incremental auctions is likely to attract more supply—primarily from new generating and demand-side resources that were not offered in the base auction—thus dampening the price impact of higher demand in incremental auctions. Possible mechanics of combined incremental auctions are illustrated below under "Potential Redesign of Incremental Auctions."

A related concern is that some resource owners could attempt to manipulate incremental auction clearing prices by submitting buy bids and sell offers simultaneously. We believe, however, that the risk of such manipulation would be mitigated by also subjecting buy bids to review by PJM's Market Monitor. The potential for market power abuse might also be reduced by restricting buy bids to the replacement of identifiable physical resources that have been committed in prior auctions. For example, in ISO-NE's FCM reconfiguration auctions, every buy bid must be associated with a capacity resource, it must have a capacity supply obligation from the FCA, and the bid quantity cannot exceed the amount of the original obligation. All demand bids are subject to review by ISO-NE.[82]

Inconsistency with the VRR Curve Concept. The incremental auctions are not fully consistent with the VRR curve concept. For example, the demand curve in the second incremental auction is vertical at a quantity corresponding to the full increase in load forecast. This is contrary to one of the main design elements of RPM and would generally lead to the over-procurement of incremental capacity compared to the capacity that would be procured under a sloped VRR curve that is shifted to the right to reflect the increased load forecast. Applying a sloped demand curve to the incremental auction would also offer the other benefits associated with sloped demand curves: it would better reflect the value of incremental capacity, reduce the volatility of incremental auction prices, and reduce the incentive to withhold capacity.

To achieve a sloped demand curve in incremental RPM auctions, we recommend that PJM consider adding as incremental demand the uncleared downward-sloping portion of the VRR curve that was used in the preceding base residual (or incremental) auction as discussed below. This would create a demand for incremental capacity that is consistent with the VRR curve used in the base auction.

[82] ISO-NE, Market Rule 1, Section III.12.4.2.2.

Potential Redesign of Incremental Auctions. The discussed modifications to incremental auction design would likely be most effective with corresponding changes to base auctions and DR/ILR rules. We thus recommend that PJM consider and more fully evaluate the redesign of incremental auctions with the following elements.

First, it would be beneficial to expand the scope of supply and demand participating in all incremental auctions:

- The demand could include both suppliers' bids for replacement capacity and PJM's bids to procure capacity when load forecasts increase. This would eliminate the current inefficiency of excluding replacement bids from the second incremental auction and excluding PJM procurement bids from the first and third incremental auctions. (As discussed above, buy bids by resource owners should be associated with the replacement of specific capacity supply obligations from the base auction and should be subject to review by PJM's Market Monitor.)
- The supply could include demand response that is currently treated as ILR. As discussed in Section V.D., we recommend eliminating the distinction between DR and ILR, forcing demand-side resources to compete in the base auction and/or the incremental auctions. Demand response resources that are not prepared to commit at the time of the base auction could offer their capacity as late as the third incremental auction occurring four months prior to the delivery year (i.e., approximately the same timing as ILR currently). This would increase the supply of capacity resources participating in the incremental auctions and improve liquidity.
- As discussed below, incremental auctions could also be expanded to address load forecast decreases (as well as increases, which are already considered in incremental auctions on a limited basis).

Adding ILR/DR to the supply while addressing decreases in demand could create a supply-demand imbalance in the incremental auctions unless a sufficient amount of demand is cleared in the auctions. To accomplish this, we recommend that PJM consider planning to procure in the incremental auctions the forecast of DR and ILR that is likely to become available after the base auction. (PJM is already defining demand in the base auction based on peak load less its ILR forecast, but then it is not adding a corresponding amount of demand to the incremental auctions). This amount could also include a forecast of other types of short lead-time UCAP that can be provided economically in incremental auctions. In addition, we recommend adding as incremental demand the portion of the VRR curve that remained uncleared in the base auction.

The demand in the incremental auctions would be adjusted for changes in load forecast and LDA import capability (CETL). For example, if the load forecast were to decrease, the updated VRR curve would shift to the left, reflecting a lower demand for capacity. This new VRR curve would then be used to determine the "uncleared portion" of the VRR curve (i.e., anything to the right of the quantity cleared in the base auction) that is used to construct the demand curve for the incremental auctions.[83] Figure 23 illustrates how the auction mechanics could work.[84]

CETL adjustments would be incorporated similarly to load adjustments with the added complication that CETL decreases could create constrained LDAs that were not constrained in the base auction.

3. Summary of Recommendations

We recommend that PJM and its stakeholders consider and further evaluate expanding the scope of the incremental auctions to bring into the market all elements of supply and demand, including adjustments that might occur after the base auction:

- Eliminate the inefficient exclusion of replacement bids from the second incremental auctions and the exclusion of PJM procurement bids from the first and third incremental auctions.
- Address decreases in load forecasts by either selling excess capacity in the incremental auctions or through a reduction in buy bids in redesigned incremental auctions.
- Address increases or decreases in LDA import capabilities (CETL) similarly to adjustments in load forecasts (although CETL adjustments should be infrequent if the recommendations in Section V.F. are implemented).
- Plan on procuring in the incremental auctions a portion of the needed resources corresponding to the estimated amount of demand response and other resources that are likely to become available after the base auction.
- Introduce elements of the downward-sloping VRR curve into the incremental auctions.

We have presented a framework for combining these elements into a potential redesign of incremental auctions.

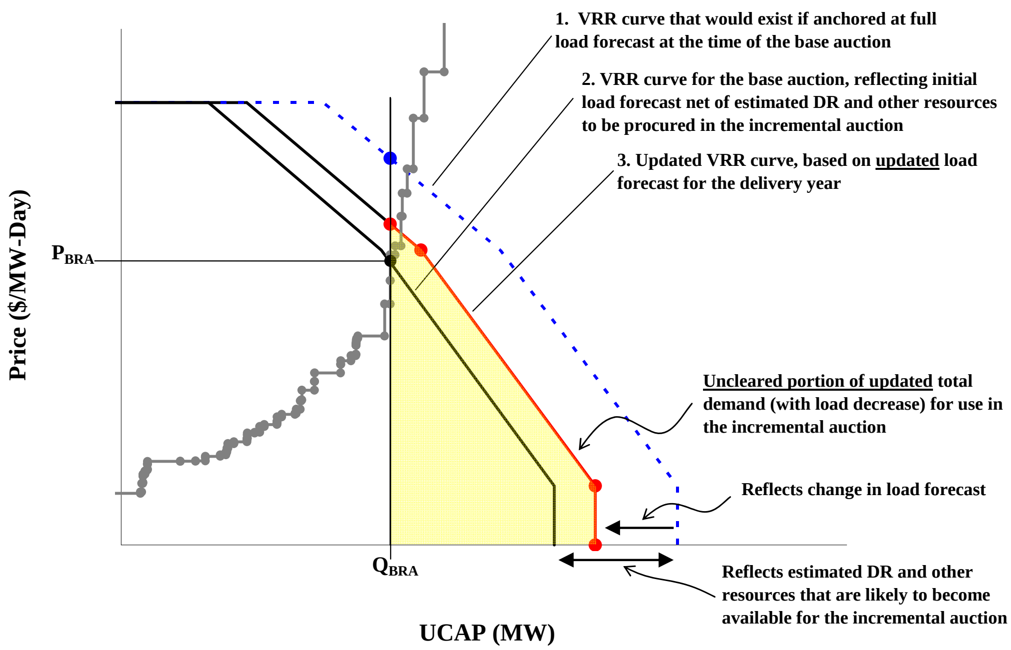
---

[83] In the special case where the load forecast decreases by more than the amount of capacity planned for procurement in the incremental auctions, there would be an excess of committed capacity, which PJM could offer into the incremental auction at a price equal to the base auction clearing price.

