State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

Independent Market Monitor for PJM

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Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2013 State of the Market Report for PJM.*

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

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Introduction

2013 in Review

The state of the PJM markets in 2013 was good, but there are significant issues that must be addressed. The results of the energy market, the results of the capacity market and the results of the regulation market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in 2013. The test of a competitive power market is how it reacts to change. PJM markets have passed that test so far, but that test continues. The significant changes in the economic environment of PJM markets continued in 2013 and will continue.

Continued success requires that market participants have access to all the information about the economic fundamentals of PJM markets necessary to make rational decisions. There are still areas where more transparency is required in order to permit markets to function effectively. The provision of clear, understandable information about market fundamentals matters. Information about the sources of energy uplift charges is notably opaque.

Continued success requires markets that are flexible and adaptive. However, wholesale power markets are defined by complex rules. Markets do not automatically provide competitive and efficient outcomes. There are still areas of market design that need further improvement in order to ensure that the PJM markets continue to adapt successfully to changing conditions. The details of market design matter.

It is more critical than ever to get capacity market prices correct. A number of capacity market design elements have resulted in a substantial suppression of capacity market prices for multiple years. The impact in the 2016/2017 base auction was about $4.6 billion. That price suppression has had and continues to have a negative impact on net revenues and thus on the incentive to continue to operate existing units and to invest in new units. Price suppression is more acute in western zones than in eastern zones. Price suppression leads to premature and uneconomic retirements and the failure to make economic investments. Coal units and nuclear units are under stress in PJM markets. The MMU estimates that the actual net revenue results for 2013 mean that 14,597 MW of capacity in PJM are at risk of retirement in addition to the 24,933 MW that are currently planning to retire.

The most fundamental required change to the capacity market design is the enforcement of a consistent definition of a capacity resource so that all capacity resources are full substitutes for one another. In the case of imports, substitutability means that the units must have a pseudo tie into PJM. Without that, capacity imports cannot be substitutes for internal capacity. As a result of the fact that all imports are included in the rest of RTO, the inadequate definition of imports has had a larger impact on western zones. In the case of demand resources, substitutability means that resources must have a day-ahead energy market must offer requirement and must be subject to the same offer cap as all other resources in addition to being an annual product.

An essential part of being full substitutes is the requirement that all capacity resources be physical resources. The definition of this requirement should be enhanced and enforced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a binding commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports. Under existing capacity market rules, capacity imports, planned new generation and demand resources all face incentives to buy out of their positions in incremental auctions and do so.

The capacity market is designed to function so that when energy market revenues are lower, capacity market prices are higher. For that reason, the design of the capacity market should ease the transition to greater reliance on renewables, but it cannot do so if the capacity market price is suppressed. The capacity market design must be corrected immediately in order to permit the market to function and the transition to be managed within the market rules.

The energy market dynamics changed in 2013. A combination of increased, weather related, demand, and higher fuel costs led to higher energy market prices than in 2012. The load-weighted average LMP was 9.7

percent higher in 2013 than in 2012, $38.66 per MWh versus $35.23 per MWh.

The price of natural gas was higher in 2013 than in 2012, and the price of coal was relatively flat in 2013. For example, the price of Northern Appalachian coal was 1.0 percent higher and the price of Central Appalachian coal was 0.3 percent higher, while the price of eastern natural gas was 40.0 percent higher in 2013 than in 2012. The price of natural gas, especially in the eastern part of PJM, increased in January, decreased for some months, and began to rise again late in the year.

The results of the energy market dynamics in 2013 were generally positive for new coal units. As a result of the relative changes in fuel costs, coal-fired units were more competitive with gas-fired units. Coal-fired units' output increased by 6.2 percent in 2013 and gas-fired units' output decreased by 12.2 percent in the same period, reversing the trend towards reduced coal output. In 2013, the yearly average operating cost of the CC was lower than the average operating costs of the CP for seven out of twelve months, as a result of the relative cost of gas versus coal.

The high demand days in the summer of 2013 highlighted the fact that demand resources are not full substitutes for generation for several additional reasons. This inadequate definition of demand resources created operational difficulties for PJM in responding to high load particularly in specific local areas. The need for the announcement of emergency conditions, two hour lead time, two hour minimum dispatch period, availability of demand resources only from 12:00-20:00, maximum number of events allowed each delivery year, and lack of nodal mapping are inappropriate limitations on demand resources that should be removed in order to ensure that demand resources serve as capacity resources and are available to resolve reliability issues when necessary. To address these issues the market rules should be modified so that demand resource dispatch is nodal to permit more effective dispatch of such resources, that demand resources are considered an economic resource rather than an emergency resource, that demand resources are available year round and that demand resources have a shorter lead time.

FTR revenue sufficiency continues to be referenced as an issue. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy defined solely with reference to day ahead congestion. Loads, which are assigned ARRs, do have those rights based on their payment for the transmission system. The market has worked and will continue to work. Market participants are paying less for each FTR and buying more FTRs. But the market could work better. FTR revenue issues could be substantially resolved by taking eight straightforward steps to modify the FTR process. None of these steps require the radical change in the definition of FTRs recommended by some parties. Load should never be required to subsidize payments to FTR holders, regardless of the reason. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system as a hedge against congestion and pay for balancing congestion in order to increase the payout to holders of FTRs who are not loads.

The fact that up to congestion transactions continue to be provided an artificial advantage over other virtual transactions is not consistent with an efficient market design. Up to congestion transactions should be required to pay uplift in exactly the same was as increment offers and decrement bids because up to congestion transactions also affect unit commitment and dispatch and contribute to increased uplift costs in the same was as increment offers and decrement bids.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need good information about constraints that can have substantial impacts on energy prices. For example, the markets need better information about unit outages in order to improve market transparency. For example, the markets need better information about transmission outages in order to improve market transparency. For example, the markets need better information about the reasons for energy uplift charges in order to permit market responses to persistent high payments of energy uplift credits. Data on the units receiving energy uplift credits and the reasons for those credits should be made publicly available to permit better understanding of energy uplift levels and to facilitate competition for providing the same services. Recent rule changes to improve the availability of information about unit retirements will make information available to potential entrants and increase the competitiveness of the capacity market.

The market design should permit market prices to reflect underlying supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed, including better LDA definitions, the effectiveness of the transmission interconnection queue process, the 2.5 percent reduction in demand that suppresses market prices, the continued inclusion of inferior demand side products that also suppress market prices and the role of imports.

The PJM markets and PJM market participants from all sectors face significant challenges as a result of the changing economic environment. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM Market Summary Statistics, 2012 and 2013[1]

	2012	2013
Load	775,184 GWh	784,515 GWh
Generation	790,090 GWh	797,100 GWh
Imports (+) / Exports (-)	672 GWh	3,101 GWh
Losses	16,970 GWh	17,389 GWh
Regulation Requirement*	943 MW	784 MW
RTO Primary Reserve Requirement **	NA	2,085 MW
Total Billing	$29.18 Billion	$33.86 Billion
Peak	**Jul 17, 2012 17:00**	**Jul 18, 2013 17:00**
Peak Load	154,344 MW	157,508 MW
Load Factor	0.76	0.76
Installed Capacity	**As of 12/31/2012**	**As of 12/31/2013**
Installed Capacity	181,990 MW	183,095 MW

* Daily average

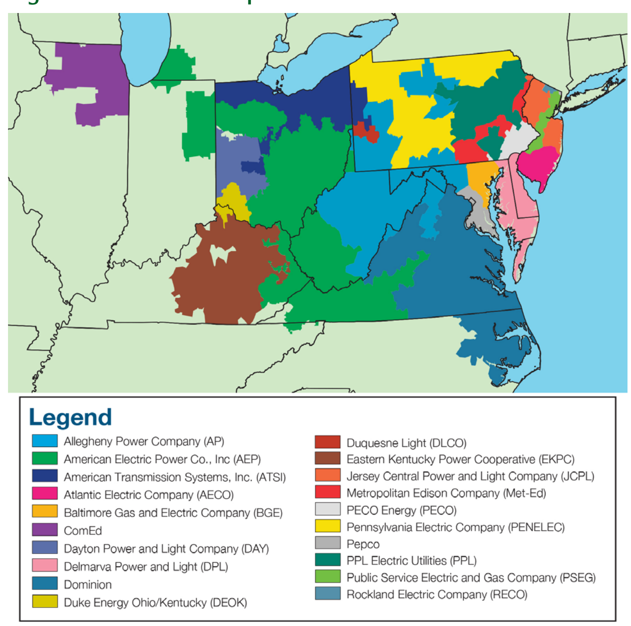
** Regulatory requirement remained 2,063MW throughout the year. Amount shown is daily average.

1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2013, had installed generating capacity of 183,095 megawatts (MW) and 879 members including market buyers, sellers and traders of electricity in a region including more than 61 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[2,3,4] In 2013, PJM had total billings of $33.86 billion, up from $29.18 billion in 2012.[5] As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 20 control zones



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day - Ahead Scheduling Reserve (DASR) Market and the Long Term,

2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.

4 See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2013.

5 Monthly billing values are provided by PJM.

Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[6,7]

On June 1, 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC).

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2013, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referenced as participant conduct.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market performance, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

6 See also the *2013 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

7 Analysis of 2013 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2013, see 2013 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography."

The MMU concludes the following for 2013:

Table 1-2 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1167 with a minimum of 844 and a maximum of 1604 in 2013.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9]

Table 1-3 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]

8 OATT Attachment M.

9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue and the inclusion of imports which are not substitutes for internal capacity resources.

Table 1-4 The Regulation Market results were competitive for 2013

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 90 percent of the hours in 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for 2013 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

Table 1-5 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

Table 1-6 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, 12 percent of offers reflected economic withholding.

- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-7 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and over sells FTRs. FTR funding levels are reduced as a result of these and other factors.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[13]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports, and reports on market issues. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU also issues reports on specific topics in depth. The MMU regularly issues reports on RPM auctions. In other ad hoc reports, the MMU responds to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[14] The MMU has

12 18 CFR § 35.28(g)(3)(ii); see also Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), reh'g denied, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

13 OATT Attachment M § IV; 18 CFR § 1c.2.

14 OATT Attachment M § IV.

direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules.[17] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[18,19] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[20]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[21] If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[22,23] If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

Another important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through ex ante mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price based or cost based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost based offer accurately reflects short run marginal cost. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[24] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[25]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[26,27,28,29]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[30] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[31] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

15 OATT Attachment M § IV.K.3.
16 OATT Attachment M § IV.H.
17 OATT Attachment M § II(d)&(q) ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")
18 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
19 OATT Attachment M § II(h-1).
20 OATT Attachment M § IV.C.
21 OATT Attachment M § IV.I.1.
22 *Id.*
23 *Id.*
24 See OATT Attachment M–Appendix § II.A.
25 OATT Attachment M–Appendix § II.E.
26 OATT Attachment M–Appendix § II.B.
27 OATT Attachment M–Appendix § II.C.
28 OATT Attachment M–Appendix § IV.
29 OATT Attachment M–Appendix § VII.
30 OATT Attachment M § IV.
31 OATT § 12A.

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[34] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

Prioritized Summary of New Recommendations

Table 1-8 includes a brief description and a priority ranking of the MMU's new recommendations for 2013.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects.

32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.

Table 1-8 Prioritized summary of new recommendations for 2013

Priority	Section	Description
Low	3 - Energy Market	No FMU status for black start units.
Medium	3 - Energy Market	Do not use ATSI Interface or similar interfaces to set zonal capacity prices to accommodate inadequacy of DR product.
Low	3 - Energy Market	Review transmission facility ratings to ensure normal, emergency and load dump ratings in transmission system modeling are accurate.
Low	3 - Energy Market	Update outage impact studies, RPM reliability analyses for capacity deliverability and reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations implemented in June 2013.
Low	3 - Energy Market	Clarify roles of PJM and the transmission owners in the decision making process to control for local contingencies. Strengthen PJM's role and make the process transparent.
Low	3 - Energy Market	Explain in the appropriate manual the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.
Low	3 - Energy Market	Treat hours with net withdrawal at a gen bus as load for calculating load and load weighted LMP. Conversely, treat injections as generation.
Low	3 - Energy Market	Identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.
Medium	4 – Energy Uplift	Reallocate the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
Medium	4 – Energy Uplift	Be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce subjectivity of their creation and implementation. Estimate their impact on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
High	4 – Energy Uplift	Require UTCs to pay operating reserve charges. Revise confidentiality rules to allow disclosure of the reasons for, and the amount of unit operating reserve charges.
Medium	4 – Energy Uplift	Base energy uplift payments on real-time output and not day-ahead scheduled output whenever operation results in a lower loss or no loss at all. Include net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
Medium	4 – Energy Uplift	Use net regulation revenues as an offset in the calculation of balancing operating reserve credits.
Low	4 – Energy Uplift	Do not compensate self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.
High	5 – Capacity Market	Enforce a consistent definition of capacity resource to be a physical resource at time of auction and in the relevant delivery year. Apply requirement to all resource types, including planned generation, demand to all resource types, including planned generation, demand resources and imports. resources and imports.
High	5 – Capacity Market	Modify definition of DR to be substitutable for other generation capacity resources. Eliminate Limited and Extended Summer DR so DR has the same obligation to provide capacity year round as generation capacity resources.
Medium	5 – Capacity Market	Terminate the 2.5 percent demand adjustment (Short Term Resource Procurement Target) and add it back to the demand curve.
Medium	5 – Capacity Market	Redefine LDA test, and include reliability analysis in redefined model.
Low	5 – Capacity Market	Require that capacity resource offers in DA market be competitive (short run marginal cost of units.).
Low	5 – Capacity Market	Clearly define operational details of protocols for recalling energy output of capacity resources in emergency conditions.
High	5 – Capacity Market	Pay capacity resources on basis of whether they produce energy when called upon in critical hours.
Medium	5 – Capacity Market	Units not capable of supplying energy consistent with DA offer should reflect outage.
Medium	5 – Capacity Market	Eliminate all OMC outages from market impacting forced outage rate calculations.
Medium	5 – Capacity Market	Eliminate the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
High	6 - Demand Response	Allow only one demand resources product, with an obligation to respond when called for all hours of the year.
High	6 - Demand Response	Apply daily must offer requirement to demand resources comparably to generation capacity resources.
High	6 - Demand Response	Apply $1,000 offer cap requirement to demand resources comparably to cap on energy offers of generation capacity resources.
Medium	6 - Demand Response	Shorten demand resource lead time to 30 minutes, with one hour minimum dispatch.
High	6 - Demand Response	Require demand resources to provide nodal location on grid.
Medium	6 - Demand Response	Adopt the ISO-NE metering requirements so dispatchers have information for reliability and so DR market payments be calculated based on interval meter data at the site of the demand reductions.
Low	6 - Demand Response	Initiate load management testing with limited warning to CSPs.
Medium	9 – Interchange Transactions	Eliminate IMO Interface Pricing Point, assign MISO pricing point to IESO transactions.
Medium	9 – Interchange Transactions	Validate submitted transactions to prohibit disaggregation that defeats the interface pricing rule by obscuring the true source or sink.
Medium	9 – Interchange Transactions	Require market participants to submit transactions on market paths that reflect expected actual flow.
Low	9 – Interchange Transactions	Eliminate NIPSCO and Southeast interface pricing points from DA and RT energy markets. With VACAR, assign SouthIMP/EXP to transactions created under reserve sharing agreement.
Low	9 – Interchange Transactions	Provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
High	10 – Ancillary Services	Modify Regulation market to consistently apply marginal benefit factor throughout optimization, assignment, and settlement.
High	10 – Ancillary Services	Eliminate rule requiring payment of tier 1 synchronized reserve resources when non-synchronized reserve price is above zero.
Medium	10 – Ancillary Services	Enforce tier 2 synchronized reserve must offer provision of scarcity pricing.
Low	10 – Ancillary Services	Define why tier 1 biasing is used in optimized solution to Tier 2 Synchronized Reserve Market. Identify rule applied to each instance of biasing.
Low	10 – Ancillary Services	Determine why secondary reserve was unavailable or not dispatched on September 10, 2013. Evaluate replacing the DASR market with an available and dispatchable real time secondary reserve product.
Low	10 – Ancillary Services	Revise the current black start confidentiality rules in order to allow a more transparent disclosure of information.
Low	12 - Planning	Create mechanism to permit a direct comparison, or competition, between transmission and generation alternatives.

Low	12 - Planning	Implement rules to permit competition to provide financing of transmission projects.
Low	12 - Planning	Address question of whether CIRs should persist after unit retirement to prevent incumbents from exploiting CIRs to block competitive entry.
Low	12 - Planning	Outsource interconnection studies to an independent party, rather than relying on incumbent transmission owners.
Low	13 – FTRs and ARRs	Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
High	13 – FTRs and ARRs	Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
High	13 – FTRs and ARRs	Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
High	13 – FTRs and ARRs	Eliminate cross geographic subsidies.
Low	13 – FTRs and ARRs	Improve transmission outage modeling in the FTR auction models.
High	13 – FTRs and ARRs	Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
Medium	13 – FTRs and ARRs	Implement a seasonal ARR and FTR allocation system to better represent outages.
High	13 – FTRs and ARRs	Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
High	13 – FTRs and ARRs	Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
Medium	13 – FTRs and ARRs	Do not use ATSI Interface or similar interfaces to set zonal capacity prices to accommodate inadequacy of DR product. Study the implementation of closed loop interface constraints so as to include them in the FTR Auction model to minimize their impact on FTR funding.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-9 provides the average price and total revenues paid, by component, for 2012 and 2013.

Table 1-9 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 94.6 percent of the total price per MWh in 2013.

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and non firm point to point transmission service.[37]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead, balancing and synchronous condensing charges.[38]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[39]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[40]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[41]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[42]

37 OATT §§ 13.7, 14.5, 27A & 34.

38 OA Schedules 1 §§ 3.2.3 & 3.3.3.

39 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-9 includes all reactive services charges.

40 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.

41 OATT Schedule 12.

42 Reliability Assurance Agreement Schedule 8.1.

- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[43]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[44]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[45]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[46]
- The Black Start component is the average cost per MWh of black start service.[47]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[48]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[49]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[50]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[51]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[52]
- The Emergency Energy component is the average cost per MWh of emergency energy.[53]

43 OATT PJM Emergency Load Response Program.
44 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
45 OATT Schedule 1A.
46 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
47 OATT Schedule 6A. The line item in Table 1-9 includes all Energy Uplift (Operating Reserves) charges for Black Start.
48 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
49 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
50 OA Schedule 1 § 3.6.
51 OA Schedule 1 § 5.3b.
52 OA Schedule 1 § 3.2.3A.001.
53 OA Schedule 1 §3.2.6.

Table 1-9 Total price per MWh by category: 2012[54] and 2013

Category	2012 $/MWh	2013 $/MWh	Percent Change Totals	2012 Percent of Total	2013 Percent of Total
Load Weighted Energy	$35.23	$38.66	9.7%	71.8%	71.7%
Capacity	$6.05	$7.13	17.8%	12.3%	13.2%
Transmission Service Charges	$4.78	$5.20	8.7%	9.7%	9.6%
Reactive	$0.43	$0.80	87.6%	0.9%	1.5%
Energy Uplift (Operating Reserves)	$0.79	$0.59	(25.5%)	1.6%	1.1%
PJM Administrative Fees	$0.44	$0.43	(2.0%)	0.9%	0.8%
Transmission Enhancement Cost Recovery	$0.34	$0.39	15.5%	0.7%	0.7%
Regulation	$0.26	$0.24	(5.3%)	0.5%	0.5%
Black Start	$0.03	$0.14	437.7%	0.1%	0.3%
Capacity (FRR)	$0.52	$0.11	(79.4%)	1.1%	0.2%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(0.3%)	0.2%	0.2%
Emergency Load Response	$0.02	$0.06	209.0%	0.0%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.06	21.9%	0.1%	0.1%
Synchronized Reserves	$0.04	$0.04	3.1%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	(1.2%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(1.4%)	0.0%	0.0%
Economic Load Response	$0.01	$0.01	41.6%	0.0%	0.0%
Non-Synchronized Reserves	$0.00	$0.00	127.3%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	17.2%	0.0%	0.0%
Emergency Energy	$0.00	$0.00		0.0%	0.0%
Total	$49.07	$53.92	9.9%	100.0%	100.0%

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 2,546, or 1.5 percent, from 173,414 MW in the summer of 2012 to 175,960 MW in the summer of 2013.[55] The increase in offered generation was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 1,127 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 18 units (2,863 MW) since January 1, 2013.

  PJM average real-time generation in 2013 increased by 1.2 percent from 2012, from 88,708 MW to 89,769 MW. The PJM average real-time generation in 2013 would have increased by 0.5 percent from 2012, from 88,708 MW to 89,126 MW, if the EKPC Transmission Zone had not been included.[56]

54 The 2012 total price per MWh is higher than previously reported due to the addition of the Capacity (FRR) component.
55 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
56 The EKPC Zone was integrated on June 1, 2013.

PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, increased by 10.3 percent from 2012, from 134,479 MW to 148,323 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 9.7 percent from 2012, from 134,479 MW to 147,541 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 758.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.
- **Generation Fuel Mix.** During 2013, coal units provided 44.3 percent, nuclear units 34.8 percent and gas units 16.3 percent of total generation. Compared to 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 1.4 percent, and generation from gas units decreased 12.2 percent. The change is primarily a result of increased natural gas prices in 2013, particularly in eastern zones, and lower or constant coal prices.
- **Marginal Resources.** In the PJM Real-Time Energy Market, for 2013, coal units were 57.7 percent and natural gas units were 32.4 percent of marginal resources. In 2012, coal units were 58.8 percent and natural gas units were 30.3 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, for 2013, up-to congestion transactions were marginal for 96.4 percent of marginal resources, the INCs were marginal for 1.3 percent of marginal resources, the DECs were marginal for 1.1 percent of marginal resources, and generation resources were marginal in only 1.2 percent of marginal resources in 2013.
- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load for 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[57]

  PJM average real-time load in 2013 increased by 1.5 percent from 2012, from 87,011 MW to 88,332 MW. The PJM average real-time load in 2013 would have increased by 0.6 percent from 2012, from 87,011 MW to 87,537 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead demand in 2013, including DECs and up-to congestion transactions, increased by 10.1 percent from 2012, from 131,612 MW to 144,858 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased 9.4 percent from 2012, from 131,612 MW to 143,962 MW, if the EKPC Transmission Zone had not been included. The day-ahead demand growth was 573.3 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.
- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 25.0 percent by spot market purchases and 64.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot market purchases increased by 1.8 percentage points and reliance on self-supply decreased by 3.3 percentage points. For 2013, 8.0 percent of day-ahead load was supplied by bilateral contracts, 24.5 percent by spot market purchases, and 67.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot market purchases increased by 2.2 percentage points, and reliance on self-supply decreased by 3.6 percentage points.

57 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2013 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **Supply and Demand: Scarcity.** PJM's market did not experience any reserve-based scarcity events in 2013. However, PJM declared a hot weather alert in all parts of the PJM territory on seventeen days in 2013 compared to twenty eight days in 2012. PJM declared cold weather alerts on seven days in 2013 and did not declare any cold weather alerts in 2012. PJM issued a maximum emergency generation alert on four days in 2013 compared to one day in 2012. PJM declared emergency mandatory load management reductions (long lead time) on five days in 2013 and on two days in 2012. PJM declared emergency mandatory load management reductions (short lead time) on one day each in 2013 and 2012. PJM declared maximum emergency generation actions on five days in 2013 that resulted in PJM direction to load maximum emergency capacity, compared to two days in 2012. PJM declared a voltage reduction warning and reduction of non-critical plant load on one day each in 2013 and 2012.

  In the week beginning September 9, 2013, unusually high temperatures in the PJM territory combined with some generation and transmission outages resulted in PJM issuing load shed directives in specific locations.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.1 percent in 2012 and 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.8 percent in 2012 to 0.4 percent in 2013.

  In 2013, 12 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.8 percent in 2012 to 3.1 percent in 2013. In the Real-Time Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.9 percent in 2012 to 2.5 percent in 2013.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. The average markup index of marginal units was calculated by offer price category.

  In the PJM Real-Time Energy Market in 2013, 93.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.04. Nonetheless, some marginal units do have substantial markups.

  In the PJM Day-Ahead Energy Market in 2013, 99.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 112 units eligible for FMU or AU status in at least one month during 2013, 22 units (19.6 percent) were FMUs or AUs for all of 2013, and 10 units (8.9 percent) qualified in only one month of 2013.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2013, up-to congestion transactions continued to displace increment offers and decrement bids. The average hourly submitted and cleared increment offer MW decreased 23.4 and 14.5 percent, and the average hourly submitted and cleared decrement bid MW decreased 18.0 and 14.6 percent in 2013 compared to 2012. The average hourly up-to congestion transaction submitted and cleared MW increased 46.3 and 34.6 percent in 2013 compared to 2012. The top five companies with cleared up-to congestion transactions are financial and account for 57.4 percent of all the cleared up-to congestion MW in PJM in 2013.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in 2013 compared to 2012. The system average LMP was 10.4 percent higher in 2013 than in 2012, \$36.55 per MWh versus \$33.11 per MWh. The load-weighted average LMP was 9.7 percent higher in 2013 than in 2012, \$38.66 per MWh versus \$35.23 per MWh.

  PJM Day-Ahead Energy Market Prices increased in 2013 compared to 2012. The system average LMP was 13.3 percent higher in 2013 than in 2012, \$37.15 per MWh versus \$32.79 per MWh. The load-weighted average LMP was 12.7 percent higher in 2013 than in 2012, \$38.93 per MWh versus \$34.55 per MWh.[58]

- **Components of LMP.** LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch in which marginal units determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system's load-weighted LMP using the components of unit offers and sensitivity factors.

  In the PJM Real-Time Energy Market, for 2013, 46.6 percent of the load-weighted LMP was the result of coal costs, 27.6 percent was the result of gas costs and 0.63 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, for 2013, 71.9 percent of the load-weighted LMP was the result of up-to congestion transactions, 11.9 percent was the result of the cost of coal and 5.7 percent was the result of the cost of gas.

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  In the PJM Real-Time Energy Market in 2013, the adjusted markup was positive, \$0.77 per MWh or 2.0 percent of the PJM real-time, load-weighted average LMP, primarily as a result of competitive behavior by coal units. In 2013, the real time load-weighted average LMP for the month of July had the highest markup component, \$4.37 per MWh using adjusted cost offers. This corresponds to 8.6 percent of July's real time load-weighted average LMP. The July results demonstrate that markups can increase significantly during high demand periods.

  In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In 2013, the adjusted markup component of LMP resulting from generation resources was negative, -\$0.53 per MWh.

  The overall markup results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between annual average day-ahead and real-time prices was \$0.32 per MWh in 2012 and -\$0.60 per MWh in 2013. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

58 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

Section 3 Recommendations

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently being evaluated in the PJM stakeholder process.
- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability.[59] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[60]
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[61] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[62]
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation increased by 2,546 MW in the summer of 2013 compared to the summer of 2012, while peak load increased by 3,165

59 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.

60 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

61 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

62 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy market results for 2013 generally reflected supply-demand fundamentals.

The high load conditions in the summer of 2013 illustrated a number of issues that are addressed in the MMU recommendations.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[63] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM

63 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in 2013.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by 35.6 percent or $231.4 million in 2013 compared to 2012, from $650.8 million to $882.2 million. This change was the result of an increase of $263.5 million in reactive services charges, an increase of $78.2 million in black start services charges and an increase of $0.2 million in synchronous condensing charges. These increases were partially offset by a decrease of $48.9 million in day-ahead operating reserve charges and a decrease of $61.6 million in balancing operating reserve charges.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.079 per MWh. The day-ahead operating reserve rate including unallocated congestion charges averaged $0.103 per MWh. The balancing operating reserve reliability rates averaged $0.051, $0.030 and $0.004 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $0.863, $1.868 and $0.122 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $0.705 per MWh and the canceled resources rate averaged $0.003 per MWh.

- **Reactive Services Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $2.538, $1.900 and $0.690 per MWh. The reactive transfer interface support rate averaged $0.224 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 48.8 percent of all day-ahead generator credits and 49.1 percent of all balancing generator credits. Combustion turbines and diesels received 72.7 percent of the lost opportunity cost credits. Coal units received 87.1 percent of all reactive services credits.

- **Economic and Noneconomic Generation.** In 2013, 81.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Charges and Credits

- In 2013, 82.2 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generators, 5.9 percent by transactions at hubs and aggregates and 11.9 percent by transactions at interfaces.

Energy Uplift Issues

- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 38.0 percent of all credits. The top 10 organizations received 89.0 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5340, balancing operating reserves HHI was 3622, lost opportunity cost HHI was 4390 and reactive services HHI was 3016.

- **Day-Ahead Unit Commitment for Reliability:** In 2013, 4.6 percent of the total day-ahead generation was scheduled as must run by PJM, of which 66.9 percent was made whole.

- **Lost Opportunity Cost Credits:** In 2013, lost opportunity cost credits decreased by $105.1 million compared to 2012. In 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 61.7 percent of all lost opportunity cost credits, 55.0 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 60.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 57.0 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.

- **Lost Opportunity Cost Calculation:** In 2013, lost opportunity cost credits would have been reduced by an additional $22.8 million, or 26.3 percent, if all recommendations proposed by the MMU on this issue had been implemented.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In 2013, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $86.4 million.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in 2013, the average rate paid by a DEC in the Eastern Region would have been $0.202 per MWh, which is 93.9 percent less ($3.099 per MWh) than the actual average rate paid.

2013 Energy Uplift Charges Increase

- **Unallocated Congestion Charges:** In 2013, congestion charges that could not be allocated to FTR holders accounted for a $19.2 million increase in energy uplift charges compared to 2012.
- **Unit Scheduling/Commitment and Allocation Change:** The need to schedule/commit resources as must run for black start and reactive support combined with the unit scheduling/commitment change performed by PJM in September 2012 and the energy uplift charges allocation change filed by PJM in December 2012 resulted in a net $21.1 million increase in energy uplift charges in 2013 compared to 2012. This issue had different impacts in each energy uplift category.
- **FMU Adders:** The impact of FMU adders included in the offers of units providing reactive support was $81.7 million. These units became eligible for FMU adders in 2013 after qualifying for the adder based on the percentage of run hours on which they were offer capped.
- **Reactive Credits Settlement Issue:** PJM announced a settlement issue due to an unintended logging error regarding units scheduled in the Day-Ahead Energy Market for reactive support. The estimated impact of this issue is $26.2 million. A portion or all of these payments might be resettled depending on the underlying reason for dispatching these units in real time.
- **Winter Days:** Energy uplift charges in the winter days of 2013 were $88.0 million more than the energy uplift charges in the winter days of 2012. This increase was primarily a result of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Section 4 Recommendations

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.
- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

    - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.
    - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU also recommends other rule changes regarding the calculation of lost opportunity cost credits to units scheduled in the Day-Ahead Energy Market and not committed in real time:
    - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be eligible for an LOC compensation when committed or decommitted within an hour.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. The MMU also recommends including real-time exports in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region.
- The MMU recommends enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their operation results in a lower loss or no loss at all.
- The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

Section 4 Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start charges.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and that the allocation of these charges reflects the reasons that the costs are incurred to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations has persisted for more than ten years.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[64] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators actions in LMP.[65]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Overview: Section 5, "Capacity Market"

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[66]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[67] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10,

64 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.

65 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

66 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2013 State of the Market Report for PJM*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

67 See 126 FERC ¶ 61,275 (2009) at P 86.

and three months prior to the Delivery Year.[68] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[69]

RPM prices are locational and may vary depending on transmission constraints.[70] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand Resources and Energy Efficiency Resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2013, PJM installed capacity increased 1,084.1 MW or 0.6 percent from 182,011.1 MW on January 1 to 183,095.2 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2013, 41.3 percent was coal; 29.2 percent was gas; 18.1 percent was nuclear; 6.2 percent was oil; 4.4 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.0 percent was solar.
- **Supply.** Total internal capacity increased 14,724.9 MW from 169,953.3 MW on June 1, 2012, to 184,678.2 MW on June 1, 2013. This increase was the result of the integration of capacity resources in the American Transmission Systems, Inc. (ATSI) Zone (13,175.2 MW), new generation (1,104.4 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-969.4 MW), Demand Resource (DR) modifications (1,894.1 MW), Energy Efficiency (EE) modifications (100.8 MW), the EFORd effect due to higher sell offer EFORds (-589.3 MW), and higher Load Management UCAP conversion factor (9.1 MW).
- **Demand.** There was a 16,060.5 MW increase in the RPM reliability requirement from 157,488.5 MW on June 1, 2012, to 173,549.0 MW on June 1, 2013. This increase was primarily due to the inclusion of the ATSI Zone in the preliminary forecast peak load for the 2013/2014 RPM Base Residual Auction. On June 1, 2013, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 72.0 percent, up slightly from 71.9 percent on June 1, 2012.
- **Market Concentration.** In the 2013/2014 RPM Base Residual Auction, 2013/2014 RPM First Incremental Auction, 2013/2014 RPM Second Incremental Auction, 2013/2014 RPM Third Incremental Auction, 2014/2015 RPM First Incremental Auction, 2014/2015 RPM Second Incremental Auction, 2015/2016 RPM Base Residual Auction, 2015/2016 RPM First Incremental Auction, 2016/2017 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[71] In the 2014/2015 RPM Base Residual Auction, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer

68 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

69 See 126 FERC ¶ 61,275 (2009) at P 88.

70 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

71 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[72,73,74]

- **Imports and Exports.** Net exchange increased 715.3 MW from June 1, 2012 to June 1, 2013. Net exchange, which is imports less exports, increased due to an increase in imports of 516.6 MW and a decrease in exports of 198.7 MW.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs increased by 1,371.5 MW from 7,118.5 MW on June 1, 2012 to 8,490.0 MW on June 1, 2013 as a result of an increase in cleared capacity for Demand Resources (2,038.7 MW), an increase in cleared capacity for Energy Efficiency Resources (238.1 MW), and a decrease in replacement capacity for Energy Efficiency Resources (159.9 MW), offset by an increase in replacement capacity for Demand Resources (1,065.2 MW).

Market Conduct

- **2013/2014 RPM Base Residual Auction.** Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). Offer caps of all kinds were calculated for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Second Incremental Auction.** Of the 163 generation resources which submitted offers, unit-specific offer caps were calculated for eight generation resources (4.9 percent). The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Third Incremental Auction.** Of the 410 generation resources which submitted offers, unit-specific offer caps were calculated for zero generation resources (0.0 percent). The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.** Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM First Incremental Auction.** Of the 190 generation resources which submitted offers, unit-specific offer caps were calculated for 21 generation resources (11.1 percent). The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 188 generation resources (16.1 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 139 generation resources (11.6 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of

72 See OATT Attachment DD § 6.5.

73 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

74 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

which 491 were based on the technology specific default (proxy) ACR values.

Market Performance

- RPM net excess increased 541.8 MW from 5,976.5 MW on June 1, 2012, to 6,518.3 MW on June 1, 2013.
- For the 2013/2014 Delivery Year, RPM annual charges to load totaled approximately $6.7 billion.
- The Delivery Year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2013 was 8.0 percent, an increase from the 7.6 percent average PJM EFORd for 2012.[75]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2013 was 83.7 percent, a slight decrease from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **Outages Deemed Outside Management Control (OMC).** In 2013, 16.8 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Section 5 Recommendations[76,77,78,79]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[80,81]
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources.
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve.
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
- The MMU recommends that protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.
- The MMU recommends improvements to the incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.

75 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the twelve months ending December 31 as downloaded from the PJM GADS database on January 27, 2014. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

76 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports.

77 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

78 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

79 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

80 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000.

81 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

- The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market.
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[82]

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in 2013. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in 2013.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[83,84,85]

Overview: Section 6, "Demand Response"

- **Demand Response Activity.** Economic program credits decreased by $836,828, from $9,284,118 in 2012 to $8,447,290 in 2013, a 9.0 percent drop. Emergency energy credits increased 250.4 percent to $36.7 million compared to 2012. In 2013, synchronized reserve credits for demand resources (DR) decreased by $1.3 million, or 29.7 percent, compared to 2012, from $4.5 million to $3.2 million in 2013.The capacity market is the primary source of revenue to participants in PJM demand response programs. In 2013, load management (LM) program revenue increased $98.8 million, or 29.9 percent, from $331.1 million in 2012 to $429.9 million in 2013. Demand response credits increased by $122.9 million or 34.6 percent to $478.3 million in 2013 compared to 2012.[86]

  Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Emergency demand response energy costs are not covered by LMP. All demand response energy payments are out of market; demand response payments are a form of uplift.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis when appropriate, but subzonal dispatches are only on a voluntary basis. Beginning with the 2014/2015 Delivery Year, demand resources will be dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency.[87]

- **Emergency Event Day Analysis.** Emergency energy revenue increased by $26.2 million, or 250.4 percent, from $10.4 million in 2012 to $36.7 in 2013. Emergency load management event rules over-calculate a participants' compliance levels. Increases in load for dispatched demand resources, negative reduction MWh values, are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero. Considering all positive and negative reported values, the observed load reduction of the five events in 2013 should have been 4,807.8 MW, rather than the 5,488.5 MW calculated by PJM's method. The correct calculation of compliance is 85.2 percent rather than PJM's calculated 97.2 percent. This does not include

82 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

83 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

84 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

85 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

86 The total credits and MWh numbers for demand resources were calculated as of March 7, 2014 and may change as a result of continued PJM billing updates.

87 If "PJM Interconnection LLC," Docket No. ER14-822-000 (December 24, 2013) is approved by the FERC, mandatory curtailment for subzonal dispatch will be delayed until the 2015/2016 Delivery Year.

locations that did not report their load during the emergency event days.

Section 6 Recommendations

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program and not an emergency program.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[88]
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[89]
- The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that demand resources measurement and verification be further modified to more accurately reflect compliance.
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[90]
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM economic load response program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. That is a prerequisite to a functional market design.

88 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

89 *Id* at 1.

90 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013). ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load.

Overview: Section 7, "Net Revenue"

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Fuel prices and energy prices were higher in 2013 than in 2012 and capacity market prices were higher in 2013 in 10 eastern zones and lower in six western zones, AEP, AP, ComEd, DAY, DLCO, and Dominion.
- In 2013, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone. But the net revenue results for a new CT bifurcate the zones into two groups with very different results. There are ten eastern zones in which net revenues cover more than 75 percent of levelized fixed costs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six western zones net revenues cover less than 30 percent of levelized fixed costs with the lowest zone at 18 percent. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets. Covering 75 percent of levelized fixed costs would result in a rate of return slightly less than half the rate of return included in the calculation of levelized fixed costs.
- In 2013, the net revenue results for a new CC also bifurcate the zones into two groups with very different results. There are ten eastern zones in which net revenues cover more than 95 percent of levelized fixed costs. These are the same ten zones with higher net revenues for CTs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six western zones net revenues cover less than 65 but more than 33 percent of levelized fixed costs. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets.
- In 2013, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone. The results for CPs are relatively uniform. A new CP would not have received sufficient net revenue to cover more than 30 percent of levelized fixed costs in any zone. However, the results for CPs in 2013 are better than they were in 2012 based on higher energy market net revenues in all but one zone and higher capacity market revenues in ten zones. These are the same ten eastern zones that increased the net revenue results for both CTs and CCs. All but two zones showed increases in the coverage of fixed costs by CPs in 2013.
- In 2013, a new nuclear plant in the western AEP zone would not have received sufficient net revenue to cover levelized fixed costs. The combination of lower energy market revenues and lower capacity market revenues in the AEP zone, similar to the other western zones, than in the eastern zones resulted in a covering only 30 percent of the annual fixed costs for a nuclear power plant.
- In 2013, actual net revenues covered more than 75 percent of the annual levelized fixed costs of a new entrant wind installation and over 200 percent of the annual levelized fixed costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for more than 40 percent of the net revenue of a wind installation and more than 75 percent of the net revenue of a solar installation.
- In 2013, a substantial portion of units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM capacity market in providing

incentives for continued operation and investment. Capacity market revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM, with the exception of some coal units and some oil or gas steam units.

- The actual net revenue results mean that 14,597 MW of capacity in PJM are at risk of retirement in addition to the 24,933 MW that are currently planning to retire.

Section 7 Conclusion

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

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. The actual net revenue results illustrate that a significant amount of generation in PJM relies on the capacity market to cover the gap between energy market net revenues and avoidable costs. Capacity market revenues are critical to covering total costs including fixed costs. The net revenue results also demonstrate the significance of capacity market design. Capacity market prices have been suppressed by a number of market design factors. These factors, including an inappropriate definition of capacity imports has led to especially low capacity market prices in the western part of the system. The impacts of this are clearly shown in the bifurcation of net revenue results between the eastern and western zones in PJM.

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

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[91] The rule establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new

91 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

coal- and oil-fired power plants based on new information and analysis.[92]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[93] The Clean Air Interstate Rule (CAIR) is in effect but CAIR is subject to remand to the EPA due to the a finding of the U.S. Court of Appeals for the District of Columbia Circuit.[94]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[95] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

  Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics in those jurisdictions.[96]

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[97] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[98]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[99] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[100]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were an average of $2.92 per ton, above the price floor for 2013. The clearing price is equivalent to a price of $3.22 per metric tonne, the unit used in other carbon markets.

92 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

93 CAA § 110(a)(2)(D)(i)(I).

94 See 550 F.3d 1176, 1177 (2008).

95 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

96 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

97 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495.

98 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).

99 N.J.A.C. § 7:27–19.

100 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).

Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. On December 31, 2013, 68.6 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 96.6 percent of coal steam MW had some type of particulate control, and 91.2 percent of fossil fuel fired capacity in PJM had NO_x emission control technology in place.

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. The out of market payments in the form of RECs and federal production tax credits mean that these units have an incentive to generate MWh until the LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are not transparent. Data on RECs prices and markets are not publicly available. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.
- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2013, PJM was a net importer of energy in the Real-Time Energy Market in January through August, and November, and a net exporter of energy in the remaining months of 2013.[101] In 2013, the real-time net interchange of 4,867.1 GWh was greater than net interchange of 2,770.9 GWh for 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2013, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. In 2013, the total day-ahead net interchange of -17,603.2 GWh was greater than net interchange of -12,548.4 GWh for 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2013, gross

101 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

imports in the Day-Ahead Energy Market were 147.4 percent of gross imports in the Real-Time Energy Market (364.4 percent for 2012), gross exports in the Day-Ahead Energy Market were 210.3 percent of the gross exports in the Real-Time Energy Market (415.8 percent for 2012).

- **Interface Imports and Exports in the Real-Time Energy Market.** In 2013, in the Real-Time Energy Market, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2013, in the Real-Time Energy Market, there were net scheduled exports at eleven of PJM's 18 interface pricing points eligible for real-time transactions.[102]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2013, in the Day-Ahead Energy Market, there were net scheduled exports at eleven of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2013, in the Day-Ahead Energy Market, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2013, in the Day-Ahead Market, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 45.0 percent of hours in 2013.
- **PJM and New York ISO Interface Prices.** In 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 54.1 percent of the hours in 2013.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2013, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[103] The average hourly flow in 2013 was -365 MW.[104] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 67.7 percent of the hours in 2013.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2013, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[105] The average hourly flow in 2013 was -131 MW.[106] The flows were consistent with price differentials in 65.8 percent of the hours in 2013.
- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. In the first seven months of operations, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[107] The average hourly flow during the first seven months of operation was -52 MW.[108] The flows were consistent with price differentials in 66.6 percent of the hours between June 3, 2013 and December 31, 2013.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power flows scheduled at an interface for a defined period. Inadvertent interchange is the

102 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

103 In 2013, there were 1,702 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $41.69 while the NYISO LMP at the Neptune Bus during non-zero flows was $60.38, a difference of $18.69.

104 The average hourly flow in 2013, ignoring hours with no flow, on the Neptune DC Tie line was -453 MW.

105 In 2013, there were 1,865 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $40.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.02, a difference of $7.40.

106 The average hourly flow in 2013, ignoring hours with no flow, on the Linden VFT line was -166 MW.

107 In its seven months of operation, there were 3,528 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $47.29 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.17, a difference of $7.88.

108 The average hourly flow during the first seven months of operations, ignoring hours with no flow, on the Hudson line was -171 MW.

difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at one or more specific interfaces.

In 2013, net scheduled interchange was 2,848 GWh and net actual interchange was 3,101 GWh, a difference of 253 GWh. In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 49 TLRs of level 3a or higher in 2013, compared to 37 TLRs issued in 2012.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 110,306 bids per day, with an average cleared volume of 1,238,361 MWh per day, in 2013, compared to an average of 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012. (Figure 9-13).

Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and auction revenue rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Overview: Section 10, "Ancillary Services"

Regulation Market

The PJM Regulation Market is a single market for the RTO. PJM jointly optimizes Regulation with Synchronized Reserve and energy to provide all three of these services at least cost.

Market Structure

- **Supply.** In 2013, the supply of offered and eligible regulation in PJM was stable, but the average daily offer decreased from 6,551 MW in 2012 to 4,166 MW in 2013 (a decrease of 36.4 percent) and the average hourly eligible regulation decreased from 3,253 MW in 2012 to 1,642 MW in 2013 (a decrease of 50.1 percent).
- **Demand.** The average hourly regulation demand was 753 MW in 2013. This is a 177 MW decrease (19.0 percent) in the average hourly regulation demand of 930 MW in the same period of 2012.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 3.40. This is a 5.8 percent decrease from 2012 when the ratio was 3.61.
- **Market Concentration.** In 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2115 which is classified as highly concentrated. In 2013, the three pivotal supplier test was failed in 90 percent of hours. In 2012, the three pivotal supplier test was failed in 40 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[109] As of December 31, 2013, there were 26 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was \$30.14/MW of regulation in 2013, an increase of \$9.79/MW of regulation, or 48.1 percent, from 2012. The cost of regulation in 2013 was \$34.57/MW of regulation, an \$8.16/MW of regulation, or 30.9 percent, increase from 2012.

Synchronized Reserve Market

The Tier 2 Synchronized Reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Zone (MAD). The MAD subzone is designed to ensure that transmission constraints will not prevent adequate synchronized reserves from being available in MAD when called. PJM has the right to define new zones or subzones "as needed for system reliability."[110]

Market Structure

- **Supply.** In 2013, the supply of offered and eligible synchronized reserve was both stable and adequate.
- **Demand.** When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. The Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012. Requirement synchronized reserve requirement remained at 1,300 MW. The integration of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone.
- **Supply and Demand.** All on-line generation resources are required to offer synchronized reserve. The 2013 ratio of on-line synchronized reserve to synchronized reserve required was 1.29.
- **Market Concentration.** In 2013, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 4205 which is classified as highly concentrated. In 2013, 56 percent of hours had a maximum market share greater than 40 percent.

109 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

110 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 66.

The MMU concludes from these results that the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each generating unit and each demand resource. The offers are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) Subzone was $6.98 per MW in 2013, a $1.04 decrease from 2012. The total cost of tier 2 synchronized reserves per MW in MAD in 2013 was $13.07, a three percent increase from the $12.71 cost of synchronized reserve in 2012. The market clearing price was 53 percent of the total synchronized reserve cost per MW in 2013, down from 63 percent in 2012.

- **Supply and Demand.** A synchronized reserve shortage occurs when the combination of tier 1 and tier 2 synchronized reserve supply is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a synchronized reserve shortage in 2013. The spinning event of September 10 raised concerns that the current method for estimating Tier 1 is incorrect leading to an overall synchronized reserve deficit.

Day-Ahead Scheduling Reserve (DASR)

The purpose of the DASR Market is to satisfy secondary supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[111] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

The MMU has identified problems with the definition and dispatchability of DASR and recommends solutions.

Market Structure

- **Concentration.** The MMU calculates that in 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

- **Supply.** DASR resources comprise of all those resources that can provide reserve capability that can be fully converted into energy within 30 minutes as requested by PJM dispatchers. MMU recommends that scheduling reserve be more definitively defined and satisfied by a real-time market.

- **Demand.** In 2013, the required DASR was 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero, but there is an opportunity cost associated with providing DASR. As of December 31, 2013, 12 percent of offers reflected economic withholding (defined as cost offers above $5.00). All units with reserve capability that can be converted into energy within 30 minutes are required to offer in the DASR Market.[112] Units that do not offer have their offers set to zero.

- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in 2013 was $0.70 per MW. This is a 23 percent increase from 2012.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an

111 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

112 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 137.

outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[113]

In 2013, black start charges were $107.5 million (compared to $50.2 million in 2012). Black start zonal charges in 2013 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $126,644) to $9.71 per MW-day in the AEP Zone (total charges were $82,588,453).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In 2013, total reactive service charges were $616.6 million compared to $368.3 million in 2012.[114] Total charges in 2013 ranged from $340.0 thousand in the RECO Zone to $76.8 million in the ATSI Zone.

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.
- The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

Section 10 Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the benefits factor in the optimization and pricing, but a miles ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be paid a different amount per effective MW than effective MW provided by RegA resources. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

113 OATT Schedule 1 § 1.3BB.
114 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Overview: Section 11, "Congestion and Marginal Losses" Energy Cost

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $147.9 million or 28.0 percent, from $529.0 million in 2012 to $676.9 million in 2013.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $231.4 million or 29.7 percent, from $779.9 million in 2012 to $1,011.3 million in 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $83.5 million or 33.3 percent from -$250.9 million in 2012 to -$334.4 million in 2013.[115]
- **Monthly Congestion.** Monthly total congestion costs in 2013 ranged from $27.8 million in April to $110.1 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the West interface, the ATSI Interface, the Bridgewater - Middlesex line, and the Bedington - Black Oak Interface.
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2013. Day-ahead congestion frequency increased by 44.0 percent from 249,572 congestion event hours in 2012 to 359,432 congestion event hours in 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

  Real-time congestion frequency decreased by 7.6 percent from 20,921 congestion event hours in 2012 to 19,321 congestion event hours in 2013. Real-time, congestion-event hours increased on the interfaces, while congestion-event hours on the transformers, the flowgates and the transmission lines decreased.

  Facilities were constrained in the Day-Ahead Energy Market more frequently than in the Real-Time Energy Market. In 2013, for only 2.0 percent of Day-Ahead Energy Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2013, for 38.1 percent of Real-Time Energy Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Energy Market.

  The AP South Interface was the largest contributor to congestion costs in 2013. With $169.1 million in total congestion costs, it accounted for 25.0 percent of the total PJM congestion costs in 2013. The top five constraints in terms of congestion costs together contributed $223.7 million, or 33.0 percent, of the total PJM congestion costs in 2013. The top five constraints were the AP South Interface, the West Interface, the ATSI Interface, the Bridgewater – Middlesex line, and the Bedington - Black Oak Interface.
- **Zonal Congestion.** ComEd was the most congested zone in 2013 in terms of total congestion cost. ComEd had -$477.3 million in total load costs, -$650.0 million in total generation credits and -$17.5 million in explicit congestion, resulting in $155.2 million in net congestion costs, reflecting significant location congestion between local generation and load, despite being the on the upstream side of system wide congestion patterns. The Nelson – Cordova line, the Byron - Cherry Valle flowgate, ,the Braidwood transformer, the Oak Grove - Galesburg flowgate and Crete - St Johns Tap flowgate contributed $56.4 million, or 36.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2013, with $106.0

115 The balancing congestion cost is greater than the balancing congestion calculated by PJM by $0.26 million due to missing dfax data on August 8, 2013. The missing dfax was a result of security constrained economic dispatch (SCED) software flat files format changes and the fact that SCED was down for many intervals for emergency fixes on August 8, 2013.

million. The AP South Interface contributed $23.5 million or 22.1 percent of the total AEP Control Zone congestion cost in 2013. The AP Control Zone was the third most congested zone in PJM in 2013, with a cost of $92.8 million.

- **Ownership.** In order to evaluate the ownership virtual bids, the MMU categorized all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries. In 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2013, financial companies received $102.8 million in net congestion credits, an increase of $19.8 million or 23.9 percent compared to 2012. In 2013, physical companies paid $779.7 million in net congestion charges, an increase of $167.7 million or 27.4 percent compared to 2012.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in 2013 increased by $53.6 million or 5.5 percent from 2012, from $981.7 million to $1,035.3 million. Day-ahead net marginal loss costs in 2013 increased by $133.9 million or 13.3 percent from 2012, from $1,003.8 million to $1,137.7 million. Balancing net marginal loss costs decreased in 2013 by $80.3 million or 363.4 percent from 2012, from -$22.1 million to -$102.4 million.
- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in 2013 ranged from $66.2 million in April to $142.1 million in July.
- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[116] The marginal loss credits decreased in 2013 by $55.8 million or 14.4 percent from 2012, from $386.7 million to $330.9 million.

Energy Cost

- **Total Energy Costs.** Total energy costs in 2013 decreased by $108.5 million or 18.3 percent from 2012, from -$593.0 million to -$701.5 million. Day-ahead net energy costs in 2013 decreased by $224.3 million or 36.8 percent from 2012, from -$609.9 million to -$834.2 million. Balancing net energy costs in 2013 increased by $132.4 million or 1,710.3 percent from 2012, from $7.7 million to $140.1 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in 2013 ranged from -$90.8 million in July to -$44.3 million in October.

Section 11 Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion in 2013. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

116 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), pp 63-64. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Increases in the LMP and fuel costs led to higher marginal loss costs in 2013 compared to 2012. Total marginal loss costs increased in 2013 by $53.6 million or 5.5 percent from 2012, from $981.7 million to $1,035.3 million.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,775 MW at the end of 2013. Of the capacity in queues, 6,557 MW, or 9.7 percent, are uprates and the rest are new generators. Wind projects account for 18,063 MW of nameplate capacity or 26.8 percent of the capacity in the queues. Combined-cycle projects account for 39,420 MW of capacity or 58.5 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-7, 23,736 MW is or is planned to be retired between 2012 and 2019, with all but 2,016.5 MW retired by June 1, 2015. The AEP Zone accounts for 4,124 MW, or 19.7 percent, of all MW planned for retirement from 2014 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be retired have withdrawn their retirement notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI Zone.
- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and the Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[117] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit or that requests interconnection of a merchant transmission facility must follow the process defined in the PJM tariff to obtain interconnection service.[118] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn and an accumulated backlog in completing studies.
- Changes to the planning process went into effect on May 12, 2012 including a return to six-month queue cycles and the creation of an alternate queue for small projects. Concurrent with these changes was a drop in new projects, starting in 2012 and a corresponding drop in withdrawn projects starting in 2013.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and

117 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones. SWMAAC consists of the BGE and Pepco control zones. See the 2013 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

118 OATT Parts IV & VI.

congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, and Susquehanna-Roseland.

Regional Transmission Expansion Plan (RTEP)

- The PJM Board of Managers authorized $1.2 billion on October 3, 2013, and $5.9 billion on December 11, 2013, in transmission upgrades and improvements that were identified as part of PJM's regional planning process.

Economic Planning Process

A goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. Transmission investments have not been fully incorporated into competitive markets. The PJM economic planning process could enhance competition in PJM in at least three ways.

- **Competition to Build.** On its own initiative and in compliance with Order No. 1000, PJM introduced limited opportunities for non-incumbent transmission owners to compete with incumbent transmission owners to identify and sponsor the development of projects in the PJM region for economic reasons.[119] The rules accord no right of first refusal to incumbents.[120]
- **Competition to Finance.** Competition to provide financing could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. The MMU recommended this approach in PJM's proceeding on compliance with Order No. 1000 and continues to recommend that PJM implement this approach.[121]
- **Competition to Meet Load.** The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics and through the ability to offer transmission projects in RPM auctions.[122,123]

Section 12 Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[124]
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This could result in a conflict of interest when transmission owners have generation interests.
- The MMU recommends improvements in queue management including: that PJM establish a review process to ensure that projects are removed from the queue if they are not viable and that PJM establish a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.

119 See FERC Docket No. ER13-198; 145 FERC ¶ 61,214.

120 See 145 FERC ¶ 61,214 at PP 221–234.

121 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) at 4–7; 145 FERC ¶ 61,214 at P 268, 281.

122 See 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

123 *See, e.g.*, OATT Attachment DD § 5.6.4 (Qualifying Transmission Upgrades).

124 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013).

Section 12 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing. The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2014 to 2017 Long Term FTR Auction include the Monticello – East Winamac flowgate, approximately 120 miles north of Indianapolis, IN, and the Cumberland Ave - Bush flowgate, approximately 100 miles north of Indianapolis, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2013 to 2014 planning period include the Cumberland Ave – Bush flowgate, approximately 100 miles north of Indianapolis, IN and the Beaver Channel - Albany flowgate, approximately 100 miles north of Springfield, IL. The geographic location of these constraints is shown in Figure 13-1.

  Market participants can also sell FTRs. In the 2014 to 2017 Long Term FTR Auction, total participant FTR sell offers were 316,056 MW, up from 211,316 MW from the 2013 to 2016 Long Term FTR Auction. In the 2013 to 2014 Annual FTR Auction, total participant FTR sell offers were 417,118 MW, up from 356,299 MW in the 2012 to 2013 planning period. In the first seven months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, total participant FTR sell offers were 3,862,503 MW, up from 3,589,824 MW for the same period during the 2012 to 2013 planning period.

- **Demand.** In the 2014 to 2017 Long Term FTR Auction, total FTR buy bids increased 10.8 percent from 2,772,621 MW to 3,072,909 MW. There were 3,274,373 MW of buy and self-scheduled bids in the 2013 to 2014 Annual FTR Auction, up from 2,561,835 MW in the previous planning period. The total FTR buy bids from the first seven months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 11.4 percent from 14,906,684 MW for the same time period of the prior planning period, to 16,604,063 MW.

- **Patterns of Ownership.** For the 2014 to 2017 Long Term FTR Auction, financial entities purchased 65.1 percent of prevailing flow FTRs and 79.7 percent of counter flow FTRs. For the 2013 to 2014 Annual FTR Auction, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 76.0 percent of prevailing flow and 85.8 percent of counter flow FTRs for January through December of 2013. Financial entities owned 59.0 percent of all prevailing and counter flow FTRs, including 50.6 percent of all prevailing flow FTRs and 75.3 percent of all counter flow FTRs during January through December 2013.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $531,678 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.
- **Credit Issues.** Ten participants defaulted during 2013 from 16 default events. The average of these defaults was $255,611 with 10 based on inadequate collateral and six based on nonpayment. The average collateral default was $93,749 and the average nonpayment default was $352,729. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** The 2014 to 2017 Long Term FTR Auction cleared 197,125 MW (6.4 percent of demand) of FTR buy bids, compared to 290,700 MW (10.5 percent) in the 2013 to 2015 Long Term FTR Auction. This is at least partially due to the newly implemented rule limiting Long Term FTR Auction capacity to 50 percent. The Long Term FTR Auction also cleared 21,501 MW (6.8 percent) of FTR sell offers, down from 56,692 MW (26.8 percent) in the 2013 to 2014 Long Term FTR Auction.

  In the Annual FTR Auction for the 2013 to 2014 planning period 420,489 MW (12.8 percent) of buy and self-schedule bids cleared. For the first seven months of the 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 2,283,411 MW (13.8 percent) of FTR buy bids and 742,731 MW (19.2 percent) of FTR sell offers.
- **Price.** In the 2014 to 2017 Long Term FTR Auction, 97.6 percent of FTRs were purchased for less than $1 per MW, up from 95.9 percent in the previous Long Term FTR Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction was -$0.18, down from $0.36 from the previous Long Term FTR Auction.

  For the 2013 to 2014 annual auction, 93.0 percent of FTRs were purchased for less than $1 per MW, up from 93.0 percent in the previous Annual FTR Auction. The weighted-average buy-bid FTR price for the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2013 to 2014 planning period was $0.06, down from $0.12 per MW in the 2012 to 2013 planning period.
- **Revenue.** The 2014 to 2017 Long Term FTR Auction generated $16.8 million of net revenue for all FTRs, down from $28.6 million in the 2013 to 2016 Long Term FTR Auction. The 2013 to 2014 Annual FTR Auction generated $558.4 million in net revenue, down $44.5 million from the 2012 to 2013 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $5.4 million in net revenue for all FTRs for the first seven months of the 2013 to 2014 planning period, down from $17.3 million for the same time period in the 2012 to 2013 planning period.
- **Revenue Adequacy.** FTRs were paid at 67.8 percent of the target allocation for the entire 2012 to 2013 planning period. FTRs were paid at 75.1 percent of the target allocation level for the first seven months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the first seven months of the 2013 to 2014 planning period and $614.0 million during the entire 2012 to 2013 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Sunnymead and the Western Hub.

  Target allocations values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs.
- **ARRs and FTRs served as an effective, but not total, offset against congestion.** ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to

2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $170.2 million in profits for physical entities, of which $167.9 million was from self-scheduled FTRs, and $177.5 million for financial entities. As shown in Table 13-8, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013. FTR profits generally increased in the summer and winter months when congestion was higher.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the annual ARR allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the annual ARR allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the first seven months of the 2013 to 2014 planning period PJM allocated a total of 6,428.8 MW of residual ARRs with a total target allocation of $3,647,248.
- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 35,501 MW of ARRs associated with approximately $233,800 of revenue that were reassigned for the first seven months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first seven months of the 2013 to 2014 planning period, the ARR target allocations were $175.0 million while PJM collected $197.5million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $587.0 million while PJM collected $653.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first seven months of the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

Section 13 Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market

prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding.

Section 13 Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested. One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system as a hedge against congestion and pay for balancing congestion in order to increase the payout to holders of FTRs who are not loads.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period, the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013, the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM monthly is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real–time markets, including reactive interfaces, which directly results in differences in congestion between day - ahead and real-time markets; differences in day-ahead and real–time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day–ahead and real–time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, PJM should reduce the number of FTRs sold.

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Summary of New Recommendations

Table 2-1 includes a brief description and a priority ranking of the MMU's new recommendations for 2013.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

Table 2-1 Prioritized summary of new recommendations: 2013

Priority	Section	Description
Low	3 - Energy Market	No FMU status for black start units.
Medium	3 - Energy Market	Do not use ATSI Interface or similar interfaces to set zonal capacity prices to accommodate inadequacy of DR product.
Low	3 - Energy Market	Review transmission facility ratings to ensure normal, emergency and load dump ratings in transmission system modeling are accurate.
Low	3 - Energy Market	Update outage impact studies, RPM reliability analyses for capacity deliverability and reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations implemented in June 2013.
Low	3 - Energy Market	Clarify roles of PJM and the transmission owners in the decision making process to control for local contingencies. Strengthen PJM's role and make the process transparent.
Low	3 - Energy Market	Explain in the appropriate manual the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.
Low	3 - Energy Market	Treat hours with net withdrawal at a gen bus as load for calculating load and load weighted LMP. Conversely, treat injections as generation.
Low	3 - Energy Market	Identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.
Medium	4 – Energy Uplift	Reallocate the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
Medium	4 – Energy Uplift	Be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce subjectivity of their creation and implementation. Estimate their impact on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
High	4 – Energy Uplift	Require UTCs to pay operating reserve charges. Revise confidentiality rules to allow disclosure of the reasons for, and the amount of unit operating reserve charges.
Medium	4 – Energy Uplift	Base energy uplift payments on real-time output and not day-ahead scheduled output whenever operation results in a lower loss or no loss at all. Include net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
Medium	4 – Energy Uplift	Use net regulation revenues as an offset in the calculation of balancing operating reserve credits.
Low	4 – Energy Uplift	Do not compensate self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.
High	5 – Capacity Market	Enforce a consistent definition of capacity resource to be a physical resource at time of auction and in the relevant delivery year. Apply requirement to all resource types, including planned generation, demand to all resource types, including planned generation, demand resources and imports. resources and imports.
High	5 – Capacity Market	Modify definition of DR to be substitutable for other generation capacity resources. Eliminate Limited and Extended Summer DR so DR has the same obligation to provide capacity year round as generation capacity resources.
Medium	5 – Capacity Market	Terminate the 2.5 percent demand adjustment (Short Term Resource Procurement Target) and add it back to the demand curve.
Medium	5 – Capacity Market	Redefine LDA test, and include reliability analysis in redefined model.
Low	5 – Capacity Market	Require that capacity resource offers in DA market be competitive (short run marginal cost of units.).
Low	5 – Capacity Market	Clearly define operational details of protocols for recalling energy output of capacity resources in emergency conditions.
High	5 – Capacity Market	Pay capacity resources on basis of whether they produce energy when called upon in critical hours.
Medium	5 – Capacity Market	Units not capable of supplying energy consistent with DA offer should reflect outage.
Medium	5 – Capacity Market	Eliminate all OMC outages from market impacting forced outage rate calculations.
Medium	5 – Capacity Market	Eliminate the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
High	6 - Demand Response	Allow only one demand resources product, with an obligation to respond when called for all hours of the year.
High	6 - Demand Response	Apply daily must offer requirement to demand resources comparably to generation capacity resources.
High	6 - Demand Response	Apply $1,000 offer cap requirement to demand resources comparably to cap on energy offers of generation capacity resources.
Medium	6 - Demand Response	Shorten demand resource lead time to 30 minutes, with one hour minimum dispatch.
High	6 - Demand Response	Require demand resources to provide nodal location on grid.
Medium	6 - Demand Response	Adopt the ISO-NE metering requirements so dispatchers have information for reliability and so DR market payments be calculated based on interval meter data at the site of the demand reductions.
Low	6 - Demand Response	Initiate load management testing with limited warning to CSPs.
Medium	9 – Interchange Transactions	Eliminate IMO Interface Pricing Point, assign MISO pricing point to IESO transactions.
Medium	9 – Interchange Transactions	Validate submitted transactions to prohibit disaggregation that defeats the interface pricing rule by obscuring the true source or sink.
Medium	9 – Interchange Transactions	Require market participants to submit transactions on market paths that reflect expected actual flow.
Low	9 – Interchange Transactions	Eliminate NIPSCO and Southeast interface pricing points from DA and RT energy markets. With VACAR, assign SouthIMP/EXP to transactions created under reserve sharing agreement.
Low	9 – Interchange Transactions	Provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
High	10 – Ancillary Services	Modify Regulation market to consistently apply marginal benefit factor throughout optimization, assignment, and settlement.
High	10 – Ancillary Services	Eliminate rule requiring payment of tier 1 synchronized reserve resources when non-synchronized reserve price is above zero.
Medium	10 – Ancillary Services	Enforce tier 2 synchronized reserve must offer provision of scarcity pricing.
Low	10 – Ancillary Services	Define why tier 1 biasing is used in optimized solution to Tier 2 Synchronized Reserve Market. Identify rule applied to each instance of biasing.
Low	10 – Ancillary Services	Determine why secondary reserve was unavailable or not dispatched on September 10, 2013. Evaluate replacing the DASR market with an available and dispatchable real time secondary reserve product.
Low	10 – Ancillary Services	Revise the current black start confidentiality rules in order to allow a more transparent disclosure of information.
Low	12 - Planning	Create mechanism to permit a direct comparison, or competition, between transmission and generation alternatives.

Low	12 - Planning	Implement rules to permit competition to provide financing of transmission projects.
Low	12 - Planning	Address question of whether CIRs should persist after unit retirement to prevent incumbents from exploiting CIRs to block competitive entry.
Low	12 - Planning	Outsource interconnection studies to an independent party, rather than relying on incumbent transmission owners.
Low	13 – FTRs and ARRs	Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
High	13 – FTRs and ARRs	Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
High	13 – FTRs and ARRs	Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
High	13 – FTRs and ARRs	Eliminate cross geographic subsidies.
Low	13 – FTRs and ARRs	Improve transmission outage modeling in the FTR auction models.
High	13 – FTRs and ARRs	Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
Medium	13 – FTRs and ARRs	Implement a seasonal ARR and FTR allocation system to better represent outages.
High	13 – FTRs and ARRs	Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
High	13 – FTRs and ARRs	Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
Medium	13 – FTRs and ARRs	Do not use ATSI Interface or similar interfaces to set zonal capacity prices to accommodate inadequacy of DR product. Study the implementation of closed loop interface constraints so as to include them in the FTR Auction model to minimize their impact on FTR funding.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[6] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2013 State of the Market Report for PJM*, the MMU makes the following new recommendations for 2013.

From Section 3, Energy Market

- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability.[7] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[9]
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection,

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

7 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.

8 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

9 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

From Section 4, Energy Uplift

- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region.
- The MMU recommends enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their operation results in a lower loss or no loss at all.The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

From Section 5, Capacity Market

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[10,11]
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources.
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve.
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
- The MMU recommends that protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.

10 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000.

11 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

- The MMU recommends improvements to the incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.
  - The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market.
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[12]

From Section 6, Demand Response

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[13]
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[14]
- The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[15]
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

From Section 9, Interchange Transactions

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

From Section 10, Ancillary Services

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.

12 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

13 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

14 *Id* at 1.

15 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013). ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.
- The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.From Section 12, Planning
- The MMU recommends additional improvements to the planning process.
  - There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
  - The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.
  - The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[16]
  - The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This could result in a conflict of interest when transmission owners have generation interests.

From Section 13, FTRs and ARRs

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to

16 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013).

include them in the FTR Auction model to minimize their impact on FTR funding.

Complete List of MMU Recommendations

The following recommendations and their context are explained in greater detail in each of the sections of the SOM.

Section 3, Energy Market

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently being evaluated in the PJM stakeholder process.
- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability.[17] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[18]
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[19] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[20]
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

Section 4, Energy Uplift

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves

17 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.
18 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
19 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).
20 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.

- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU also recommends other rule changes regarding the calculation of lost opportunity cost credits to units scheduled in the Day-Ahead Energy Market and not committed in real time.
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be eligible for an LOC compensation when committed or decommitted within an hour.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. The MMU also recommends including real-time exports in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region.
- The MMU recommends enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their operation results in a lower loss or no loss at all.
- The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

Section 5, Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[21,22]

- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources.
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve.
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
- The MMU recommends that protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.
- The MMU recommends improvements to the incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.
  - The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market.
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[23]

Section 6, Demand Response

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program and not an emergency program.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[24]
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[25]
- The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that demand resources measurement and verification be further modified to more accurately reflect compliance.
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE metering requirements in order to ensure that

21 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000.

22 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

23 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "Capacity in the PJM Market," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

24 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

25 *Id* at 1.

dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[26]

- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

Section 7, Net Revenue

There are no recommendations in this section.

Section 8, Environmental

There are no recommendations in this section.

Section 9, Interchange Transactions

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

Section 10, Ancillary Services

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real

26 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

time secondary reserve product that is available and dispatchable in real time.

- The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[27]
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This could result in a conflict of interest when transmission owners have generation interests.
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable and that PJM establish a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.

Section 13, FTRs and ARRs

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding.

27 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013).

Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for 2013, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2013.

Table 3-1 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1167 with a minimum of 844 and a maximum of 1604 in 2013.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power,

1 Analysis of 2013 market results requires comparison to prior years. In 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2013 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M.

PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3]

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 2,546 MW, or 1.5 percent, from 173,414 MW in the summer of 2012 to 175,960 MW in the summer of 2013.[4] The increase in offered generation was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 1,127 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 18 units (2,863 MW) since January 1, 2013.

  PJM average real-time generation in 2013 increased by 1.2 percent from 2012, from 88,708 MW to 89,769 MW. The PJM average real-time generation in 2013 would have increased by 0.5 percent from 2012, from 88,708 MW to 89,126 MW, if the EKPC Transmission Zone had not been included.[5]

  PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, increased by 10.3 percent from 2012, from 134,479 MW to 148,323 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 9.7 percent from 2012, from 134,479 MW to 147,541 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 758.3 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Generation Fuel Mix.** During 2013, coal units provided 44.3 percent, nuclear units 34.8 percent and gas units 16.3 percent of total generation. Compared to 2012, generation from coal units increased 6.2 percent, generation from nuclear units increased 1.4 percent, and generation from gas units decreased 12.2 percent. The change is primarily a result of increased natural gas prices in 2013, particularly in eastern zones, and lower or constant coal prices.

- **Marginal Resources.** In the PJM Real-Time Energy Market, for 2013, coal units were 57.7 percent and natural gas units were 32.4 percent of marginal resources. In 2012, coal units were 58.8 percent and natural gas units were 30.3 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, for 2013, up-to congestion transactions were marginal for 96.4 percent of marginal resources, the INCs were marginal for 1.3 percent of marginal resources, the DECs were marginal for 1.1 percent of marginal resources, and generation resources were marginal in only 1.2 percent of marginal resources in 2013.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load for 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for 2012, which was 154,344 MW in the HE 1700 on July 17, 2012.[6]

  PJM average real-time load in 2013 increased by 1.5 percent from 2012, from 87,011 MW to 88,332 MW. The PJM average real-time load in 2013 would have increased by 0.6 percent from 2012, from 87,011 MW to 87,537 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead demand in 2013, including DECs and up-to congestion transactions, increased by 10.1 percent from 2012, from 131,612 MW to 144,858 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased 9.4 percent from 2012, from 131,612 MW to 143,962 MW, if the EKPC

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

4 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

5 The EKPC Zone was integrated on June 1, 2013.

6 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2013 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

Transmission Zone had not been included. The day-ahead demand growth was 573.3 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 25.0 percent by spot market purchases and 64.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot market purchases increased by 1.8 percentage points and reliance on self-supply decreased by 3.3 percentage points. For 2013, 8.0 percent of day-ahead load was supplied by bilateral contracts, 24.5 percent by spot market purchases, and 67.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot market purchases increased by 2.2 percentage points, and reliance on self-supply decreased by 3.6 percentage points.

- **Supply and Demand: Scarcity.** PJM's market did not experience any reserve-based scarcity events in 2013. However, PJM declared a hot weather alert in all or parts of the PJM territory on seventeen days in 2013 compared to twenty eight days in 2012. PJM declared cold weather alerts on seven days in 2013 and did not declare any cold weather alerts in 2012. PJM issued a maximum emergency generation alert on four days in 2013 compared to one day in 2012. PJM declared emergency mandatory load management reductions (long lead time) on five days in 2013 and on two days in 2012. PJM declared emergency mandatory load management reductions (short lead time) on one day each in 2013 and 2012. PJM declared maximum emergency generation actions on five days in 2013 that resulted in PJM direction to load maximum emergency capacity, compared to two days in 2012. PJM declared a voltage reduction warning and reduction of non-critical plant load on one day each in 2013 and 2012.

  In the week beginning September 9, 2013, unusually high temperatures in the PJM territory combined with some generation and transmission outages resulted in PJM issuing load shed directives in specific locations.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.1 percent in 2012 and 2013. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.8 percent in 2012 to 0.4 percent in 2013.

  In 2013, 12 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.8 percent in 2012 to 3.1 percent in 2013. In the Real-Time Energy Market, for units committed to provide energy for reliability reasons, offer-capped unit hours increased from 0.9 percent in 2012 to 2.5 percent in 2013.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.

The average markup index of marginal units was calculated by offer price category.

In the PJM Real-Time Energy Market in 2013, 93.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.04. Nonetheless, some marginal units do have substantial markups.

In the PJM Day-Ahead Energy Market in 2013, 99.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 112 units eligible for FMU or AU status in at least one month during 2013, 22 units (19.6 percent) were FMUs or AUs for all of 2013, and 10 units (8.9 percent) qualified in only one month of 2013.
- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2013, up-to congestion transactions continued to displace increment offers and decrement bids. The average hourly submitted and cleared increment offer MW decreased 23.4 and 14.5 percent, and the average hourly submitted and cleared decrement bid MW decreased 18.0 and 14.6 percent in 2013 compared to 2012. The average hourly up-to congestion transaction submitted and cleared MW increased 46.3 and 34.6 percent in 2013 compared to 2012. The top five companies with cleared up-to congestion transactions are financial and account for 57.4 percent of all the cleared up-to congestion MW in PJM in 2013.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion.

  PJM Real-Time Energy Market prices increased in 2013 compared to 2012. The system average LMP was 10.4 percent higher in 2013 than in 2012, \$36.55 per MWh versus \$33.11 per MWh. The load-weighted average LMP was 9.7 percent higher in 2013 than in 2012, \$38.66 per MWh versus \$35.23 per MWh.

  PJM Day-Ahead Energy Market Prices increased in 2013 compared to 2012. The system average LMP was 13.3 percent higher in 2013 than in 2012, \$37.15 per MWh versus \$32.79 per MWh. The load-weighted average LMP was 12.7 percent higher in 2013 than in 2012, \$38.93 per MWh versus \$34.55 per MWh.[7]

- **Components of LMP.** LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch in which marginal units determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system's load-weighted LMP using the components of unit offers and sensitivity factors.

  In the PJM Real-Time Energy Market, for 2013, 46.6 percent of the load-weighted LMP was the result of coal costs, 27.6 percent was the result of gas costs and 0.63 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, for 2013, 71.9 percent of the load-weighted LMP was the result of up-to congestion transactions, 11.9 percent was the result of the cost of coal and 5.7 percent was the result of the cost of gas.

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  In the PJM Real-Time Energy Market in 2013, the adjusted markup was positive, \$0.77 per MWh or 2.0 percent of the PJM real-time, load-weighted average LMP, primarily as a result of competitive

7 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

behavior by coal units. In 2013, the real time load-weighted average LMP for the month of July had the highest markup component, $4.37 per MWh using adjusted cost offers. This corresponds to 8.6 percent of July's real time load-weighted average LMP. The July results demonstrate that markups can increase significantly during high demand periods.

In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In 2013, the adjusted markup component of LMP resulting from generation resources was negative, -$0.53 per MWh.

The overall markup results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between annual average day-ahead and real-time prices was $0.32 per MWh in 2012 and -$0.60 per MWh in 2013. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Recommendations

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently being evaluated in the PJM stakeholder process.
- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability.[8] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[9]
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[10] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of

8 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.

9 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

10 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 22 (February 28, 2013).

hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[11]

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation increased by 2,546 MW in the summer of 2013 compared to the summer of 2012, while peak load increased by 3,165 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy market results for 2013 generally reflected supply-demand fundamentals.

The high load conditions in the summer of 2013 illustrated a number of issues that are addressed in the MMU recommendations.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[12] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily

11 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

12 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in 2013.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market for 2013 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[13] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in these areas during 2013.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 3-2).

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[14]

13 A unit is classified as base load if it runs for more than 50 percent of hours in the year, as intermediate if it runs for less than 50 percent but greater than 10 percent of hours in the year, and as peak if it runs for less than 10 percent of hours in the year.