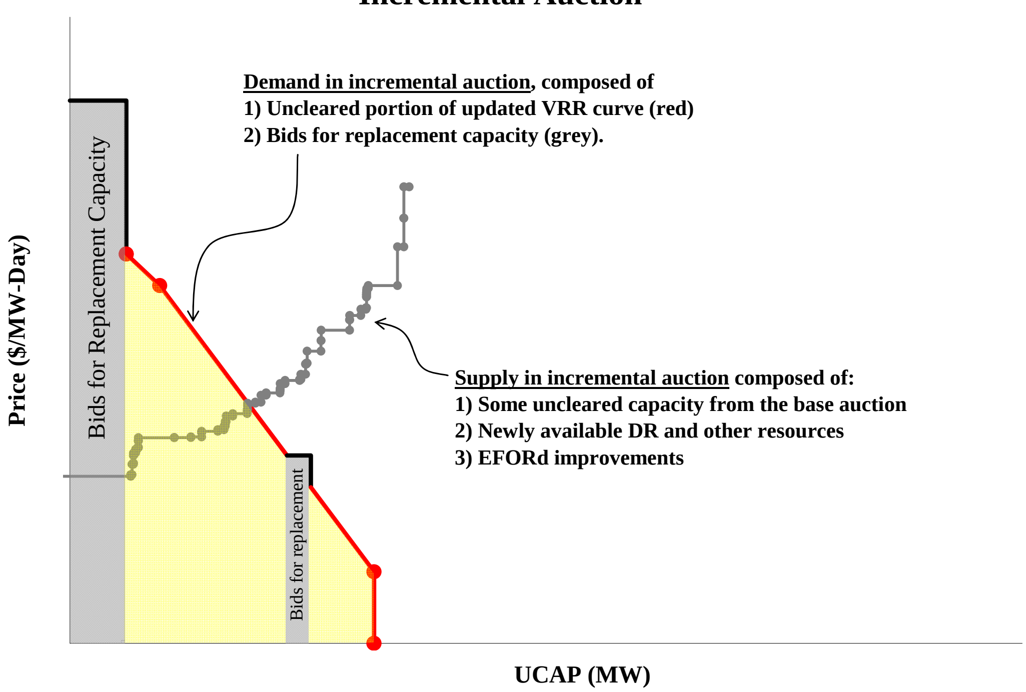
[84] Figure 23 contemplates only one incremental auction, but the same process could be applied to sequential incremental auctions. The original VRR curve would be updated sequentially, adding each time a portion (e.g., one third) of the demand that was planned to be served in the incremental auctions and updating the load forecast and CETL. The demand added to the incremental auction would be determined by the part of the updated VRR curve that remained in excess of the total quantity cleared in the base auction and prior incremental auctions.

Figure 23
Derivation of the Demand Curve for Incremental Auctions

Base Residual Auction



Incremental Auction



F. LOCATIONAL DELIVERABILITY AREAS

One of the primary goals of RPM is to provide "Locational Capacity Pricing to recognize and quantify the locational value of capacity."[85] To this end, RPM defines Locational Deliverability Areas (LDAs) that have their own reliability requirements. These local reliability requirements can be met by a combination of resources outside the LDA (to the extent allowed by the transmission system) and by local resources. The auction clearing process allows an LDA price to separate from the rest of the RTO if local resources must be committed at a cost above RTO-wide levels to meet the LDA's reliability requirement. In that case, all local resources receive the premium price. This provides incentives for new resources to locate inside the LDA.

We have identified several concerns about RPM's current ability to provide the correct price signals and the desired level of reliability in constrained areas under some circumstances. First, and perhaps most importantly, the definition and screening of LDAs might inappropriately eliminate some constrained areas from consideration in the auctions. Second, it is unclear how consistent the 1-in-25 year reliability target for constrained LDAs is with the overall reliability objectives. Third, planned but delayed transmission enhancements into the LDAs can inappropriately depress auction prices and capacity commitments. Finally, prices in constrained LDAs are very sensitive to the entry of large, new resources or transmission facilities, and this can create barriers to developing or retaining local resources.

To address these concerns, we recommend a number of measures for PJM's consideration. These measures include refining the LDA definitions, modifying or eliminating the pre-auction screen, re-evaluating the application of reliability criteria, and being more conservative about planned transmission enhancements into the LDAs.

1. Background

LDA Definition. There are currently 23 defined LDAs, only four of which were defined for the initial four base residual auctions. The 23 LDAs include the 16 individual PJM load zones, five aggregations of zones (MAAC, Western PJM, Eastern MAAC, Southwestern MAAC, and Western MAAC), and two subzones (PSEG Northern Region and DPL Southern Region). In addition, there is a stakeholder process by which new LDAs can be established, although the first attempt to create a new LDA failed.[86] As discussed below, not all LDAs are considered in any given auction, and even those that are considered do not necessarily have a different (higher) price from the RTO.

---

85 RPM Manual 18, p. 4

86 The proposed "Central PJM" LDA for the 2010/11 auction would have consisted of parts of the current Southwestern MAAC LDA, APS, and Dominion load zones. PJM's Board Reliability Committee decided not to approve any changes to the LDA definitions due to the lack of member support, the fact that the new LDA would not have added any new reliability violations not already under consideration in RPM, and the fact that a deferral of one year would have limited impact on investment signals.

Pre-Auction LDA Screening. RPM considers local reliability requirements in its auctions only for "Constrained LDAs." A constrained LDA is one in which the Capacity Emergency Transfer Limit ("CETL") is less than 1.05 times the Capacity Emergency Transfer Objective ("CETO," described below). CETL is the N-1 normal import limit on the interface into the LDA assuming no transmission outages. That means CETL is the amount of energy that can be transferred on an intact system such that no element would be overloaded under the single worst contingency. (In the event of an actual outage, the operating limit would be decreased to an N-1-1 limit within 30 minutes.)

This screening criterion has eliminated most LDAs from consideration in the most recent auctions, reflecting the fact that most areas now have enough projected capacity to meet the 1-in-25 year LOLE reliability criterion (assuming the N-1 import capability is always available and that there would always be supply available to import).[87] Both EMAAC and SWMAAC were constrained LDAs only in the first several auctions until CETL increased to reflect a planned transmission upgrade.

LDA Reliability Requirements. RPM is designed to maintain reliability in the LDA within acceptable levels using criteria that are similar to those applied to the RTO as a whole, but that additionally consider transmission limitations into the LDA. The LDA reliability requirement is given by the following equation:

LDA Rel. Req. = Projected Internal UCAP + CETO – FRR Adjustment[88]

"Projected Internal UCAP" refers to the dependable internal capacity, not including potential new entrants that might be solicited through RPM, except units with an executed Interconnection Service Agreement (ISA). CETO is the level of resources needed, in addition to the projected internal UCAP, in order to achieve a conditional loss of load expectation (LOLE) of one day in 25 years in the LDA.[89]

CETO is determined using a reliability model that considers stochastic load (based on the LDA's non-coincident peak load forecast) and stochastic availability of existing and new generation with executed ISA. For a candidate CETO the model evaluates LOLE, and if it is below the 1-

---

87 The only exceptions are Southwestern MAAC, MAAC+APS, and DPL South LDAs. Eastern MAAC was defined as a Constrained LDA in the first two auctions, despite the fact that the pre-auction screen would have eliminated it.

88 The FRR adjustment is the minimum of FRR-internal resources required. However, because this adjustment is relevant only for LDAs containing FRR entities -- but none of the currently-defined LDA do -- this term is not further considered in the remainder of this discussion.

89 This is a *conditional* LOLE, because CETO is treated as imported capacity that is 100 percent available, in spite of the fact that neither transmission nor outside generation availability is guaranteed in actual operations. The unconditional LOLE includes the event that generation supply is inadequate (assuming infinite transmission), the target for which is one day in ten years. The combined LOLE target is approximately one day in ten years plus one day in 25 years plus the LOLE associated with transmission line outages or derates, for a total of more than 1.4 days in ten years. See *PJM Manual 20: PJM Resource Adequacy Analysis*, Section 4, available at http://www.pjm.com/contributions/pjm-manuals/manuals.html.

in-25 target, import capability is increased (and the LDA Reliability Requirement is correspondingly increased, megawatt-for-megawatt) until the target level of reliability is met. The import capability corresponding to this case determines CETO.

The terminology in this equation may obscure its implications for RPM. Describing resources that are needed to fulfill the reliability requirement not covered by projected internal capacity as a "transmission objective" seems to suggest that any supply shortfall will be met by new transmission under PJM's Transmission Expansion Planning Process ("RTEPP").[90] If existing and planned transmission is below the level of the "transmission objective," only new generation or demand response can meet the shortfall. PJM procures new generation and DR through auctions. The demand in the base auction is set by the LDA Reliability Requirement. Hence, every megawatt of increased CETO translates into an incremental megawatt of demand for new capacity inside the LDA (and a corresponding decrease in the resources required outside the LDA to meet the total RTO reliability requirement).

Market Clearing. To determine market clearing prices within an LDA, a separate VRR curve is developed for each constrained LDA and for the rest of the RTO. The target quantity of resources is based on the reliability requirements described above, and the target price is based on the local Net CONE. The local Net CONE reflects the local CONE minus a local E&AS offset based on historical average E&AS market prices within the LDA.

After offers are submitted (and mitigated to offer caps as prescribed by the offer mitigation rules), all constrained LDAs are cleared simultaneously with the remainder of the RTO. Capacity is committed in merit order on an RTO-wide basis until transmission import limits (CETL) are reached, at which point local capacity is committed out of merit order until each sub-market clears. Depending on the location of resources, their offers, the CETLs, and the local VRR curves, the clearing price in each LDA may be a price equal to or higher than the price for the rest of the RTO. In addition, the amount of capacity clearing in the LDAs can result in reserve margins that differ from that of the rest of the RTO. LDA reserve margins including imports are typically higher, reflecting their relative size and isolation.[91]

Base auction clearing prices and reserve margins for each LDA are summarized in Section III.

Settlement Rules. Committed supply resources located within the LDA receive the LDA's clearing price. Load pays the zonal capacity price[92] times the obligation, less the value of

---

90 The "transmission objective" is an anachronism that predates RPM. RPM was intended to replace the old paradigm (in which installing transmission upgrades was the primary formal mechanism for addressing localized capacity shortages), with a new paradigm that gives generation and DR economic incentives to solve the problem.

91 The reserve margin is calculated as the ratio of the sum of cleared capacity and CETL to coincident peak load.

92 The zonal capacity price tends to be very close to the LDA clearing price. These prices may differ because the zonal capacity price may include adders for uplift payments to capacity resources that are not reflected in the LDA clearing price.

revenues for Capacity Transfer Rights (CTRs).[93] As shown in Figure 3 in Section III of this report, this also means that the price per megawatt paid by load within LDAs is below the price received by the capacity resources within the LDA, because the LDA load obligation is met by both internal and less expensive outside resources. Finally, the quantity of the obligation is not given by the cleared quantity in the LDA but is equal to the LDA's coincident peak load as a fraction of the total RTO peak load multiplied by the total committed capacity in the RTO.

Part of the LDA clearing and settlement arrangement is also a provision that allows new supply resources in LDAs to "lock in" the clearing prices of the particular base auction for up to three years if adding the new resource would depress capacity clearing prices in the LDA from a price corresponding to the target capacity level on the VRR curve to less than 40 percent of Net CONE, thus eliminating the incentive to enter. However, no resource has yet qualified for or exercised this option.

2. Identified Concerns

We have identified several concerns about RPM's effectiveness in recognizing the local value of capacity and achieving the desired level of reliability in constrained areas. The concerns identified fall into five broad categories:

- LDA Definitions – LDAs are based on service areas, not transmission constraints, which could lead to undersupply in some locations and oversupply in others.
- Pre-Auction Screening – the pre-auction screening may artificially remove the price premium from an LDA that has adequate but expensive local capacity.
- Reliability Requirements – the rationale for setting a conditional LOLE target (assuming imports into the LDA are 100 percent available) at one day in 25 years for all LDAs with varying degrees of import dependence is unclear.
- Transmission Upgrades – transmission additions are treated as if they will be brought on line as planned even when their completion dates are uncertain. This can inappropriately depress prices and lead to actual reserve margins that are well below reliability requirements.
- LDA Price Stability – the anticipated entry of large, new resources or transmission facilities can depress expected capacity prices in LDAs to a degree that blunts incentives to develop or retain local resources.

LDA Definitions. The LDAs are defined based on service territories instead of transmission constraints. Theoretically, this could lead to misplaced incentives, with some constrained locations becoming undersupplied while unconstrained portions of LDAs have excess capacity.

---

[93] CTR revenues are determined by multiplying CTRs (MW) by the price differential between the LDA and the rest of the RTO ($/MW-day).

To address the concern that current zone-based LDA definitions might be inefficient, PJM should reconsider defining future LDAs based on electrical locations. PJM could use the distribution factor (DFAX) method (or equivalent method), as had been applied to the recently proposed new LDA.[94]

Pre-Auction Screening. An LDA that has higher priced supply offers than the rest of the RTO should have higher clearing prices, even if existing plus firm new capacity is sufficient to satisfy local reliability requirements without maximizing imports (i.e., CETO is less than CETL). Yet the pre-auction screening process ignores economics and would eliminate such an LDA from the auction clearing process. This can inadvertently remove important price signals, which could result in uneconomic retirements or missed opportunities to develop new capacity within some of the LDAs. Hence, we recommend eliminating this particular pre-auction screen.

The potential disadvantages of eliminating the pre-auction screen appear to be minor. It would require PJM to define CETL for all LDAs, even those that currently pass the pre-auction screen easily. (Currently, PJM needs to determine CETL exactly only if it does not exceed 110 percent of CETO.) This would impose a small increase in the analytical demands on PJM. As a second best solution, PJM should consider raising the "1.05 times CETO" threshold CETL above which potential LDAs are eliminated from an RPM auction. This change would reduce the likelihood that "economically-constrained" LDAs are eliminated by the pre-auction screening.

Reliability Requirements. It is unclear whether the 1-in-25 year conditional LOLE target is at the optimal level. The target should depend on the marginal costs relative to the marginal benefits. We recommend that PJM consider conducting a benefit-cost analysis to reevaluate these targets. (We also recommended reviewing the RTO-wide reliability target and the application of this target, as discussed in Section IV.B.1.)

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 (corresponding to the optimistic assumption that imports are 100 percent available) than an LDA that is less dependent on imports.

Transmission Upgrades. Changes in transmission plans immediately change CETL, which affects the demand for local capacity in the base auction. This can create significant volatility of capacity clearing prices in constrained LDAs, potentially reducing the attractiveness of investing in needed new capacity resources to serve the LDA.[95] Importantly, plans for new transmission

---

[94] Paul McGlynn, "LDA Analytic Method Update," PJM Transmission Expansion Advisory Committee Presentation, December 19, 2007.

[95] The Wilson APPA Report suggests that premium LDA prices are not productive if the premium can disappear in subsequent auctions when CETL increases. While we agree that the prospect of price decreases makes investment less attractive, we do not see price variation as problematic. High prices can induce a response even if they are temporary. For example, temporarily high prices in SWMAAC may have been responsible for the rapid increase in DR and deferred retirements, which quickly provided

can increase CETL after the planned in-service date even if the proposed new facilities are not yet permitted and their actual in-service date is still uncertain. For example, the CETL value assumed for Eastern MAAC LDA increased from 5,845 MW in the base auction for the 2007/08 delivery year (held in April, 2007), to 8,505 MW in the base auction for the 2009/10 delivery year (held in October, 2007). This increase in CETL reduces the need for LDA-internal capacity resources. However, if the new transmission is not completed as planned, there will be a shortfall of capacity. This can reduce reliability to potentially unacceptable levels because there is not currently a mechanism to replace capacity shortfalls in import capabilities due to delayed transmission projects through incremental auctions.

We recommend that PJM consider addressing these problems through the following adjustments to the RPM market design:

- Adjust CETL for major new transmission projects only when there is a reasonable expectation that the project can be online as anticipated (e.g., after key permits have been received).
- Use incremental auctions to procure replacement capacity within an LDA if CETL does not increase as planned due to delayed transmission projects. Correcting CETL downward after the base auction could also create a corresponding surplus of capacity outside the LDA. This surplus could similarly be cleared in the incremental auctions. (See Section V.E. for further discussion of incremental auctions).

LDA Price Stability. The entry of sizeable new resources or transmission into relatively small LDAs can substantially depress expected capacity prices. This can create a disincentive to develop relatively large new projects or make major capital additions needed to retain existing generation. It also discourages suppliers from providing smaller resources that cannot avoid the risk that the LDA price premium will be eliminated by the actions of other market participants or PJM itself (through its transmission planning). Indeed, price premiums in SWMAAC and EMAAC have disappeared in recent base auctions, partly as a result of transmission enhancements that PJM assumed would be available by the delivery year.