14 Order No. 592, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," 77 FERC ¶ 61,263, pp. 64-70 (1996)

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2013 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly Energy Market HHI: 2012 and 2013[15]

	Hourly Market HHI (2012)	Hourly Market HHI (2013)
Average	1240	1167
Minimum	931	844
Maximum	1657	1604
Highest market share (One hour)	32%	31%
Average of the highest hourly market share	23%	22%
# Hours	8,784	8,760
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

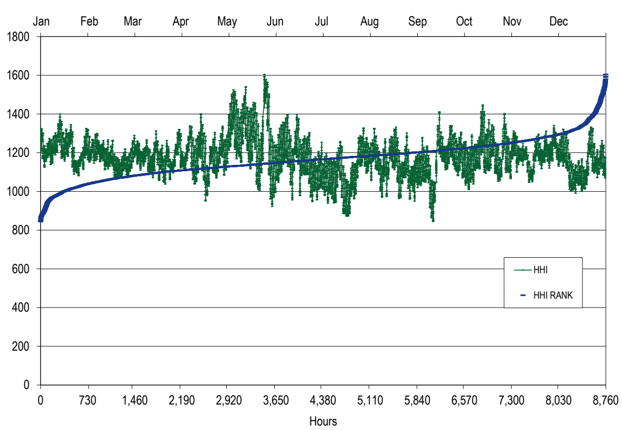
Table 3-3 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): 2012 and 2013

	2012			2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1025	1239	1624	878	1064	1464
Intermediate	787	1625	3974	946	2527	9194
Peak	679	5262	10000	580	6397	10000

Figure 3-1 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

Figure 3-1 PJM hourly Energy Market HHI: 2013



15 This analysis includes all hours in 2013, regardless of congestion.

Ownership of Marginal Resources

Table 3-4 shows the contribution to PJM real-time, load-weighted LMP by individual marginal resource owner.[16] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in 2013, the offers of one company contributed 21.7 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 56.2 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during 2012, the offers of one company contributed 22.0 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 54.3 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2012 and 2013

2012		2013	
Company	Percent of Price	Company	Percent of Price
1	22.0%	1	21.7%
2	12.8%	2	13.1%
3	11.6%	3	11.1%
4	7.9%	4	10.2%
5	7.8%	5	6.7%
6	6.2%	6	4.3%
7	5.7%	7	4.0%
8	5.2%	8	3.6%
9	3.7%	9	3.3%
Other (55 companies)	17.2%	Other (59 companies)	22.0%

Table 3-5 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[17] The contribution of each marginal resource to price at each load bus is calculated hourly for 2012 and 2013 period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

16 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

17 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): 2012 and 2013

2012		2013	
Company	Percent of Price	Company	Percent of Price
1	15.9%	1	23.1%
2	6.8%	2	9.1%
3	6.2%	3	8.7%
4	6.1%	4	8.1%
5	5.6%	5	5.3%
6	4.6%	6	3.2%
7	4.1%	7	3.1%
8	4.0%	8	2.7%
9	3.5%	9	2.5%
Other (145 companies)	43.2%	Other (147 companies)	34.2%

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources, particularly in the Day-Ahead Energy Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In 2013, coal units were 57.75 percent and natural gas units were 32.39 percent of marginal resources. In 2012, coal units were 58.84 percent and natural gas units were 30.35 percent of the total marginal resources.[18]

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal. In 2013, coal and gas were both marginal in 24.7 percent of the five-minute intervals, natural gas units were marginal with no marginal coal units in 21.4 percent of the intervals and coal units were marginal with no marginal natural gas units in 53.4 percent of the intervals.

In 2013, 46.3 percent of the wind marginal units had negative offer prices, 52.2 percent had zero offer prices and 1.5 percent had positive offer prices.

Table 3-6 Type of fuel used (By real-time marginal units): 2012 and 2013

Fuel Type	2012	2013
Coal	58.84%	57.75%
Gas	30.35%	32.39%
Oil	6.00%	4.79%
Wind	4.19%	4.76%
Other	0.47%	0.20%
Municipal Waste	0.13%	0.07%
Demand Response	0.00%	0.02%
Uranium	0.02%	0.02%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2013, up-to congestion transactions were 96.4 percent of the total marginal resources. In comparison, up-to congestion transactions were 88.4 percent of the total marginal resources in 2012.[19]

Table 3-7 Day-ahead marginal resources by type/fuel: 2012 and 2013

Type/Fuel	2012	2013
Up-to Congestion Transaction	88.4%	96.4%
DEC	4.3%	1.3%
INC	3.8%	1.1%
Coal	2.3%	0.8%
Gas	1.0%	0.4%
Dispatchable Transaction	0.1%	0.0%
Price Sensitive Demand	0.0%	0.0%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Diesel	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Total	100.0%	100.0%

Supply

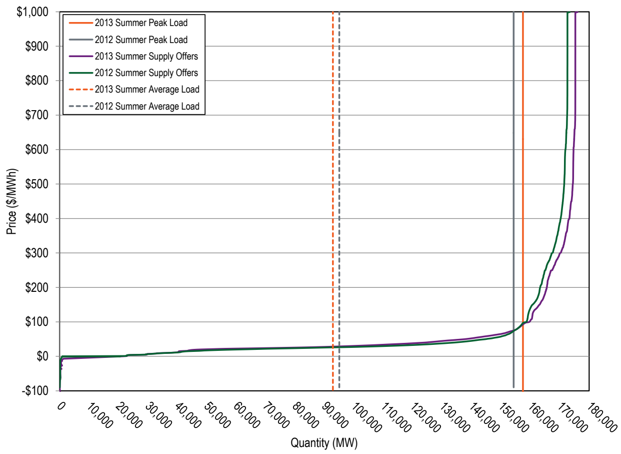
Supply includes physical generation and imports and virtual transactions.

Figure 3-2 shows the average PJM aggregate real-time generation supply curves, peak load and average load for the summers of 2012 and 2013.

18 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, were based on both locational pricing algorithm (LPA) and dispatch (SCED) marginal resources. Starting with the *2012 State of the Market Report for PJM*, marginal fuel percentages are based only on SCED. See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

19 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Figure 3-2 Average PJM aggregate real-time generation supply curves: Summer of 2012 and 2013



Energy Production by Fuel Source

Compared to 2012, generation from coal units increased 6.2 percent and generation from natural gas units decreased 12.5 percent (Table 3-8).[20] This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output.

Table 3-8 PJM generation (By fuel source (GWh)): 2012 and 2013[21]

	2012		2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	332,762.0	42.1%	353,463.5	44.3%	6.2%
Standard Coal	323,043.5	40.9%	343,957.5	43.2%	6.3%
Waste Coal	9,718.5	1.2%	9,506.1	1.2%	(0.1%)
Nuclear	273,372.2	34.6%	277,277.8	34.8%	1.4%
Gas	148,230.4	18.8%	130,102.3	16.3%	(12.2%)
Natural Gas	146,007.5	18.5%	127,726.8	16.0%	(12.5%)
Landfill Gas	2,222.3	0.3%	2,321.0	0.3%	4.4%
Biomass Gas	0.5	0.0%	54.5	0.0%	10,323.4%
Hydroelectric	12,649.7	1.6%	14,085.0	1.8%	11.3%
Pumped Storage	6,521.9	0.8%	6,690.4	0.8%	2.6%
Run of River	6,127.8	0.8%	7,394.5	0.9%	20.7%
Wind	12,633.6	1.6%	14,826.9	1.9%	17.4%
Waste	5,177.6	0.7%	5,040.1	0.6%	(2.7%)
Solid Waste	4,200.3	0.5%	4,185.0	0.5%	(0.4%)
Miscellaneous	977.3	0.1%	855.1	0.1%	(12.5%)
Oil	5,030.9	0.6%	1,948.3	0.2%	(61.3%)
Heavy Oil	4,796.9	0.6%	1,730.7	0.2%	(63.9%)
Light Oil	218.9	0.0%	187.2	0.0%	(14.5%)
Diesel	9.9	0.0%	14.6	0.0%	47.5%
Kerosene	5.1	0.0%	15.7	0.0%	204.6%
Jet Oil	0.0	0.0%	0.1	0.0%	219.4%
Solar	233.5	0.0%	355.0	0.0%	52.0%
Battery	0.3	0.0%	0.7	0.0%	122.3%
Total	790,090.3	100.0%	797,099.6	100.0%	0.9%

20 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

21 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	31,689.2	28,886.8	29,680.4	24,637.5	25,824.6	30,722.3	34,879.0	31,619.9	29,172.7	26,597.2	27,073.3	32,680.8	353,463.5
Standard Coal	30,814.3	28,102.4	28,670.2	24,060.8	24,962.6	29,884.0	33,916.0	30,862.6	28,562.7	25,984.7	26,427.7	31,709.5	343,957.5
Waste Coal	874.9	784.4	1,010.2	576.7	862.0	838.3	962.9	757.4	610.0	612.5	645.6	971.2	9,506.1
Nuclear	25,610.7	22,563.1	23,854.9	19,614.0	21,106.9	23,109.3	24,458.0	24,985.8	21,951.7	21,878.1	22,597.7	25,547.6	277,277.8
Gas	10,261.4	10,319.8	10,055.6	9,276.0	10,240.2	10,594.4	14,788.8	13,356.2	10,372.6	10,226.0	10,371.0	10,240.4	130,102.3
Natural Gas	10,072.4	10,143.6	9,859.7	9,096.1	10,047.2	10,404.5	14,593.7	13,158.1	10,174.8	10,009.5	10,156.1	10,011.1	127,726.8
Landfill Gas	189.0	176.2	195.9	179.9	193.0	189.8	195.1	198.1	196.2	203.1	197.6	207.2	2,321.0
Biomass Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	13.4	17.3	22.1	54.5
Hydroelectric	1,234.0	1,127.0	1,215.8	1,273.0	1,250.7	1,401.7	1,609.2	1,167.5	865.7	855.1	853.1	1,232.1	14,085.0
Pumped Storage	488.1	440.0	486.4	481.9	562.9	730.2	848.5	710.2	528.9	491.3	433.4	488.6	6,690.4
Run of River	745.8	687.0	729.4	791.0	687.9	671.5	760.8	457.3	336.8	363.8	419.7	743.5	7,394.5
Wind	1,784.4	1,397.5	1,606.2	1,639.6	1,271.3	862.5	588.2	510.4	719.2	1,070.8	1,833.1	1,543.7	14,826.9
Waste	414.4	385.2	391.5	358.2	421.3	428.7	447.1	465.4	407.4	434.9	425.2	460.9	5,040.1
Solid Waste	324.8	301.5	325.2	323.9	349.9	368.6	385.3	382.3	350.4	356.5	348.3	368.2	4,185.0
Miscellaneous	89.6	83.7	66.2	34.3	71.4	60.2	61.8	83.0	57.0	78.4	76.8	92.7	855.1
Oil	62.5	23.8	50.3	79.1	220.3	190.7	629.8	154.8	209.2	116.0	17.0	194.8	1,948.3
Heavy Oil	55.8	21.9	27.9	66.8	206.1	179.4	575.0	139.9	167.6	101.1	7.5	181.8	1,730.7
Light Oil	4.2	1.5	17.7	11.7	13.2	10.7	43.6	13.0	36.7	14.9	7.8	12.1	187.2
Diesel	0.6	0.1	0.0	0.5	1.1	0.4	8.2	0.2	3.0	0.1	0.4	0.0	14.6
Kerosene	1.9	0.3	4.7	0.1	0.0	0.2	3.0	1.7	1.8	0.0	1.2	0.9	15.7
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1
Solar	15.6	17.6	26.7	38.1	39.6	38.4	37.9	35.6	39.0	28.9	23.4	14.2	355.0
Battery	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.7
Total	71,072.0	64,720.7	66,881.4	56,915.4	60,374.9	67,348.2	77,438.0	72,295.8	63,737.6	61,207.1	63,193.7	71,914.6	797,099.6

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Real-Time Supply

Average offered real-time generation increased by 2,546 MW, or 1.5 percent, from 173,414 MW in the summer of 2012 to 175,960 MW in summer of 2013.[22] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 1,127 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 18 units (2,863 MW) since January 1, 2013.

PJM average real-time generation in 2013 increased by 1.2 percent from 2012, from 88,708 MW to 89,769 MW. PJM average real-time generation in 2013 would have increased by 0.5 percent from 2012, from 88,708 MW

22 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

to 89,126 MW, if the EKPC Transmission Zone had not been included in the comparison.[23,24]

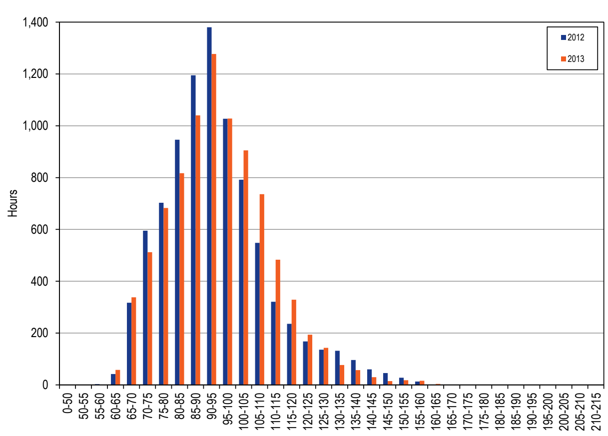
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-3 shows the hourly distribution of PJM real-time generation plus imports for 2012 and 2013.

Figure 3-3 Distribution of PJM real-time generation plus imports: 2012 and 2013[25]



PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the 14-year period from 2000 through 2013.[26]

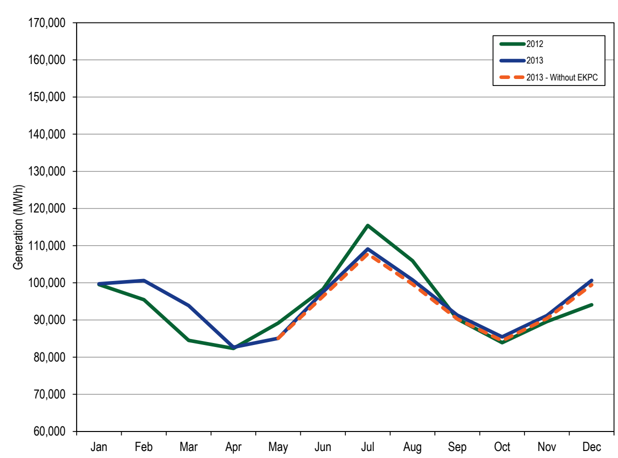
Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: 2000 through 2013

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Year	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,301	4,980	33,256	5,456	NA	NA	NA	NA
2001	29,553	4,937	32,552	5,285	(2.5%)	(0.9%)	(2.1%)	(3.1%)
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2013 with those in 2012.

Figure 3-4 PJM real-time average monthly hourly generation: January 2012 through December 2013



23 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

24 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

25 Each range on the horizontal axis excludes the start value and includes the end value.

26 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

Day-Ahead Supply

PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, increased by 10.3 percent from 2012, from 134,479 MW to 148,323 MW. The PJM average day-ahead supply in 2013, including INCs and up-to congestion transactions, would have increased by 9.7 percent from 2012, from 134,479 MW to 147,541 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead supply growth was 758.3 percent higher in 2013 than the real-time generation growth in 2012 because of the continued growth of up-to congestion transactions. If 2013 up-to congestion transactions had been held to 2012 levels, the day-ahead supply, including INCs and up-to congestion transactions, would have increased 0.4 percent instead of 10.3 percent and day-ahead supply growth would have been 63.3 percent lower than the real-time generation growth.

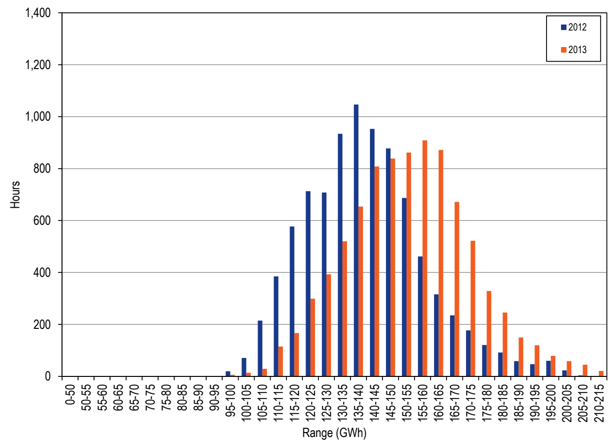
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up-to Congestion Transaction.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for 2012 and 2013.

Figure 3-5 Distribution of PJM day-ahead supply plus imports: 2012 and 2013[27]



27 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 14-year period from 2000 through 2013.[28]

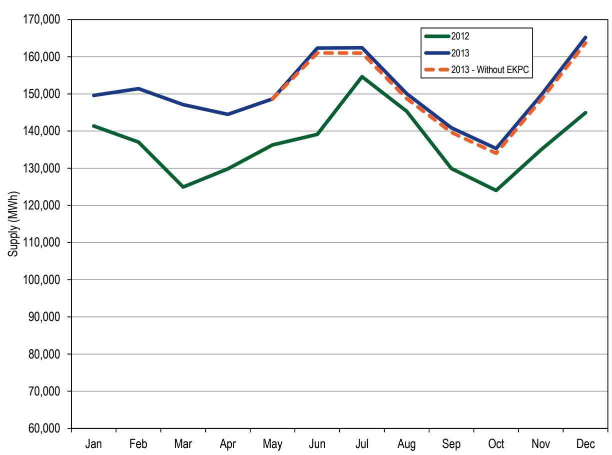
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 2000 through 2013

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Year	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,135	4,858	27,589	4,895	NA	NA	NA	NA
2001	26,762	4,595	27,497	4,664	(1.4%)	(5.4%)	(0.3%)	(4.7%)
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%

PJM Day-Ahead, Monthly Average Supply

Figure 3-6 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, of 2013 with those of 2012.

Figure 3-6 PJM day-ahead monthly average hourly supply: January 2012 through December 2013



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for 2012 and 2013 for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2013, up-to congestion transactions were 34.3 percent of the total day-ahead supply compared to 28.0 percent in 2012.

28 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Table 3-12 Day-ahead and real-time supply (MWh): 2012 and 2013

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Year	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2012	90,134	6,000	38,344	2,424	136,903	88,708	94,083	42,820	1,426
	2013	91,593	5,131	51,598	2,273	150,595	89,769	94,833	55,763	1,825
Median	2012	88,404	5,976	37,015	2,381	135,826	86,513	91,920	43,907	1,891
	2013	90,767	5,099	51,992	2,249	150,475	88,721	93,518	56,957	2,046
Standard Deviation	2012	17,301	922	7,978	503	18,080	15,701	16,505	1,575	1,600
	2013	16,059	856	10,061	429	18,978	15,012	15,878	3,101	1,046
Peak Average	2012	100,130	6,348	37,347	2,612	146,437	97,134	103,097	43,340	2,996
	2013	101,479	5,369	52,246	2,374	161,469	98,622	104,192	57,276	2,857
Peak Median	2012	96,163	6,291	36,899	2,596	143,614	93,361	99,063	44,551	2,802
	2013	99,284	5,420	53,079	2,366	159,563	96,660	102,041	57,523	2,625
Peak Standard Deviation	2012	15,068	753	5,663	466	15,405	14,272	14,979	426	796
	2013	13,183	799	9,563	370	15,798	12,706	13,606	2,192	477
Off-Peak Average	2012	81,400	5,697	39,215	2,261	128,573	81,346	86,207	42,367	55
	2013	82,975	4,923	51,033	2,184	141,116	82,050	86,673	54,443	925
Off-Peak Median	2012	79,555	5,618	37,142	2,221	126,367	79,350	84,065	42,302	205
	2013	81,764	4,892	51,070	2,092	140,236	80,697	85,164	55,072	1,067
Off-Peak Standard Deviation	2012	14,103	950	9,467	476	16,012	12,951	13,468	2,544	1,152
	2013	13,105	849	10,444	456	16,239	12,378	12,944	3,295	727

Figure 3-7 shows the average hourly cleared volumes of day-ahead supply and real-time supply. The day-ahead supply consists of day-ahead generation, imports, increment offers and up-to congestion transactions. The real-time generation includes generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average hourly volumes): 2013

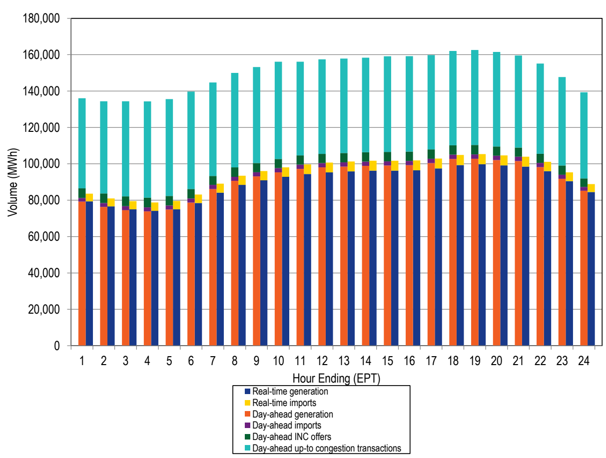


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2012 and 2013.

Figure 3-8 Difference between day-ahead and real-time supply (Average daily volumes): January 2012 through December of 2013

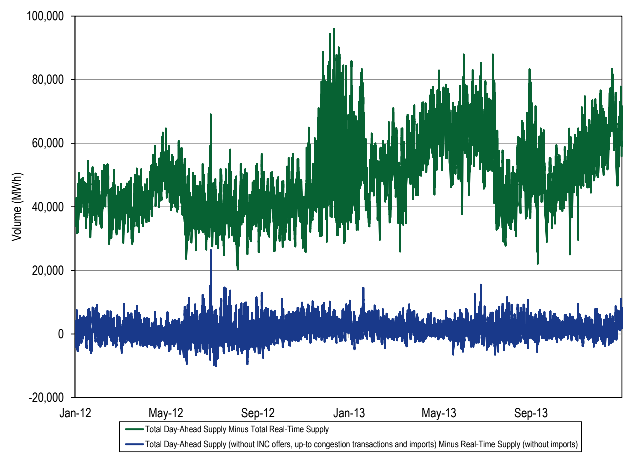
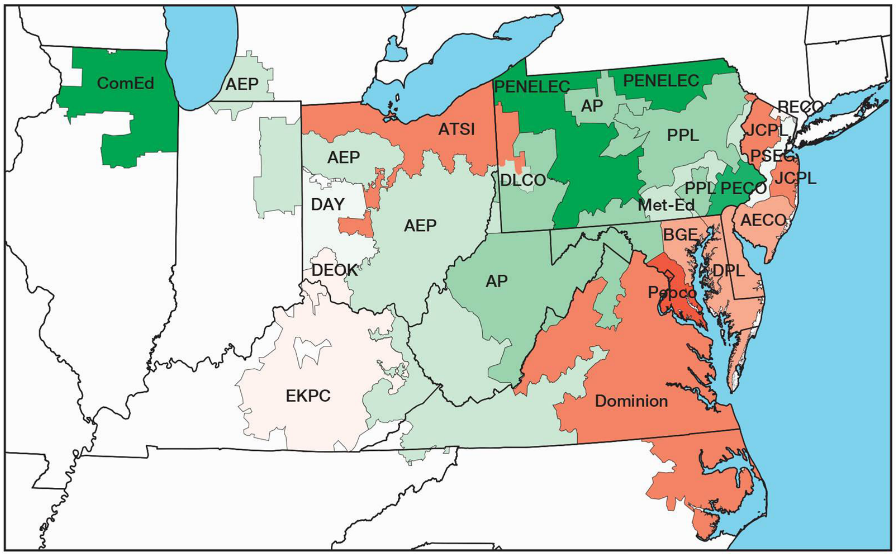


Figure 3-9 shows the difference between the PJM real-time generation and real-time load by zone in 2013. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2012 and 2013. Figure 3-9 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load.

Figure 3-9 Map of PJM real-time generation less real-time load by zone: 2013[29]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(8,178)	ComEd	28,686	DPL	(10,884)	PENELEC	26,357
AEP	3,653	DAY	308	EKPC	(1,455)	Pepco	(21,151)
AP	7,316	DEOK	(1,811)	JCPL	(11,867)	PPL	8,915
ATSI	(11,757)	DLCO	2,976	Met-Ed	4,847	PSEG	1,503
BGE	(10,401)	Dominion	(12,875)	PECO	19,935	RECO	(1,531)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): 2012 and 2013

	Zonal Generation and Load (GWh)					
	2012			2013		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,003.5	10,655.9	(8,652.4)	2,219.5	10,397.8	(8,178.4)
AEP	142,723.2	131,002.1	11,721.0	133,130.2	129,477.6	3,652.6
AP	50,900.7	46,036.5	4,864.2	54,539.3	47,223.6	7,315.7
ATSI	57,934.8	66,653.6	(8,718.8)	55,061.7	66,818.8	(11,757.1)
BGE	20,796.6	32,422.2	(11,625.5)	21,794.6	32,196.1	(10,401.4)
ComEd	128,101.3	99,348.9	28,752.5	127,235.2	98,548.9	28,686.3
DAY	15,486.4	16,761.5	(1,275.1)	17,047.5	16,739.6	307.9
DEOK	19,913.4	26,523.2	(6,609.8)	24,845.3	26,656.0	(1,810.7)
DLCO	17,773.9	14,937.0	2,836.9	17,650.0	14,674.3	2,975.7
Dominion	76,717.5	91,713.0	(14,995.5)	80,988.9	93,863.4	(12,874.5)
DPL	8,425.1	18,240.5	(9,815.4)	7,575.3	18,459.1	(10,883.8)
EKPC	NA	NA	NA	5,629.8	7,085.0	(1,455.2)
JCPL	12,659.6	22,597.0	(9,937.5)	11,145.3	23,012.3	(11,867.0)
Met-Ed	20,973.5	14,996.9	5,976.6	19,937.3	15,090.7	4,846.5
PECO	61,033.8	39,794.6	21,239.2	60,062.2	40,127.2	19,935.0
PENELEC	38,185.2	17,103.0	21,082.2	43,582.3	17,225.2	26,357.1
Pepco	12,399.9	30,658.2	(18,258.3)	9,264.6	30,416.0	(21,151.4)
PPL	47,863.8	39,748.6	8,115.2	49,475.8	40,560.9	8,914.8
PSEG	45,316.4	43,589.6	1,726.8	45,189.5	43,686.4	1,503.0
RECO	0.0	1,520.2	(1,520.2)	0.0	1,530.8	(1,530.8)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

The PJM system load reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market. In this section, demand refers to the physical load and exports and in the Day-Ahead Energy Market also includes the virtual transactions, which include decrement bids and up-to congestion transactions.

The PJM system peak load for 2013 was 157,508 MW in the HE 1700 on July 18, 2013, which was 3,165 MW, or 2.1 percent, higher than the PJM peak load for 2012, which was 154,344 MW in the HE 1700 on July 17, 2012. The EKPC Transmission Zone accounted for 2,175 MW in the peak hour of 2013. The peak load excluding the EKPC

29 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/bus-model-updates.aspx>.

Transmission Zone was 155,333 MW, also occurring on July 18, 2013, HE 1700, an increase of 990 MW, or 0.6 percent.

Table 3-14 shows the coincident peak loads for the years 1999 through 2013.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2013[30]

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, July 06	14	51,689	NA	NA
2000	Wed, August 09	17	49,469	(2,220)	(4.3%)
2001	Thu, August 09	15	54,015	4,546	9.2%
2002	Wed, August 14	16	63,762	9,747	18.0%
2003	Fri, August 22	16	61,499	(2,263)	(3.5%)
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013 (with EKPC)	Thu, July 18	17	157,508	3,165	2.1%
2013 (without EKPC)	Thu, July 18	17	155,333	990	0.6%

Figure 3-10 shows the peak loads for the years 1999 through 2013.

Figure 3-10 PJM footprint calendar year peak loads: 1999 to 2013

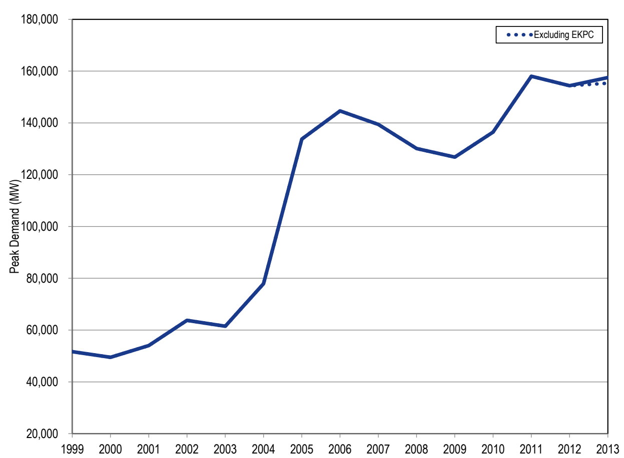
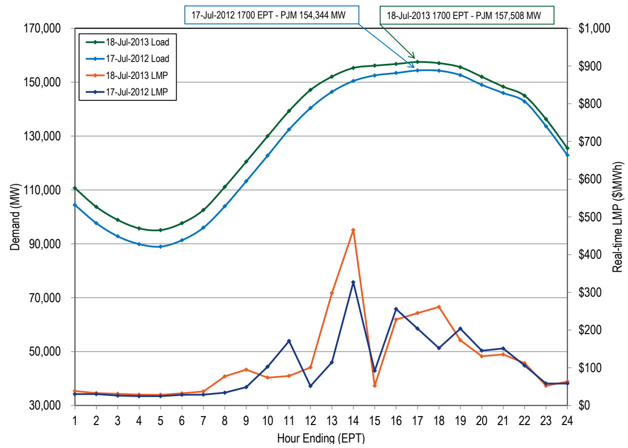


Figure 3-11 compares the peak load days in 2012 and 2013. In every hour on July 18, 2013, the average hourly real-time load was higher than the average hourly real-time load on July 17, 2012. The average hourly real-time LMP peaked at $465.18 on July 18, 2013 and peaked at $326.72 on July 17, 2012.

Figure 3-11 PJM peak-load comparison: Thursday, July 18, 2013, and Tuesday, July 17, 2012



Real-Time Demand

PJM average real-time load in 2013 increased by 1.5 percent from 2012, from 87,011 MW to 88,332 MW. The PJM average real-time load in 2013 would have increased by 0.6 percent from 2012, from 87,011 MW to 87,537 MW, if the EKPC Transmission Zone had not been included in the comparison.[31,32]

In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-12 shows the hourly distribution of PJM real-time load plus exports for 2012 and 2013.[33]

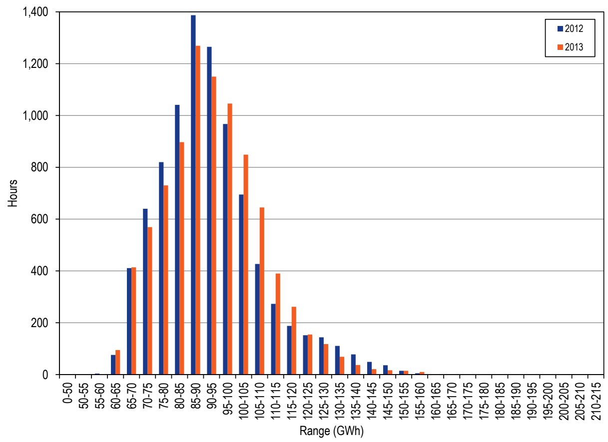
30 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

31 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

32 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

33 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-12 Distribution of PJM real-time accounting load plus exports: 2012 and 2013[34,35]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for each year during the 16 year period 1998 to 2013. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[36]

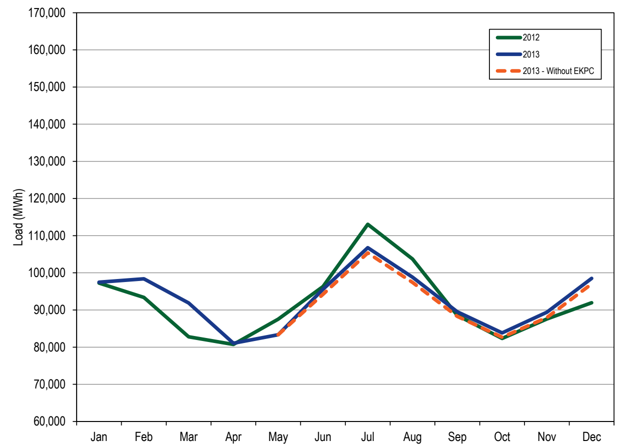
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2013[37,38]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Year	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	NA	NA	NA	NA	NA	NA
1999	29,641	5,955	NA	NA	3.7%	8.1%	NA	NA
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	NA	NA
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)

PJM Real-Time, Monthly Average Load

Figure 3-13 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

Figure 3-13 PJM real-time monthly average hourly load: January 2012 through December 2013



PJM real-time load is significantly affected by temperature. Figure 3-14 compares the total PJM monthly heating and cooling degree days in 2013 with those in 2012.[39] The figure shows that in 2013, the heating degree days were higher, except October and November, and the cooling degree days were lower, except September and October, than in the corresponding months of 2012.

34 Each range on the horizontal axis excludes the start value and includes the end value.

35 The 2012 data used in the version of this figure in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are included in this figure.

36 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

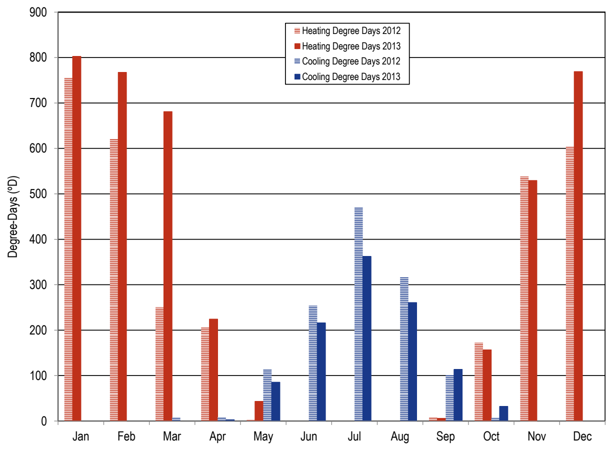
37 The data used in the version of this table in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are reflected in this table.

38 The export data in this table are not available before June 1, 2000. The export data in 2000 are for the last six months of 2000.

39 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).

Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average daily temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, ORD, ORF, PHL, PIT, RIC, ROA, SDF, TOL and WAL.

Figure 3-14 PJM heating and cooling degree days: 2012 and 2013



Day-Ahead Demand

PJM average day-ahead demand, including DECs and up-to congestion transactions, in 2013 increased by 10.1 percent from 2012, from 131,612 MW to 144,858 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased 9.4 percent from 2012, from 131,612 MW to 143,962 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead demand growth was 573.3 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If 2013 up-to congestion transactions had been held to 2012 levels, the day-ahead demand would have decreased 0.01 percent instead of increasing 10.1 percent. The day-ahead demand growth would have been 100.7 percent lower than the real-time load growth.

In the PJM Day-Ahead Energy Market, five types of financially binding demand bids are made and cleared:

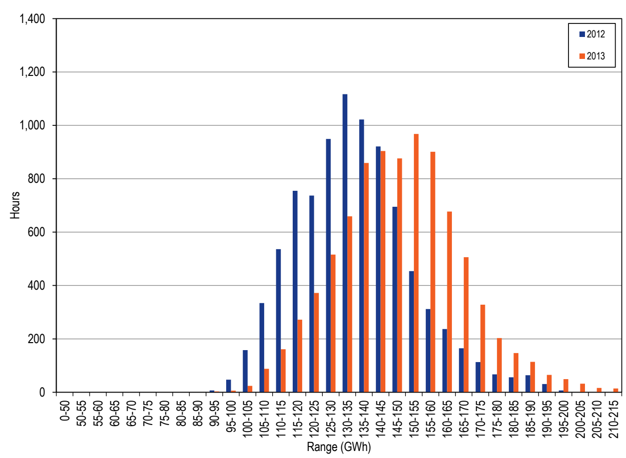
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up-to Congestion Transaction.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-15 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for 2012 and 2013.

Figure 3-15 Distribution of PJM day-ahead demand plus exports: 2012 and 2013[40]



40 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-16 presents summary day-ahead demand statistics for each year of the 14-year period 2000 to 2013.[41]

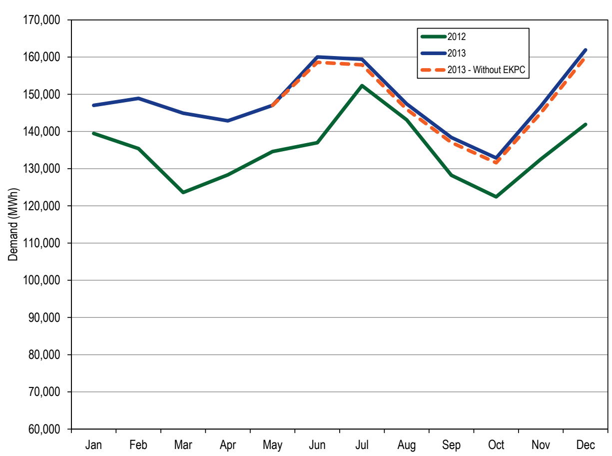
Table 3-16 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: 2000 through 2013

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Year	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	33,039	6,852	33,411	6,757	NA	NA	NA	NA
2001	33,370	6,562	33,757	6,431	1.0%	(4.2%)	1.0%	(4.8%)
2002	42,305	10,161	42,413	10,208	26.8%	54.9%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	5.9%

PJM Day-Ahead, Monthly Average Demand

Figure 3-16 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, of 2013 with those of 2012.

Figure 3-16 PJM day-ahead monthly average hourly demand: January 2012 through December 2013



41 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Real-Time and Day-Ahead Demand

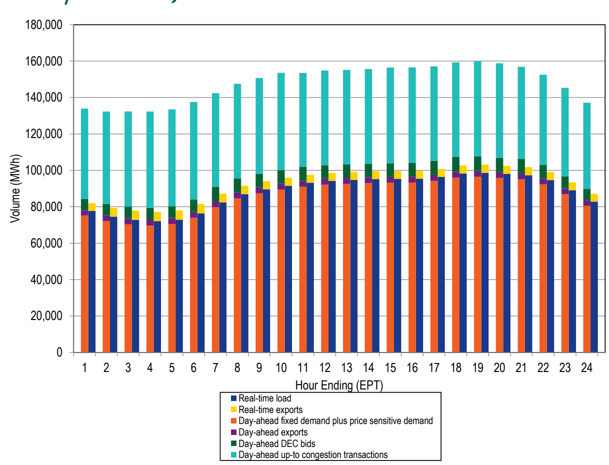
Table 3-17 presents summary statistics for 2012 and 2013 day-ahead and real-time demand. The last two columns of Table 3-17 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price sensitive demand) less the physical real-time load.

Table 3-17 Cleared day-ahead and real-time demand (MWh): 2012 and 2013[42]

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2012	84,112	720	8,435	38,344	3,335	134,947	87,011	92,135	42,812	(2,179)
	2013	84,859	1,199	7,202	51,598	3,273	148,132	88,332	92,879	55,253	(2,275)
Median	2012	82,422	692	8,169	37,015	3,281	133,896	85,018	90,024	43,872	(1,903)
	2013	83,734	1,229	6,930	51,992	3,231	148,008	87,072	91,572	56,436	(2,108)
Standard Deviation	2012	15,855	143	1,818	7,978	697	17,527	16,212	16,052	1,476	(214)
	2013	14,789	245	1,438	10,061	662	18,570	15,489	15,418	3,152	(455)
Peak Average	2012	93,339	771	9,421	37,347	3,354	144,232	96,186	100,899	43,333	(2,076)
	2013	94,149	1,295	7,821	52,246	3,276	158,788	97,624	101,993	56,795	(2,179)
Peak Median	2012	89,430	741	9,174	36,899	3,322	141,439	92,192	96,887	44,552	(2,021)
	2013	92,358	1,347	7,516	53,079	3,232	157,103	95,465	99,864	57,240	(1,761)
Peak Standard Deviation	2012	13,984	145	1,671	5,663	666	14,976	14,404	14,604	372	(275)
	2013	12,265	257	1,424	9,563	667	15,479	13,105	13,202	2,276	(583)
Off-Peak Average	2012	76,049	676	7,574	39,215	3,318	126,834	78,994	84,478	42,356	(2,268)
	2013	76,759	1,115	6,663	51,033	3,271	138,841	80,232	84,933	53,908	(2,357)
Off-Peak Median	2012	73,982	656	7,260	37,142	3,251	124,781	76,897	82,408	42,373	(2,260)
	2013	75,503	1,144	6,422	51,070	3,230	138,112	78,751	83,509	54,602	(2,104)
Off-Peak Standard Deviation	2012	12,680	125	1,472	9,467	723	15,445	13,168	13,067	2,378	(363)
	2013	11,721	199	1,215	10,444	658	15,854	12,588	12,548	3,306	(668)

Figure 3-17 shows the average hourly cleared volumes of day-ahead demand and real-time demand. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up-to congestion transactions. The real-time demand includes real-time load and real-time exports.