PJM has attempted to partially address this disincentive through the New Entry Price Adjustment ("NEPA"). NEPA is supposed to allow providers of new resources in LDAs to lock in prices for three years under certain special conditions, as described in Section IV.D. However, the conditions that new entrants must meet in order to qualify for NEPA are too stringent, effectively eliminating the price lock-in option. It is extremely unlikely that a new resource would be large enough to lower the clearing price from 112.5 percent of Net CONE to only 40 percent of Net CONE in the LDA and the rest of the RTO (with such a large addition to the LDA, the LDA would be unconstrained from the rest of the RTO). In addition, NEPA does not address the risk of others' actions depressing the LDA price, such as recent increases to CETL have already done in SWMAAC and EMAAC. PJM could consider modifying NEPA to make it more broadly

capacity when it was needed. After the new transmission comes online, some of these resources might not be needed any more.

available to all new capacity and existing generation with major capital expenditure requirements in constrained LDAs, with less stringent qualification criteria or no qualification criteria.

A potential problem with offering a lock-in option based on a single year's prices is that suppliers would take the option whenever market fundamentals point to decreasing prices and avoid the option when market fundamentals point to increasing prices. A more efficient alternative would be to determine the LDA-internal capacity price based on an auction for a three- to five-year delivery period that incorporates market fundamentals over the entire period. Such auctions would cover a fraction of the demand, and the residual would be covered through auctions for single delivery years like the current auctions. This would require a substantial redesign of the auction process, however, and it would have a large impact on the prices and risks faced by customers. Customer prices would be less connected to the short-term value of capacity.

Because capacity has in fact been attracted and retained within LDAs as the result of the first several auctions, we do not believe that the lower level of price stability offered within LDAs constitutes a major design problem. However, PJM should nevertheless consider addressing the identified issues by offering an expanded lock-in option that allows all new capacity and existing capacity with major capital expenditure requirements within an LDA to lock-in prices for a three- to five-year period.

3. Summary of Recommendations

As discussed above, we have identified several concerns about RPM's current ability to provide the right price signals and the desired level of investment in constrained areas. To address these concerns, we recommend that PJM and its stakeholders consider and more fully evaluate the following measures:

- Study defining LDAs electrically based on proximity to major transmission constraints rather than on a service area basis. If such an approach would result in substantially different prices in some locations, PJM should consider redefining LDAs accordingly.
- Eliminate the pre-auction screen, which can artificially eliminate price premiums in the LDAs that have adequate but expensive local capacity. As a second best, PJM should consider raising the threshold used in the pre-auction screen.
- Reevaluate the 1-in-25 conditional LOLE target for LDAs. Consider differentiating the target conditional LOLE based on each LDA's level of import reliance.
- In base auctions, incorporate planned transmission additions into CETL only when there is a reasonable expectation that the project can be online as anticipated (e.g., after key permits have been received). If actual CETL is later found to differ from the assumptions applied for the base auction, consider adjusting for associated LDA capacity shortfalls or surpluses through incremental auctions.
- For new generating units and existing units with major capital expenditure requirements, consider offering three- to five-year lock-in of single-year prices or three- to five-year auctions to set prices within LDAs.

G. CAPITAL EXPENDITURE AND PROJECT INVESTMENT PROVISIONS OF RPM

Attachment DD of the PJM Tariff specifies provisions for considering capital expenditures in suppliers' offer caps as they apply to RPM auctions. These offer caps, which can have significant implications for capacity market results, vary substantially for different types of existing capacity resources and new capacity resources. Some of the limits imposed on offers from existing resources could yield inefficient outcomes, and we recommend that PJM evaluate modifying certain offer-mitigation provisions, in particular as they apply to major capital investments for existing units.

1. Background

In each RPM auction, PJM applies market structure tests to constrained LDAs and to the entire PJM region. If the market structure tests indicate the presence of structural market power, PJM applies offer caps to all existing units in the regions that fail.[96] In the first five base auctions, all LDAs and the entire PJM region failed the market structure test, resulting in offer mitigation for all existing units.

Offer mitigation involves the application of unit-specific offer caps to existing generating capacity resources. DR and planned new capacity resources are generally not subject to such offer caps.[97] Offers from planned new capacity resources are mitigated in the first year only if their sell offers are deemed "uncompetitive" by PJM's MMU.[98] After a commitment is made in the first delivery year, a new capacity resource becomes an existing resource.

Mitigation of existing units' offers is generally based on an offer cap that reflects a *portion* of each unit's going-forward costs that is not expected to be covered by operating margins from the sale of energy and ancillary services.[99] Hence, PJM defines unit-specific avoidable cost rates ("ACR") that include ongoing fixed O&M costs that the supplier would not incur if it did not operate the resource. Each unit's offer cap is given by the supplier's choice of either (1) its unit-specific ACR less expected operating margins or (2) a default cost rate for the unit's technology type. Offer caps may also include adders for capital expenditures that are necessary for the unit's continued operation.

The fixed costs of project investments that are intended to extend the operating life or availability of an existing capacity resource can be included in ACRs in two ways: (1) as the

96 Section 6.8, Attachment DD of the PJM Tariff.

97 Existing DR cannot set the resource-clearing price, PJM Tariff, Attachment DD, Section 6.5(b).

98 Bids of planned new units that are deemed "competitive" are not mitigated if the new capacity offered in an LDA exceeds two times the amount of new capacity needed to meet the reliability requirement, more than two unaffiliated suppliers submit such offers, and no such offer is pivotal. The MMU can reject a bid for planned capacity if these conditions are not met.

99 In addition to offer caps based on going-forward costs, suppliers of exiting capacity resources may also choose to have their offer caps calculated based on their opportunity cost, which is a documented price they can receive in a market outside of PJM. Starting with the third incremental auction for the 2009/10 delivery year, suppliers will also have the option to select 110 percent of the base auction clearing price as their offer caps for third incremental auctions.

Avoidable Project Investment Rate ("APIR"); or (2) as the Avoidable Refunds of Project Investment Reimbursements ("ARPIR"). The ARPIR applies only to a fairly narrow set of resources; it specifies an offer cap related to refunds that certain resource owners have to make to PJM that could be avoidable if the resource were not operated during the delivery years.[100]

The APIR represents a broadly applicable cap on the amount of project investment costs that may be included in the determination of the ACR-based offer cap for existing resources. Project investment costs are eligible for inclusion only if the investment is reasonably required to enable the capacity resource to continue operating or improve availability during peak periods of the delivery year. The APIR is calculated as the product of an annual capital recovery factor (CRF) and the cost of the project investment. The maximum allowed CRF depends primarily on the age of the resource, for which the PJM Tariff specifies an amortization schedule as shown in Table 18 below. Under the APIR approach, a resource qualifies for the highest CRF corresponding to its age, although it may choose the lower CRF from the next higher age category.[101] The APIR adder based on the selected CRF can be included in capacity offers for the full remaining life over which the project investment is assumed to be amortized.

Table 18
Amortization Schedules of Project Investment Costs in RPM

Age of Existing Unit (years)	Remaining Life of Plant (years)	Levelized CRF	Maximum Offer
1 to 5	20	0.125	no limit
6 to 10	15	0.146	no limit
11 to 15	10	0.198	no limit
16 Plus	5	0.363	Net CONE[1]
Mandatory Capital Expenditures ("CapEx")	4	0.45	0.9*Net CONE
40 Plus Alternative	1	1.1	Net CONE

Notes: [1] Only applicable in delivery years 2007/08 and 2008/09.

[100] These payments include refunds of Project Investment Reimbursements and refunds under a cost of service rate filed under provisions of Part V of the PJM Tariff. Project Investment Reimbursements are payments the resource owner receives for a capacity resource that requested deactivation but was needed for reliability, and the resource required additional investments to continue operating. If such project investment allows the resource to remain operational beyond the completion date of the necessary transmission system reliability upgrades, the resource owner is required, under Section V of the PJM Tariff, to refund PJM a pro rata share of the amount of any project investment for which it received reimbursement. Alternatively, a resource that is proposed to deactivate but is kept in service for reliability may request a cost of service rate to recover the entire cost of operating the generating unit until the unit is deactivated. Under current RPM rules, avoidable refunds by the owner to PJM under such cost of service rates can be included in the offer caps as part of ARPIR.

[101] For example, an existing unit in the "16 Plus" category can chose a CRF of 0.363 or 0.198. The only exceptions to this rule are the 40 Plus Alternative with a CRF of 1.1 and the Mandatory Capital Expenditures option with a CRF of 0.45, for both of which the alternative CRF factor is 0.363 from the "16 Plus" category.