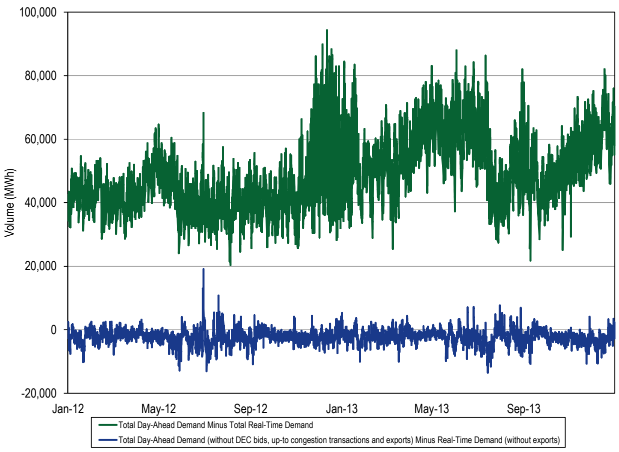
Figure 3-17 Day-ahead and real-time demand (Average hourly volumes): 2013



42 The data used in the version of this table in the *2012 State of the Market Report for PJM* have been updated by PJM and the updates are accounted for in this table.

Figure 3-18 shows the difference between the day-ahead and real-time average daily demand in 2012 and 2013.

Figure 3-18 Difference between day-ahead and real-time demand (Average daily volumes): January 2012 through December of 2013



Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a non-affiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-18 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2012 and 2013 based on parent company. For 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 25.0 percent by spot market purchase and 64.4 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot supply increased by 1.8 percentage points and reliance on self-supply decreased by 3.3 percentage points.

Table 3-18 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.9%	22.0%	69.1%	10.4%	22.3%	67.3%	1.5%	0.2%	(1.8%)
Feb	8.8%	21.2%	70.0%	10.5%	22.0%	67.5%	1.7%	0.8%	(2.4%)
Mar	9.4%	23.6%	67.1%	10.4%	24.2%	65.4%	1.1%	0.6%	(1.6%)
Apr	9.4%	23.8%	66.8%	10.7%	24.2%	65.1%	1.3%	0.4%	(1.6%)
May	8.6%	23.5%	67.9%	10.9%	25.4%	63.6%	2.4%	1.9%	(4.3%)
Jun	8.7%	22.3%	69.0%	10.7%	25.0%	64.3%	2.0%	2.7%	(4.8%)
Jul	8.0%	22.7%	69.3%	10.2%	25.2%	64.7%	2.2%	2.5%	(4.6%)
Aug	8.5%	23.6%	67.9%	10.2%	24.5%	65.3%	1.7%	0.8%	(2.6%)
Sep	9.1%	24.4%	66.5%	10.1%	24.2%	65.7%	1.1%	(0.2%)	(0.9%)
Oct	9.6%	25.5%	64.9%	11.1%	28.2%	60.7%	1.5%	2.7%	(4.2%)
Nov	9.9%	23.9%	66.3%	10.6%	27.2%	62.2%	0.7%	3.3%	(4.0%)
Dec	10.2%	22.6%	67.3%	11.3%	27.1%	61.7%	1.1%	4.5%	(5.6%)
Annual	9.0%	23.2%	67.8%	10.6%	25.0%	64.4%	1.6%	1.8%	(3.3%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

Table 3-19 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2012 through 2013

	2012			2013			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.6%	21.4%	72.0%	6.8%	22.1%	71.1%	0.2%	0.7%	(0.9%)
Feb	6.7%	20.0%	73.3%	7.0%	22.1%	71.0%	0.3%	2.1%	(2.3%)
Mar	6.7%	22.8%	70.5%	7.0%	23.6%	69.4%	0.3%	0.8%	(1.1%)
Apr	6.7%	22.8%	70.6%	7.1%	23.1%	69.8%	0.5%	0.3%	(0.8%)
May	6.6%	22.7%	70.7%	7.8%	23.5%	68.7%	1.2%	0.8%	(2.0%)
Jun	7.7%	20.7%	71.6%	8.2%	23.8%	68.0%	0.5%	3.1%	(3.5%)
Jul	5.9%	22.0%	72.0%	8.0%	24.1%	67.9%	2.0%	2.1%	(4.1%)
Aug	6.4%	22.5%	71.0%	8.1%	23.9%	68.0%	1.7%	1.4%	(3.1%)
Sep	6.5%	23.9%	69.6%	7.8%	23.9%	68.3%	1.3%	(0.0%)	(1.3%)
Oct	6.6%	25.2%	68.2%	9.8%	29.0%	61.3%	3.2%	3.7%	(6.9%)
Nov	6.9%	22.7%	70.5%	9.3%	29.1%	61.7%	2.4%	6.4%	(8.8%)
Dec	7.0%	21.2%	71.8%	9.9%	25.6%	64.5%	2.9%	4.4%	(7.4%)
Annual	6.7%	22.3%	71.0%	8.0%	24.5%	67.5%	1.4%	2.2%	(3.6%)

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-19 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2012 and 2013, based on parent companies. For 2013, 8.0 percent of day-ahead demand was supplied by bilateral contracts, 24.5 percent by spot market purchases, and 67.5 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot supply increased by 2.2 percentage points, and reliance on self-supply decreased by 3.6 percentage points.

Market Behavior

Offer Capping for Local Market Power

In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

Levels of offer capping have historically been low in PJM, as shown in Table 3-20. The offer capping percentages shown in Table 3-20 include units that are committed to provide constraint relief whose owners failed the TPS test in the Energy Market, excluding offer capping for reliability reasons.

Table 3-20 Offer-capping statistics – Energy only: 2009 to 2013

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%

Table 3-21 shows the offer capping percentages including units committed to provide constraint relief as well as units committed to provide black start service and reactive support. The units that are committed and offer capped for reliability reasons have been steadily increasing since 2011. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic (and are therefore committed on their cost schedule for reliability reasons) has steadily increased.

Table 3-21 Offer-capping statistics for energy and reliability: 2009 to 2013

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.7%	0.2%	0.0%	0.0%
2012	1.7%	1.0%	0.9%	0.5%
2013	2.9%	2.4%	3.2%	2.1%

Table 3-22 presents data on the frequency with which units were offer capped in 2012 and 2013 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-22 Real-time offer-capped unit statistics: 2012 and 2013[43]

Run Hours Offer-Capped, Percent Greater Than Or Equal To:		Offer-Capped Hours: Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2013	0	0	0	0	0	0
	2012	0	1	0	1	1	1
80% and < 90%	2013	0	0	0	1	1	3
	2012	0	1	1	0	1	2
75% and < 80%	2013	0	0	0	0	1	2
	2012	0	0	0	0	0	2
70% and < 75%	2013	0	0	1	0	0	3
	2012	0	0	0	0	1	2
60% and < 70%	2013	0	0	0	0	0	4
	2012	0	0	0	1	1	9
50% and < 60%	2013	0	0	0	0	0	9
	2012	3	0	1	0	1	6
25% and < 50%	2013	0	3	3	1	7	44
	2012	6	1	0	3	2	45
10% and < 25%	2013	2	0	0	4	3	46
	2012	2	2	0	3	12	58

Table 3-22 shows that no units were offer capped for 90 percent or more of their run hours in 2013.

Offer Capping for Local Market Power

In 2013, the AECO, AEP, ATSI, BGE, ComEd, Dominion, DPL, PECO, PENELEC, Pepco, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The AP, DAY, DEOK, DLCO, JCPL, Met-Ed, and RECO control zones did not have constraints binding for 100 or more hours in 2013. Table 3-23 shows that BGE, ComEd, Dominion and PSEG were the only control zones with 100 or more hours of congestion in every year from 2009 through 2013.

Table 3-23 Numbers of hours when control zones experienced congestion for 100 or more hours: 2009 through 2013

	2009	2010	2011	2012	2013
AECO	149	172	234	NA	208
AEP	2,449	1,941	2,032	NA	873
AP	4,486	5,538	962	206	NA
ATSI	NA	NA	NA	208	135
BGE	456	940	807	2,196	880
ComEd	2,626	3,310	1,134	3,467	2,760
DEOK	NA	NA	NA	109	NA
DLCO	312	260	103	209	NA
Dominion	702	1,246	1,052	1,020	981
DPL	NA	244	NA	1,070	426
Met-Ed	NA	360	162	NA	NA
PECO	494	NA	483	386	488
PENELEC	103	568	NA	NA	176
Pepco	298	NA	NA	143	145
PPL	176	118	NA	NA	294
PSEG	442	549	613	913	2,014

Competitive conditions in the Real-Time Energy Market associated with each of the frequently binding constraints were analyzed using the three pivotal supplier results for 2013.[44] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-24 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

43 This table was modified from the previous State of the Market report to include only units that are offer capped for failing the TPS test in the Real-Time Energy Market.

44 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

Table 3-24 Three pivotal supplier test details for interface constraints: 2013

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	279	313	13	2	11
	Off Peak	205	282	12	3	9
AEP - DOM	Peak	167	167	5	0	5
	Off Peak	153	189	5	0	5
AP South	Peak	306	464	10	1	9
	Off Peak	330	506	10	1	9
ATSI	Peak	321	717	15	12	3
	Off Peak	0	0	0	0	0
BC/PEPCO	Peak	204	415	11	5	6
	Off Peak	262	469	10	5	5
Bedington - Black Oak	Peak	126	279	13	6	7
	Off Peak	181	367	13	6	7
Cleveland	Peak	97	119	2	0	2
	Off Peak	0	0	0	0	0
Eastern	Peak	488	449	13	1	12
	Off Peak	0	0	0	0	0
PL North	Peak	37	99	1	0	1
	Off Peak	151	321	2	0	2
Western	Peak	470	530	14	3	11
	Off Peak	1,295	1,800	20	6	14

be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-25 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 3-25 Summary of three pivotal supplier tests applied for interface constraints: 2013

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	766	57	7%	19	2%	33%
	Off Peak	705	52	7%	16	2%	31%
AEP - DOM	Peak	133	4	3%	0	0%	0%
	Off Peak	31	2	6%	0	0%	0%
AP South	Peak	5,771	226	4%	48	1%	21%
	Off Peak	4,412	124	3%	27	1%	22%
ATSI	Peak	144	4	3%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
Bedington - Black Oak	Peak	316	3	1%	0	0%	0%
	Off Peak	95	2	2%	0	0%	0%
BC/PEPCO	Peak	910	48	5%	7	1%	15%
	Off Peak	819	33	4%	8	1%	24%
Cleveland	Peak	108	6	6%	3	3%	50%
	Off Peak	0	0	0%	0	0%	0%
Eastern	Peak	26	0	0%	0	0%	0%
	Off Peak	0	0	0%	0	0%	0%
PL North	Peak	5	0	0%	0	0%	0%
	Off Peak	212	0	0%	0	0%	0%
Western	Peak	404	14	3%	7	2%	50%
	Off Peak	254	7	3%	5	2%	71%

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would

Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[45] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Markup

Table 3-26 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. For convenience, the marginal units are grouped into one of seven categories based on their respective offer prices. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In 2013, 93.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.04. The data shows that despite the fact that markup had a negligible impact on LMP in 2013, some marginal units do have substantial markups.

Table 3-26 Average, real-time marginal unit markup index (By price category): 2012 and 2013

	2012			2013		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.25)	31.3%	(0.01)	($3.27)	17.8%
$25 to $50	(0.05)	($2.67)	56.5%	(0.01)	($1.23)	65.3%
$50 to $75	0.05	$1.23	4.8%	(0.01)	($3.90)	8.4%
$75 to $100	0.28	$24.24	0.7%	0.04	($1.50)	1.5%
$100 to $125	0.23	$23.67	0.5%	0.10	$9.85	0.7%
$125 to $150	0.20	$27.69	0.2%	0.04	$4.98	1.7%
>= $150	0.04	$9.40	5.9%	0.03	$7.21	4.5%

Day-Ahead Markup

Table 3-27 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time. In 2013, 99.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data shows that despite the fact that markup had a negligible impact on LMP in 2013, some marginal units do have substantial markups.

Table 3-27 Average marginal unit markup index (By offer price category): 2012 and 2013

	2012			2013		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.69)	29.5%	(0.07)	($1.78)	19.2%
$25 to $50	(0.05)	($2.43)	67.3%	(0.04)	($2.40)	75.2%
$50 to $75	0.09	$4.20	2.7%	0.00	($2.46)	4.6%
$75 to $100	0.45	$36.22	0.1%	0.08	$6.63	0.4%
$100 to $125	0.00	$0.00	0.0%	0.00	$0.00	0.1%
$125 to $150	(0.06)	($8.33)	0.1%	0.00	$0.00	0.0%
>= $150	0.03	$4.84	0.2%	0.75	$118.80	0.0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped for 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[46] These categories are designated Tier 1, Tier 2 and Tier 3.[47,48]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped. For example, if a generating station had two identical units with identical electrical impacts on the system, one of

45 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

46 OA, Schedule 1 § 6.4.2.

47 114 FERC ¶ 61, 076 (2006).

48 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[49]

Table 3-28 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2012 and 2013. Of the 112 units eligible in at least one month during 2013, 22 units (19.6 percent) were FMUs or AUs for all twelve months, and 10 units (8.9 percent) qualified in only one month of 2013.

Table 3-28 Frequently mitigated units and associated units total months eligible: 2012 and 2013

	FMU & AU Count	
Number of Months Adder-Eligible	2012	2013
1	25	10
2	12	22
3	4	14
4	9	10
5	2	5
6	4	8
7	14	7
8	16	3
9	15	1
10	5	2
11	2	8
12	25	22
Total	133	112

Figure 3-19 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through December 31, 2013, there have been 341 unique units that have qualified for an FMU adder in at least one month. Of these 341 units, no unit qualified for an adder in all potential months. Two units qualified in 95 of the 96 possible months, and 103 of the 341 units (30.2 percent) have qualified for an adder in more than half of the possible months.

Figure 3-19 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2013

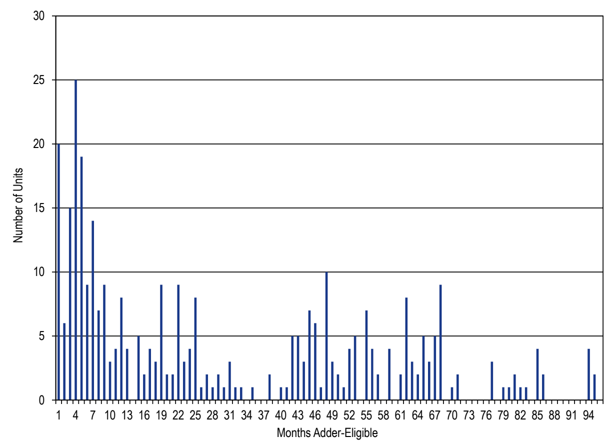


Table 3-29 shows, by month, the number of FMUs and AUs in 2012 and 2013. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

Table 3-29 Number of frequently mitigated units and associated units (By month): 2012 and 2013

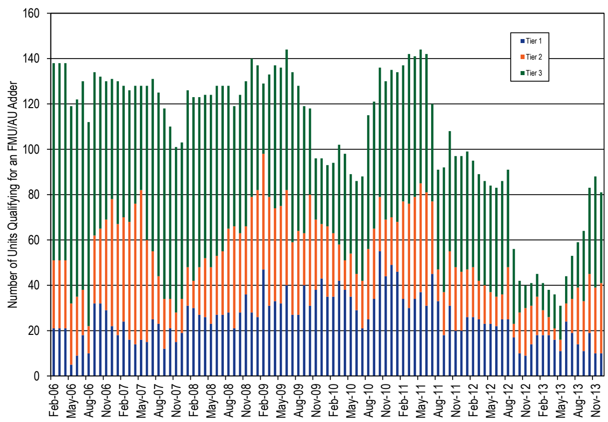
	FMUs and AUs							
	2012				2013			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86	16	5	15	36
May	23	14	47	84	11	5	15	31
June	22	13	48	83	24	8	12	44
July	25	11	50	86	19	15	19	53
August	25	23	43	91	14	25	20	59
September	17	6	33	56	11	22	31	64
October	10	18	14	42	19	26	38	83
November	9	21	10	40	10	29	49	88
December	14	17	10	41	10	31	40	81

Figure 3-20 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The reduction in the total number of units qualifying for an FMU or AU adder in 2012 resulted from the decrease in congestion, which was in turn the result of changes in fuel costs, changes in the generation mix and changes in system topology. The increase in the total number of units

49 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria

qualifying for an FMU or AU adder in 2013 was the result of modifications to commitment of black start and reactive units in the Day-Ahead Energy Market. In September 2012, PJM began to schedule units in the Day-Ahead Energy Market for black start and reactive that otherwise would not clear the market based on economics. Whenever these units are scheduled in the Day-Ahead Energy Market for black start and reactive, they are offer capped for all run hours in day ahead and real time. As FMU status is determined on a rolling 12-month period, this change started to affect the number of eligible FMU units in 2013.

Figure 3-20 Frequently mitigated units and associated units (By month): February, 2006 through December, 2013



The PJM Tariff defines offer capped units as those capped to maintain system reliability as a result of limits on transmission capability.[50] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.

The goal of the FMU adders was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). The relevant units were all CTs, typically running less than 500 hours per year and the adders were specifically designed to cover ACR for such units. The FMU adders were not designed for baseload units like those providing reactive service. If the FMU adders are not eliminated, adders must be specifically designed for such baseload units.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[51] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). That function became unnecessary with the introduction of the RPM capacity market design in 2007. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus if there is a shortfall in ACR recovery, that shortfall is included in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently being evaluated in the PJM stakeholder process.

If an FMU rule were to remain, it should include a requirement that no unit receive an FMU adder if unit net revenues cover unit ACR. In 2013, of the 112 units that received FMU payments in 2013, 28 units did not cover ACR. Of those 28 units, 22 units are scheduled to retire. (Table 3-30.)

Table 3-30 Frequently mitigated units at risk of retirement

	No. of Units	MW
Units that received FMU payments in 2013	112	14,763
FMUs that did not cover ACR in 2013	28	5,342
FMUs that did not cover ACR in 2013 that are scheduled to retire	22	3,908
FMUs at risk of retirement	6	1,434

50 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.

51 110 FERC ¶ 61,053 (2005).

Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up-to congestion transactions may be submitted between any two buses eligible for UTCs.[52] Import and export transactions may be submitted at any interface pricing point, where an import looks like a virtual offer that is injected into PJM and an export looks like a virtual bid that is withdrawn from PJM.

Figure 3-21 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2013.

Figure 3-21 PJM day-ahead aggregate supply curves: 2013 example day

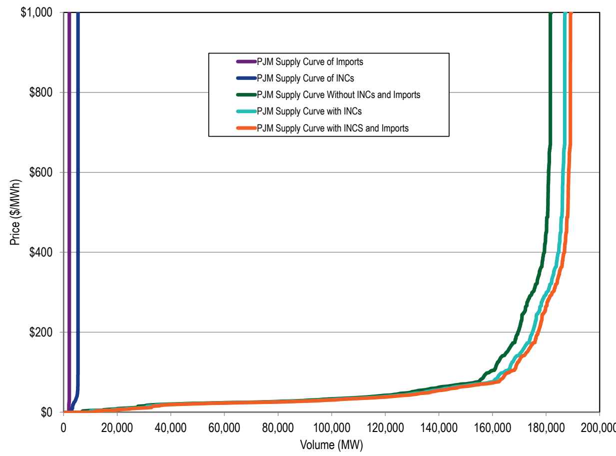


Table 3-31 shows the average hourly number of increment offers and decrement bids and the average hourly MW for 2012 and 2013. In 2013, the average hourly submitted and cleared increment offer MW decreased 23.4 and 14.5 percent, and the average hourly submitted and cleared decrement bid MW decreased 18.0 and 14.6 percent, compared to 2012.

52 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up-to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-31 Hourly average number of cleared and submitted INCs, DECs by month: 2012 and 2013[53]

	Increment Offers				Decrement Bids			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number
2012 Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012 Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012 Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012 Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012 May	6,224	8,447	80	271	8,785	11,141	109	316
2012 Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012 Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012 Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012 Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012 Oct	5,231	6,953	82	275	8,901	11,526	110	361
2012 Nov	5,423	6,944	67	190	8,678	11,758	102	289
2012 Dec	5,622	7,090	69	183	8,456	10,007	84	207
2012 Annual	6,000	8,418	81	310	8,435	11,089	105	343
2013 Jan	5,682	7,271	80	195	7,944	9,653	81	211
2013 Feb	5,949	7,246	61	130	7,689	8,942	75	165
2013 Mar	5,414	6,192	50	94	6,890	7,907	65	140
2013 Apr	5,329	6,179	56	108	6,595	7,732	63	145
2013 May	5,415	6,651	57	130	7,036	8,803	74	185
2013 Jun	5,489	7,031	64	187	7,671	9,768	88	258
2013 Jul	5,374	6,710	60	173	7,566	9,786	89	267
2013 Aug	4,633	6,169	62	179	6,819	8,295	78	195
2013 Sep	4,262	5,464	60	191	6,646	8,400	82	233
2013 Oct	4,375	5,642	70	215	6,694	8,899	93	287
2013 Nov	4,906	6,803	81	304	7,202	10,200	105	386
2013 Dec	4,803	6,123	75	278	7,700	10,650	98	393
2013 Annual	5,131	6,451	65	182	7,202	9,088	83	239

In 2013, up-to congestion transactions continued to displace increment offers and decrement bids. Table 3-32 shows the average hourly number of up-to congestion transactions and the average hourly MW for 2012 and 2013. In 2013, the average hourly up-to congestion submitted MW increased 46.3 percent and cleared MW increased 34.6 percent, compared to 2012.

53 In prior versions of this table, the annual averages were the average of the monthly averages. In this table, the annual averages and the monthly averages are the averages of the hourly values.

Table 3-32 Hourly average of cleared and submitted up-to congestion bids by month: 2012 and 2013[54]

	Up-to Congestion				
Year		Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,969	105,364	866	2,227
2012	Apr	43,777	120,955	1,013	2,519
2012	May	43,468	119,374	1,052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Oct	35,365	106,819	990	2,692
2012	Nov	40,443	143,654	1,327	3,928
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,346	119,817	1,034	2,804
2013	Jan	44,844	157,229	1,384	4,205
2013	Feb	46,351	144,066	1,419	3,862
2013	Mar	49,003	163,178	1,467	3,745
2013	Apr	57,938	193,366	1,683	4,229
2013	May	59,700	203,521	1,679	4,754
2013	Jun	60,210	229,912	1,984	5,997
2013	Jul	49,674	201,630	1,658	5,300
2013	Aug	44,765	157,748	1,477	3,923
2013	Sep	45,412	136,813	1,408	3,507
2013	Oct	45,918	145,026	1,705	4,267
2013	Nov	54,643	171,439	2,108	5,365
2013	Dec	60,588	197,092	2,204	5,948
2013	Annual	51,598	175,255	1,682	4,596

Table 3-33 shows the average hourly number of import and export transactions and the average hourly MW for 2012 and 2013. In 2013, the average hourly submitted and cleared import transaction MW decreased 6.5 and 6.3 percent, and the average hourly submitted and cleared export transaction MW decreased 1.4 and 1.9 percent, compared to 2012.

54 In prior versions of this table, the annual averages were averages of the monthly averages. In this table, the annual averages and the monthly averages are averages of the hourly values.

Table 3-33 Hourly average number of cleared and submitted import and export transactions by month: 2012 and 2013

	Imports				Exports			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number	Average Cleared MW	Average Submitted MW	Average Cleared Number	Average Submitted Number
2012 Jan	1,962	2,269	11	15	3,746	3,763	22	22
2012 Feb	2,467	2,585	14	15	3,825	3,854	20	21
2012 Mar	2,268	2,305	12	13	2,946	2,981	21	21
2012 Apr	2,496	2,525	12	13	2,887	2,917	19	19
2012 May	2,795	2,928	13	15	2,754	2,767	19	19
2012 Jun	2,542	2,636	11	13	2,852	2,878	17	17
2012 Jul	2,633	2,781	13	15	3,743	3,769	22	23
2012 Aug	2,846	2,900	15	16	3,871	3,918	23	23
2012 Sep	2,089	2,131	11	11	3,488	3,494	21	21
2012 Oct	2,562	2,614	12	13	3,525	3,529	21	21
2012 Nov	2,436	2,545	11	12	2,934	2,947	18	18
2012 Dec	1,994	2,034	10	11	3,446	3,448	21	21
2012 Annual	2,424	2,521	12	14	3,335	3,356	20	20
2013 Jan	2,071	2,177	10	11	3,278	3,293	21	21
2013 Feb	2,098	2,244	11	13	3,275	3,288	19	19
2013 Mar	1,997	2,097	12	13	3,326	3,329	18	18
2013 Apr	2,004	2,097	12	13	2,691	2,691	16	16
2013 May	2,160	2,316	12	13	2,824	2,838	18	19
2013 Jun	2,712	2,818	15	16	3,420	3,507	19	20
2013 Jul	2,930	3,019	15	16	3,621	3,720	19	20
2013 Aug	2,577	2,656	13	15	3,734	3,766	20	20
2013 Sep	2,089	2,135	9	10	3,561	3,567	19	19
2013 Oct	2,191	2,216	10	10	3,215	3,225	18	18
2013 Nov	2,182	2,196	10	11	2,531	2,564	16	16
2013 Dec	2,243	2,315	10	10	3,774	3,889	21	22
2013 Annual	2,273	2,359	12	13	3,273	3,309	19	19

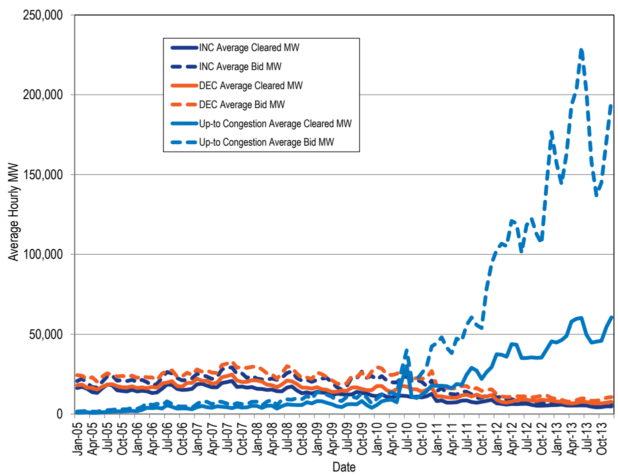
Table 3-34 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 3-34 Type of day-ahead marginal units: 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	91.7%	2.6%	1.8%	0.0%
Feb	3.4%	0.1%	92.9%	1.8%	1.8%	0.0%
Mar	2.5%	0.1%	95.8%	0.8%	0.8%	0.0%
Apr	0.4%	0.0%	98.5%	0.4%	0.6%	0.0%
May	0.6%	0.1%	98.4%	0.5%	0.4%	0.0%
Jun	0.6%	0.0%	97.5%	1.3%	0.7%	0.0%
Jul	0.8%	0.1%	97.0%	1.4%	0.7%	0.0%
Aug	0.4%	0.0%	97.6%	0.9%	1.1%	0.0%
Sep	0.6%	0.0%	96.2%	1.5%	1.6%	0.0%
Oct	0.5%	0.0%	96.9%	1.6%	1.0%	0.0%
Nov	0.4%	0.0%	96.9%	0.9%	1.8%	0.0%
Dec	0.3%	0.0%	97.2%	1.6%	0.8%	0.0%
Annual	1.2%	0.0%	96.4%	1.3%	1.1%	0.0%

Figure 3-22 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 3-22 Hourly number of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through December, 2013



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-35 shows, for 2012 and 2013, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-36 shows, for 2012 and 2013, the total up-to congestion transactions by the type of parent organization. Table 3-37 shows, for 2012 and 2013, the total import and export transactions by whether the parent organization is financial or physical.

The top five companies with cleared up-to congestion transactions are financial and account for 57.4 percent of all the cleared up-to congestion MW in PJM in 2013.

Table 3-35 PJM INC and DEC bids by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	59,843,681	34.9%	38,937,242	28.6%
Physical	111,507,235	65.1%	97,174,588	71.4%
Total	171,350,915	100.0%	136,111,830	100.0%

Table 3-36 PJM up-to congestion transactions by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	318,217,668	94.7%	432,126,914	95.6%
Physical	17,660,315	5.3%	19,875,032	4.4%
Total	335,877,984	100.0%	452,001,946	100.0%

Table 3-37 PJM import and export transactions by type of parent organization (MW): 2012 and 2013

	2012		2013	
Category	Total Import and Export MW	Percentage	Total Import and Export MW	Percentage
Financial	18,967,523	37.5%	20,687,175	42.6%
Physical	31,625,338	62.5%	27,894,650	57.4%
Total	50,592,861	100.0%	48,581,824	100.0%

Table 3-38 shows increment offers and decrement bids bid by top ten locations for 2012 and 2013.

Table 3-38 PJM virtual offers and bids by top ten locations (MW): 2012 and 2013

2012					2013				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	30,251,322	34,038,502	64,289,824	WESTERN HUB	HUB	23,704,798	26,371,972	50,076,770
AEP-DAYTON HUB	HUB	5,095,250	6,203,179	11,298,428	N ILLINOIS HUB	HUB	2,505,103	5,215,686	7,720,789
N ILLINOIS HUB	HUB	2,523,882	6,051,839	8,575,721	AEP-DAYTON HUB	HUB	3,518,334	3,519,477	7,037,811
SOUTHIMP	INTERFACE	8,243,907	0	8,243,907	SOUTHIMP	INTERFACE	6,789,355	0	6,789,355
MISO	INTERFACE	311,129	7,046,379	7,357,509	IMO	INTERFACE	6,024,071	50,665	6,074,736
PPL	ZONE	327,795	5,785,740	6,113,535	PPL	ZONE	93,834	5,350,860	5,444,694
PECO	ZONE	889,065	4,026,280	4,915,345	MISO	INTERFACE	372,546	3,911,548	4,284,094
IMO	INTERFACE	3,665,471	73,627	3,739,098	PECO	ZONE	118,146	3,844,769	3,962,915
BGE	ZONE	173,888	2,161,310	2,335,198	BGE	ZONE	34,983	2,187,127	2,222,109
METED	ZONE	153,851	1,421,991	1,575,842	DOMINION HUB	HUB	346,732	1,582,833	1,929,564
Top ten total		51,635,560	66,808,846	118,444,406			43,507,901	52,034,937	95,542,838
PJM total		73,945,975	97,404,941	171,350,915			56,506,245	79,605,585	136,111,830
Top ten total as percent of PJM total		69.8%	68.6%	69.1%			77.0%	65.4%	70.2%

Table 3-39 shows up-to congestion transactions by import bids for the top ten locations for 2012 and 2013.[55]

Table 3-39 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): 2012 and 2013

2012 Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	9,190,395
OVEC	INTERFACE	DEOK	ZONE	2,413,946
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,381,726
OVEC	INTERFACE	JEFFERSON	EHVAGG	2,143,300
NYIS	INTERFACE	HUDSON BC	AGGREGATE	2,111,405
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,864,666
MISO	INTERFACE	COOK	EHVAGG	1,841,613
OVEC	INTERFACE	COOK	EHVAGG	1,785,331
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	1,784,828
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	1,686,217
Top ten total				27,203,428
PJM total				146,428,449
Top ten total as percent of PJM total				18.6%
2013 Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	1,277,685
OVEC	INTERFACE	STUART 1	AGGREGATE	1,033,271
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	971,443
NYIS	INTERFACE	HUDSON BC	AGGREGATE	894,530
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	733,906
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	576,253
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	569,729
OVEC	INTERFACE	SPORN 2	AGGREGATE	524,883
IMO	INTERFACE	WESTERN HUB	HUB	489,032
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	482,986
Top ten total				7,553,718
PJM total				40,902,161
Top ten total as percent of PJM total				18.5%

Table 3-40 shows up-to congestion transactions by export bids for the top ten locations for 2012 and 2013.

Table 3-40 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): 2012 and 2013

2012 Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,715,287
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,343,889
23 COLLINS	EHVAGG	MISO	INTERFACE	3,085,476
STUART 1	AGGREGATE	OVEC	INTERFACE	2,386,394
GAVIN	EHVAGG	OVEC	INTERFACE	1,932,567
ROCKPORT	EHVAGG	MISO	INTERFACE	1,854,904
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,841,009
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,803,365
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,792,405
WESTERN HUB	HUB	MISO	INTERFACE	1,661,684
Top ten total				23,416,981
PJM total				150,988,394
Top ten total as percent of PJM total				15.5%
2013 Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,337,713
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	1,489,113
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,347,573
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,233,366
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	1,157,724
ROCKPORT	EHVAGG	OVEC	INTERFACE	1,007,610
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	828,452
GAVIN	EHVAGG	OVEC	INTERFACE	706,465
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	688,745
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	661,555
Top Ten Total				11,458,315
PJM total				49,738,703
Top ten total as percent of PJM total				23.0%

55 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-41 shows up-to congestion transactions by wheel bids for the top ten locations for 2012 and 2013.

Table 3-41 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): 2012 and 2013

2012				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	540,158
MISO	INTERFACE	NIPSCO	INTERFACE	198,665
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	192,006
NYIS	INTERFACE	IMO	INTERFACE	167,433
SOUTHIMP	INTERFACE	MISO	INTERFACE	149,798
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	149,407
MISO	INTERFACE	OVEC	INTERFACE	147,574
IMO	INTERFACE	NYIS	INTERFACE	138,041
NORTHWEST	INTERFACE	MISO	INTERFACE	131,420
OVEC	INTERFACE	IMO	INTERFACE	118,486
Top ten total				1,932,987
PJM total				2,974,891
Top ten total as percent of PJM total				65.0%
2013				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	766,264
NORTHWEST	INTERFACE	MISO	INTERFACE	677,453
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	479,746
IMO	INTERFACE	NYIS	INTERFACE	330,340
MISO	INTERFACE	NIPSCO	INTERFACE	303,181
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	143,047
OVEC	INTERFACE	IMO	INTERFACE	131,155
MISO	INTERFACE	SOUTHEXP	INTERFACE	118,693
LINDENVFT	INTERFACE	NYIS	INTERFACE	86,796
MISO	INTERFACE	OVEC	INTERFACE	83,065
Top ten total				3,119,740
PJM total				4,177,320
Top ten total as percent of PJM total				74.7%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.[56] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 8.1 percent of the PJM total internal up-to congestion transactions in 2013.

Table 3-42 shows up-to congestion transactions by internal bids for the top ten locations for November through December of 2012, and 2013.

Table 3-42 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): November through December of 2012, and 2013

2012 (Nov - Dec)				
Internal				
Source	Source Type	Sink	Sink Type	MW
NAPERVILLE	AGGREGATE	ZION 1	AGGREGATE	213,928
MARQUIS	EHVAGG	STUART DIESEL	AGGREGATE	205,066
JOLIET 8	AGGREGATE	JOLIET 7	AGGREGATE	189,609
WESTERN HUB	HUB	BGE	ZONE	174,710
SULLIVAN-AEP	EHVAGG	AK STEEL	AGGREGATE	166,152
RENO 138 KV T1	AGGREGATE	OAKGROVE 1	AGGREGATE	160,935
TANNERS CRK 4	AGGREGATE	SPORN 3	AGGREGATE	159,006
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	156,568
CONEMAUGH	EHVAGG	HUNTERSTOWN	EHVAGG	153,698
N ILLINOIS HUB	HUB	AEP-DAYTON HUB	HUB	152,976
Top ten total				1,732,647
PJM total				35,486,249
Top ten total as percent of PJM total				4.9%
2013				
Internal				
Source	Source Type	Sink	Sink Type	MW
ATSI GEN HUB	HUB	ATSI	ZONE	5,675,792
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	4,405,866
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,910,366
FE GEN	AGGREGATE	ATSI	ZONE	2,980,966
WYOMING	EHVAGG	BROADFORD	EHVAGG	2,939,931
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	2,142,829
SUNBURY 1-3	AGGREGATE	FOSTER WHEELER	AGGREGATE	1,917,015
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,868,461
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,559,654
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,522,733
Top ten total				28,923,614
PJM total				357,183,762
Top ten total as percent of PJM total				8.1%

Table 3-43 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and 2013. The annual row in Table 3-43 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in November and December of 2012 and 2013 illustrates that PJM's modification of the rules governing the location of up-to congestion transactions bids resulted in a significant increase in the number of offered and cleared up-to congestion transactions.

56 For more information, see the *2013 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," Up-to Congestion.

Table 3-43 Number of PJM offered and cleared source and sink pairs: 2012 and 2013[57]

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2012	Jan	1,771	2,182	1,126	1,568
2012	Feb	1,816	2,198	1,156	1,414
2012	Mar	1,746	2,004	1,128	1,353
2012	Apr	1,753	2,274	1,117	1,507
2012	May	1,866	2,257	1,257	1,491
2012	Jun	2,145	2,581	1,425	1,897
2012	Jul	2,168	2,800	1,578	2,078
2012	Aug	2,541	3,043	1,824	2,280
2012	Sep	2,140	3,032	1,518	2,411
2012	Oct	2,344	3,888	1,569	2,625
2012	Nov	4,102	8,142	2,829	5,811
2012	Dec	9,424	13,009	5,025	8,071
2012	Jan-Oct	2,031	3,888	1,371	2,625
2012	Nov-Dec	6,806	13,009	3,945	8,071
2012	Annual	2,827	13,009	1,800	8,071
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,064	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069

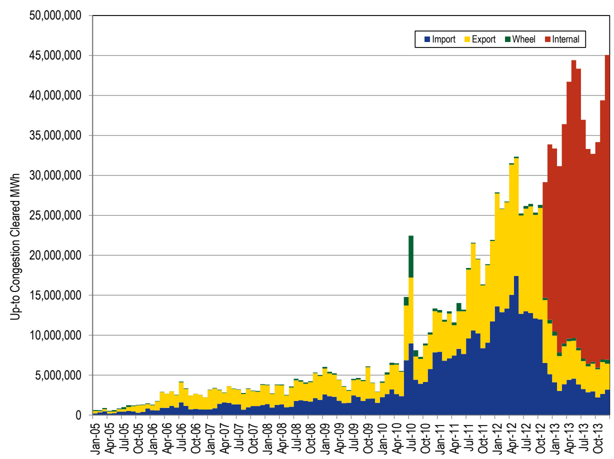
Table 3-44 and Figure 3-23 show total cleared up-to congestion transactions by type for 2012 and 2013. Internal up-to congestion transactions in 2013 were 79.0 percent of all up-to congestion transactions for 2013. In 2013, nine internal up-to congestion transactions were in the top ten total in MW.

Table 3-44 PJM cleared up-to congestion transactions by type (MW): 2012 and 2013

	2012				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	27,203,428	23,416,981	1,932,987	1,732,647	32,704,386
PJM total (MW)	146,428,449	150,988,394	2,974,891	35,486,249	335,877,984
Top ten total as percent of PJM total	18.6%	15.5%	65.0%	4.9%	9.7%
PJM total as percent of all up-to congestion transactions	43.6%	45.0%	0.9%	10.6%	100.0%
	2013				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	7,553,718	628,674	3,119,740	28,923,614	29,738,595
PJM total (MW)	40,902,161	49,738,703	4,177,320	357,183,762	452,001,946
Top ten total as percent of PJM total	18.5%	1.3%	74.7%	8.1%	6.6%
PJM total as percent of all up-to congestion transactions	9.0%	11.0%	0.9%	79.0%	100.0%

Figure 3-23 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012 and 2013, following the November 1, 2012, rule change permitting such transactions.

Figure 3-23 PJM cleared up-to congestion transactions by type (MW): January 2005 through December of 2013



57 The max offered data in the April 2013 row and Annual rows in the corresponding table in the *2013 State of the Market Report for PJM: January through September* were averages and not maximums.

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[58]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-45 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-45 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-26.

All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price

58 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP.

offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually marginal costs and market behavior reflected that fact.[59]

Table 3-45 shows the mark-up component of the load weighted LMP by primary fuel and unit-type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $0.44 in 2012 to $0.77 in 2013. The markup component of coal units in 2013 was - $0.49. After removing 10 percent adder from the cost offers of coal units, the markup contribution of coal units in 2013 was $1.03. The adjusted mark-up component of all gas-fired units in 2013 was $0.22. The markup component of wind units is zero but this includes a range from negative to positive. If a price-based offer is negative but less negative than a cost-based offer, the markup is positive. In 2013, among the wind units that were marginal, 1.5 percent of units had positive offer prices.

Table 3-45 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2012 and 2013[60]

		2012		2013	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.69)	$0.11	($0.49)	$1.03
Demand Response	Demand Response	$0.00	$0.00	$0.00	$0.00
Gas	CC	$0.42	$0.42	$0.04	$0.04
Gas	CT	($0.03)	($0.03)	$0.15	$0.15
Gas	Diesel	$0.02	$0.02	$0.03	$0.03
Gas	Steam	($0.03)	($0.03)	$0.00	$0.00
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.02	$0.02	($0.01)	($0.01)
Oil	CT	$0.01	$0.01	$0.00	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.08)	($0.08)	($0.46)	($0.46)
Other	Solar	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.00)	($0.00)	($0.02)	($0.02)
Uranium	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind		($0.00)	($0.00)	$0.00	$0.00
Total		($1.37)	$0.44	($0.76)	$0.77

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Markup Component of Real-Time Price

Table 3-46 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-47 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In 2013, when using unadjusted cost offers, -$0.76 per MWh of the PJM real-time load weighted average LMP was attributable to markup. Using adjusted cost offers, $0.77 per MWh of the PJM real-time load weighted average LMP was attributable

59 See *PJM Manual 15: Cost Development Guidelines*, Revision: 23 (Effective August 1, 2013).

60 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and municipal waste.

to markup. In 2013, the real time load-weighted average LMP for the month of July had the highest markup component, $3.01 per MWh using unadjusted cost offers and $4.37 per MWh using adjusted cost offers. This corresponds to 5.9 percent and 8.6 percent of the July month's real time load-weighted average LMP. The July results demonstrate that markups can increase significantly during high demand periods.

The smallest zonal on peak average markup was in the PPL Control Zone, -$0.41 per MWh, while the highest zonal on peak average markup was in the RECO Control Zone, $1.12 per MWh.

Table 3-46 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.28)	($3.58)	($2.98)	($3.12)	($3.86)	($2.43)
Feb	($2.07)	($2.92)	($1.26)	($1.98)	($3.16)	($0.83)
Mar	($2.30)	($2.51)	($2.10)	$0.26	($1.05)	$1.62
Apr	($2.71)	($3.60)	($1.86)	($1.71)	($2.79)	($0.80)
May	($1.10)	($3.34)	$0.93	($0.46)	($2.25)	$1.04
Jun	($2.67)	($3.24)	($2.17)	($0.62)	($1.09)	($0.15)
Jul	$3.38	($2.36)	$8.82	$3.01	($1.43)	$6.93
Aug	($0.90)	($2.30)	$0.20	($1.69)	($1.88)	($1.53)
Sep	($0.70)	($1.89)	$0.60	($0.94)	($2.35)	$0.46
Oct	($1.16)	($3.00)	$0.37	($0.49)	($1.03)	($0.03)
Nov	($1.25)	($2.40)	($0.13)	($1.14)	($1.60)	($0.64)
Dec	($2.93)	($3.16)	($2.67)	($0.76)	($1.76)	$0.29
Total	($1.37)	($2.85)	$0.03	($0.76)	($2.01)	$0.42

Table 3-47 Monthly markup components of real-time load-weighted LMP (Adjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($0.93)	($1.40)	($0.43)	($1.28)	($1.88)	($0.72)
Feb	($0.06)	($1.04)	$0.87	($0.19)	($1.24)	$0.83
Mar	($0.59)	($1.07)	($0.15)	$1.93	$0.73	$3.19
Apr	($0.81)	($1.79)	$0.11	($0.43)	($1.13)	$0.16
May	$0.64	($1.71)	$2.78	$0.89	($0.58)	$2.12
Jun	($1.14)	($1.92)	($0.45)	$0.81	$0.35	$1.27
Jul	$5.08	($0.47)	$10.34	$4.37	$0.09	$8.14
Aug	$1.07	($0.60)	$2.38	($0.27)	($0.35)	($0.20)
Sep	$1.01	($0.29)	$2.45	$0.56	($0.58)	$1.68
Oct	$0.30	($1.45)	$1.75	$0.94	$0.61	$1.22
Nov	$0.51	($0.45)	$1.45	$0.44	$0.07	$0.84
Dec	($1.16)	($1.41)	($0.87)	$0.83	($0.05)	$1.76
Total	$0.44	($1.11)	$1.90	$0.77	($0.32)	$1.79

Markup Component of Real-Time Zonal Prices

The average real-time price component of unit markup using unadjusted offers is shown for each zone for 2013 and 2012 in Table 3-48 and for adjusted offers in Table 3-49. The smallest zonal all hours average markup component using unadjusted offers for the 2013 was in the PPL Control Zone, -$1.16 per MWh, while the highest all hours average zonal markup component for 2013 was in the RECO Control Zone, -$0.06 per MWh.

Table 3-48 Average real-time zonal markup component (Unadjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($1.17)	($2.64)	$0.26	($0.86)	($1.84)	$0.08
AEP	($1.65)	($2.94)	($0.39)	($0.95)	($2.06)	$0.11
APS	($1.49)	($2.91)	($0.11)	($0.98)	($2.09)	$0.08
ATSI	($1.61)	($3.06)	($0.25)	($0.93)	($2.05)	$0.12
BGE	($1.03)	($2.42)	$0.31	($0.75)	($2.14)	$0.58
ComEd	($1.36)	($3.00)	$0.16	($0.90)	($2.03)	$0.13
DAY	($1.69)	($3.07)	($0.41)	($1.01)	($2.06)	($0.04)
DEOK	($1.66)	($2.97)	($0.42)	($0.98)	($2.03)	$0.01
DLCO	($1.43)	($2.93)	($0.02)	($1.08)	($2.03)	($0.18)
DPL	($1.50)	($3.10)	$0.05	($1.07)	($1.92)	($0.25)
Dominion	($1.01)	($2.49)	$0.42	($0.71)	($1.99)	$0.54
EKPC	NA	NA	NA	($0.61)	($1.68)	$0.47
JCPL	($0.99)	($2.89)	$0.73	($1.11)	($1.99)	($0.32)
Met-Ed	($1.42)	($2.97)	$0.02	($0.91)	($1.99)	$0.08
PECO	($1.28)	($2.74)	$0.10	($1.02)	($1.84)	($0.25)
PENELEC	($1.58)	($3.07)	($0.18)	($1.10)	($2.12)	($0.15)
PPL	($1.51)	($2.99)	($0.12)	($1.16)	($1.96)	($0.41)
PSEG	($1.13)	($2.73)	$0.35	($0.59)	($1.73)	$0.46
Pepco	($0.89)	($2.47)	$0.58	($0.73)	($2.21)	$0.65
RECO	($1.00)	($2.85)	$0.60	($0.06)	($1.45)	$1.12

Table 3-49 Average real-time zonal markup component (Adjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.54	($1.03)	$2.06	$0.64	($0.17)	$1.42
AEP	$0.16	($1.19)	$1.48	$0.61	($0.33)	$1.51
APS	$0.38	($1.16)	$1.87	$0.57	($0.37)	$1.47
ATSI	$0.19	($1.34)	$1.63	$0.66	($0.31)	$1.57
BGE	$1.01	($0.45)	$2.40	$0.77	($0.39)	$1.87
ComEd	$0.43	($1.28)	$2.00	$0.61	($0.41)	$1.53
DAY	$0.16	($1.30)	$1.52	$0.60	($0.31)	$1.43
DEOK	$0.12	($1.26)	$1.43	$0.57	($0.34)	$1.42
DLCO	$0.28	($1.29)	$1.78	$0.46	($0.35)	$1.22
DPL	$0.28	($1.40)	$1.92	$0.44	($0.26)	$1.11
Dominion	$0.86	($0.67)	$2.33	$0.81	($0.26)	$1.85
EKPC	NA	NA	NA	$0.91	($0.02)	$1.84
JCPL	$0.74	($1.21)	$2.51	$0.33	($0.33)	$0.93
Met-Ed	$0.27	($1.36)	$1.79	$0.56	($0.36)	$1.41
PECO	$0.42	($1.09)	$1.85	$0.46	($0.22)	$1.10
PENELEC	$0.19	($1.36)	$1.65	$0.47	($0.40)	$1.27
PPL	$0.19	($1.37)	$1.65	$0.35	($0.31)	$0.96
PSEG	$0.64	($1.07)	$2.22	$0.88	($0.10)	$1.78
Pepco	$1.03	($0.59)	$2.54	$0.74	($0.51)	$1.90
RECO	$0.81	($1.11)	$2.47	$1.41	$0.24	$2.42

Markup by Real Time Price Levels

Table 3-50 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

Table 3-50 Average real-time markup component (By price category, unadjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.80)	24.8%	($0.73)	92.1%
$25 to $50	($1.89)	67.7%	($0.11)	7.1%
$50 to $75	$0.35	4.6%	$0.04	0.7%
$75 to $100	$0.25	1.4%	$0.01	0.1%
$100 to $125	$0.10	0.7%	$0.00	0.0%
$125 to $150	$0.11	0.2%	$0.01	0.0%
>= $150	$0.45	0.5%	$0.00	0.0%

Table 3-51 Average real-time markup component (By price category, adjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.53)	24.8%	$0.70	92.1%
$25 to $50	($0.44)	67.7%	$0.03	7.1%
$50 to $75	$0.44	4.6%	$0.04	0.7%
$75 to $100	$0.28	1.4%	$0.01	0.1%
$100 to $125	$0.12	0.7%	$0.00	0.0%
$125 to $150	$0.12	0.2%	$0.01	0.0%
>= $150	$0.46	0.5%	$0.00	0.0%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

Table 3-52 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2012 and 2013

		2012		2013	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.72)	($0.72)	($0.41)	($0.15)
Gas	Steam	($0.13)	($0.13)	($0.36)	($0.36)
Oil	Steam	($0.06)	($0.06)	($0.00)	($0.00)
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Wind	Wind	($0.00)	($0.00)	$0.00	$0.00
Gas	CT	$0.06	$0.06	($0.02)	($0.02)
Total		($1.86)	($0.85)	($0.78)	($0.53)

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-52. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 96.4 percent of marginal resources in 2013. INCs were marginal for 1.3 percent of marginal resources and DECs were marginal for 1.1 percent of marginal resources in 2013. The adjusted markup of coal units is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. Table 3-52 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 1.2 percent of marginal resources in 2013.

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced based offers or on cost based offers were included in the markup calculation.

Table 3-53 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-54 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-53 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.76)	($2.22)	($3.28)	($3.77)	($3.99)	($3.54)
Feb	($3.01)	($3.61)	($2.38)	($2.53)	($1.43)	($3.67)
Mar	($2.30)	($1.99)	($2.63)	($1.84)	($0.18)	($3.45)
Apr	($2.67)	($2.36)	($2.98)	($0.11)	($0.01)	($0.22)
May	($1.52)	($1.11)	($1.97)	($0.10)	($0.04)	($0.17)
Jun	($1.93)	($1.09)	($2.88)	($0.06)	$0.03	($0.14)
Jul	$0.35	$2.60	($2.07)	($0.08)	($0.01)	($0.15)
Aug	($1.86)	($0.95)	($3.05)	($0.06)	($0.01)	($0.11)
Sep	($1.75)	($1.36)	($2.10)	($0.27)	($0.13)	($0.42)
Oct	($0.95)	($0.06)	($2.03)	($0.06)	($0.06)	($0.06)
Nov	($2.05)	($0.86)	($3.29)	($0.32)	($0.10)	($0.52)
Dec	($2.42)	($1.97)	($2.82)	$0.01	$0.00	$0.02
Annual	($1.86)	($1.14)	($2.63)	($0.78)	($0.51)	($1.07)

Table 3-54 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.43)	($1.00)	($1.84)	($2.66)	($3.01)	($2.28)
Feb	($1.74)	($2.21)	($1.25)	($1.67)	($0.67)	($2.70)
Mar	($1.37)	($1.05)	($1.72)	($1.29)	$0.07	($2.61)
Apr	($1.49)	($1.18)	($1.81)	($0.03)	$0.04	($0.11)
May	($0.76)	($0.33)	($1.23)	($0.04)	($0.02)	($0.06)
Jun	($0.92)	($0.04)	($1.91)	($0.02)	$0.04	($0.07)
Jul	$1.24	$3.35	($1.03)	($0.03)	$0.02	($0.09)
Aug	($0.93)	($0.11)	($2.01)	($0.02)	$0.01	($0.05)
Sep	($0.82)	($0.44)	($1.17)	($0.17)	($0.08)	($0.26)
Oct	($0.14)	$0.56	($1.00)	($0.04)	($0.02)	($0.07)
Nov	($1.09)	($0.40)	($1.82)	($0.23)	($0.07)	($0.39)
Dec	($1.34)	($0.93)	($1.69)	$0.04	$0.00	$0.07
Annual	($0.85)	($0.21)	($1.54)	($0.53)	($0.32)	($0.74)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-55. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-56.

Table 3-55 Day-ahead, average, zonal markup component (Unadjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.56)	($0.66)	($2.53)	($0.80)	($0.56)	($1.06)
AEP	($1.94)	($1.26)	($2.65)	($0.80)	($0.49)	($1.12)
AP	($1.87)	($1.30)	($2.47)	($0.86)	($0.55)	($1.19)
ATSI	($1.99)	($1.32)	($2.72)	($0.80)	($0.49)	($1.13)
BGE	($1.86)	($1.19)	($2.57)	($0.80)	($0.55)	($1.06)
ComEd	($1.77)	($1.17)	($2.44)	($0.72)	($0.44)	($1.02)
DAY	($1.90)	($1.19)	($2.68)	($0.81)	($0.49)	($1.16)
DEOK	($1.85)	($1.17)	($2.56)	($0.76)	($0.44)	($1.11)
DLCO	($1.83)	($1.13)	($2.59)	($0.76)	($0.47)	($1.07)
DPL	($1.67)	($0.85)	($2.55)	($0.84)	($0.52)	($1.18)
Dominion	($1.79)	($1.03)	($2.57)	($0.78)	($0.53)	($1.06)
EKPC	NA	NA	NA	($0.12)	($0.03)	($0.22)
JCPL	($1.54)	($0.66)	($2.53)	($0.95)	($0.82)	($1.08)
Met-Ed	($1.85)	($1.13)	($2.65)	($0.86)	($0.61)	($1.14)
PECO	($1.71)	($0.98)	($2.49)	($0.80)	($0.52)	($1.11)
PENELEC	($2.07)	($1.50)	($2.69)	($0.72)	($0.52)	($0.93)
PPL	($2.04)	($1.43)	($2.71)	($0.89)	($0.64)	($1.16)
PSEG	($1.59)	($0.61)	($2.69)	($0.77)	($0.51)	($1.07)
Pepco	($1.86)	($1.25)	($2.52)	($0.80)	($0.56)	($1.06)
RECO	($1.49)	($0.54)	($2.63)	($0.75)	($0.46)	($1.08)

Table 3-56 Day-ahead, average, zonal markup component (Adjusted): 2012 and 2013

	2012			2013		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.60)	$0.23	($1.48)	($0.55)	($0.37)	($0.74)
AEP	($0.91)	($0.30)	($1.55)	($0.52)	($0.29)	($0.77)
AP	($0.83)	($0.33)	($1.36)	($0.57)	($0.35)	($0.81)
ATSI	($0.93)	($0.32)	($1.60)	($0.52)	($0.29)	($0.77)
BGE	($0.79)	($0.20)	($1.42)	($0.56)	($0.39)	($0.73)
ComEd	($0.82)	($0.27)	($1.43)	($0.48)	($0.26)	($0.73)
DAY	($0.85)	($0.20)	($1.56)	($0.53)	($0.29)	($0.80)
DEOK	($0.84)	($0.22)	($1.50)	($0.50)	($0.26)	($0.76)
DLCO	($0.86)	($0.21)	($1.56)	($0.50)	($0.28)	($0.73)
DPL	($0.71)	$0.03	($1.49)	($0.57)	($0.34)	($0.82)
Dominion	($0.79)	($0.13)	($1.47)	($0.54)	($0.35)	($0.73)
EKPC	NA	NA	NA	($0.07)	($0.01)	($0.13)
JCPL	($0.57)	$0.23	($1.47)	($0.65)	($0.55)	($0.76)
Met-Ed	($0.90)	($0.26)	($1.60)	($0.60)	($0.42)	($0.80)
PECO	($0.75)	($0.10)	($1.46)	($0.55)	($0.34)	($0.78)
PENELEC	($1.04)	($0.52)	($1.59)	($0.46)	($0.31)	($0.61)
PPL	($1.07)	($0.54)	($1.65)	($0.62)	($0.44)	($0.82)
PSEG	($0.62)	$0.27	($1.63)	($0.52)	($0.33)	($0.74)
Pepco	($0.84)	($0.31)	($1.42)	($0.56)	($0.39)	($0.73)
RECO	($0.52)	$0.35	($1.56)	($0.51)	($0.30)	($0.75)

Markup by Day-Ahead Price Levels

Table 3-57 and Table 3-58 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-57 Average, day-ahead markup (By LMP category, unadjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($3.25)	21.0%	($1.25)	5.0%
$25 to $50	($2.69)	74.9%	($2.76)	84.5%
$50 to $75	$2.06	3.0%	$0.69	8.6%
$75 to $100	$6.62	0.6%	$0.03	1.1%
$100 to $125	$18.93	0.2%	$0.01	0.4%
$125 to $150	$4.54	0.1%	$0.00	0.1%
>= $150	$16.80	0.2%	($0.30)	0.4%

Table 3-58 Average, day-ahead markup (By LMP category, adjusted): 2012 and 2013

	2012		2013	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.29)	21.0%	($0.70)	5.0%
$25 to $50	($1.33)	74.9%	($1.91)	84.5%
$50 to $75	$2.40	3.0%	$0.76	8.6%
$75 to $100	$6.84	0.6%	$0.09	1.1%
$100 to $125	$19.30	0.2%	($0.03)	0.4%
$125 to $150	$4.91	0.1%	$0.00	0.1%
>= $150	$16.85	0.2%	($0.30)	0.4%

Prices

The conduct of individual market entities within a market structure is reflected in market prices.[61] PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. Real-time and day-ahead energy market load-weighted prices were 9.7 percent and 12.7 percent higher in 2013 than in 2012 as a result of higher fuel costs and higher demand.[62] Natural gas prices were higher, particularly in eastern zones, while coal prices were relatively constant.

PJM real-time energy market prices increased in 2013 compared to 2012. The system average LMP was 10.4 percent higher in 2013 than in 2012, $36.55 per MWh versus $33.11 per MWh. The load-weighted average LMP was 9.7 percent higher in 2013 than in 2012, $38.66 per MWh versus $35.23 per MWh.

The fuel-cost adjusted, load weighted, average LMP for 2013 was 10.9 percent lower than the load weighted, average LMP for 2013. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $34.46 per MWh instead of the observed $38.66 per MWh.

PJM day-ahead energy market prices increased in 2013 compared to 2012. The system average LMP was 13.3 percent higher in 2013 than in 2012, $37.15 per MWh versus $32.79 per MWh. The load-weighted average LMP was 12.7 percent higher in 2013 than in 2012, $38.93 per MWh versus $34.55 per MWh.[63]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[64]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-24 shows the hourly distribution of PJM real-time average LMP for 2012 and 2013. In 2012, there 40 hours in PJM where the real-time LMP for the entire system was negative compared to one hour in 2013. The average negative real-time LMP, for the hours when the LMP was negative, in 2012 was -$18.55 compared to -$0.57 in 2013. Negative LMPs in the PJM Real-Time Market result primarily when wind units with negative offer prices become marginal, but may also result within a constrained area when inflexible generation exceeds the forecasted load. In 2012, there were 12 hours where the PJM real-time LMP was $0.00 compared to two

61 See the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the Technical Reference for PJM Markets, at "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

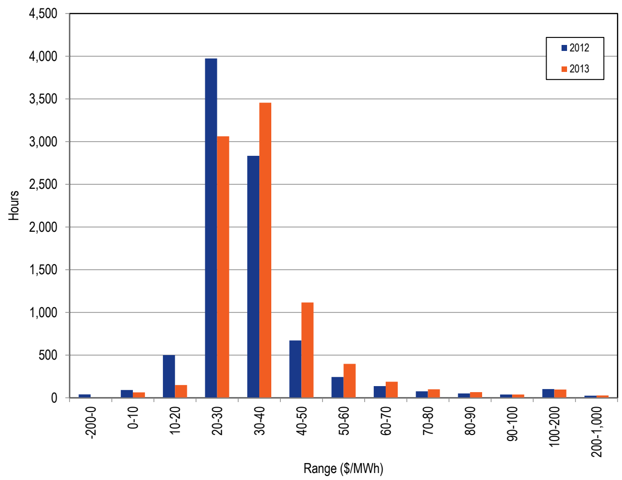
62 There was an average increase of 2.3 heating degree days and an average reduction of 0.7 cooling degree days in 2013 compared to 2012 which meant overall increased demand.

63 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

64 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

hours in 2013. The real-time LMP is $0.00 for hours where a minimum generation event occurs.

Figure 3-24 Average LMP for the PJM Real-Time Energy Market: 2012 and 2013



PJM Real-Time, Average LMP

Table 3-59 shows the PJM real-time, average LMP for each year of the 16-year period 1998 to 2013.[65]

Table 3-59 PJM real-time, average LMP (Dollars per MWh): 1998 through 2013

	Real-Time LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-60 shows the PJM real-time, load-weighted, average LMP for each year of the 16-year period 1998 to 2013.

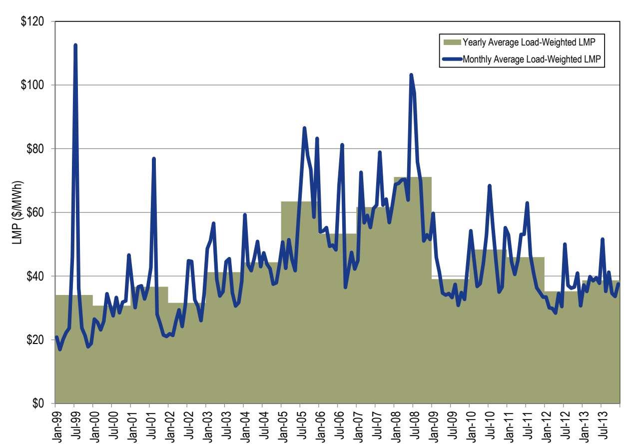
Table 3-60 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2013

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-25 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through 2013.

Figure 3-25 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2013



65 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas, especially in the eastern part of PJM increased in price in 2013. Comparing prices in 2013 to 2012, the price of Northern Appalachian coal was 1.0 percent higher; the price of Central Appalachian coal was 0.3 percent higher; the price of Powder River Basin coal was 20.0 percent higher; the price of eastern natural gas was 40.0 percent higher; and the price of western natural gas was 32.0 percent higher. Figure 3-26 shows monthly average spot fuel prices for 2012 and 2013.[66] Natural gas prices were above coal prices in 2013.

Figure 3-26 Spot average fuel price comparison with fuel delivery charges: 2012 through 2013 ($/MMBtu)

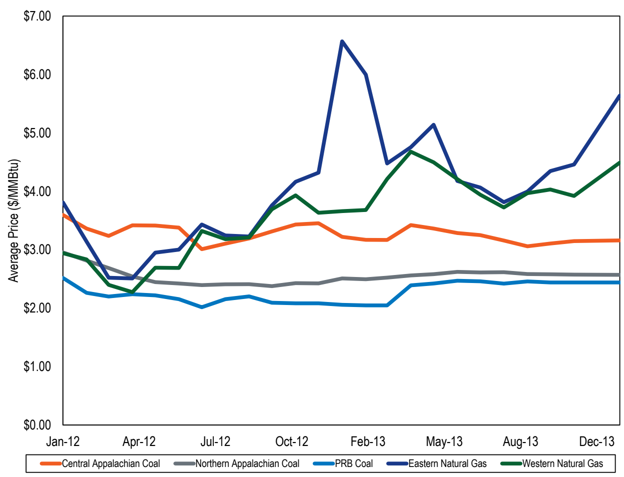


Table 3-61 compares the 2013 PJM real time fuel-cost adjusted, load weighted, average LMP to the 2012 load-weighted, average LMP. The real time fuel-cost adjusted, load weighted, average LMP for 2013 was 10.9 percent lower than the real time load weighted, average LMP for 2013. The real-time, fuel-cost adjusted, load weighted, average LMP for 2013 was 2.2 percent lower than the real time load weighted LMP for 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 real time load weighted LMP would have been lower, $34.46 per MWh instead of the observed $38.66 per MWh.

Table 3-61 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$38.66	$34.46	(10.9%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.23	$34.46	(2.2%)
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$35.23	$38.66	9.7%

Table 3-62 shows the impact of each fuel type on the difference between the 2013 fuel-cost adjusted, load-weighted average LMP and the 2013 load weighted LMP. Table 3-62 shows that higher natural gas prices explain almost all of the fuel-cost related increase in the real time annual load-weighted average LMP in 2013.

Table 3-62 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: Year-over-year method

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.13	3.0%
Gas	$4.19	99.7%
Oil	($0.10)	(2.5%)
Other	($0.00)	(0.0%)
Uranium	($0.00)	(0.0%)
Wind	($0.00)	(0.0%)
Total	$4.20	100.0%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and

66 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[67] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post (five minutes) to account for realized system conditions. This is sometimes referred to as an ex-post LMP calculation. The extent to which the ex-post LMP in a five-minute interval deviated from the LMP calculated by SCED (ex-ante LMP) reflected the change in system conditions between the time when the dispatch was solved, and the end of the five-minute interval. The contribution of this deviation to real-time LMPs is shown as the LPA-SCED differential. Starting with the October 1, 2012, implementation of scarcity pricing, PJM eliminated ex-post pricing and now relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the SCED solution.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. In periods when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the lowered generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost contributes to LMP.

The components of LMP are shown in Table 3-63, including markup using unadjusted cost offers.[68] Table 3-63 shows that for 2013, 46.6 percent of the load-weighted LMP was the result of coal costs, 27.6 percent was the result of gas costs and 0.63 percent was the result of the cost of emission allowances. Markup was -$0.76 per MWh. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplainable portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In 2013, nearly eight percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between 2013 and 2012.

Table 3-63 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: 2013 and 2012

	2012		2013		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$18.90	53.6%	$18.04	46.6%	(7.0%)
Gas	$8.39	23.8%	$10.69	27.6%	3.8%
Ten Percent Adder	$3.48	9.9%	$3.51	9.1%	(0.8%)
VOM	$2.52	7.2%	$2.24	5.8%	(1.4%)
NA	$1.16	3.3%	$1.61	4.2%	0.9%
FMU Adder	$0.10	0.3%	$1.55	4.0%	3.7%
Oil	$1.69	4.8%	$1.28	3.3%	(1.5%)
LPA Rounding Difference	$0.35	1.0%	$0.22	0.6%	(0.4%)
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.17	0.4%	0.4%
Emergency DR Adder	$0.00	0.0%	$0.17	0.4%	0.4%
CO_2 Cost	$0.09	0.3%	$0.13	0.3%	0.1%
NO_x Cost	$0.10	0.3%	$0.10	0.2%	(0.0%)
Increase Generation Adder	$0.12	0.3%	$0.04	0.1%	(0.2%)
SO_2 Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	$0.00	0.0%	0.1%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Decrease Generation Adder	($0.22)	(0.6%)	($0.13)	(0.3%)	0.3%
LPA-SCED Differential	($0.10)	(0.3%)	($0.21)	(0.6%)	(0.3%)
Markup	($1.37)	(3.9%)	($0.76)	(2.0%)	1.9%
Total	$35.23	100.0%	$38.66	100.0%	

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, (Table 3-63 and Table 3-67) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-64 and Table 3-68) the 10 percent markup is removed from the cost offers of coal units.

67 New Jersey withdrew from RGGI, effective January 1, 2012.

68 These components are explained in the *Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have also excluded components of operating and maintenance cost that, while permitted under the PJM manuals, are not actually marginal costs.[69]

The components of LMP are shown in Table 3-64, including markup using adjusted cost offers.

Table 3-64 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: 2013 and 2012

	2012		2013		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$19.06	54.1%	$18.35	47.5%	(6.7%)
Gas	$8.39	23.8%	$10.69	27.6%	3.8%
VOM	$2.53	7.2%	$2.27	5.9%	(1.3%)
Ten Percent Adder	$1.50	4.3%	$1.87	4.8%	0.6%
NA	$1.16	3.3%	$1.61	4.2%	0.9%
FMU Adder	$0.10	0.3%	$1.32	3.4%	3.1%
Oil	$1.69	4.8%	$1.28	3.3%	(1.5%)
Markup	$0.44	1.2%	$0.77	2.0%	0.7%
LPA Rounding Difference	$0.35	1.0%	$0.22	0.6%	(0.4%)
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.17	0.4%	0.4%
Emergency Demand Response Adder	$0.00	0.0%	$0.17	0.4%	0.4%
CO_2 Cost	$0.09	0.3%	$0.13	0.3%	0.1%
NO_x Cost	$0.10	0.3%	$0.10	0.3%	(0.0%)
Increase Generation Adder	$0.12	0.3%	$0.04	0.1%	(0.2%)
SO_2 Cost	$0.02	0.1%	$0.01	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.04)	(0.1%)	$0.00	0.0%	0.1%
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Constraint Violation Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
Market-to-Market Adder	$0.02	0.1%	($0.00)	(0.0%)	(0.1%)
Decrease Generation Adder	($0.22)	(0.6%)	($0.13)	(0.3%)	0.3%
LPA-SCED Differential	($0.10)	(0.3%)	($0.21)	(0.6%)	(0.3%)
Total	$35.23	100.0%	$38.66	100.0%	

Day-Ahead LMP

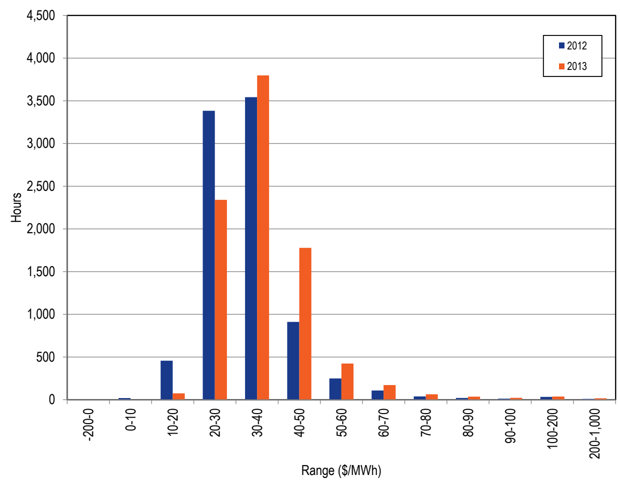
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[70]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-27 shows the hourly distribution of PJM day-ahead average LMP for 2012 and 2013.

Figure 3-27 Average LMP for the PJM Day-Ahead Energy Market: 2012 and 2013



69 See *PJM Manual 15: Cost Development Guidelines*, Revision: 23 (Effective August 1, 2013).

70 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead, Average LMP

Table 3-65 shows the PJM day-ahead, average LMP for each year of the 13-year period 2001 to 2013.

Table 3-65 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2013

	Day-Ahead LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-66 shows the PJM day-ahead, load-weighted, average LMP for each year of the 13-year period 2001 to 2013.

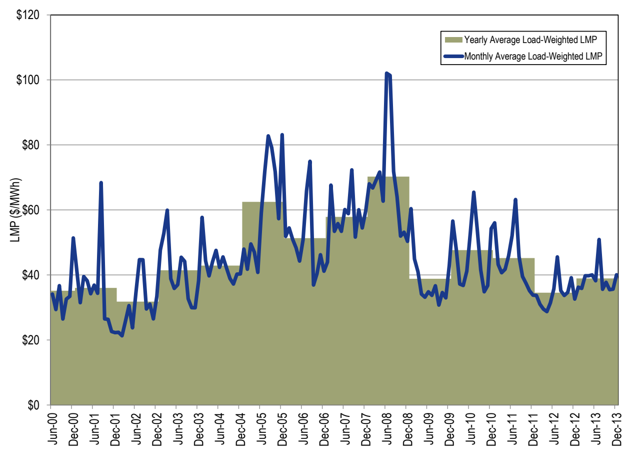
Table 3-66 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2013

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Year	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-28 shows the PJM day-ahead, monthly annual, load-weighted LMP from 2000 through 2013.[71]

Figure 3-28 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through 2013



Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate

71 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

in RGGI: Delaware, Maryland and New Jersey.[72] Day-ahead scheduling reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

The components of day-ahead LMP are shown in Table 3-67, including markup using unadjusted cost offers. Table 3-67 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2013, 71.9 percent of the load-weighted LMP was the result of up-to congestion transactions, 11.9 percent was the result of the cost of coal and 5.7 percent was the result of the cost of gas.

Table 3-67 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): 2012 and 2013[73]

	2012		2013		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Up-to Congestion Transaction	$1.69	4.9%	$28.00	71.9%	67.0%
Coal	$13.60	39.4%	$4.63	11.9%	(27.5%)
Gas	$4.60	13.3%	$2.21	5.7%	(7.6%)
DEC	$8.17	23.7%	$1.89	4.9%	(18.8%)
INC	$3.33	9.7%	$1.31	3.4%	(6.3%)
Ten Percent Cost Adder	$2.02	5.9%	$0.74	1.9%	(4.0%)
VOM	$1.54	4.5%	$0.50	1.3%	(3.2%)
Dispatchable Transaction	$0.53	1.5%	$0.13	0.3%	(1.2%)
FMU Adder	$0.01	0.0%	$0.08	0.2%	0.2%
Price Sensitive Demand	$0.45	1.3%	$0.05	0.1%	(1.2%)
NO_x	$0.06	0.2%	$0.02	0.1%	(0.1%)
CO_2	$0.06	0.2%	$0.02	0.0%	(0.1%)
DASR LOC Adder	($0.31)	(0.9%)	$0.01	0.0%	0.9%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Oil	$0.35	1.0%	$0.00	0.0%	(1.0%)
DASR Offer Adder	$0.15	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Markup	($1.86)	(5.4%)	($0.78)	(2.0%)	3.4%
Diesel	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.14	0.4%	$0.11	0.3%	(0.1%)
Total	$34.55	100.0%	$38.93	100.0%	

Table 3-68 shows the components of the PJM day ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal units.

72 New Jersey withdrew from RGGI, effective January 1, 2012.

73 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Table 3-68 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): 2012 and 2013

	2012		2013		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Up-to Congestion Transaction	$1.69	4.9%	$28.00	71.9%	67.0%
Coal	$13.60	39.4%	$4.63	11.9%	(27.5%)
Gas	$4.60	13.3%	$2.21	5.7%	(7.6%)
DEC	$8.17	23.7%	$1.89	4.9%	(18.8%)
INC	$3.33	9.7%	$1.31	3.4%	(6.3%)
VOM	$1.54	4.5%	$0.50	1.3%	(3.2%)
Ten Percent Cost Adder	$1.02	2.9%	$0.48	1.2%	(1.7%)
Dispatchable Transaction	$0.53	1.5%	$0.13	0.3%	(1.2%)
FMU Adder	$0.01	0.0%	$0.08	0.2%	0.2%
Price Sensitive Demand	$0.45	1.3%	$0.05	0.1%	(1.2%)
NO_x	$0.06	0.2%	$0.02	0.1%	(0.1%)
CO_2	$0.06	0.2%	$0.02	0.0%	(0.1%)
DASR LOC Adder	($0.31)	(0.9%)	$0.01	0.0%	0.9%
SO_2	$0.01	0.0%	$0.00	0.0%	(0.0%)
Oil	$0.35	1.0%	$0.00	0.0%	(1.0%)
DASR Offer Adder	$0.15	0.4%	$0.00	0.0%	(0.4%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Markup	($0.85)	(2.5%)	($0.53)	(1.4%)	1.1%
Diesel	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.14	0.4%	$0.11	0.3%	(0.1%)
Total	$34.55	100.0%	$38.93	100.0%	

Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between Day-Ahead and Real-Time Energy Market expectations, the resulting behavior can lead to more efficient market outcomes by improving day-ahead commitments relative to real-time system requirements.

But there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to arbitrage price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

While the profitability of an INC or DEC position is an indicator that the INC or DEC, all else held equal, contributed to price convergence at the specific bus, unprofitable INCs and DECs may also contribute to price convergence.

Profitability is a less reliable indicator of whether a UTC contributes to price convergence than for INCs and DECs. The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side. A profitable UTC can contribute to both price divergence on one side and to price convergence on the other side.

Table 3-69 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in 2012 and 2013. In 2013, 55.4 percent of all cleared UTC transactions were net profitable, with 67.1 percent of the source side profitable and 39.4 percent of the sink side profitable (Table 3-69).

Table 3-69 Cleared UTC profitability by source and sink point: 2012 and 2013[74]

Year	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2012	9,053,260	4,908,131	5,627,266	3,567,325	54.2%	62.2%	39.4%
2013	14,736,798	8,162,744	9,883,565	4,994,347	55.4%	67.1%	33.9%

PJM performed a study (May Study) of market results for May 2, 3, 22, 23 and 27, with and without UTCs using its day-ahead model.[75] The MMU used PJM's results from the May Study to analyze the effects of UTCs on price convergence.

Figure 3-29 Node hours, by hour, that day-ahead and real-time LMP was closer with or without UTC in PJM's May Study: May 2, 4, 22, 23 and 27

Due to multiple cleared UTCs sourcing and sinking concurrently at or near the same buses, the net effects of UTCs on the system model can provide results that do not match expectations when UTCs are examined on an individual bus basis. For example, while 75.1 percent of cleared UTC source points cleared consistent with day-ahead and real-time point specific (not spread) LMP arbitrage when examined on an individual UTC basis, PJM's results showed increased divergence between day-ahead and real-time LMP at 43.5 percent of UTC day-ahead source locations when UTCs were added. Similarly, while 27.5 percent of UTC sink points cleared consistent with day-ahead and real-time LMP arbitrage, PJM's results showed increased divergence between day-ahead and real-time LMP at 45.5 percent of cleared UTC day-ahead sink locations when UTCs were added.

Figure 3-29 shows total node hours, by hour, that day-ahead and real-time LMP was closer with or without UTC in PJM's results. The results do not support the assertion that UTC transactions contribute to node specific convergence between day-ahead and real-time prices. UTC transactions are associated with both convergence and divergence.

There are incentives to use virtual transactions to arbitrage price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Energy Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-31).

Table 3-70 shows that the difference between the average real-time price and the average day-ahead price

74 Calculations exclude PJM administrative charges.

75 ALSTOM SPD program and unit commitment process.

was $0.32 per MWh in 2012 and -$0.60 per MWh in 2013. The difference between average on-peak real-time price and the average day-ahead price was $1.37 per MWh in 2012 and -$0.39 per MWh in 2013.