Mandatory Capital Expenditures (CapEx) and the "40 Plus Alternative" are special schedules available starting with the third base residual auction (for the 2009/10 delivery year). These two options allow resource owners to use a relatively high CRF in setting their offer cap. The "40 Plus Alternative" allows a CRF to include up to 110 percent of the project investment cost for one year. The Mandatory CapEx option allows the owner to include up to 45 percent of the project investment cost for four years. This option is available to investments that are required in order to comply with a government mandate that would otherwise reduce the availability of the resource during the delivery year. Such a capacity resource must (1) be fossil-fired; (2) in commercial operation no fewer than 15 years prior to the start of the first delivery year; and (3) the project investment needed to extend its operating life must exceed $200/kW. In addition, a coal-fired unit located in a constrained LDA can also take advantage of the Mandatory CapEx option regardless of the level of its project investments costs, as long as the unit has been in commercial operation for at least 50 years prior to the relevant base auction. The "40 Plus Alternative" is available to gas- or oil-fired resources in commercial operation for at least 40 years prior to the relevant base auction.

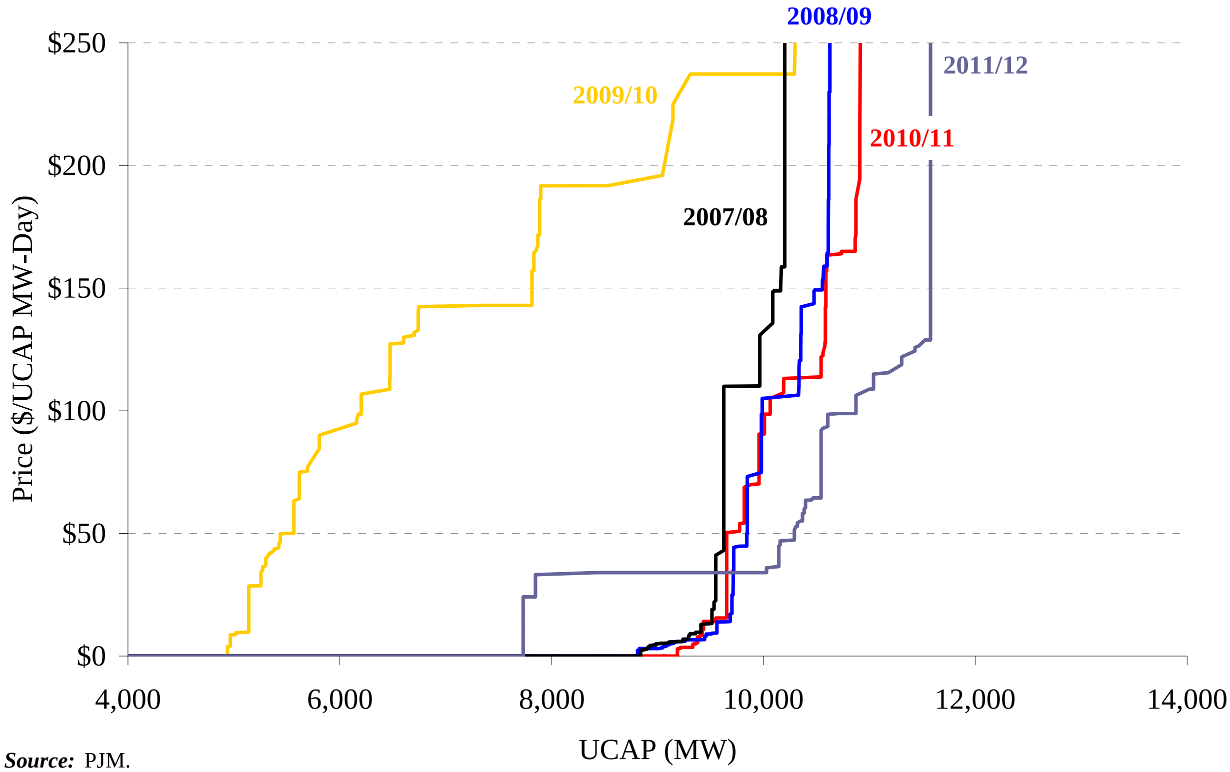
2. Identified Concerns and Recommendations

Project Investment Cost Recovery Period. The APIR amortization schedules allow resource owners to include CRF-based investment costs in their offers for the entire selected remaining life of the plant. This raises some concerns regarding the consistency of this treatment with bidding behavior in competitive markets. In competitive markets, competition between suppliers would drive down the offers to the going-forward avoidable cost of providing capacity during the particular delivery year, which does not depend on the amortization of past investment costs.

Project investment costs are incremental and avoidable only before the investment decision has been made—that is at the time of the base auction for the first delivery year, three years in the future. Once a project investment is completed, it becomes a sunk cost and does not represent an incremental or avoidable cost of supplying capacity. A supplier in a competitive market would not include such costs in its offers because doing so would risk not clearing at a price that exceeds going-forward avoidable costs. The supplier would, however, hope that other suppliers with new projects or project investments would set the market clearing price at a level sufficiently above its going-forward costs so that it would be able to recover the rest of its own project investment costs. If the supplier does not expect sufficiently high future prices to allow for the recovery of its investment costs, then the project investment should not be made in the first place. Based on these considerations, it would be more consistent with competitive bidding behavior if APIR adders to ACR-based offer caps would be allowed only in the first delivery year during which the capital addition is operational. This approach would also be consistent with the mitigation treatment of new units, which also only applies during the first delivery year. However, as discussed in Section V.F. above, adding a three- to five-year "lock- in" option should be considered for major capital expenditures that are required to retain existing units within LDAs.

Offer Caps for Major Capital Additions. In the base auction for the 2009/10 delivery year, several large baseload plants submitted APIR cost data totaling several billion dollars for over 4,000 MW of capacity. The significant investments combined with a low selected remaining life of the plants resulted in high offer caps. Offers consistent with these high caps resulted in a significant shift in the supply curve for SWMAAC for the 2009/10 delivery year, as shown in Figure 24. The SWMAAC resource clearing price for the 2009/10 delivery year increased to \$237.33/MW-day, from \$188.54/MW-day and \$210.11/MW-day for the 2007/08 and 2008/09 delivery years; it subsequently decreased to \$174.29/MW-day for the 2010/11 delivery year. Some market observers have suggested that this outcome indicates overly generous project investment provisions that led to the elevated price for the 2009/10 delivery year. This price is consistent with offers under the settlement-based project amortization schedules and may have been needed to retain sufficient capacity while the availability of new resources was limited.[102] However, the magnitude of the effect suggests that the amortization schedules and other project investment provisions should be reevaluated—in particular with respect to major capital expenditures.

Figure 24
Supplier Offer Curves in SWMAAC



Source: PJM.
Note: Y-axis is truncated and omits a small quantity above \$250.

We are not aware of any evidence suggesting that this experience in SWMAAC is inconsistent with market conditions and the settlement-based market rules. Nevertheless, in some cases the assumed remaining life in Table 18 may not be appropriate for major capital expenditures at

---

102 With respect to the outcome of the base auction for the 2009/10 delivery year it should also be noted that the auction occurred less than two years before the delivery period, leaving little opening for new capacity to satisfy reliability targets.

plants in the higher age categories of that table. An understated remaining life of an older plant would be associated with an overstated CRF rate. For major capital investment this could lead to an ineffectively high offer cap, which could allow offer prices that unreasonably affect auction clearing prices, particularly within relatively small geographic areas, such as LDAs. For example, the CRF schedule of Table 18 assumes that there are only five years of remaining life for any power plant older than 16 years. While appropriate in some cases, this could be unrealistic in some circumstances as many power plants can be expected to be operate for 30, 40, or even 50 years.

A five-year recovery period may be appropriate for minor capital expenditures or for major capital expenditures under certain circumstances. However, such rapid cost recovery often does not apply to major capital additions. For example, if a 20-year old plant is anticipated to operate for another 10 to 20 years, it may be economic to commit to certain major capital investments (such as expensive environmental controls). Such major investments may not be economic if the remaining life of the plant were expected to be only five years. In fact, typical cost recovery periods for such major investments will often be in the 10-to-20 year range even for plants in the "16 Plus" age category.

By giving suppliers the ability to select, in this example, a five-year cost recovery factor even for major capital investments that are expected to be recovered over 10 to 20 years, the offer cap would likely be too high: the annual CRF of 0.363 (more than one third of the full investment costs) associated with a five year remaining life is two-to-four times higher than the CRFs associated with a remaining life of 10, 15, or 20 years.

To avoid unnecessarily high offer caps, we recommend that PJM reevaluate CRF rates for major capital expenditures at existing plants. One could also limit the CRF rate to no more than the 0.198 factor associated with a 10-year remaining life whenever the size of capital expenditures exceeds a certain threshold level. A threshold level could also be determined for each of the remaining life categories in Table 18 based on estimates of the amount of capital investments that would be economic given the particular cost recovery period. However, to avoid creating entry barriers by lowering offer caps for major capital expenditures, it would also be advisable to allow for exemptions to such lower offer caps. Exemptions could be allowed based on documentation by the supplier showing that—in order to recover a major capital expenditure needed to retain the resource—a higher offer cap is justified by a shorter remaining life of the facility. In other words, shorter CRF periods would be allowed if the actual remaining life of the unit can be documented to be less than what is stated in the tariff.

Limits on Offer Caps. Two of the APIR schedules described above are subject to an upper limit on the amount of project investment cost that may be included in the ACR. Under the "Mandatory CapEx" option, the offer cap may not exceed 90 percent of Net CONE as a result of the project investment cost inclusion. Under the "40 Plus Alternative" the highest allowed offer cap is at the level of Net CONE. A limit was also applied temporarily to a third option, the "16 Plus" option, for which offers were not allowed to rise above Net CONE for the 2007/08 and 2009/10 delivery years. Such limits do not apply to the treatment of other existing units or new units.

While we are generally not concerned about imposing some limits, they could prevent efficient investments under certain circumstances. Again, to avoid creating such potential investment barriers, we recommend that PJM consider allowing for exemptions to these limits based on documentation by the supplier showing that a higher offer cap is justified by a remaining life of the facility that is shorter than what is considered in the tariff.

3. Summary of Recommendations

We recommend that PJM consider and more fully evaluate the following modifications on how capital expenditures are reflected in ACR-based offer caps:

- Consider including APIR cost adders in the ACR-based offer caps for only the first delivery year.
- Consider revising CRF rates for major capital expenditures at existing plants based on more realistic estimates of investment recovery periods and remaining facility lives, as discussed in more detail above.
- Consider allowing for exemptions to APIR-based offer caps and to CONE-based limits on APIR factors if suppliers can document that a higher offer cap is justified by a shorter remaining life of the facility.

H. Non-Dispatchable Demand-Side Resources and Load Forecasting

The current RPM framework allows for the direct participation of DR and ILR resources that are dispatchable by PJM. The reliability value of non-dispatchable resources such as energy efficiency ("EE") and price-responsive demand ("PRD") initiatives is currently recognized within RPM only after the impact of EE and PRD programs is reflected in the historic load data. As has already been acknowledged by PJM and its stakeholders, this current treatment does not reflect the reliability and capacity value of these programs in a sufficiently timely fashion.

While EE and PRD programs are not directly controllable by PJM, they nevertheless provide reliability benefits in the form of measurable peak load reductions. Similar to the treatment of DR and ILR programs, the reliability benefits of EE and PRD initiatives should be reflected in the RPM framework as soon as LSEs or third-party providers are willing to commit to specific load reductions. We recommend that PJM consider incorporating the value of EE and PRD initiatives either through updated and proactive adjustments to its load forecasts or by allowing direct participation as a capacity resource in RPM auctions. Particularly for EE, direct participation in RPM auctions may be a more effective solution.

1. Background

As discussed in Section V.D. of this report, the RPM framework currently allows direct participation of qualifying DR and ILR resources that can be called upon by PJM. In contrast, the reliability benefits of demand-side resources that provide peak load reductions without being dispatchable directly by PJM are currently considered within the RPM framework only passively, through the eventual reduction of the observed normalized peak load for the prior summer, which forms the basis for the load forecasts used to set reliability targets in future RPM auctions and delivery periods.

"Non-dispatchable" demand-side programs include energy efficiency programs and price-responsive demand-side programs. EE programs, also referred to as energy conservation or demand-side management ("DSM") programs, are targeted to reduce energy consumption during much of the year, but many also reduce consumption during peak load conditions. Similarly, PRD programs—such as real-time pricing, critical peak pricing, or other dynamic pricing programs—have been shown to provide reliability benefits by measurably reducing customer loads during peak hours.[103]

PJM forecasts future peak loads using an econometric approach that essentially extrapolates the weather-normalized peak load for the previous summer based on forecasts for key variables (such as economic growth) and the historically observed relationship between peak loads and those variables. Forecasts are prepared for actual peak loads (which reflect DR- and ILR-related load reductions) as well as "unrestricted" peak loads (which add back DR- and ILR-related load reductions). PJM does not currently make such explicit adjustments to its load forecasts based on EE- or PRD-related load reductions. Rather, load forecasts are currently adjusted for achieved EE and PRD savings only *after* these savings are reflected in the historic data (i.e., last summer's peak load), which forms the basis for forecasting the peak loads of future delivery years. Hence, EE- or PRD-related load reduction generally will not be recognized in RPM until approximately four years after implementation.

Under the current design, EE- or PRD-related load reductions can also reduce an LSE's capacity obligations in the near term, but only by shifting the obligation to other LSEs in the same zone. The capacity obligation for each load zone is determined in the base auction three years prior to the delivery year, and also in the second incremental auction (if held) 13 months prior to the delivery year. The capacity obligation for each load zone is then allocated to individual LSEs prior to the delivery year on a load-ratio basis, with daily adjustments for changes in the number of customers during the delivery year. A load zone that implements EE and PRD programs would not see a reduction in RPM capacity charges, and the added demand-side resources would not reduce RPM reliability targets and auction clearing prices until the load reductions were also reflected in PJM's load forecast.

2. Identified Concerns and Recommendations

EE and PRD programs that measurably reduce peak load reductions provide two sources of capacity benefits: (1) they reduce the amount of capacity that is needed to satisfy reliability targets; and, by lowering the quantity for other capacity resources, (2) they may also reduce RPM auction clearing prices. These benefits should be reflected in the RPM framework as soon as market participants are willing to commit to specific load reductions.

---

[103] Ahmad Faruqui and Sanem Sergici, "The Power of Experimentation: New Evidence on Residential Demand Response," discussion paper, May 11, 2008, available at http://www.brattle.com/_documents/UploadLibrary/Upload683.pdf.

The current treatment of these demand-side programs results in a significant lag during which the reliability and capacity value of EE and PRD programs will not be reflected within the RPM framework. Specifically, there is a lag between the time when committed EE/PRD measures are expected to provide reliability benefits and the time when the impacts of those EE/PRD measures are actually reflected in PJM's load forecast used for setting the RPM reliability targets.

For example, suppose an LSE decided in 2008 to implement certain EE and PRD programs by late 2011 or early 2012. The full reliability benefit would be realized during the 2012/13 delivery year, for which a base auction is conducted in early 2009. However, these programs would not be eligible to participate in the auction, nor would their effect be reflected in PJM's load forecast (thus reducing reliability requirements) until after the programs' load reductions appear in the historic data that form the basis for load forecasting. This would occur in early 2013, when PJM uses the normalized 2012 summer peak load to prepare the load forecast for the 2016/17 delivery year. The four-year lag – between the 2012/13 delivery year during which the EE/PRD measures are first effective and the 2016/17 delivery year during which the measures first change PJM's peak load forecast and associated reliability requirement – significantly diminishes the capacity value that EE and PRD efforts can capture. This will tend to create a market barrier to the implementation of such programs.

The same lag currently exists for near-term implementation of EE and PRD initiatives. For example, if an LSE's energy efficiency program had been implemented in early 2008 to be effective during the 2008/09 delivery year, the program would reduce the 2008 summer peak loads for the LSE and its corresponding load zone. However, because the capacity obligation for the load zone had already been determined through base auctions for the 2008/09, 2009/10, 2010/11, and 2011/12 delivery years, no RPM-related savings would be realized at the load zone level until the 2012/13 delivery year.[104] The EE measure's impact would first be realized during the summer of 2008, and the summer 2008 weather-normalized peak loads would then be reflected in the load forecast for the base auction held in 2009 for the 2012/13 delivery year. Again, a four-year lag would exist before the RPM framework would fully reflect the reliability benefits of the EE measure.

PJM and stakeholder groups are already exploring various options to reduce this lag for energy efficiency programs. We recommend that PJM consider addressing this lag for all demand-side initiatives that provide reliability benefits, including price-responsive demand initiatives such as critical peak pricing and other dynamic pricing programs. We believe there are at least three options to address this lag:

- Adjustments to the capacity obligations for individual load zones that were set during the base auction prior to all incremental auctions and prior to the delivery year to update and reallocate zonal capacity obligations within the PJM footprint.