Table 3-70 Day-ahead and real-time average LMP (Dollars per MWh): 2012 and 2013[76]

	2012				2013			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$32.79	$33.11	$0.32	1.0%	$37.15	$36.55	($0.60)	(1.6%)
Median	$30.89	$29.53	($1.36)	(4.6%)	$34.63	$32.25	($2.38)	(7.4%)
Standard deviation	$13.27	$20.67	$7.40	35.8%	$15.46	$20.57	$5.11	24.8%
Peak average	$38.46	$39.83	$1.37	3.4%	$43.63	$43.24	($0.39)	(0.9%)
Peak median	$34.71	$33.13	($1.58)	(4.8%)	$39.67	$36.75	($2.92)	(8.0%)
Peak standard deviation	$15.86	$25.47	$9.61	37.7%	$19.20	$25.69	$6.49	25.3%
Off peak average	$27.88	$27.29	($0.59)	(2.2%)	$31.50	$30.72	($0.78)	(2.5%)
Off peak median	$27.15	$26.18	($0.97)	(3.7%)	$30.19	$28.44	($1.76)	(6.2%)
Off peak standard deviation	$7.66	$12.74	$5.08	39.9%	$7.59	$11.99	$4.40	36.7%

The price difference between the Real-Time and the Day-Ahead Energy Markets results in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-71 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for each year of the 13-year period 2001 to 2013.

Table 3-71 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2013

Year	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)

Table 3-72 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the years 2007 through 2013.

76 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-72 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2013[77]

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%	5	0.06%	4	0.05%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%	6	0.13%	5	0.10%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%	17	0.32%	9	0.21%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%	5,576	63.80%	5,994	68.63%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%	3,061	98.65%	2,659	98.98%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%	82	99.58%	64	99.71%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%	17	99.77%	12	99.85%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%	12	99.91%	10	99.97%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%	5	99.97%	1	99.98%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%	1	99.98%	2	100.00%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%	2	100.00%	0	100.00%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%

Figure 3-30 shows the hourly differences between day-ahead and real-time hourly LMP in 2013.

Figure 3-30 Real-time hourly LMP minus day-ahead hourly LMP: 2013[78]

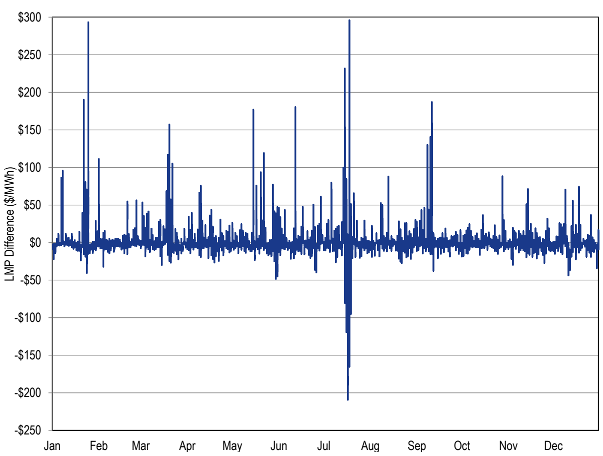
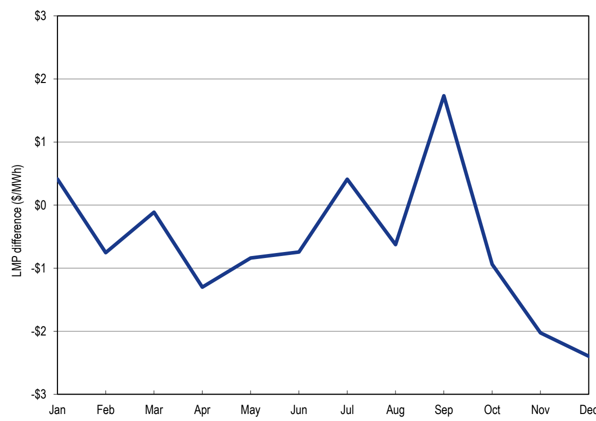


Figure 3-31 shows the monthly average differences between the day-ahead and real-time LMP in 2013.

Figure 3-31 Monthly average of real-time minus day-ahead LMP: 2013

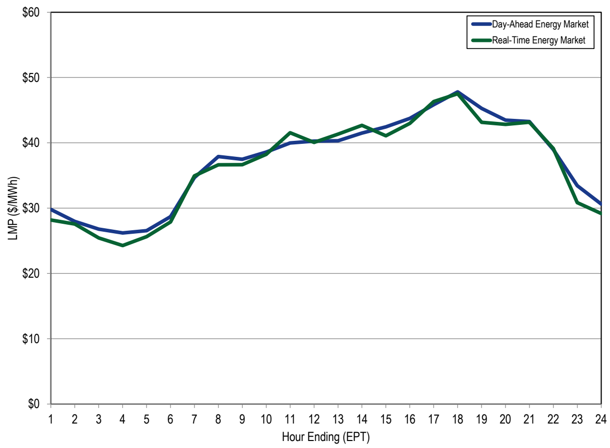


77 This table, which included "load-weighted" in its title in the *2013 State of the Market Report for PJM: January through September*, includes data on hourly prices for which "load-weighted" is not relevant.

78 This figure, which previously contained "load-weighted" in its description and title in the *2013 State of the Market Report for PJM: January through September*, has been updated to not include "load-weighted" in its title and description because the figure is about prices and not load.

Figure 3-32 shows day-ahead and real-time LMP on an average hourly basis for 2013.

Figure 3-32 PJM system hourly average LMP: 2013



Scarcity

PJM's Energy Market did not experience any reserve-based shortage events in 2013. However, hot weather alerts were declared on seventeen days in 2013 in all or parts of the PJM territory. Cold weather alerts were declared on seven days in 2013 in all or parts of the PJM territory. A maximum emergency generation alert was called on four days in 2013 and maximum emergency generation action was declared on five days in parts of PJM in 2013. Emergency demand resources were dispatched in parts of PJM on five days in 2013. A voltage reduction warning and reduction of non-critical plant load was issued on one day in 2013. During the week beginning September 9, PJM issued load shed directives in specific locations. This section addresses issues related to the emergency operations and extreme weather events in the PJM service territory in 2013.

Emergency Procedures in 2013

PJM declared hot weather alerts on 17 days in 2013 and 28 days in 2012.[79] The purpose of a hot weather alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions. PJM communicates to members whether fuel limited resources are to be placed into maximum emergency category.

PJM declared cold weather alerts on seven days in 2013 and did not declare any cold weather alerts in 2012.[80] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below ten degrees Fahrenheit.

PJM declared maximum emergency generation alerts on four days in 2013 and on one day in 2012. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency procedures. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[81] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM declared emergency mandatory load management reductions (long lead time) on five days in 2013 and on two days in 2012. The purpose of emergency mandatory load management (long lead time) is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours.

PJM declared emergency mandatory load management reductions (short lead time) on one day each in 2013 and 2012. The purpose of emergency mandatory load management (short lead time) is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of up to one hour.

PJM declared maximum emergency generation actions on five days in 2013 and on two days in 2012. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which is above the maximum economic level. A maximum emergency generation action can be

79 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.4 Hot Weather Alert, p. 44.

80 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.

81 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 2.3.1 Day-Ahead Emergency Procedures: Alerts, p. 16.

issued for the entire RTO, for specific control zones or for parts of control zones.

PJM declared a voltage reduction warning and reduction of non-critical plant load on one day each in 2013 and 2012. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that actual synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the entire RTO or for specific control zones.

Table 3-73 provides a description of PJM declared emergency procedures.

Table 3-73 Description of Emergency Procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities if extreme hot and/or humid weather conditions, which may cause capacity requirements/unit unavailability to be substantially higher than forecast, are expected to persist for an extended period.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Emergency Mandatory Load Management Reductions (Long Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need between one to two hours lead time to make reductions.
Emergency Mandatory Load Management Reductions (Short Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need up to one hour lead time to make reductions.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.

Table 3-74 shows the dates on which emergency procedures were implemented in 2013.

Table 3-74 PJM declared emergencies: 2013

Dates	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Maximum Emergency Generation Action	Emergency Mandatory Load Management Long Lead Time	Emergency Mandatory Load Management Short Lead Time	Voltage Reduction Warning and Reduction of Non-Critical Plant Load
1/21/2013	ComEd						
1/22/2013	PJM Western Region						
1/23/2013	PJM						
1/24/2013	PJM						
5/30/2013		Mid-Atlantic and Dominion					
5/31/2013		Mid-Atlantic and Dominion					
6/1/2013		Mid-Atlantic and Dominion					
6/13/2013		Dominion					
6/25/2013		Mid-Atlantic					
6/26/2013		Mid-Atlantic and Dominion					
7/15/2013		PJM except ComEd		ATSI	ATSI		
7/16/2013		PJM except ComEd	PJM	ATSI	ATSI		
7/17/2013		PJM except ComEd	PJM				
7/18/2013		PJM	PJM	AEP(Canton subzone), ATSI, PECO, PPL	AEP (Canton subzone), ATSI, PECO, PPL		
7/19/2013		PJM					
7/20/2013		Mid-Atlantic and Dominion					
8/26/2013		ComEd					
8/30/2013		ComEd					
9/9/2013		ComEd					
9/10/2013		PJM Western Region		ATSI	AEP (Canton subzone), ATSI		
9/11/2013		PJM	PJM	AEP, ATSI, DLCO, Mid-Atlantic and Dominion	AEP, ATSI, DLCO, Mid-Atlantic and Dominion	Mid-Atlantic	AEP, ATSI
12/12/2013	PJM						
12/30/2013	ComEd						
12/31/2013	ComEd						

Load Shed Events in September

In the week beginning September 9, 2013, unusually high temperatures resulted in emergency conditions in the PJM service territory which resulted in local reliability issues. In order to avoid potential cascading outages, PJM issued load shed directives in specific locations.[82] Table 3-75 contains a summary of the load shed events on September 9 and 10. In addition to the load shed events, there was a synchronized reserve event on September 10 to recover from a low area control error (ACE). The response of Tier 1 resources to the synchronized reserve event was significantly less than expected and the event lasted an hour and six minutes.

Table 3-75 Summary of load shed events in September 2013

Event	Date	Start and End Times (EPT)	Duration	Zone	Total MW
Pigeon River 1	9-Sep-13	1617 - 1631	14 min	AEP	3.1
		1249 - 2123	8 hr 34 min		5.0
Pigeon River 2	10-Sep-13	1314 - 2123	8 hr 9 min	AEP	3.0
FE Tod	10-Sep-13	1507 - 1642	1 hr 35 min	ATSI	16.0
		1741 - 0002(9/11)	6 hr 21 min		70.0
Penelec Erie South	10-Sep-13	1819 - 0002(9/11)	5 hr 43 min	Penelec	35.0
AEP Summit	10-Sep-13	1913 - 2016	1 hr 3 min	AEP	25.0

On September 9, at 1538, PJM directed AEP to shed 3.1 MW of load at the Pigeon River substation of AEP Zone in southern Michigan. The substation is at the 69kV level, below the level where PJM monitors and controls, but the loss of a 138 kV line (East Elkhart-Mottville Tap-Mottville-Corey 138-kV line) that feeds the load pocket would have triggered a voltage collapse in the area and a potential cascading event. The load was restored at 1631.

On September 10, PJM directed AEP to shed eight MW of load (five MW at 1249 and an additional three MW

82 For a detailed assessment of the load shed events, see PJM. "Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave" (December 23, 2013), pp 11-38.

at 1314) at the Pigeon River substation. The conditions from September 9 remained, with higher loads recorded in AEP on September 10. PJM directed a pre-contingency load shed to avoid a potential cascading event. The load was restored at 2123 on September 10.

On September 10, at 1501, PJM directed ATSI to shed 16 MW of load at the Tod 138 kV substation in the ATSI Zone. On September 9, at 1849, the South Canton #1 345/138 kV transformer tripped and resulted in the loss of four 345 kV lines at South Canton. Two of the lines were restored on the morning of September 10 at 0834. At 1350 on September 10, PJM issued long lead emergency load management in the ATSI Zone and the AEP South Canton subzone. In order to avoid a potential cascading event, PJM directed ATSI to shed 16 MW of load at the Tod station. The load was restored after the South Canton #1 transformer was returned to service.

On September 10, at 1739, PJM directed FirstEnergy to shed 105 MW of load in the FirstEnergy Penelec Zone near Erie, PA in increments of 70 MW at 1749 and an additional 35 MW at 1822. The unplanned loss of Seneca #1 hydro unit on September 9 at 2139, Seneca #2 hydro unit on September 10 at 1010 and the Erie West – Ashtabula – Perry 345 kV line on September 10 at 1336 meant that at 1659, PJM's power flow study indicated a potential post-contingency voltage collapse. The load was restored by 0002 on September 11.

On September 10, at 1913, PJM directed AEP to shed 25 MW of load in the Fort Wayne, IN area. The Summit – Industrial 138 kV line is a monitored priority 2 (MP2) facility which means that PJM can manually redispatch generation to relieve an overload on the line only at the request of the Transmission Owner and the generation does not set price.[83] PJM issued a post contingency local load relief warning (PCLLRW) at 1146 to alert the TO that it would need to shed load within five minutes if the Robison Park T5 transformer were to trip. At 1850, AEP notified PJM that the post contingency flow on the Industrial – Summit 138 kV line was 20MVA higher than PJM's post contingency analysis indicated and that it exceeded 115 percent of the load dump limit. At 1913, PJM directed AEP to shed 25 MW of load in the Summit area. The load was restored at 2016.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) subzone. In times of reserve shortage, the cost of foregone reserves, reflected as a penalty factor in the optimization, is reflected in the price of energy.

Designation of Maximum Emergency MW

During extreme system conditions, when PJM declares maximum emergency generation alerts, the PJM tariff specifies that capacity can only be designated as maximum emergency if the capacity has limitations on its availability based on environmental limitations, short term fuel limitations, or emergency conditions at the unit, or the additional capacity is obtained by operating the unit past its normal limits.[84,85] The intent of the rule regarding maximum emergency designation is to ensure that only capacity with a clearly defined short term issue limiting its economic availability is defined as maximum emergency MW, which can be made available, at PJM's direction, to maintain the system during emergency conditions.

Declarations of hot/cold weather alerts also affect declarations of maximum emergency capacity under the rules. Hot weather alerts are issued when the system is expected to experience possible resource adequacy issues as a result of forecast consecutive days with projected temperatures in excess of 90 degrees with high humidity. Cold weather alerts are issued when the system

83 See PJM. "Manual 12: Balancing Operations," Revision 30 (December 1, 2013), Attachment B.3 Analyzing and Controlling Non-Market BES Facilities, p. 79.

84 See PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

85 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 74.

is expected to experience possible resource adequacy issues as a result of forecast temperatures below ten degrees Fahrenheit.[86] A hot/cold weather alert indicates conditions that require that combustion turbine (CT) and steam units with limited fuel availability need to be removed from economic availability and made available as emergency only capacity.[87] The hot/cold weather alert rule defines specific criteria to use to determine fuel limited generation, thereby classifying that part of the capacity of a unit as maximum emergency generation. The hot/cold weather alert rule regarding maximum emergency capacity declarations, as outlined in Manual 13, is consistent with the maximum emergency alert rule and its intent.[88] The rule also prevents the misclassification of units or a portion of their capacity as maximum emergency and resultant physical withholding under the defined conditions.

There are incentives to keep capacity incorrectly designated as maximum emergency. Capacity designated as maximum emergency is considered as available, not on outage, even during the peak five hundred hours of the year defined in RPM. Capacity designated as maximum emergency is substantially less likely to be dispatched than capacity with an economic offer on high load days.

The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[89]

Emergency Operations

Prior to June 2013, PJM issued a post contingency local load relief warning (PCLLRW) if it projected the post contingency flows on a facility to exceed 115 percent of the load dump limit. Following PJM's review of the Southwest cascading outage that occurred in September 2011, PJM updated emergency operation procedures to implement a cascading outage analysis in June 2013.[90] After June 2013, the post contingency load dump limit exceedance analysis was incorporated in emergency operations to study possible cascading events. If PJM's security analysis indicates that post contingency flows on a facility are projected to exceed the 15-minute load dump rating, PJM will perform up to an N-5 contingency analysis. If the analysis indicates a non-converged case or that flows exceed 115 percent of load dump limits on any additional facilities, PJM will direct a pre-contingency load shed to prevent a potential cascading outage.

In light of the updated emergency procedures, the outage impact studies and planning studies should be updated to identify these reliability issues. It is not clear how PJM's outage impact studies have incorporated the stronger reliability criteria.[91,92] It is not clear how PJM's reliability analysis which directly affects key RPM parameters has incorporated the stronger reliability criteria.

The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.

PJM-Transmission Owner Coordination

The AEP Summit load shed event on September 10, 2013, illustrated an issue related to the coordination between PJM and the local transmission owner (TO) in monitoring MP2 transmission facilities. The Summit – Industrial 138 kV line is a monitored priority 2 (MP2) facility which means that PJM can only manually redispatch generation to relieve an overload on the line at the request of the TO. The TO must pay the cost of the generation and the dispatched generation does not set price. MP2 facilities are not modeled in PJM's congestion management and LMP model.[93]

PJM saw post contingency flows on the Industrial – Summit 138 kV line exceed the 251 MVA limit and issued a post contingency local load relief warning (PCLLRW) at 1146. The purpose of the PCLLRW was to alert the TO that it would need to shed load within five minutes if the Robison Park T5 transformer were to trip. It is not clear whether the TO requested that PJM manually

86 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 41.
87 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), p. 86.
88 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), pp 73-74.
89 See PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014) p. 1740, 1796.
90 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 5.4.1 Post Contingency Load Dump Limit Exceedance Analysis, p. 77.
91 See PJM. "Manual 14b: PJM Region Transmission Planning Process," Revision 25 (October 24, 2013) Section 2.3.8 NERC Category C3 "N-1-1" Analysis, p. 25.
92 See PJM. "Manual 14b: PJM Region Transmission Planning Process," Revision 25 (October 24, 2013) Section 2.7 Evaluation of Operational Performance Issues, p. 38.
93 See PJM. "Manual 12: Balancing Operations," Revision 30 (December 1, 2013), Attachment B.3 Analyzing and Controlling Non-Market BES Facilities, p. 79.

redispatch generation to address the issue on the MP2 facility. If there is potential for an MP2 contingency to lead to a cascading event that could affect the reliability of the bulk electric system, the decision should not be made by the transmission owner.

The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent.

Definition of ATSI Constraint

The ATSI Interface was created by PJM effective July 17, 2013. It is not an interconnection reliability operating limit (IROL) transfer interface, which includes reactive transfer interfaces, nor does it reflect actual thermal transmission limits. The ATSI Interface, comprised of all the tie lines into the ATSI Control Zone,[94] was created by PJM in order to let emergency demand resources set real time prices in the ATSI Control Zone. The creation of the ATSI Interface allows demand resources (DR) dispatched in the ATSI Control Zone to be marginal for providing energy during real-time emergency operations. The ATSI Interface is not defined or modeled in the Day-Ahead Energy Market and it cannot be defined in the Day-Ahead Energy Market because Emergency DR is not in the Day-Ahead Energy Market.

The ATSI Interface was binding in real time for three hours on July 18, seven hours on September 10 and eight hours on September 11. For 12 of these 18 hours, the hourly ATSI zonal LMP was between $1,795 and $1,803 per MWh and for 16 of these 18 hours it was greater than $1,000.

PJM created the ATSI Interface with the goal of reflecting PJM operator actions in the LMP in the ATSI Control Zone which means operators calling on emergency demand response.[95] The ATSI Interface is a closed loop interface, which means that only the capacity available inside of the ATSI Control Zone can relieve the constraint and capacity available outside of the ATSI Control Zone cannot relieve the constraint.[96]

Unlike generators, emergency demand resources are not identified by node, instead, they are aggregated by zone. During the 2013/2014 Delivery Year, subzonal dispatch of demand resources was available only on a voluntary basis and required that a subzone be defined before the dispatch day. Zonal dispatch was mandatory.[97] To achieve a mandatory curtailment, PJM must call all demand resources in a zone. PJM does not have the information available to permit a more targeted call. PJM does not have information on the nodal location of demand resources and does not have information on the impact that demand resources would have had (distribution factors) on specific transmission facilities. This limitation on the commitment of demand resources does not allow PJM dispatchers to estimate the impact of DR on specific constrained facilities and also means that DR cannot be used to set locational prices.

Whenever the ATSI Interface binds, energy prices at all the nodes within the ATSI Control Zone are set at the offer of the marginal resource within the ATSI Control Zone as a result of the definition of the ATSI Interface. This does not provide the locational price signals within the ATSI Control Zone to dispatch resources up or down to relieve constraints within the ATSI Control Zone. Therefore, PJM operators have to make manual dispatch decisions in order to keep the flows on facilities within the ATSI Control Zone below their limits. This problem was evident on September 11 when a small number of units within the ATSI Control Zone were dispatched down in order to control the flow on a line within the ATSI Control Zone. These units were paid energy uplift in the form of lost opportunity cost credits because these units were instructed not to operate at full output although their offers were significantly lower than the $1,800 per MWh LMP set by Emergency demand resources. Since the ATSI Interface is not modeled in the Day-Ahead Energy Market but only during real-time peak load conditions, when the ATSI Interface was binding the result was negative balancing congestion and a negative impact on FTR revenue adequacy in July and September.

The MMU agrees that operators' decisions should be reflected in pricing, but only within the nodal pricing framework. Incorporating a closed loop interface is not

94 See PJM. "ATSI Interface" <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>

95 See PJM. "Hot Weather Operations (July 2013) Questions, Comments and Responses" (August 28, 2013), p. 2.

96 See the *2013 State of the Market Report for PJM*, Section 4: Energy Uplift, at "Closed-loop Interfaces".

97 See PJM. "Manual 18: PJM Capacity Market," Revision 20 (November 21, 2013), Section 9.1.9 Demand Response Compliance Penalty Charge, p. 139.

a substitute for addressing the underlying issue, which is the inflexibility of DR and the lack of nodal DR dispatch among other issues. PJM should not have the authority to decide when energy prices should be high in an entire zone, yet that is what PJM did when it established the ATSI Interface. The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals.

The MMU continues to recommend that demand resource dispatch be nodal to permit more effective dispatch of such resources, that demand resources be required to make day-ahead offers, that demand resources be considered an economic resource rather than an emergency resource, that demand resources be available year round and that demand resources have a shorter lead time.[98,99] The requirement for an announcement of emergency conditions, two hour lead time, two hour minimum dispatch period, availability of demand resources only from 12:00-20:00, maximum number of events allowed each delivery year, maximum of hours per event, and lack of nodal mapping are inappropriate limitations on demand resources that should be removed in order to ensure that demand resources serve as capacity resources and are available to resolve reliability issues when necessary. When DR is treated like other capacity resources, LMP will be set according to the market rules and will appropriately reflect market conditions.

Transmission facility ratings

For the South Canton #3 transformer, AEP reviewed the ratings and found an error in their database on July 17, 2013. The most restrictive rating (normal) was revised from 1,718 MVA to 1,852 MVA. Having a lower rating on a facility would have led to dispatch of out of merit resources earlier than necessary. In the Pigeon River load shed events in southern Michigan on September 9 and 10, PJM was notified of the relay trip rating on the Lagrange - Howe 69 kV line in the Northern Indiana Public Service Corp (NIPSCO) territory within MISO for the first time on September 9. Prior to September 9, PJM was not aware of a relay trip rating on the line and it was not modeled in PJM's energy management system.

In the load shed event in Ft. Wayne, Indiana on September 10, ratings on the Summit – Industrial 138 kV line were the same for normal (24 hours), emergency (4 hours) and load dump (15 minute) levels. In May 2013, AEP changed the load dump rating on the Summit – Industrial 138 kV line from 289 MVA to 251 MVA until the line could be resagged. Resagging is necessary when a line sags due to heat and the distance between the line and any obstruction does not meet the minimum required clearance. As the other line ratings were not changed concurrently, ratings on the Summit – Industrial 138 kV line were the same for normal, emergency and load dump levels at 251 MVA.

During real-time emergency operations on September 10, there was a discrepancy between the overloads in AEP's power flow analysis and PJM's state estimator. This discrepancy was a result of modeling differences between PJM and AEP. A pseudo-series device modeled at Industrial in PJM's state estimator model should have had zero impedance and therefore no impact on the state estimator solution. But PJM's model had a non-zero impedance value and the estimated post-contingency flows on the Summit – Industrial line for the loss of the Robison Park T5 transformer were 20 MVA lower than AEP's correct solution indicated. The post contingency flows on the Summit – Industrial line (for the loss of the Robison Park T5 345/138 kV transformer) observed in the day-ahead case were within an acceptable limit (86 percent of the load dump limit). The modeling error (along with inaccurate load forecast) contributed to the lower observed post contingency flows in the day-ahead case. PJM has resolved this issue.

It is critical to both reliability and market outcomes that dispatchers have accurate transmission facility ratings. The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.

Behind the Meter Generation

In the Pigeon River load shed event on September 9 and 10, both PJM and AEP were unaware of the six MW behind the meter (BTM) generator in the city of

98 See the *2013 State of the Market Report for PJM*, Section 6, "Demand Response" at "Recommendations".

99 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014).

Sturgis. The generator was not modeled in the energy management systems of PJM and AEP. This unit had a 67 percent distribution factor on the post contingency flow on the LaGrange - Howe 69 kV line. If the unit had been generating, it would have avoided the load shed on September 9 and reduced the amount of load shed on September 10 in the Pigeon River area. AEP personnel identified the unit in preparation for September 11 and notified the city of Sturgis about the PJM system emergency. On September 11, the unit was started and produced 5.4 MW of energy. The combination of the unit and voluntary customer load curtailment initiated by the city of Sturgis provided enough relief to prevent pre contingency load shed in the Pigeon River area on September 11.

The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.

Interchange Transactions

On July 18, 2013, PJM issued emergency mandatory load management in the ATSI, PECO and PPL zones at 1240 and in AEP's South Canton subzone at 1300. Long lead demand response has a two hour notification time. These actions were based on the expectation that demand resources would be required to be dispatched to maintain sufficient reserves over the peak. In hour ending 1400, the RTO system marginal price reached $464.88, which provided a signal for market participants to import energy into PJM from neighboring balancing authorities. At that time, PJM's MISO interface price (the price a transaction receives from PJM for imports from MISO or pays to PJM to export to MISO) was $397.24, while MISO's PJM interface price (the price a transaction pays to MISO to export to PJM or receives from MISO for an import from PJM) was $48.97, and PJM's NYISO interface price (the price a transaction receives from PJM for imports from NYISO or pays to PJM to export to NYISO) was $503.16, while NYISO's PJM interface price (the price a transaction pays to NYISO to export to PJM or receives from NYISO for an import from PJM) was $154.80.

By 1500, net interchange imports into PJM increased by more than 3,000 MW, from 4,686 MW in hour ending 1400 to 7,692 MW in hour ending 1500. The RTO system marginal price in hour ending 1500 dropped to $52.17. At that time, the PJM's MISO interface price dropped to $31.28, while MISO's PJM interface price increased slightly to $59.01, and PJM's NYISO interface price dropped to $73.46, while NYISO's PJM interface price increased to $325.80. While PJM continued to be a net importer of energy, net imports to PJM gradually declined in the following hours as market participants responded to the lower prices. By hour ending 2000, net imports were reduced to 5,804 MW, a 1,888 MW reduction from the imports observed in hour ending 1500.

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible to reliably predict the quantity or sustainability of imports. In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments all affect the duration of interchange transactions. Real-time interchange transactions can be submitted with 20 minutes notice.

Emergency demand resources must be called two hours in advance. At the time the decision needs to be made to call for demand resources, the expected interchange is not known.

Optimizing interchange between neighboring balancing authorities could resolve many of the issues observed during high-load days. The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. In addition, implementing a more flexible demand response program that requires a shorter lead time, and shorter minimum response times would also reduce the need to call for demand resources when not necessary.

Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.[2]

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by 35.6 percent or $231.4 million in 2013 compared to 2012, from $650.8 million to $882.2 million. This change was the result of an increase of $263.5 million in reactive services charges, an increase of $78.2 million in black start services charges and an increase of $0.2 million in synchronous condensing charges. These increases were partially offset by a decrease of $48.9 million in day-ahead operating reserve charges and a decrease of $61.6 million in balancing operating reserve charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.079 per MWh. The day-ahead operating reserve rate including unallocated congestion charges averaged $0.103 per MWh. The balancing operating reserve reliability rates averaged $0.051, $0.030 and $0.004 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $0.863, $1.868 and $0.122 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $0.705 per MWh and the canceled resources rate averaged $0.003 per MWh.
- **Reactive Services Rates.** The DPL, PENELEC and ATSI control zones had the three highest reactive local voltage support rates: $2.538, $1.900 and $0.690 per MWh. The reactive transfer interface support rate averaged $0.224 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 48.8 percent of all day-ahead generator credits and 49.1 percent of all balancing generator credits. Combustion turbines and diesels received 72.7 percent of the lost opportunity cost credits. Coal units received 87.1 percent of all reactive services credits.
- **Economic and Noneconomic Generation.** In 2013, 81.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Charges and Credits

- In 2013, 82.2 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions (at control zones or buses within a control zone), demand and generators, 5.9 percent by transactions at hubs and aggregates and 11.9 percent by transactions at interfaces.

Energy Uplift Issues

- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 38.0 percent of all credits. The top 10 organizations received 88.4 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5340, balancing operating reserves HHI was 3622, lost opportunity cost HHI was 4390 and reactive services HHI was 3016.
- **Day-Ahead Unit Commitment for Reliability:** In 2013, 4.6 percent of the total day-ahead generation was scheduled as must run by PJM, of which 66.9 percent was made whole.
- **Lost Opportunity Cost Credits:** In 2013, lost opportunity cost credits decreased by $105.1 million compared to 2012. In 2013, the top three control zones receiving lost opportunity cost credits, AEP, ComEd and Dominion accounted for 61.7 percent

1 This section has been renamed Energy Uplift rather than Operating Reserves. Energy uplift is a more accurate description of the topic than operating reserves, which may be confused with the concept of operating reserves for reliability as defined in FERC Order 888.

2 Other types of energy uplift charges are make whole payments to emergency demand response resources and emergency transaction purchases. These categories are not covered in this section.

of all lost opportunity cost credits, 55.0 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 60.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 57.0 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.

- **Lost Opportunity Cost Calculation:** In 2013, lost opportunity cost credits would have been reduced by an additional $22.8 million, or 26.3 percent, if all recommendations proposed by the MMU on this issue had been implemented.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In 2013, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $86.4 million.
- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing operating reserves credits.
- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to operating reserve charges proposed by the MMU on operating reserve charge rates would be significant. For example, in 2013, the average rate paid by a DEC in the Eastern Region would have been $0.202 per MWh, which is 93.9 percent less ($3.099 per MWh) than the actual average rate paid.

2013 Energy Uplift Charges Increase

- **Unallocated Congestion Charges:** In 2013, congestion charges that could not be allocated to FTR holders accounted for a $19.2 million increase in energy uplift charges compared to 2012.
- **Unit Scheduling/Commitment and Allocation Change:** The need to schedule/commit resources as must run for black start and reactive support combined with the unit scheduling/commitment change performed by PJM in September 2012 and the energy uplift charges allocation change filed by PJM in December 2012 resulted in a net $21.1 million increase in energy uplift charges in 2013 compared to 2012. This issue had different impacts in each energy uplift category.
- **FMU Adders:** The impact of FMU adders included in the offers of units providing reactive support was $81.7 million. These units became eligible for FMU adders in 2013 after qualifying for the adder based on the percentage of run hours on which they were offer capped.
- **Reactive Credits Settlement Issue:** PJM announced a settlement issue due to an unintended logging error regarding units scheduled in the Day-Ahead Energy Market for reactive support. The estimated impact of this issue is $26.2 million. A portion or all of these payments might be resettled depending on the underlying reason for dispatching these units in real time.
- **Winter Days:** Energy uplift charges in the winter days of 2013 were $88.0 million more than the energy uplift charges in the winter days of 2012. This increase was primarily a result of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Recommendations

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.
- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost

credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

- The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.
- The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

- The MMU also recommends other rule changes regarding the calculation of lost opportunity cost credits to units scheduled in the Day-Ahead Energy Market and not committed in real time:
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be eligible for an LOC compensation when committed or decommitted within an hour.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. The MMU also recommends including real-time exports in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region.
- The MMU recommends enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their operation results in a lower loss or no loss at all.
- The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start charges.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and that the allocation of these charges reflects the reasons that the costs are incurred to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations has persisted for more than ten years.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[3] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators actions in LMP.[4]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Energy Uplift

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when hourly LMP is less than the offer price including energy, no load and startup costs.

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

3 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.

4 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

Table 4-1 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:	Charges Category:	Charges Paid By:	
Day-Ahead				
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Balancing				
Generation Resources	Balancing Operating Reserve Generator	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
		Balancing Operating Reserve for Deviations	Deviations	
		Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC			
Real-Time Import Transactions	Balancing Operating Reserve Transaction			
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator			
Economic Load Response Resources	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:	Charges Category:	Charges Paid By:
Reactive			
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	Reactive Services Charge	Zonal Real-Time Load
		Reactive Services Local Constraint	Applicable Requesting Party
Synchronous Condensing			
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
Black Start			
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Day-Ahead Operating Reserves

Day-ahead operating reserve credits consist of make whole payments to generators, import transactions and load response resources in the Day-Ahead Energy Market.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. In addition any unallocated congestion charges that could not be allocated to FTR holders are allocated as day-ahead operating reserve charges.

Balancing Operating Reserves

Balancing operating reserve credits consist of make whole and lost opportunity cost payments in the balancing market. Balancing operating reserve credits are paid to generators, import transactions and load response resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generators when their output is reduced or suspended at PJM's request for reliability purposes from their economic or self-scheduled output level or when combustion turbines or diesels are scheduled in the Day-Ahead Energy Market and not committed in real time. Balancing operating reserve credits are paid to real-time import transactions, if the real-time LMP at the import pricing point is less than the price specified in the transaction. Balancing operating reserve credits are also paid to resources when canceled before coming online.

The balancing operating reserve charges that result from paying the total balancing operating reserve credits are allocated daily to PJM members in different categories defined by the balancing operating reserve cost allocation rules (BORCA). The rules classify the charges as reliability and deviations. Balancing operating reserve credits paid to units that operate at a loss at the request of a third party are paid by the requesting party.[5]

Reactive Services

Reactive service credits are paid to units committed in real time for the purpose of maintaining the reactive reliability of the PJM region. Units are paid reactive services credits if such units are reduced or suspended at the request of PJM and the LMP at the unit's bus is higher than its offered price or if their output is increased at the request of PJM for the purpose of reactive services and the offered price is higher than the LMP at the unit's bus. Synchronous condensers may also receive reactive service credits by providing synchronous condensing for the purpose of maintaining reactive reliability at the request of PJM.

Reactive services credits are also paid in the form of day-ahead operating reserve credits to units scheduled in the Day-Ahead Energy Market to provide reactive services in real time. These credits consist of make whole payments to units scheduled in Day-Ahead Energy Market to maintain the reactive reliability in real time.[6]

The costs of units committed in real time and scheduled in Day-Ahead Energy Market to maintain the reactive reliability of the PJM region are allocated as reactive services charges. Reactive service charges are allocated daily to real-time load in the control zone or zones where the reactive service was provided.

Synchronous Condensing

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency operation or reactive services.[7]

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions.

Black Start Services

Black start services credits are paid in the form of day-ahead operating reserve credits or balancing operating reserve credits depending on whether the unit was scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service. These credits consist of make whole payments to units capable of providing black start services.[8]

The black start services charges that result from paying day-ahead and balancing operating reserve credits to units providing black start services or performing black start testing are allocated monthly to PJM members in proportion to their zone/non-zone peak transmission use and point to point transmission reservations.[9]

5 Balancing operating reserve charges and credits to units requested by a third party are categorized as balancing local constraint charges and credits in this report.

6 Day-ahead operating reserve credits paid to units scheduled to provide reactive services are categorized as day-ahead reactive services credits in this report.

7 See "Section 5.2.3 Credits for Synchronous Condensing," of "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013).

8 Day-ahead and balancing operating reserve credits paid to units providing black start services or performing black start testing are categorized as day-ahead or balancing black start services credits in this report.

9 See OATT. Schedule 6A for the definition of zone and non-zone peak transmission use.

Balancing Operating Reserve Cost Allocation

Table 4-3 Balancing operating reserve cost allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market**: LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:**Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least four 5-minutes intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 4-3 shows the process for identifying balancing operating reserves credits as related either to reliability or deviations. Such credits are assigned to units during two periods, the reliability analysis (performed after the Day-Ahead Energy Market is cleared) and the Real-Time Energy Market.

During PJM's reliability analysis, performed after the Day-Ahead Energy Market is cleared, credits are allocated for conservative operations or to meet forecasted real-time load. Conservative operations mean that units are committed due to conditions that warrant noneconomic actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are defined as reliability credits and are allocated to real-time load plus exports. Units are also committed to operate to meet the forecasted real-time load plus any operating reserve requirements in addition to the physical units committed in the Day-Ahead Energy Market. The resultant credits are defined as deviation credits.

In the Real-Time Energy Market, credits are also identified as related to either reliability or deviations. Credits are paid to units that are committed by PJM for reliability purposes if the LMP at the unit's bus is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are defined as reliability credits and are allocated to real-time load plus exports.

Credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour are defined as deviation credits and are allocated to real-time supply, demand, and generator deviations.

Reliability and deviations credits are categorized by region based on whether a unit was committed for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500 kV or 765 kV are assigned to RTO credits while credits associated with constraints of all other voltages are assigned to regional credits.

Determinants and Deviation Categories

Under PJM's operating reserve rules, balancing operating reserve charges are allocated regionally. PJM defined the Eastern and Western regions, in addition to the RTO region to allocate the cost of balancing operating reserves. These regions consist of control zones, hubs/aggregates and interfaces. Table 4-4 shows the composition of the Eastern and Western balancing operating reserve regions.

Table 4-4 Balancing operating reserve regions[10]

Location Type	Eastern Region	Western Region
Control Zones	AECO	AEP
	BGE	AP
	Dominion	ATSI
	DPL	ComEd
	JCPL	DAY
	Met-Ed	DEOK
	PECO	DLCO
	PENELEC	EKPC
	Pepco	
	PPL	
	PSEG	
	RECO	
Hubs / Aggregates	Eastern	AEP - Dayton
	New Jersey	ATSI Generators
	Western	Ohio
Interfaces	CLPE Exp	IMO
	CPLE Imp	MISO
	Duke Exp	NIPSCO
	Duke Imp	Northwest
	Hudson	OVEC
	Linden	
	NCMPA Exp	
	NCMPA Imp	
	Neptune	
	NYIS	
	South Exp	
	South Imp	

Credits paid to generators defined to be operating for reliability purposes are charged to real-time load and exports, credits paid to generators and import transactions defined to be operating to control deviations on the system, paid for energy lost opportunity credits and paid to resources canceled before coming online are charged to deviations. Table 4-5 shows the different types of deviations.

Table 4-5 Operating reserve deviations

	Deviations	
Day-Ahead		Real-Time
Day-Ahead Demand Bid	Demand (Withdrawal)	Real-Time Load
Day-Ahead Bilateral Sales	(RTO, East, West)	Real-Time Bilateral Sales
Day-Ahead Export Transactions		Real-Time Export Transactions
Decrement Bids		
Day-Ahead Bilateral Purchases	Supply (Injection)	Real-Time Bilateral Purchases
Day-Ahead Import Transactions	(RTO, East, West)	Real-Time Import Transactions
Increment Offers		
Day-Ahead Scheduled Generation	Generator (Unit)	Real-Time Generation

Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by control zone, hub/aggregate, or interface. Each hourly deviation absolute value is totaled for the day for daily deviation. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared day-ahead load plus day-ahead exports plus day-ahead bilateral sale transactions; and b) the sum of real-time load plus real-time bilateral sale transactions plus real-time exports.
- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports plus day-ahead bilateral purchase transactions; and b) the sum of the real-time bilateral purchase transactions plus real-time imports.
- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations are calculated for individual units, except where netting at a bus is permitted. A deviation from a generator may offset a deviation from another generator if they are connected to the same electrically equivalent bus, and are owned by the same participant.

10 Only two hubs include buses in both the Eastern and Western regions: the Dominion Hub and the Western Interface Hub.

Demand and supply deviations are netted by control zone, hub/aggregate, or interface. For example, a negative deviation at a bus can be offset by a positive deviation at another bus in the same control zone.

The sum of each organization's netted deviations by control zone, hub/aggregate, or interface is assigned to either the Eastern or Western Region, depending on the location of the control zone, hub/aggregate, or interface. The RTO Region deviations are the sum of an organization's Eastern and Western regions deviations, plus deviations that occurred at hubs/aggregates that include buses in both regions. Generating units that deviate from real-time dispatch may offset deviations by another generating unit at the same bus if that unit is electrically equivalent and owned by the same participant.

An organization's total daily balancing operating reserve charges based on deviations are the sum of the three deviation categories, by region (including the RTO), for the day, multiplied by each regional deviation rate plus lost opportunity cost and canceled resources rates.

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges increased by 35.6 percent in 2013 compared to 2012, to a total of $882.2 million. Table 4-6 shows total energy uplift charges from 1999 through 2013.[11]

Table 4-6 Total energy uplift charges: 1999 through 2013

	Total Energy Uplift Charges	Annual Change	Annual Percentage Change	Energy Uplift as a Percent of Total PJM Billing
1999	$133,897,428	NA	NA	7.5%
2000	$216,985,147	$83,087,719	62.1%	9.6%
2001	$284,046,709	$67,061,562	30.9%	8.5%
2002	$273,718,553	($10,328,156)	(3.6%)	5.8%
2003	$376,491,514	$102,772,961	37.5%	5.4%
2004	$537,587,821	$161,096,307	42.8%	6.1%
2005	$712,601,789	$175,013,968	32.6%	3.1%
2006	$365,572,034	($347,029,755)	(48.7%)	1.7%
2007	$503,279,869	$137,707,835	37.7%	1.6%
2008	$474,268,500	($29,011,369)	(5.8%)	1.4%
2009	$322,729,996	($151,538,504)	(32.0%)	1.2%
2010	$622,843,365	$300,113,369	93.0%	1.8%
2011	$605,017,353	($17,826,013)	(2.9%)	1.7%
2012	$650,777,886	$45,760,533	7.6%	2.2%
2013	$882,219,896	$231,442,009	35.6%	2.6%

11 Table 4-3 includes all categories of charges as defined in Table 4-1 and Table 4-2 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 20, 2014.

Total energy uplift charges increased by $231.4 million or 35.6 percent in 2013 compared to 2012. Table 4-7 compares energy uplift charges by category for 2012 and 2013. The increase of $231.4 million in 2013 is comprised of a decrease of $48.9 million in day-ahead operating reserve charges, a decrease of $61.6 million in balancing operating reserve charges, an increase of $263.5 million in reactive services charges, an increase of $0.2 million in synchronous condensing charges and an increase of $78.2 million in black start services charges. The change in total energy uplift charges was due to several factors that impacted all categories. These factors were unallocated congestion charges, reactive and black start unit scheduling/commitment change, energy uplift charges allocation change associated with units needed for black start and reactive support, improvement in combustion turbines commitment, colder winter weather, FMU adders and reactive services credits settlement issue.

Table 4-7 Energy uplift charges by category: 2012 and 2013

Category	2012	2013	Change	Percentage Change
Day-Ahead Operating Reserves	$134,445,132	$85,588,105	($48,857,027)	(36.3%)
Balancing Operating Reserves	$431,789,677	$370,159,625	($61,630,052)	(14.3%)
Reactive Services	$76,010,175	$339,482,039	$263,471,864	346.6%
Synchronous Condensing	$148,250	$396,377	$248,127	167.4%
Black Start Services	$8,384,651	$86,593,749	$78,209,098	932.8%
Total	$650,777,886	$882,219,896	$231,442,009	35.6%

Table 4-8 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges attributable to unallocated congestion charges.[12,13,14] Day-ahead operating reserve charges decreased 36.3 percent or $48.9 million in 2013 compared to 2012. Day-ahead operating reserve charges (excluding unallocated congestion charges) decreased by $68.1 million in 2013 compared to 2012. This decrease was mainly due to the December 1, 2012, allocation change for day-ahead operating reserve

12 Attributable means that these charges are the result of credits paid to the identified resources.

13 See OATT Attachment K-Appendix § 3.2.3 (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves ten times, totaling $26.9 million, of which 74.6 percent was charged in 2013.

14 See Section 13, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

charges associated with units scheduled in the Day-Ahead Energy Market to provide black start and reactive support. These units started to be scheduled in the Day-Ahead Energy Market in September 2012. Between September and November 2012, day-ahead operating reserve credits to units providing black start and reactive support were allocated as day-ahead operating reserve charges. Between September and November 2013, day-ahead operating reserve charges decreased by $58.3 million when compared to the same three month period of 2012. The change in the remaining nine months was a decrease of $9.8 million. Unallocated congestion charges increased by $19.2 in 2013 compared to 2012. Day-ahead operating reserve charges are paid by day-ahead demand, day-ahead exports and decrement bids.

Table 4-8 Day-ahead operating reserve charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Day-Ahead Operating Reserve Charges	$133,614,503	$65,116,984	($68,497,518)	99.4%	76.1%
Day-Ahead Operating Reserve Charges for Load Response	$107	$442,597	$442,490	0.0%	0.5%
Unallocated Congestion Charges	$830,522	$20,028,523	$19,198,001	0.6%	23.4%
Total	$134,445,132	$85,588,105	($48,857,027)	100.0%	100.0%

Table 4-9 Balancing operating reserve charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Balancing Operating Reserve Reliability Charges	$75,763,342	$53,475,908	($22,287,434)	17.5%	14.4%
Balancing Operating Reserve Deviation Charges	$348,174,780	$316,054,920	($32,119,860)	80.6%	85.4%
Balancing Operating Reserve Charges for Load Response	$236,202	$552,379	$316,177	0.1%	0.1%
Balancing Local Constraint Charges	$7,615,353	$76,419	($7,538,934)	1.8%	0.0%
Total	$431,789,677	$370,159,625	($61,630,052)	100.0%	100.0%

Table 4-9 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $61.6 million in 2013 compared to 2012. This decrease was mainly a result of the change in allocation of energy uplift credits to units providing black start support. These units started to be scheduled in the Day-Ahead Energy Market in September 2012. Before September 2012, these units were committed in real time and any associated energy uplift charges were allocated as balancing operating reserve charges for reliability in the Western Region. West reliability charges decreased by $46.3 million in 2013 compared to 2012. Another factor that contributed to the decrease of balancing operating reserve charges was lower lost opportunity cost (LOC) credits. In 2013, LOC and canceled resources related charges decreased by $108.2 million compared to 2012. This occurred in part because PJM began scheduling units in the Day-Ahead Energy Market for black start and reactive support and PJM's implementation of the combustion turbine optimizer tool (CTO).[15] In spite of these reductions in balancing operating reserve charges, the cold weather of 2013 compared to 2012 had an increasing effect on total balancing operating reserve charges. In the 2013 winter days, balancing operating reserve charges (excluding west reliability charges, LOC and canceled resources related charges) increased by $88.0 compared to the 2012 winter days. This increase was mainly a result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. Balancing local constraint charges decreased by $7.5 million in 2013 compared to 2012, these charges are directly allocated to the third-party that requested the operation of a unit or units to provide relief to constraints not under PJM's responsibility.

Table 4-10 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In 2013, 72.5 percent of

15 See "Commitment Decision Making," PJM Presentation to the Energy Market Uplift Senior Task Force (August 20, 2013) for more detail on the combustion turbine optimizer tool. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130820/20130820-bor-commitment-education.ashx>.

all balancing operating reserve deviation charges were attributable to make whole payments to generators and import transactions, an increase of 28.5 percentage points compared to the share in 2012. The increase was primarily due to higher deviation credits to generators in central and northeastern New Jersey during the 2013 winter days and lower balancing operating reserve deviation charges attributable to energy lost opportunity cost and canceled resources.

Table 4-10 Balancing operating reserve deviation charges: 2012 and 2013

Charge Attributable To	2012	2013	Change	2012 Share	2013 Share
Make Whole Payments to Generators and Imports	$152,983,924	$229,063,509	$76,079,585	43.9%	72.5%
Energy Lost Opportunity Cost	$191,756,987	$86,635,563	($105,121,424)	55.1%	27.4%
Canceled Resources	$3,433,870	$355,849	($3,078,021)	1.0%	0.1%
Total	$348,174,780	$316,054,920	($32,119,860)	100.0%	100.0%

Table 4-11 Additional energy uplift charges: 2012 and 2013

Type	2012	2013	Change	2012 Share	2013 Share
Reactive Services Charges	$76,010,175	$339,482,039	$263,471,864	89.9%	79.6%
Synchronous Condensing Charges	$148,250	$396,377	$248,127	0.2%	0.1%
Black Start Services Charges	$8,384,651	$86,593,749	$78,209,098	9.9%	20.3%
Total	$84,543,077	$426,472,166	$341,929,089	100.0%	100.0%

Table 4-12 Regional balancing charges allocation: 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18,820,641	4.4%	$8,015,395	1.9%	$46,269,752	10.9%	$73,105,788	17.2%
	Real-Time Exports	$594,759	0.1%	$169,794	0.0%	$1,893,001	0.4%	$2,657,554	0.6%
	Total	$19,415,400	4.6%	$8,185,189	1.9%	$48,162,753	11.4%	$75,763,342	17.9%
Deviation Charges	Demand	$186,403,740	44.0%	$16,506,118	3.9%	$4,777,995	1.1%	$207,687,853	49.0%
	Supply	$56,154,963	13.2%	$4,579,688	1.1%	$1,263,970	0.3%	$61,998,621	14.6%
	Generator	$71,003,792	16.7%	$5,263,176	1.2%	$2,221,339	0.5%	$78,488,306	18.5%
	Total	$313,562,495	74.0%	$26,348,982	6.2%	$8,263,304	1.9%	$348,174,780	82.1%
Total Regional Balancing Charges		$332,977,895	78.5%	$34,534,171	8.1%	$56,426,056	13.3%	$423,938,122	100%

Table 4-11 shows reactive services, synchronous condensing and black start services charges. Black start services charges were introduced in December 2012. Reactive services charges increased by $263.5 million in 2013 compared to 2012. This increase was mainly a result of the unit scheduling/commitment change for reactive support, the impact of FMU adders and a dispatch logging issue that impacted the reactive services charges settlement in the second half of 2013.

Table 4-12 and Table 4-13 show the amount and percentages of regional balancing charges allocation for 2012 and 2013. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2013, regional balancing operating reserve charges decreased by $54.4 million compared to 2012. Balancing operating reserve reliability charges decreased by $22.3 million or 29.4 percent and balancing operating reserve deviation charges decreased by $32.1 million or 9.2 percent. Total balancing operating reserve deviation charges decreased in 2013 compared to 2012, but in 2013, deviation charges in the Eastern Region increased by $89.6 million compared to 2012, as a result of payments to units providing relief to transmission constraints in north/central New Jersey and units providing support to the Con Edison – PSEG wheeling contracts.[16,17] The remaining two deviation categories decreased by $121.8 million.

16 See "Selected MMU Market Issues," MMU Presentation to the Members Committee (February 25, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mc/20130225-webinar/20130225-item-08-imm-flowchart.ashx>.

17 See "Winter 2012-2013: Balancing Operating Reserve Rates," PJM Presentation at the Market Implementation Committee (March 6, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-10-winter-2012-2013-bor-rates.ashx>.

Table 4-13 Regional balancing charges allocation: 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$39,446,593	10.7%	$10,903,811	3.0%	$1,782,049	0.5%	$52,132,453	14.1%
	Real-Time Exports	$989,139	0.3%	$309,122	0.1%	$45,195	0.0%	$1,343,455	0.4%
	Total	$40,435,731	10.9%	$11,212,932	3.0%	$1,827,244	0.5%	$53,475,908	14.5%
Deviation Charges	Demand	$115,143,323	31.2%	$72,417,440	19.6%	$3,904,232	1.1%	$191,464,995	51.8%
	Supply	$31,112,602	8.4%	$19,274,386	5.2%	$1,094,445	0.3%	$51,481,434	13.9%
	Generator	$46,765,077	12.7%	$24,298,419	6.6%	$2,044,995	0.6%	$73,108,491	19.8%
	Total	$193,021,002	52.2%	$115,990,246	31.4%	$7,043,673	1.9%	$316,054,920	85.5%
Total Regional Balancing Charges		$233,456,733	63.2%	$127,203,178	34.4%	$8,870,917	2.4%	$369,530,828	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. See Table 4-1 for how these charges are allocated.[18]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2012 and 2013. The average rate in 2013 was $0.079 per MWh, $0.082 per MWh lower than the average in 2012. The highest rate occurred on July 16, when the rate reached $0.646 per MWh, 41.3 percent lower than the $1.100 per MWh reached in 2012, on October 30. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. The average rate in 2013, including unallocated congestion charges, was $0.103 per MWh, 30.8 percent higher than the day-ahead operating reserve rate without unallocated congestion charges.

The increase in the day-ahead operating reserve rate on July 16 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 25 percent of their scheduled run time. On July 16, 86 units received day-ahead operating reserve credits, 46 were noneconomic for their entire scheduled run time and four were economic for 25 percent or less of their scheduled run time. That was the highest number of units scheduled noneconomic in the Day-Ahead Energy Market in 2013. On July 16, 43 units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; 32 of these units received enough net revenues from day-ahead scheduling reserves to cover their total energy offer (including no load and startup cost), which would have resulted in zero day-ahead operating reserve credits if the net revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[19] The day-ahead operating reserve rate for July 16 would have been $0.148 per MWh or 22.9 percent lower if the offset had been credited. Similar circumstances occurred on July 17, 18, 19 and September 11.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2012 and 2013[20]

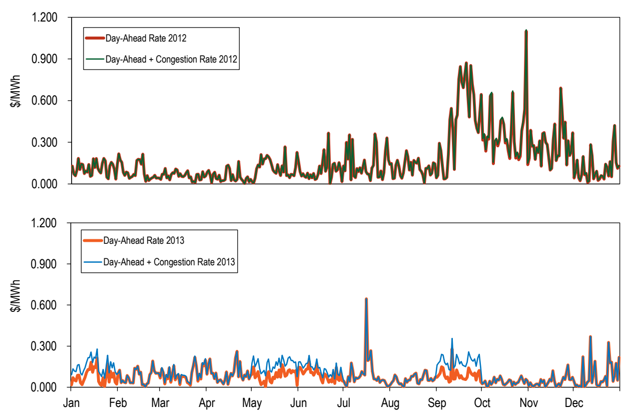


Figure 4-2 shows the RTO and the regional reliability rates for 2012 and 2013. The average daily RTO reliability rate was $0.051 per MWh. The highest RTO reliability rate in 2013 occurred on January 23, when the rate reached $0.802 per MWh. The average daily Eastern Region reliability rate was $0.030 per MWh. The highest Eastern Region reliability rate in 2013 occurred on January 24, when the rate reached $2.887 per MWh.

18 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost rate and the canceled resources rates to the deviation rate for the RTO region since these three charges are allocated following the same rules.

19 Net revenues from day-ahead scheduling reserves are used as offsets in the balancing operating reserve calculation.

20 On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation of certain operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market. See the *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

The spikes in both rates were the result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. The transmission constraints were the result of issues with the 500 kV system which resulted in overloads on the 230 kV system. The issues on the 500 kV system were a combination of unplanned outages and unforeseen outages resulting from damage due to Hurricane Sandy. Cold weather in the region resulted in an increase in the Transco Zone 6 NY natural gas price index in January and February 2013 compared to previous months and compared to January and February 2012. The units committed to provide relief for the transmission constraints only set the LMP during short periods of time in comparison to their minimum run times, which increased the costs of operating reserves during periods when the units continue operating out of merit as a result of their operating parameters.[21]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2012 and 2013

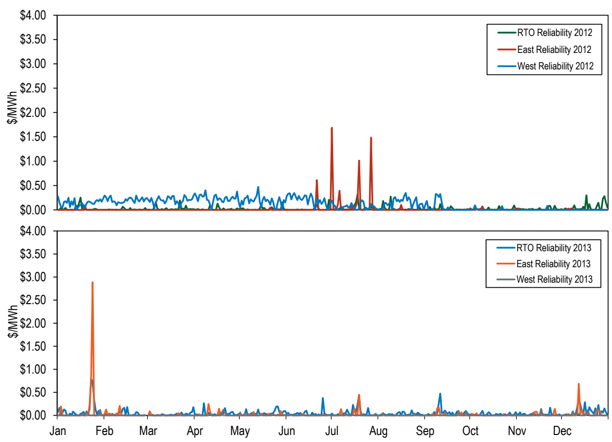


Figure 4-3 shows the RTO and regional deviation rates for 2012 and 2013. The average daily RTO deviation rate was $0.863 per MWh. The highest daily rate in 2013 occurred on January 23, when the RTO deviation rate reached $10.172 per MWh. Between January 1 and February 21, 2013, the Eastern Region deviation rate averaged $8.982 per MWh, reaching its highest rate on February 9, when it reached $32.876 per MWh. Prior to the 2012 – 2013 winter, the highest daily eastern region deviation rate since the creation of this rate on December 2008 occurred on December 18, 2012 when it reached $5.735 per MWh. The spikes in the eastern deviation rate in early January and from mid-January until the end of February were caused by the same issues that caused the RTO and eastern reliability rates to spike on January 25, a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area.

Current balancing operating reserve rules allocate the costs of operating reserves in real time for reliability or deviations according to when the units are committed (before or during the operating day) and the number of intervals the units were operating noneconomic (more or less than four intervals). The spike in the RTO deviation rate on September 11 was mainly a result of the commitment in real time of combustion turbines that did not clear the Day-Ahead Energy Market and did not recover their total offer through energy and ancillary services revenues. This commitment was triggered by the issuance of a maximum generation action on that day.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2012 and 2013

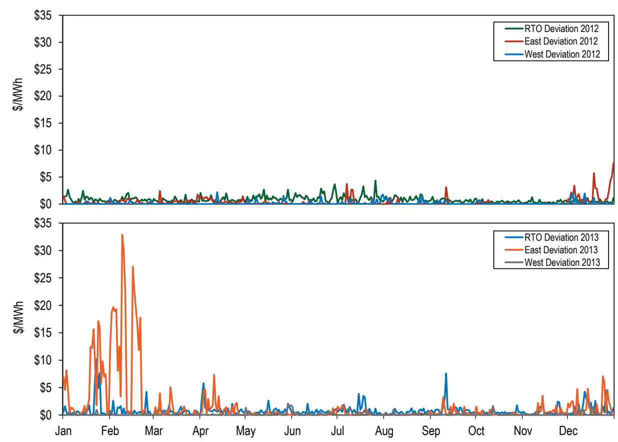


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2012 and 2013. The lost opportunity rate averaged $0.705 per MWh. The highest lost opportunity cost rate occurred on September 11, when it reached $8.509 per MWh.

The LOC rate has shown smaller spikes in 2013 compared to 2012. In 2013, the top 10 daily LOC rates averaged $4.837 per MWh, $3.482 per MWh less than the average of the top 10 daily LOC rates in 2012. The top LOC rates in 2013 occurred between July 16 and

21 The relevant parameters are minimum run time, minimum down time, maximum daily starts and maximum weekly starts.

July 18 and between September 10 and 11. The main reasons for these high rates continue to be combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not committed in real time. Another reason was the need to reduce the output of steam units due to transmission line limits. On September 11, the manual dispatch of a small number of units in the ATSI Control Zone was responsible for 54.0 percent of the LOC rate on that day, the units were manually dispatched down because of a constraint within ATSI during hours when the ATSI interface was binding and demand resources were setting ATSI prices at $1,800 per MWh.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2012 and 2013

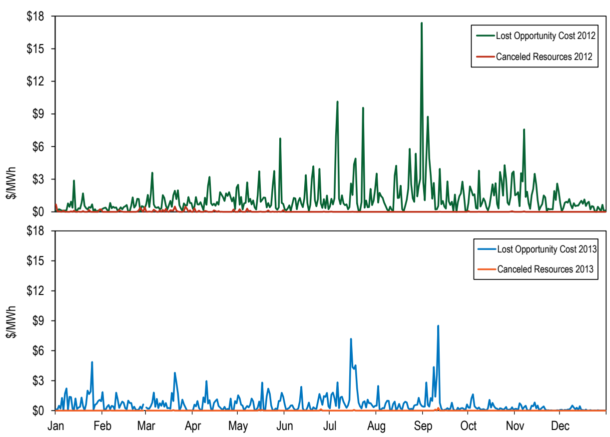


Table 4-14 shows the average rates for each region in each category for 2012 and 2013.

Table 4-14 Operating reserve rates ($/MWh): 2012 and 2013

Rate	2012 ($/MWh)	2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.161	0.079	(0.082)	(51.1%)
Day-Ahead with Unallocated Congestion	0.162	0.103	(0.059)	(36.5%)
RTO Reliability	0.025	0.051	0.026	107.2%
East Reliability	0.022	0.030	0.008	35.9%
West Reliability	0.115	0.004	(0.111)	(96.2%)
RTO Deviation	0.820	0.863	0.043	5.2%
East Deviation	0.333	1.868	1.535	460.8%
West Deviation	0.127	0.122	(0.006)	(4.6%)
Lost Opportunity Cost	1.329	0.705	(0.623)	(46.9%)
Canceled Resources	0.024	0.003	(0.021)	(87.8%)

Table 4-15 shows the operating reserve cost of a one MW transaction during 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $3.301 per MWh with a maximum rate of $33.056 per MWh, a minimum rate of $0.147 per MWh and a standard deviation of $5.029 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-15 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-15 Operating reserve rates statistics ($/MWh): 2013

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	33.024	3.198	0.024	5.028
	DEC	33.056	3.301	0.147	5.029
	DA Load	0.646	0.103	0.000	0.076
	RT Load	3.610	0.073	0.000	0.226
	Deviation	33.024	3.198	0.024	5.028
West	INC	16.429	1.561	0.024	1.804
	DEC	16.785	1.664	0.116	1.825
	DA Load	0.646	0.103	0.000	0.076
	RT Load	0.802	0.053	0.000	0.087
	Deviation	16.429	1.561	0.024	1.804

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer. Even though reactive services rates are not published, a local voltage support rate for each control zone can be calculated, also a reactive transfer interface support rate can calculated for the entire RTO.

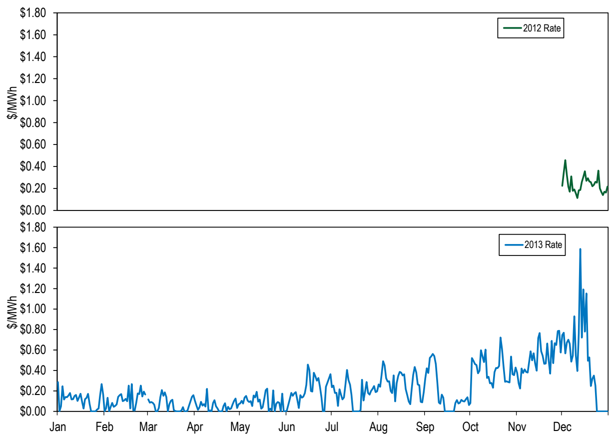
Table 4-16 shows the reactive services rates associated with local voltage support 2012 and 2013. Table 4-16 shows that in 2013 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $2.538 per MWh for reactive services associated with local voltage support, $1.568 or 161.8 percent higher than the average rate paid in 2012.

Table 4-16 Local voltage support rates: 2012 and 2013

Control Zone	2012 ($/MWh)	2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.132	0.227	0.095	71.6%
AEP	0.005	0.057	0.051	943.2%
AP	0.002	0.002	(0.001)	(24.1%)
ATSI	0.219	0.690	0.472	215.4%
BGE	0.174	0.305	0.130	74.6%
ComEd	0.001	0.001	0.000	58.0%
DAY	0.003	0.000	(0.003)	(100.0%)
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.001	0.000	(0.001)	(100.0%)
Dominion	0.015	0.022	0.007	48.8%
DPL	0.969	2.538	1.568	161.8%
EKPC	NA	0.006	NA	NA
JCPL	0.199	0.346	0.147	73.7%
Met-Ed	0.092	0.021	(0.071)	(77.3%)
PECO	0.099	0.030	(0.068)	(69.4%)
PENELEC	0.508	1.900	1.392	274.2%
Pepco	0.145	0.011	(0.134)	(92.3%)
PPL	0.154	0.016	(0.138)	(89.6%)
PSEG	0.211	0.183	(0.029)	(13.6%)
RECO	0.084	0.001	(0.083)	(98.3%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2012 and 2013. PJM began allocating these operating reserve charges to reactive services on December 1, 2012. This rate is charged to real-time load in the entire RTO. The average rate in 2013 was $0.224 per MWh. The increase in this reactive rate in the second half of 2013 has been in part a result of the inclusion of FMU adders in the cost-based offers of some of the units routinely used for this service. These units are eligible for FMU adders because they are being offer capped.[22]

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2012 and 2013



22 See OATT Attachment K - Appendix § 6.4.

Balancing Operating Reserve Determinants

Table 4-17 shows the determinants used to allocate the regional balancing operating reserve charges for 2012 and 2013. Total real-time load and real-time exports were 3,943,503 MWh or 0.5 percent higher in 2013 compared to 2012. Total deviations summed across the demand, supply, and generator categories were 21,482,468 MWh or 14.9 percent lower in 2013 compared to 2012.

Table 4-17 Balancing operating reserve determinants (MWh): 2012 and 2013

		Reliability Charge Determinants			Deviation Charge Determinants			
		Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2012	RTO	764,248,367	26,601,926	790,850,293	85,045,749	26,275,474	32,986,724	144,307,947
	East	362,985,584	10,425,635	373,411,219	48,968,172	14,730,071	15,390,340	79,088,583
	West	401,262,783	16,176,291	417,439,074	35,792,061	11,477,683	17,596,384	64,866,127
2013	RTO	773,789,714	21,004,083	794,793,797	72,881,402	19,570,481	30,373,596	122,825,478
	East	366,566,019	9,763,023	376,329,041	38,926,826	9,797,593	13,357,715	62,082,133
	West	407,223,695	11,241,060	418,464,755	31,767,799	9,188,787	17,015,882	57,972,467
Difference	RTO	9,541,347	(5,597,843)	3,943,503	(12,164,347)	(6,704,993)	(2,613,128)	(21,482,468)
	East	3,580,434	(662,612)	2,917,822	(10,041,346)	(4,932,479)	(2,032,625)	(17,006,450)
	West	5,960,912	(4,935,231)	1,025,681	(4,024,262)	(2,288,896)	(580,502)	(6,893,660)

Deviations fall into three categories, demand, supply and generator deviations. Table 4-18 shows the different categories by the type of transactions that incur deviations. In 2013, 19.5 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 80.5 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 4-18 Deviations by transaction type: 2013

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	1,015,262	502,953	512,309	0.8%	0.8%	0.9%
	DECs Only	7,743,083	3,032,612	2,523,694	6.3%	4.9%	4.4%
	Exports Only	5,505,601	3,115,186	2,390,415	4.5%	5.0%	4.1%
	Load Only	47,522,671	27,807,763	19,714,908	38.7%	44.8%	34.0%
	Combination with DECs	5,729,451	3,094,113	2,635,338	4.7%	5.0%	4.5%
	Combination without DECs	5,365,333	1,374,199	3,991,135	4.4%	2.2%	6.9%
Supply	Bilateral Purchases Only	1,297,947	828,666	469,281	1.1%	1.3%	0.8%
	Imports Only	7,708,563	4,011,345	3,697,218	6.3%	6.5%	6.4%
	INCs Only	5,900,154	1,837,538	3,478,515	4.8%	3.0%	6.0%
	Combination with INCs	4,579,475	3,045,942	1,533,534	3.7%	4.9%	2.6%
	Combination without INCs	84,342	74,103	10,239	0.1%	0.1%	0.0%
Generators		30,373,596	13,357,715	17,015,882	24.7%	21.5%	29.4%
Total		122,825,478	62,082,133	57,972,467	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-19 shows the totals for each credit category for 2012 and 2013. During 2013, 42.9 percent of total energy uplift credits were in the balancing operating reserve category. This percentage decreased 23.5 percentage points from 66.4 percent in. This decrease was in part due to the reallocation of energy uplift credits paid to units providing black start services and reactive services. In 2013, the percent of total energy uplift credits in the reactive services category increased to 39.4 percent, 27.7 percentage points higher than 2012.

Table 4-19 Energy uplift credits by category: 2012 and 2013

Category	Type	2012	2013	Change	Percentage Change	2012 Share	2013 Share
Day-Ahead	Generators	$133,613,948	$65,116,975	($68,496,972)	(51.3%)	20.6%	7.6%
	Imports	$554	$9	($545)	(98.3%)	0.0%	0.0%
	Load Response	$108	$442,597	$442,490	411,077.8%	0.0%	0.1%
Balancing	Canceled Resources	$3,433,872	$355,849	($3,078,023)	(89.6%)	0.5%	0.0%
	Generators	$228,590,056	$282,494,308	$53,904,252	23.6%	35.2%	32.8%
	Imports	$159,564	$45,112	($114,452)	(71.7%)	0.0%	0.0%
	Load Response	$236,077	$552,212	$316,135	133.9%	0.0%	0.1%
	Local Constraints Control	$7,615,353	$76,419	($7,538,934)	(99.0%)	1.2%	0.0%
	Lost Opportunity Cost	$191,756,979	$86,635,564	($105,121,415)	(54.8%)	29.5%	10.0%
Reactive Services	Day-Ahead	$24,234,095	$290,687,063	$266,452,968	1,099.5%	3.7%	33.7%
	Local Constraints Control	$37,266	$106,287	$69,022	185.2%	0.0%	0.0%
	Lost Opportunity Cost	$2,458,300	$5,130,166	$2,671,866	108.7%	0.4%	0.6%
	Reactive Services	$49,134,480	$43,171,412	($5,963,068)	(12.1%)	7.6%	5.0%
	Synchronous Condensing	$146,035	$387,111	$241,076	165.1%	0.0%	0.0%
Synchronous Condensing		$148,250	$396,377	$248,127	167.4%	0.0%	0.0%
Black Start Services	Day-Ahead	$8,204,976	$84,121,142	$75,916,167	925.2%	1.3%	9.8%
	Balancing	$190,568	$2,277,634	$2,087,066	1,095.2%	0.0%	0.3%
	Testing	$0	$363,916	$363,916	NA	0.0%	0.0%
Total		$649,960,482	$862,360,155	$212,399,674	32.7%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-20 shows the distribution of total energy uplift credits by unit type for 2012 and 2013. Credits paid to combined cycle units increased 142.7 percent or $113.0 million, mainly due to units providing relief for transmission constraints and supporting the Con Edison – PSEG wheeling contracts during days with high natural gas prices. In 2013, 22.3 percent of all operating reserve credits paid to units were paid to combined cycle units, 10.1 percentage points more than the share in 2012.

Table 4-20 Energy uplift credits by unit type: 2012 and 2013

Unit Type	2012	2013	Change	Percentage Change	2012 Share	2013 Share
Combined Cycle	$79,199,434	$192,201,505	$113,002,071	142.7%	12.2%	22.3%
Combustion Turbine	$226,859,986	$149,523,385	($77,336,601)	(34.1%)	34.9%	17.4%
Diesel	$3,728,045	$6,525,487	$2,797,442	75.0%	0.6%	0.8%
Hydro	$294,991	$555,413	$260,422	88.3%	0.0%	0.1%
Nuclear	$1,655,968	$136,961	($1,519,006)	(91.7%)	0.3%	0.0%
Steam - Coal	$284,453,370	$458,937,387	$174,484,017	61.3%	43.8%	53.3%
Steam - Other	$44,681,160	$42,891,533	($1,789,626)	(4.0%)	6.9%	5.0%
Wind	$8,691,224	$10,548,551	$1,857,327	21.4%	1.3%	1.2%
Total	$649,564,178	$861,320,224	$211,756,046	32.6%	100.0%	100.0%

Table 4-21 shows the distribution of energy uplift credits by category and by unit type in 2013. Combined cycle units received 48.8 percent of the day-ahead generator credits in 2013, 32.4 percentage points higher than the share received in 2012. Combined cycle units received 49.1 percent of the balancing generator credits in 2013, 31.1 percentage points higher than the share received in 2012. Combustion turbines and diesels received 72.7 percent of the lost opportunity cost credits in 2013, 14.0 percentage points lower than the share received in 2012.

Table 4-21 Energy uplift credits by unit type: 2013

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	48.8%	49.1%	0.0%	13.5%	7.1%	4.6%	0.0%	0.0%
Combustion Turbine	10.7%	24.0%	8.8%	59.5%	72.5%	3.2%	100.0%	0.4%
Diesel	0.1%	0.4%	0.0%	16.0%	0.1%	1.6%	0.0%	0.0%
Hydro	0.3%	0.0%	62.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
Steam - Coal	35.9%	16.5%	9.1%	10.0%	7.7%	87.1%	0.0%	99.6%
Steam - Others	4.3%	10.0%	19.8%	0.0%	0.2%	3.4%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	1.0%	12.1%	0.0%	0.0%	0.0%
Total	$65,116,975	$282,494,308	$355,849	$76,419	$86,635,563	$339,482,040	$396,377	$86,762,692

Table 4-21 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In 2013, coal units received 87.1 percent of all reactive services credits, 11.9 percentage points higher than the share received in 2012. Synchronous condensing was only provided by combustion turbines. Coal units received 99.6 percent of all black start services credits.

Economic and Noneconomic Generation[23]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 4-22 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In 2013, 32.6 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 31.5 percent of the real-time generation was eligible for balancing operating reserve credits.[24]

Table 4-22 Day-ahead and real-time generation (GWh): 2013

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	809,695	263,755	32.6%
Real-Time	797,100	250,907	31.5%

Table 4-23 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In 2013, 81.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-23 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

23 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

24 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

Table 4-23 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2013

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	215,263	48,492	81.6%	18.4%
Real-Time	167,363	83,544	66.7%	33.3%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-24 shows the generation receiving day-ahead and balancing operating reserve credits. In 2013, 13.2 percent of the day-ahead generation eligible for operating reserve credits received credits and 8.3 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-24 Day-ahead and real-time generation receiving operating reserve credits (GWh): 2013

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	263,755	34,805	13.2%
Real-Time	250,907	20,732	8.3%

Geography of Charges and Credits

Table 4-25 shows the geography of charges and credits in 2013. Table 4-25 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 1.4 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 6.5 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 37.4 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had an 85.1 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-25 also shows that 82.2 percent of all charges were allocated in control zones, 5.9 percent in hubs and aggregates and 11.9 percent in interfaces.

Table 4-25 Geography of regional charges and credits: 2013[25]

Location		Charges	Credits	Balance	Shares Total Charges	Shares Total Credits	Shares Deficit	Shares Surplus
Zones	AECO	$6,236,329	$4,015,220	($2,221,109)	1.4%	0.9%	1.4%	0.0%
	AEP - EKPC	$41,489,378	$29,746,951	($11,742,427)	9.5%	6.8%	7.4%	0.0%
	AP - DLCO	$23,274,970	$17,055,594	($6,219,376)	5.4%	3.9%	3.9%	0.0%
	ATSI	$19,723,093	$20,575,022	$851,929	4.5%	4.7%	0.0%	0.5%
	BGE - Pepco	$39,873,096	$41,149,212	$1,276,116	9.2%	9.5%	0.0%	0.8%
	ComEd - External	$34,984,178	$22,708,351	($12,275,827)	8.0%	5.2%	7.8%	0.0%
	DAY - DEOK	$15,367,451	$2,403,483	($12,963,968)	3.5%	0.6%	8.2%	0.0%
	Dominion	$40,129,662	$48,809,888	$8,680,226	9.2%	11.2%	0.0%	5.5%
	DPL	$12,138,887	$16,876,401	$4,737,514	2.8%	3.9%	0.0%	3.0%
	JCPL	$13,687,678	$17,285,344	$3,597,665	3.1%	4.0%	0.0%	2.3%
	Met-Ed	$10,284,379	$5,619,746	($4,664,633)	2.4%	1.3%	3.0%	0.0%
	PECO	$25,019,877	$7,049,433	($17,970,445)	5.8%	1.6%	11.4%	0.0%
	PENELEC	$17,666,232	$6,609,420	($11,056,812)	4.1%	1.5%	7.0%	0.0%
	PPL	$27,762,768	$32,091,195	$4,328,427	6.4%	7.4%	0.0%	2.7%
	PSEG	$28,409,227	$162,607,436	$134,198,208	6.5%	37.4%	0.0%	85.1%
	RECO	$1,079,633	$0	($1,079,633)	0.2%	0.0%	0.7%	0.0%
	All Zones	$357,126,839	$434,602,696	$77,475,857	82.2%	100.0%	50.9%	100.0%
Hubs and Aggregates	AEP - Dayton	$2,367,043	$0	($2,367,043)	0.5%	0.0%	1.5%	0.0%
	Dominion	$3,020,526	$0	($3,020,526)	0.7%	0.0%	1.9%	0.0%
	Eastern	$349,106	$0	($349,106)	0.1%	0.0%	0.2%	0.0%
	New Jersey	$918,228	$0	($918,228)	0.2%	0.0%	0.6%	0.0%
	Ohio	$112,200	$0	($112,200)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$1,459,083	$0	($1,459,083)	0.3%	0.0%	0.9%	0.0%
	Western	$17,421,845	$0	($17,421,845)	4.0%	0.0%	11.0%	0.0%
	RTEP B0328 Source	$189	$0	($189)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$25,648,219	$0	($25,648,219)	5.9%	0.0%	16.3%	0.0%
Interfaces	CPLE Imp	$0	$0	$0	0.0%	0.0%	0.0%	0.0%
	Hudson	$483,810	$0	($483,810)	0.1%	0.0%	0.3%	0.0%
	IMO	$5,954,434	$0	($5,954,434)	1.4%	0.0%	3.8%	0.0%
	Linden	$1,873,295	$0	($1,873,295)	0.4%	0.0%	1.2%	0.0%
	MISO	$6,895,321	$0	($6,895,321)	1.6%	0.0%	4.4%	0.0%
	Neptune	$1,084,662	$0	($1,084,662)	0.2%	0.0%	0.7%	0.0%
	NIPSCO	$34,330	$0	($34,330)	0.0%	0.0%	0.0%	0.0%
	Northwest	$189,945	$0	($189,945)	0.0%	0.0%	0.1%	0.0%
	NYIS	$8,845,643	$0	($8,845,643)	2.0%	0.0%	5.6%	0.0%
	OVEC	$1,520,343	$0	($1,520,343)	0.3%	0.0%	1.0%	0.0%
	South Exp	$6,231,249	$0	($6,231,249)	1.4%	0.0%	4.0%	0.0%
	South Imp	$18,759,729	$0	($18,759,729)	4.3%	0.0%	11.9%	0.0%
	All Interfaces	$51,872,760	$45,122	($51,827,639)	11.9%	0.0%	32.9%	0.0%
	Total	$434,647,818	$434,647,818	$0	100.0%	100.0%	100.0%	100.0%

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 4-26 shows the geography of reactive services charges. In 2013, 46.2 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 2.7 percent were paid by real-time load in multiple zones and 51.1 percent were paid by real-time load across the entire RTO. In 2013, resources in two control zones accounted for 99.8 percent of all reactive services costs allocated across the entire RTO.