[104] If there is only one LSE in that load zone, the LSE would not realize any savings. If there were more than one LSE in that load zone, LSEs with load reductions exceeding the average for the zone would realize some savings as the zonal capacity obligations were allocated to LSEs based on their load ratio share.

- Proactive adjustments to PJM's load forecasts for future RPM delivery years based on estimates of committed load reductions associated with planned energy efficiency and price-responsive demand initiatives subject to measurement and verification of the load reductions during the delivery year.
- Treatment of EE and PRD measures as a capacity resource that can offer and be committed in RPM auctions subject to measurement and verification of the committed capacity impact during the delivery year.

The first option would only partially address this identified lag. Treating EE and PRD as capacity resources could eliminate the lag and enable third-party providers to participate. As discussed below, to avoid the risk of double counting any demand-side related savings (including those associated with DR and ILR) it is also advisable to refine PJM's load forecasting process.

Adjusting Capacity Obligations of Load Zones. Under the present design, the capacity obligations of individual PJM load zones are determined through the base auction and the second incremental auctions (if held), three years and 13 months prior to each delivery year, respectively. Load reductions achieved through EE and PRD that are implemented between the summer prior to the base auction and the delivery year do not reduce the host zone's capacity obligation or provide capacity credit. In order to recognize the reliability value provided by the EE and PRD measures, PJM could consider adjusting the allocation of PJM-wide (and LDA-wide) capacity obligations to individual load zones prior to each delivery year based on the most recent summer load ratio shares. For example, a particular load zone may have accounted for 15 percent of total PJM-wide peak load during the base auction. If this share has decreased to 12 percent immediately prior to the delivery year due to accelerated implementation of EE and PRD measures—or for any other reasons such as lower customer growth—the total PJM-wide capacity obligation for that delivery year could be reallocated based on these updated load ratio shares. This would benefit the zones which were able to reduce their peak loads relative to others, but would not reduce PJM-wide capacity costs.

An extension to reallocating the capacity obligations of load zones would be to adjust zonal peak loads for a delivery year with updated load forecasts prior to each incremental auction. If RTO-wide capacity requirements are reduced because of accelerated EE and PRD implementation the unneeded capacity commitments from prior base auctions could be offered as supply in incremental auctions. (See our recommendations regarding incremental auctions as discussed in Section V.E.)

A disadvantage of these adjustments is that they only partially address the lag between realization of EE- and PRD-based load reductions and when their full value is reflected in the RPM framework through base auctions. These adjustments do not address proactive adjustments to load forecasts nor the option to allow third-party providers to offer this type of demand-side option directly in the RPM auctions as a capacity resource.

Adjustments to PJM's Load Forecasts. To reflect the reliability value of EE and PRD initiatives on a more timely basis, PJM could consider estimates of expected load reductions associated with planned initiatives in its load forecasts as soon as market participants commit to these initiatives and the initiatives satisfy PJM-specified design criteria. If, for example, an LSE commits to certain EE or PRD initiatives in the base or incremental auctions for a given delivery year, the estimated load reduction could be subtracted by PJM from its load forecast to decrease the reliability target that PJM would seek to meet through that auction. This would reduce the quantity procured and likely also reduce the price of the capacity that PJM would procure in that auction, similar to counting the load reductions as supply. The actual load reduction of these EE or PRD initiatives during the delivery year would then need to be determined through PJM-approved measurement and verification protocols. Performance penalties (e.g., 120 percent of the LSE's net load charge per MW-day) could be imposed on the LSE if implementation of committed measures were deficient, unless replacement capacity was procured bilaterally or in incremental auctions to offset the performance deficiency. Availability adjustments could be applied if verified load reductions were below or above committed levels.

Energy Efficiency and Price-Responsive Demand as a Capacity Resource. The disadvantage of reflecting demand-side initiatives as adjustments to LSE, zonal, and PJM-wide load forecasts (rather than treating it as an RPM-committed capacity resource) is that it may make participation by third-party energy service providers more difficult. Third-party providers would either need to implement measures for LSEs or make contractual arrangements with LSEs to capture the capacity benefit of the load reductions. This may create a market barrier for energy efficiency measures offered by providers unaffiliated with LSEs. However, such third-party provision seems less likely for price-responsive demand programs than for EE programs, since PRD programs would be offered to customers primarily through LSEs' own rate structures.

We understand that PJM's RPM Working Group has been discussing how to allow RPM participation for EE initiatives similar to that of DR resources. One of the current proposals would limit an EE measure's participation as a capacity resource to one year and then incorporate the load reduction into the load forecast for the rest of the "measure life" of the investment.[105]

A concern associated with this treatment of EE measures is that it automatically applies the load reductions reflected in the most recent summer peak load to set the target reliability requirements for the next base residual auction, which is equivalent to assuming that the load reductions of the EE measure will last at least another three years. It is, however, unclear that the most recently observed impact of EE measures will actually last that long. It would appear to be more likely that the impacts of EE measures decline over time as equipment reaches the end of its useful life (e.g., energy-saving light bulbs) or as energy-saving technology is increasingly adopted by customers even in the absence of specific EE incentives, thus decreasing the baseline against which savings need to be measured.

It might be more appropriate to allow EE and PRD participation through offers/commitments made in base residual and incremental auctions similar to what we recommended for DR and ILR programs in the prior subsection of this report. The actual load reduction of these EE or PRD initiatives during each delivery year could then be determined through PJM-approved

[105] Synapse recommended an alternative proposal, under which the resource would receive capacity payments for the "measure life" of the upgrade, not just a single year.

measurement and verification protocols. Performance penalties (e.g., 120 percent of the higher of the base and incremental auction clearing prices) could be imposed on the provider with deficient implementation of committed measures unless replacement capacity has been procured to offset the performance deficiency. Similarly, availability adjustments could be applied if verified load reductions were below or above committed levels.

Refinements to PJM's Load Forecasting Process. Both of these options—adjusting load forecasts for EE/PRD commitments or allowing the direct participation in RPM auctions of EE/PRD as capacity resources—would likely require refining PJM's load forecasting process to (1) proactively include explicit adjustments based on committed future load reductions; and (2) update the econometric forecasting process to consider the extent to which penetration and impact of demand-side initiatives is already reflected in the historic load data used to establish future trends through econometric modeling.[106] The first refinement would simply apply to EE and PRD initiatives the types of adjustments PJM already makes to its load forecasts for DR and ILR programs.

The second refinement to PJM's load forecasting process may be necessary to avoid misinterpreting incremental impacts of existing demand-side initiatives as efficiency trends that will continue into perpetuity. For example, if the existing data reflects an acceleration of demand-side initiatives that reduced summer peak load by 100 MW in 2006, by 200 MW in 2007, and by 300 MW in 2008, the current econometric forecasting approach will tend to project a trend that implies additional incremental savings of approximately 100 MW in 2009 and every subsequent year. This could cause two problems. First, it could lead to understated load forecasts if the acceleration of demand-side savings does not continue at the observed historical rate. Second, the forecast would not be an appropriate baseline from which the impact of future demand-side activities could be subtracted without inadvertently double counting the anticipated future load reductions.

In contrast, if the impact of existing demand-side initiatives on historic load data were measured and reflected in the forecasting process, a load forecast could be prepared based on actual and "unrestricted" historic load that reflect the increasing penetration of demand-side measures. This would allow PJM to forecast peak loads that would reflect (1) "unrestricted" future loads without demand-side measures; (2) the impact of *pre-existing* demand-side measures; and (3) the load reductions associated with *additional* demand-side commitments. This load forecasting process would be able to capture more reliably the deterioration of load reductions associated with preexisting efficiency measures as well as the incremental impacts of additional demand-side initiatives without double counting achievable load reductions and understating future peak loads.

[106] This would, again, need to be based on explicit measurement and verification of the implemented demand-side programs.

3. Summary of Recommendations

We recommend that PJM consider and further evaluate measures to incorporate in a more timely and more accurate fashion the capacity value of demand-side initiatives, including EE and price-responsive demand. Similar to the treatment of DR and ILR programs, the benefits of EE and PRD initiatives should be reflected in the RPM framework as soon as LSEs or third-party providers are willing to commit to the associated load reductions. We have presented and discussed the following options:

- Reallocate the capacity obligations of individual load zones that were set during the base auction prior to the delivery year to reflect changes in the relative size of zonal peak loads. Consider an update to zonal and PJM-wide peak load forecasts prior to incremental auctions as discussed in Section V.E. of this report.
- In the case of EE and PRD commitments by LSEs, such as critical peak pricing and other dynamic pricing programs, we recommend that PJM consider pro-active adjustments to its peak load forecasts that reflect the estimated load reduction of these programs. After-the-fact measurement and verification and potential penalties for underperformance would apply.
- Direct participation in RPM auctions may be a more effective solution, particularly for EE initiatives, as it would reduce market barriers by allowing third parties to implement demand-side measures independently of LSEs. After-the-fact measurement and verification protocols and potential penalties for underperformance would similarly apply.
- It would likely be necessary to refine PJM's load forecasting process to more accurately project the future impact of demand-side initiatives, including existing DR and ILR programs, and to mitigate the risk of overstating or double counting future loads in light of accelerated implementation of demand-side measures.

VI. CONCLUSIONS

We conclude that the five base auctions conducted to date have been successful in achieving the stated reliability and economic objectives of RPM. This was achieved despite the very compressed time frame under which, starting in April 2007, RPM auctions have transitioned to procuring capacity on full three-year forward basis. We find that RPM has already attracted and retained over 14,500 MW of resources that likely would not have been made available to PJM otherwise. In addition, RPM helps retain over 20,000 MW of other existing resources that likely would *not* be financially viable in the absence of capacity payments.

As a result of these added and retained resources and with the help of planned transmission upgrades in LDAs, target reserve margins have been achieved both on a PJM system-wide and LDA-internal basis. The increase in new generating and transmission capacity committed to serve SWMAAC and EMAAC has integrated these regions into the RTO-wide capacity market and improved reliability within these regions from levels that were one percent to two percent *below* target to RTO-wide levels of one percent to two percent *above* target reliability levels. Some of the improved LDA reliability is also associated with planned new transmission facilities that were projected to be operational for the 2010/11 and 2011/12 delivery years.

The positive impact of RPM already extends beyond the 2011/12 delivery year. RPM has stimulated the development of an unprecedented amount of potential new resources, which include approximately 33,000 MW of new generation projects in PJM's interconnection queue that that are eligible to offer into future RTO auctions.[107] The vast majority of these proposed generation projects did not exist before 2006, the year during which RPM was approved and finalized.

To obtain these results, customers have paid capacity prices that are roughly consistent with resource adequacy balances and the administratively-determined marginal cost of capacity for the RTO—the Net CONE of approximately $170/MW-day. While RTO-wide capacity prices have increased until the most recent auction, LDA-internal capacity prices have decreased from levels that are above Net CONE through the 2009/10 delivery year to the RTO-wide level of $174/MW-day for the 2010/11 delivery year and $110/MW-day for the 2011/12 delivery year.

We recommend maintaining the basic design elements of RPM—including the sloped VRR curve, the three-year forward time frame, and the one-year commitment periods—but offer a number of recommendations that could enhance the effectiveness of the RPM market design. Specifically, we recommend that PJM and its stakeholder community consider and further evaluate the following options:

1. Implement changes to certain market rules and design elements that would increase the pool of resources able to offer capacity into RPM by: (1) reducing capacity that is "excused" from RPM, in particular the excluded excess capacity of FRR entities; (2) streamlining the generation interconnection process; and (3) adopting various

[107] 28,000 MW of these proposed generation projects are from non-renewable sources.

measures that allow energy efficiency and price-responsive demand resources to be reflected in RPM on a more timely basis. These changes would increase the future supply of capacity resources.

2. Revise the deficiency and unavailability penalty provisions of RPM. Current penalties faced by generating capacity resources seem overly punitive, while penalties faced by demand resources seem too lenient. We recommend changes to the penalty structure that would reduce the risks faced by suppliers, while maintaining performance incentives for all resource types.

3. Improve processes to maintain and cost-effectively provide reliability within LDAs by: (1) defining LDAs electrically based on proximity to major transmission constraints; (2) modifying or eliminating the pre-auction screening of LDAs; (3) reevaluating the current reliability criterion applied to LDAs; (4) adjusting for LDA capacity shortfalls due to delays in planned transmission projects; and (5) offering to resources within LDAs an option to "lock in" capacity prices for three to five years.

4. Redesign incremental auctions so that they are more liquid, more able to address decreases in load and changes in LDA import capabilities, and more consistent with the base auctions by: (1) creating a single type of incremental auction; (2) adding into incremental auctions the portion of the VRR curve that did not clear in the base auction, updated for changes in load forecasts; and (3) integrating ILR resources into the incremental auctions.

5. Reevaluate RPM's project investment cost provisions and evaluate potential modifications to how capital expenditures (cap-ex) may be included in suppliers' offers, including: (1) allowing cap-ex adders to offer caps only in the first delivery year in which the particular capital addition is operational; (2) reevaluating investment recovery periods, particularly for major capital expenditures; and (3) allowing exemptions from offer caps for existing resources, based on a showing by a supplier that a higher offer cap is justified.

6. Evaluate how reliability targets and Net CONE values are selected to anchor the VRR curve by: (1) reviewing the reliability targets; and (2) improving administrative updates to Net CONE, including an update to gross CONE and the use of forward-looking offsets for energy and ancillary service margins with ex post true-ups; and (3) refining the empirical adjustment option to update Net CONE.

APPENDIX — LIST OF ACRONYMS

ACR	Avoidable Cost Rate (used in offer mitigation)
ALM	Active Load Management
APIR	Avoidable Project Investment Rate (used in offer mitigation)
APPA	American Public Power Association
ARPIR	Avoidable Refunds of Project Investment Reimbursements (offer mitigation)
ARR	Annual Revenue Rate (payment to DR provider)
ATDCF	After-Tax Discounted Cash Flow (financial model)
BRA	Base Residual Auction
BTM	Behind the Meter Generation
CAPEX	Capital Expenditure (used in offer mitigation)
CC	Combined-Cycle power plant
CCM	Capacity Credit Market
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CONE	Cost of New Entry
CRF	Capital Recovery Factor
CSP	Curtailment Service Provider
CT	Combustion Turbine power plant
DDR	Daily Deficiency Rate (penalties)
DFAX	Distribution Factor
DSM	Demand-Side Management
DR	Demand Resources (participating in FRR capacity plans or RPM auctions)
DUQ	Duquesne Lighting Company
DY	Delivery Year
E&AS	Energy and Ancillary Services
EE	Energy Efficiency
EFORd	Equivalent Demand Forced Outage Rate
EFORp	Peak-Period Equivalent Forced Outage Rate
EMAAC	Eastern Mid-Atlantic Area Council (PSEG, JCPL, PECO, RECO, AE, and DPL service areas within PJM region)

EPC	Engineering, Procurement and Construction
FCA	Forward Capacity Auction (ISO-NE capacity market auction)
FCM	Forward Capacity Market (ISO-NE capacity market)
FERC	Federal Energy Regulatory Commission
FPR	Forecast Pool Requirement
FRR	Fixed Resource Requirement
ICAP	Installed Capacity
ILR	Interruptible Load for Reliability
IRM	Installed Reserve Margin
ISA	Interconnection Service Agreement
ISO-NE	ISO New England
LDA	Locational Deliverability Area
LM	Load Management
LOLE	Loss of Load Expectation
LSE	Load-Serving Entity
MAAC	Mid-Atlantic Area Council (NERC reliability region)
MAAC+APS	Mid-Atlantic Area Council plus Allegheny Power System (within PJM region)
MISO	Midwest Independent System Operator
MMU	Market Monitoring Unit
MO	Maintenance Outage
MW	Megawatt
MWh	Megawatt-hour
NEPA	New Entry Price Adjustment (3-year price lock-in within LDAs)
Net CONE	Net Cost of New Entry (CONE net of E&AS offset)
NERC	North American Electric Reliability Council
NUG	Non-Utility Owned Generator
NYISO	New York ISO
O&M	Operations and Maintenance
QTU	Qualifying Transmission Upgrade
PRD	Price Responsive Demand
RCP	Resource Clearing Price
RPM	Reliability Pricing Model

RTEP	Regional Transmission Expansion Plan
RTEPP	Regional Transmission Expansion Planning Process
SEC	U.S. Securities and Exchange Commission
SWMAAC	Southwestern Mid-Atlantic Area Council (PEPCO and BG&E service areas within PJM region)
UCAP	Unforced Capacity
VOLL	Value of Lost Load
VRR	Variable Resource Requirement (sloping demand curve)