Table 4-26 Geography of reactive services charges: 2013[26]

Location	Charges	Share of Charges
Single Zone	$156,669,607	46.2%
Multiple Zones	$9,203,271	2.7%
Entire RTO	$173,502,875	51.1%
Total	$339,375,753	100.0%

In 2013, the top three zones accounted for 68.3 percent of all the reactive services charges allocated to single zones.

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone

25 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-25 does not include synchronous condensing, local constraint control, black start services and reactive services charges and credits since these are allocated zonally.

26 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services, synchronous condensing or certain other ancillary services because of confidentiality requirements. See PJM. Manual 33: Administrative Services for the PJM Interconnection Agreement, Revision 09 (July 22, 2010).

accounted for 99.6 percent of all the black start services costs in 2013. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in six control zones accounted for all synchronous condensing costs in 2013.

Energy Uplift Issues

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating characteristics, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it impossible for competition to affect these dynamic payments.

Table 4-27 Top 10 energy uplift credits units (By percent of total system): 2001 through 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%
2010	33.2%	0.8%
2011	28.1%	0.8%
2012	22.7%	0.7%
2013	38.0%	0.7%

Table 4-28 Top 10 units and organizations energy uplift credits: 2013

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$39,068,884	60.0%	$58,869,965	90.4%
Balancing	Canceled Resources	$348,850	98.0%	$355,849	100.0%
	Generators	$149,278,224	52.8%	$250,054,898	88.5%
	Local Constraints Control	$71,358	93.4%	$76,419	100.0%
	Lost Opportunity Cost	$23,048,824	26.6%	$72,187,429	83.3%
Reactive Services		$235,940,926	69.5%	$330,586,143	97.4%
Synchronous Condensing		$161,775	40.8%	$396,377	100.0%
Black Start Services		$66,768,005	77.0%	$86,738,688	100.0%
Total		$327,278,403	38.0%	$761,093,145	88.4%

The concentration of energy uplift credits is first examined by analyzing the characteristics of the top 10 units receiving energy uplift credits. The focus on the top 10 units is illustrative.

The concentration of energy uplift credits in the top 10 units remains high and it increased in 2013 compared to 2012. Table 4-27 shows that the top 10 units receiving total energy uplift credits, which make up less than one percent of all units in PJM's footprint, received 38.0 percent of total energy uplift credits in 2013, compared to 22.7 percent in 2012. The increase in the concentration of energy uplift credits was in part the result of lower lost opportunity cost credits paid to combustion turbines and diesels in 2013 compared to 2012, which increased the share of credits paid to the top 10 units receiving day-ahead operating reserve, balancing operating reserve, reactive services and black start services credits.

Table 4-28 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators. The shares of the top 10 organizations in all categories separately were above 83.0 percent.

Table 4-29 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2013, 89.0 percent of all credits paid to these units were allocated to deviations while the remaining 11.0 percent were paid for reliability reasons.

Table 4-29 Identification of balancing operating reserve credits received by the top 10 units by category and region: 2013

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$13,853,952	$2,528,270	$0	$42,266,138	$90,629,864	$0	$149,278,224
Share	9.3%	1.7%	0.0%	28.3%	60.7%	0.0%	100.0%

In 2013, concentration in all energy uplift credit categories was high.[27,28] The HHI for energy uplift credits was calculated based on each organization's daily credits for each category. Table 4-30 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 5340, for balancing operating reserve credits to generators was 3622, for lost opportunity cost credits was 4390 and for reactive services credits was 3016.

Table 4-30 Daily energy uplift credits HHI: 2013

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	5340	899	10000	100.0%	55.2%
	Imports	10000	10000	10000	100.0%	38.1%
	Load Response	10000	10000	10000	100.0%	99.2%
Balancing	Canceled Resources	10000	10000	10000	100.0%	62.2%
	Generators	3622	931	9888	99.4%	43.7%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9993	9724	10000	100.0%	97.5%
	Lost Opportunity Cost	4390	627	10000	100.0%	23.1%
Reactive Services		3016	1105	10000	100.0%	62.0%
Synchronous Condensing		8587	4133	10000	100.0%	74.0%
Black Start Services		9165	3696	10000	100.0%	110.2%
Total		1675	413	7279	85.1%	29.2%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[29] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[30] Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for day-ahead operating reserve credits.

Table 4-31 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In 2013, 4.6 percent of the total day-ahead generation was scheduled as must run by PJM, 1.2 percentage points higher than 2012.[31]

Table 4-31 Day-ahead generation scheduled as must run by PJM (GWh): 2012 and 2013

	2012			2013		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,152	1,312	1.8%	72,681	2,907	4.0%
Feb	63,642	1,191	1.9%	65,632	2,474	3.8%
Mar	60,513	1,109	1.8%	67,940	3,178	4.7%
Apr	55,999	1,099	2.0%	57,570	2,522	4.4%
May	62,986	1,944	3.1%	61,169	2,848	4.7%
Jun	69,190	1,841	2.7%	68,452	3,724	5.4%
Jul	82,984	3,618	4.4%	78,639	4,395	5.6%
Aug	76,161	2,438	3.2%	73,783	3,678	5.0%
Sep	63,535	2,902	4.6%	64,757	3,162	4.9%
Oct	60,656	3,509	5.8%	62,134	2,940	4.7%
Nov	62,985	3,542	5.6%	63,827	2,675	4.2%
Dec	68,759	2,347	3.4%	73,112	2,612	3.6%
Total	798,561	26,851	3.4%	809,695	37,115	4.6%

27 See Section 3, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

28 Table 4-30 excludes the local constraints control categories.

29 See "Item 12 - October 2012 MIC DAM Cost Allocation," PJM Presentation to the Market Implementation Committee (October 12, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.

30 See "PJM eMkt Users Guide," Section Managing Unit Data (version November 11, 2013) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

31 PJM increased the amount of generation scheduled as must run on September 13, 2012. See the *2012 State of the Market Report for PJM*: Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments. The only reason for having a day-ahead operating reserve credit is to enable the allocation of these uplift costs to transactions in the Day-Ahead Energy Market.

Table 4-32 shows the total day-ahead generation scheduled as must run by PJM by category. In 2013, 66.9 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 13.8 percent was generation from units scheduled to provide black start services, 42.0 percent was generation from units scheduled to provide reactive services and 11.1 percent was generation paid normal day-ahead operating reserve credits. The remaining 33.1 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-32 Day-ahead generation scheduled as must run by PJM by category (GWh): 2013

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	433	1,271	250	954	2,907
Feb	430	1,356	206	481	2,474
Mar	424	909	490	1,354	3,178
Apr	451	840	439	792	2,522
May	429	1,058	346	1,016	2,848
Jun	484	1,601	459	1,181	3,724
Jul	420	1,616	234	2,124	4,395
Aug	465	1,644	387	1,182	3,678
Sep	338	1,461	453	911	3,163
Oct	493	1,358	317	772	2,940
Nov	437	1,287	192	760	2,675
Dec	325	1,197	330	760	2,612
Total	5,130	15,597	4,104	12,285	37,116
Share	13.8%	42.0%	11.1%	33.1%	100.0%

Total day-ahead operating reserve credits in 2013 were $65.1 million, of which $34.9 million or 53.6 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to inform all market participants of the reason for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.[32] The overall goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[33] If a unit generating in real time with an offer price lower than the real-time LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue, the unit will receive a credit for LOC based on the desired output. For purposes of this report, this LOC will be referred as real-time LOC.

In 2013, LOC credits decreased by $105.1 million or 54.8 percent compared to 2012. The decrease of $105.1 million is comprised of a decrease of $104.6 million in day-ahead LOC and a decrease of $0.5 million in real-time LOC. Table 4-35 shows the monthly composition of LOC credits in 2012 and 2013. The reduction in LOC credits was mainly a result of lower day-ahead scheduled generation from combustion turbines and diesels that could have resulted in day-ahead LOC credits. Day-ahead scheduled generation from combustion turbines and diesels decreased by 7,259 GWh or 35.8 percent in 2013 compared to 2012.

This reduction appears to be primarily the result of the reduction in day-ahead scheduled generation in

32 The classification could occur via defined logging codes for dispatchers. That would create data that could be analyzed by the MMU and summarized for participants.

33 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market subtracted by the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not committed in real time incurs in balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

combination with PJM's implementation of a new tool to improve the commitment of combustion turbines (combustion turbine optimizer or CTO) which reduced the amount of generation from combustion turbines and diesels that was scheduled in the Day-Ahead Energy Market but that was not committed in real time. In 2013, 30.7 percent of the day-ahead scheduled generation from combustion turbines and diesels received LOC credits for being scheduled in the Day-Ahead Energy Market and not committed in real time, 22.2 percentage points lower than 2012.

Table 4-33 Monthly lost opportunity cost credits: 2012 and 2013

	2012			2013		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$5,165,871	$236,780	$5,402,651	$8,728,322	$2,752,980	$11,481,302
Feb	$4,523,969	$107,118	$4,631,087	$2,049,518	$2,681,143	$4,730,662
Mar	$10,523,644	$221,695	$10,745,339	$4,803,277	$2,324,036	$7,127,313
Apr	$11,843,133	$635,839	$12,478,972	$3,893,268	$1,567,916	$5,461,184
May	$15,665,485	$3,607,291	$19,272,775	$5,266,582	$3,247,955	$8,514,538
Jun	$14,570,930	$466,323	$15,037,254	$6,200,721	$807,362	$7,008,083
Jul	$27,629,292	$3,067,390	$30,696,682	$16,300,953	$3,188,446	$19,489,398
Aug	$25,561,031	$1,200,612	$26,761,643	$5,449,177	$210,367	$5,659,544
Sep	$19,962,559	$1,549,391	$21,511,950	$6,377,820	$4,579,815	$10,957,635
Oct	$12,437,131	$7,899,960	$20,337,091	$2,455,137	$619,446	$3,074,584
Nov	$14,771,088	$3,802,458	$18,573,547	$1,365,945	$701,949	$2,067,894
Dec	$5,334,673	$973,316	$6,307,989	$503,846	$559,582	$1,063,428
Total	$167,988,807	$23,768,172	$191,756,979	$63,394,565	$23,240,998	$86,635,564
Share	87.6%	12.4%	100.0%	73.2%	26.8%	100.0%

Although day-ahead LOC credits (payments to combustion turbines and diesels scheduled in the Day-Ahead Energy Market and not requested in real time) decreased in 2013 compared to 2012, it continues to comprise the majority of LOC credits. In 2013, day-ahead LOC were 73.2 percent of all LOC credits. Combustion turbines and diesels are only eligible for day-ahead lost opportunity cost if the units are scheduled in day ahead and follow PJM instructions in real time.[34] Table 4-34 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits.

34 Combustion turbines and diesels with lead times of two hours or less are automatically eligible for lost opportunity cost credits. Combustion turbines and diesels with lead times greater than two hours are assumed to be committed in real time for the duration of their day-ahead schedule unless instructed not to run by PJM.

Table 4-34 Day-ahead generation from combustion turbines and diesels (GWh): 2012 and 2013

	2012			2013		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	579	437	375	886	633	561
Feb	758	587	546	430	206	173
Mar	1,392	1,070	918	809	395	282
Apr	1,872	1,429	1,247	684	325	256
May	1,928	1,248	1,045	1,031	387	260
Jun	2,588	1,613	1,227	1,284	696	440
Jul	3,900	1,412	979	2,950	947	748
Aug	2,358	1,380	1,119	1,772	778	544
Sep	1,635	1,167	1,031	1,219	480	295
Oct	1,079	892	796	929	451	267
Nov	1,319	1,012	819	578	213	120
Dec	851	677	624	426	109	47
Total	20,258	12,925	10,727	12,999	5,620	3,992
Share	100.0%	63.8%	53.0%	100.0%	43.2%	30.7%

In 2013, the top three control zones in which generation received LOC credits, AEP, ComEd and Dominion, accounted for 61.7 percent of all LOC credits, 55.0 percent of all the day-ahead generation from combustion turbines and diesels, 60.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 57.0 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Table 4-35 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012 and 2013

	2012			2013		
	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total	Units that Did Not Run in Real Time	Units that Ran in Real Time for at Least One Hour of Their Day-Ahead Schedule	Total
Jan	$4,816,244	$349,627	$5,165,871	$8,081,096	$647,226	$8,728,322
Feb	$4,382,996	$140,973	$4,523,968	$1,860,546	$188,972	$2,049,518
Mar	$9,645,950	$877,694	$10,523,644	$2,985,098	$1,818,180	$4,803,277
Apr	$10,830,247	$1,012,886	$11,843,133	$2,476,452	$1,416,816	$3,893,268
May	$12,906,912	$2,758,573	$15,665,485	$3,615,804	$1,650,778	$5,266,582
Jun	$12,446,658	$2,124,272	$14,570,930	$4,758,076	$1,442,645	$6,200,721
Jul	$13,813,602	$13,815,690	$27,629,292	$7,462,411	$8,838,541	$16,300,952
Aug	$22,148,176	$3,412,855	$25,561,031	$3,378,510	$2,070,667	$5,449,177
Sep	$17,776,726	$2,185,833	$19,962,559	$4,200,542	$2,177,278	$6,377,820
Oct	$11,167,613	$1,269,518	$12,437,131	$2,167,106	$288,031	$2,455,137
Nov	$12,671,035	$2,100,053	$14,771,088	$846,109	$519,836	$1,365,945
Dec	$4,974,333	$360,340	$5,334,673	$192,456	$311,390	$503,846
Total	$137,580,491	$30,408,315	$167,988,806	$42,024,206	$21,370,359	$63,394,565
Share	81.9%	18.1%	100.0%	66.3%	33.7%	100.0%

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for LOC credits for hours 10, 11, 17 and 18. Table 4-35 shows the LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 4-35 shows that in 2013, $42.0 million or 66.3 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 15.6 percentage points lower than 2012.

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-36 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-36 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In 2013, 67.6 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 32.4 percent was noneconomic.

Table 4-36 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2012 and 2013[35]

	2012			2013		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	308	136	444	544	121	664
Feb	422	246	668	171	53	224
Mar	800	287	1,087	269	144	413
Apr	1,125	329	1,455	225	93	318
May	874	361	1,235	228	129	357
Jun	829	662	1,491	364	272	635
Jul	823	400	1,222	713	202	915
Aug	943	397	1,340	436	275	711
Sep	880	304	1,184	293	166	459
Oct	710	191	901	256	175	431
Nov	781	276	1,057	131	64	195
Dec	434	298	732	34	59	92
Total	8,931	3,886	12,817	3,663	1,753	5,416
Share	69.7%	30.3%	100.0%	67.6%	32.4%	100.0%

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs (LOC) calculations consistent throughout the PJM rules.[36] PJM and the MMU jointly proposed two specific modifications.[37] The MMU also believes that two additional modifications would be appropriate but the MMU did not formally recommend these to the MIC for consideration although they were brought to the attention of the MIC.

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the LOC in the energy market. The MMU recommends that the LOC in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. This recommendation was proposed at the MIC.
- **No load and startup costs:** Current rules do not include in the calculation of LOC credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not committed in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation was proposed at the MIC.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the LOC calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the Day-Ahead Energy

35 The total generation in Table 4-36 is lower than the day-ahead generation not requested in real time in Table 4-34 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-36 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

36 See "Meeting Minutes," from the Market Implementation Committee (February 17, 2012). <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>.

37 See "LOC Session MA Energy LOC Proposal," MMU Presentation to the Market Implementation Committee (October 19, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121019/20121019-loc-session-ma-energy-loc-proposal.ashx>.

Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives LOC credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits if necessary. If the unit is not committed in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual LOC. The MMU recommends eliminating the use of the day-ahead LMP to calculate LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

- **Offer Curve:** Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the actual or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between the LMP and the offer curve) when calculating the LOC in the PJM Energy Markets for units scheduled in day ahead but which are reduced, suspended or not committed in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real time by PJM should be paid LOC based on the area between the real-time LMP and their offer curve between the actual and desired output points. Units scheduled in day ahead and not dispatched in real time should be paid LOC based on the area between the real-time LMP and their offer curve between zero output and scheduled output points. The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy LOC.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' schedule on which it is committed.

Table 4-37 shows the impact that each of these changes would have had on the LOC credits in the Energy Market in 2013, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $22.8 million, or 26.3 percent, if all these changes had been implemented.[38]

Table 4-37 Impact on energy market lost opportunity cost credits of rule changes: 2013

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$23,240,998	$63,394,565	$86,635,563
Impact 1: Committed Schedule	$1,186,428	$18,944,558	$20,130,986
Impact 2: Eliminating DA LMP	NA	($453,018)	($453,018)
Impact 3: Using Offer Curve	($1,198,276)	$7,553,265	$6,354,989
Impact 4: Including No Load Cost	NA	($37,440,979)	($37,440,979)
Impact 5: Including Startup Cost	NA	($11,353,697)	($11,353,697)
Net Impact	($11,848)	($22,749,871)	($22,761,719)
Credits After Changes	$23,229,150	$40,644,694	$63,873,844

The MMU is also proposing other rule changes regarding the calculation of LOC credits to units scheduled in the Day-Ahead Energy Market and not committed in real time.

- **Intra-hour LOC:** CTs and diesels scheduled in the Day-Ahead Energy Market and not committed in real time are compensated for LOC based on their real-time hourly integrated output. Market settlements in PJM are based on hourly integrated values. The hourly integrated value of generation is the average power produced within an hour. In order to compensate a unit for LOC, PJM must determine if the unit was scheduled in the Day-Ahead Energy Market and if the unit was not committed in real time. Units are scheduled in the Day-Ahead Energy Market when their cleared output is greater than zero. Units clear the Day-Ahead Energy Market for full hours. That means that if a unit cleared the Day-Ahead Energy Market in an hour it is expected to produce energy in real time for the entire hour. The determination by PJM of whether a unit is committed or not committed in real time is based on the unit's hourly integrated output. If the hourly integrated output is greater than zero, the unit was committed during that hour. In real time, a unit may be committed for part of

38 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

an hour. The LOC compensation calculation does not take into account the exact time at which the unit was turned on. For example, a unit does not receive LOC compensation if it is scheduled in the Day-Ahead Energy Market for one specific hour and that unit is committed in real time for only the last five minutes of the hour. The MMU recommends that the calculation of LOC for units scheduled in the Day-Ahead Energy Market and not committed in real time account for committed or decommitted status within the hour.

Black Start Service Units

Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the automatic load rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[39]

In 2013, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $86.4 million, and 95.0 percent of these costs was paid by peak transmission use in the AEP Control Zone while the remaining 5.0 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP Control Zone. Load in the AEP Control Zone paid an average of $9.65 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.06 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP Control Zone. PJM awarded all viable solutions from the last RFP.[40] PJM also approved new rules concerning black start service procurement, and the new selection process will be effective on April 1, 2015.[41,42]

Con Edison – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the wheeling contracts between Con-Ed and PSEG.[43] These units are often run out-of-merit and receive substantial day-ahead and balancing operating reserve credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

Reactive / Voltage Support Units

Closed Loop Interfaces

In 2013, PJM began to develop solutions to improve the incorporation of reactive constraints into energy prices. One of PJM's solutions was to create interfaces that could be used in such a way that units needed for reactive support could set the energy price. These closed loop interfaces would be used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside of the loop with the rest of PJM. PJM has currently defined four closed loop interfaces: ComEd, Cleveland, ATSI and BC/PEPCO.[44,45]

Under the status quo, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. Under the proposed solution these units could be made marginal even when not needed for energy, by adjusting the limit of the closed loop interface. This would create congestion in

39 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

40 See "Item 3: Black Start RFP Status," PJM Presentation to the System Restoration Strategy Task Force (June 14, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.

41 See the *2013 State of the Market Report for PJM*, Volume II, Section 10, "Ancillary Services" at "Black Start Service".

42 See PJM.Manual 14D: Generator Operational Requirement, Revision 26 (November 1, 2013) at "Section 10: Black Start Generation Procurement".

43 See the *2013 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.

44 See PJM. Manual 3: Transmission Operations, Revision 44 (November 1, 2013) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)" for a description of these interfaces, except for the ATSI interface.

45 See the ATSI Interface definition at <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>.

the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift attributable to the noneconomic operation of units needed for reactive support by making these units marginal to the extent possible, hence reducing energy uplift costs.

PJM proposed a Seneca Interface but later announced that an alternate solution to the reactive issue was developed through changes in the transmission system topology which minimized the need for reactive support in the area.[46]

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid disruption of the way in which the transmission network is modeled. The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional energy uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.

AP South / Bedington – Black Oak Reactive Support

Beginning in 2012 and during almost all 2013, a set of units located in the BGE and Pepco control zones were scheduled and committed to provide reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces. These units were scheduled as must run in the Day-Ahead Energy Market whenever they would not clear the market based on economics and were selected by PJM to provide reactive support.

At the end of December 2013, PJM began to schedule fewer units in the BGE and Pepco control zones for reactive support.[47] At the same time, PJM restarted modeling the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy Markets and reduced FMU adders for reactive units.[48] These actions eliminated energy uplift costs attributable to the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 26, 2013. As these actions were just a few days before the end of 2013 and system conditions were unusual in January 2014, additional analysis is needed for a better assessment.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[49] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In 2013, units providing reactive services were paid $8.2 million in balancing operating reserve credits in order to cover their total energy offer. In 2012, this misallocation was $18.6 million, for a total of $26.7 million in the last two years.

On October 10, 2012 and November 7, 2012, the MMU presented this issue at PJM's Market Implementation

46 See "Item 02 - Action Item Responses," question 19. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140304/20140304-item-02-action-item-responses.ashx>

47 See "Reactive Charges Update," PJM Presentation at the Market Implementation Committee (January 8, 2014) <http://www.pjm.com/committees-and-groups/committees/mic.aspx>.

48 In 2012, the BC/PEPCO interface was modeled in the Day-Ahead Energy Market starting on August 22, 2012. In 2013, the interface was stopped being modeled on September 25, 2013 and was resumed on December 27, 2013. In real time the interface was only modeled twice in 2012 and once in 2013 (before December 24). After December 24, 2013, the interface was modeled every day.

49 OATT Attachment K - Appendix § 3.2.3B (f).

Committee (MIC).[50] [51] The MIC endorsed the issue charge and approved merging this issue with the long term solution for the allocation of the cost of day-ahead operating reserves for reliability.[52]

The MMU had previously proposed changes to the way reactive services credits are calculated and how reactive services charges are allocated. The MMU continues to recommend that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also continues to recommend including real-time exports in the allocation of the cost of providing reactive support to the 500 kV system or above. Currently only real-time RTO load pays.[53]

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of balancing operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[54] Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids also incur deviations. These transactions are grouped in the demand and supply categories.

Generators are allowed to offset their deviations with other generators at the same bus if the generators have the same electrical impact on the transmission system. Load, interchange transactions, internal bilateral transactions, demand resources, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped into two categories, demand and supply and aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are in the same location at the same hour.[55] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The impact of eliminating the use of internal bilateral transactions in the calculation of deviations use to allocated balancing operating reserve charges has been aggregated with the impacts of other recommendations.

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on operating reserve rates if up-to congestion transactions had paid operating reserve charges based on deviations in the same way that increment offers and decrement

50 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," MMU Problem Statement to the Market Implementation Committee (October 10, 2012). <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>.

51 See "Minutes," from the Market Implementation Committee (November 7, 2012). <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx>.

52 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}>.

53 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>

54 See OATT 3.2.3 (o) for a complete description of how generators deviate.

55 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" at "Energy Uplift" for a full description of balancing operating reserve locations.

bids do, while accounting for the impact of such payments on the profitability of the transactions.

In 2013, 53.1 percent of all up-to congestion transactions were profitable.

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied and the other identified quantifiable recommendations had been implemented. It was assumed that up-to congestion transactions would have maintained the same shares of profitable and unprofitable transactions after paying operating reserve charges as when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, 66.7 percent of all up-to congestion transactions would have been made. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. Up-to congestion transactions would have paid an average rate between $0.276 and $0.377 per MWh in 2013 if the MMU's recommendations regarding operating reserves had been in place.[56]

Quantifiable Recommendations Impact

The MMU calculated the impact that all quantifiable recommendations would have had on the operating reserve rates paid by participants in the RTO, Eastern and Western regions. For reasons of confidentiality, these impacts cannot be disaggregated by issue. Five recommendations have been aggregated in this analysis: reallocation of operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts; reallocation of no load and startup costs of units providing reactive services; implementation of the proposed changes to lost opportunity cost calculations; elimination of internal bilateral transactions from the deviations calculation; and the allocation of operating reserve charges to up-to congestion transactions.

Table 4-38 shows the combined impact that these recommendations would have had on all operating reserve rates in 2013. The reduction in the rates is due to a decrease of 41.7 percent of the credits used to calculate these rates and a weighted average increase of 655.3 percent in the denominator used to calculate these rates.[57]

Table 4-38 MMU recommendations impact on operating reserve rates: 2013

	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.079	0.027	(0.052)	(65.8%)
RTO Reliability	0.051	0.036	(0.015)	(29.9%)
East Reliability	0.030	0.030	0.000	0.0%
West Reliability	0.004	0.004	0.000	0.0%
RTO Deviations	0.863	0.058	(0.805)	(93.2%)
East Deviations	1.868	0.061	(1.807)	(96.7%)
West Deviations	0.122	0.012	(0.110)	(90.3%)
Lost Opportunity Cost	0.705	0.052	(0.653)	(92.6%)
Canceled Resources	0.003	0.000	(0.003)	(90.0%)

Table 4-39 shows the operating reserve cost of a 1 MW transaction had these recommendations been implemented in 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.202 per MWh, $3.099 per MWh or 93.9 percent less than the actual average rate paid. Any up-to congestion transactions sourced in the Eastern Region and sinking at the Western Region would have been charged an average rate of $0.327 per MWh. Table 4-39 illustrates the current and proposed average operating reserve rates for all transactions.

Table 4-39 Current and proposed average operating reserve rate by transaction: 2013

	Transaction	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Change ($/MWh)	Change (%)
East	INC	3.198	0.176	(3.022)	(94.5%)
	DEC	3.301	0.202	(3.099)	(93.9%)
	DA Load	0.103	0.026	(0.077)	(74.6%)
	RT Load	0.073	0.057	(0.016)	(22.5%)
	Deviation	3.198	0.176	(3.022)	(94.5%)
West	INC	1.561	0.125	(1.436)	(92.0%)
	DEC	1.664	0.151	(1.513)	(90.9%)
	DA Load	0.103	0.026	(0.077)	(74.6%)
	RT Load	0.053	0.036	(0.016)	(31.4%)
	Deviation	1.561	0.125	(1.436)	(92.0%)
UTC	East to East	NA	0.377		
	West to West	NA	0.276		
	East to/from West	NA	0.327		

56 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.

57 The weighted average was calculated based on the total charges by rate.

Confidentiality of Energy Uplift Information

PJM rules require all data posted publicly by PJM or the MMU to comply with existing confidentiality rules. Current confidentiality rules do not appear to allow posting data containing three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[58]

Energy uplift are out of market, non-transparent payments made to resources operating on the behalf of PJM to provide transmission constraint relief or other reliability services. Energy uplift charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other participants to compete with the resources receiving energy uplift payments. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and the absence of relevant information creates a very effective barrier to entry. The MMU recommends that PJM revise the current energy uplift operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for energy uplift payments in the PJM region. This information would include the publication of energy uplift information by zone, by owner and by resource.

Operating Reserve Credits Recommendations

Day-Ahead Operating Reserve Credits

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[59]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss or not until the unit actually operates. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. In the same way, if units are dispatched in real time by PJM below their day-ahead scheduled output, they could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss because real-time LMP is greater than the day-ahead LMP or they could be paid energy uplift in the form of lost opportunity cost credits if by decreasing their output units lose profit because real-time LMP is greater than their offers. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their profits in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time generation is lower than their day-ahead scheduled generation which

58 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 9 (July 22, 2012), Market Data Posting.

59 Balancing operating reserve credit calculation uses the net DASR revenues, net synchronized reserve revenues, net non-synchronized reserve revenues and reactive services revenues.

subsequently results in reduced losses do not have a reduction in uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss or not, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output.

The MMU recommends enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output when their operation results in reduced losses. The MMU calculated the impact of this recommendation in 2013 and estimated a decrease of $25.5 million in day-ahead operating reserve credits or 5.8 percent ($13.4 million paid to units providing reactive support and $5.0 million paid to units providing black start support, the remaining $7.1 were normal day-ahead operating reserves) and an increase of $0.2 million in balancing operating reserve credits. This estimate was calculated using the current settlement database which is not structured to account for this rule change.

Net DASR Revenues Offset

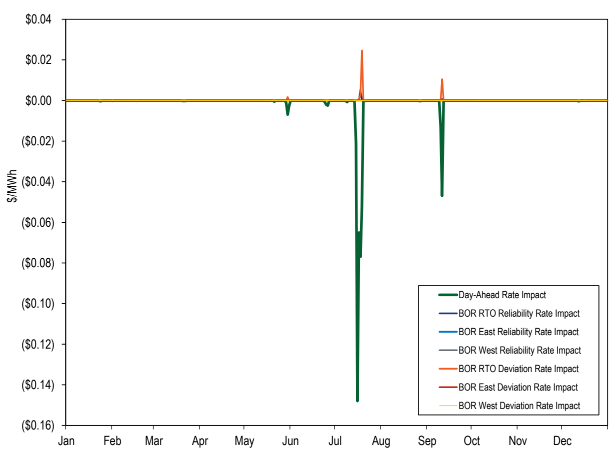
Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM at a loss. The current rules determine whether a unit is scheduled at a loss by comparing units' total offers (including no load and startup costs) to the units' day-ahead energy revenues. If day-ahead energy revenues are not enough to cover the total offer then units are made whole through day-ahead operating reserve credits.

This determination of whether a unit is scheduled at a loss is inaccurate because it does not take into account all the revenues received in the Day-Ahead Energy Market. The PJM Day-Ahead Energy Market includes a joint procurement of energy and day-ahead scheduling reserves (DASR).[60] The current rules governing day-ahead operating reserve credits do not include the net revenues from the DASR Market in units' revenues. The net DASR revenues equal gross DASR revenues minus DASR offer (which includes lost opportunity cost). The current rules do include net DASR revenues in the balancing operating reserve credit calculation.

The result of not including the net DASR revenues in the day-ahead operating reserve credit calculation is that resources scheduled to provide day-ahead scheduling reserves may appear to be scheduled to operate at a loss when they are not. This issue only becomes relevant whenever the DASR clearing price is above zero. In 2013, the DASR price reached $1 per MW or more during 114 hours or 1.3 percent of the time.

The MMU recommends including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits. In 2013, this recommendation would have had a net impact of a $1.2 million reduction, comprised of a $1.3 million decrease in day-ahead operating reserve credits and an increase of $0.1 million increase in balancing operating reserve credits. Balancing operating reserve credits increase because the current rules ensure that resources do not operate at a loss, which means that if revenues from the Day-Ahead Energy Market, plus revenues or charges from the Balancing Energy Market, net revenues from a subset of ancillary services are not enough to cover a units offer based on their real-time operation, such units are made whole to their offers. Figure 4-6 shows the impact this recommendation would have had on the day-ahead operating reserve and balancing operating reserve rates.

Figure 4-6 Impact of net DASR net revenues offset change on daily operating reserve rates ($/MWh): 2013



60 See *2013 State of the Market Report for PJM*, Section 10, "Ancillary Service Markets," at "Day-Ahead Scheduling Reserve (DASR)," for an explanation of this service.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the Regulation Market. The filing included four elements: implement the TPS test in the regulation market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and non-synchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price-taker, but in the Energy Market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2013, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $13.0 million, of which $11.7 million or 89.7 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.

Self-Startup

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[61] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled are price takers in both the Day-Ahead and Real-Time Energy Markets. Self-scheduled units may elect to submit a fixed energy amount per hour or a minimum must run amount from which the unit may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

In some cases, units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup cost. The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. This issue was not significant in 2013 since it only had an impact of $0.2 million among a small number of units, but it is important to establish rules that properly compensate resources.

2013 Energy Uplift Charges Increase

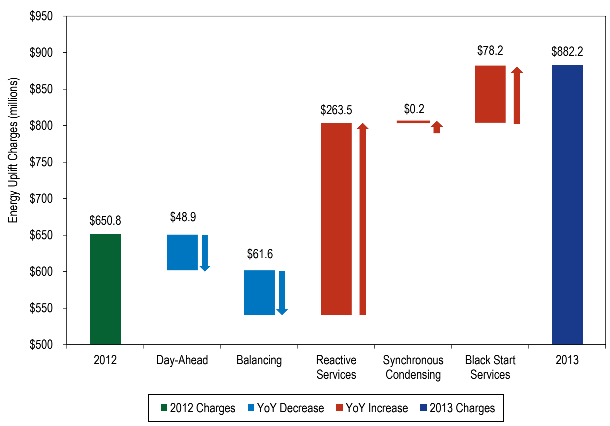
Energy uplift charges increased by $231.4 million, from $650.8 million in 2012 to $882.2 million in 2013. This change resulted from an increase of $263.5 million in reactive services charges, an increase of $78.2 million in black start services charges and an increase of $0.2 million in synchronous condensing charges. These

61 See "PJM eMkt Users Guide," Section Managing Unit Data (version November 11, 2013) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

increases were partially offset by a decrease of $48.9 million in day-ahead operating reserve charges and a decrease of $61.6 million in balancing operating reserve charges.

Figure 4-7 shows the net impact of each category on the change in total energy uplift charges from the 2012 level to the 2013 level. The outside bars show the 2012 total energy uplift charges (left side) and the 2013 total energy uplift charges (right side). The bars in between show the year over year change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in 2013 compared to 2012 (a decrease of $48.9 million).

Figure 4-7 Energy uplift charges change from 2012 to 2013 by category



The main contributing factors of the $231.4 million increase in energy uplift charges in 2013 compared to 2012 were the impact of FMU adders included in the offers of units providing reactive support ($81.7 million) and colder winter days in 2013 compared to 2012 ($88.0 million). Even though these were the two most relevant factors for the increase in energy uplift charges, the change in unit scheduling/commitment and allocation of energy uplift charges related to black start and reactive support had different impacts on each category of energy uplift. Day-ahead and balancing operating reserve charges were significantly reduced while reactive services and black start services charges increased. The net impact of the change in unit scheduling/commitment and allocation was an increase of $21.1 million.

In September 2012, PJM began to schedule in the Day-Ahead Energy Market units out of merit (must run) needed for black start and reactive support in real time. Before September 2012, these units were being committed out of merit in real time after PJM, through the reliability assessment commitment run (RAC), identified that these units were needed for those services. Because the day-ahead energy model does not capture the need to schedule units for black start or reactive support, these units were not normally scheduled in the Day-Ahead Energy Market but committed in real time.[62] The MMU supported the concept of PJM's change in unit scheduling/commitment since it improved market efficiency.

The change in unit scheduling/commitment had a significant impact on the allocation of the energy uplift charges associated with units needed for black start and reactive support. The unit scheduling/commitment change shifted substantial energy uplift charges from the balancing operating reserves and reactive services to day-ahead operating reserves. That shift was significant because balancing operating reserve charges, reactive services charges and day-ahead operating reserve charges are allocated differently. Balancing operating reserve charges are paid by real-time load and real-time exports or by deviations from the day ahead depending on the allocation process. Balancing operating reserve charges are allocated across three different regions. Reactive services charges are paid by real-time load on a zonal level. Day-ahead operating reserve charges are paid by day-ahead load, day-ahead exports and decrement bids across the entire RTO Region.

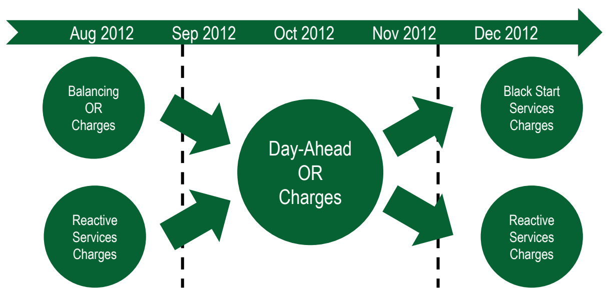
In December 2012, PJM filed proposed revisions to PJM's tariff and operating agreement with FERC to change the allocation methodology for operating reserve make whole payments in the Day-Ahead Energy Market for black start and reactive support.[63] The proposed revisions allocated the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide black start service as determined by Schedule 6A of the OATT and the costs of day-ahead operating reserves of units scheduled in the Day-Ahead Energy Market to provide reactive service or transfer interface

62 These units would clear the Day-Ahead Energy Market normally only when they are economic.
63 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).

control would be allocated zonally in proportion to the real-time deliveries of energy to load.

Figure 4-8 shows a diagram of how the energy uplift charges related to units needed for black start and reactive support changed in 2012. Before September 2012, these charges were allocated as balancing operating reserve charges or reactive services charges. Between September and November 2012, these charges were allocated as day-ahead operating reserve charges. After November 2012 these costs are being allocated as black start services charges or reactive services charges.

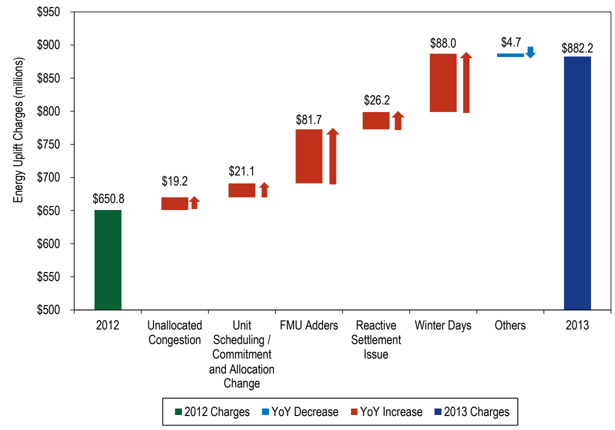
Figure 4-8 Allocation changes of energy uplift charges associated with units needed for black start and reactive support



Other factors that contributed to the increase in energy uplift charges were unallocated congestion charges and the reactive services credits settlement issue.[64] Unallocated congestion charges increased by $19.2 million, from $0.8 million in 2012 to $20.0 million in 2013. PJM also announced a settlement issue created due to an unintended logging error regarding units scheduled in the Day-Ahead Energy Market for reactive support in the second half of 2013, the estimated impact of this issue is $26.2 million.

Figure 4-9 shows the impact that each issue had on the change in energy uplift charges from 2012 to 2013. For example, the second bar from the left shows that unallocated congestion charges increased energy uplift charges by $19.2 million in 2013 when compared to 2012.

Figure 4-9 Energy uplift charges change from 2012 to 2013 by issue



64 See "Item 03 – Reactive Charges Update," PJM Presentation to the Energy Market Uplift Senior Task Force (January 16, 2014) for more detail on the reactive credit settlement issue. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140116/20140116-item-03-reactive-charges-update.ashx>

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for 2013, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue and the inclusion of imports which are not substitutes for internal capacity resources.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

4 The terms *PJM Region, RTO Region and RTO* are synonymous in the *2013 State of the Market Report for PJM,* Section 5, "Capacity Market," and include all capacity within the PJM footprint.

5 See 126 FERC ¶ 61,275 (2009) at P 86.

6 See *PJM Interconnection, L.L.C.,* Letter Order in Docket No. ER10-366-000 (January 22, 2010).

procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

RPM prices are locational and may vary depending on transmission constraints.[8] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand Resources and Energy Efficiency Resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During 2013, PJM installed capacity increased 1,084.1 MW or 0.6 percent from 182,011.1 MW on January 1 to 183,095.2 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2013, 41.3 percent was coal; 29.2 percent was gas; 18.1 percent was nuclear; 6.2 percent was oil; 4.4 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.0 percent was solar.
- **Supply.** Total internal capacity increased 14,724.9 MW from 169,953.3 MW on June 1, 2012, to 184,678.2 MW on June 1, 2013. This increase was the result of the integration of capacity resources in the American Transmission Systems, Inc. (ATSI) Zone (13,175.2 MW), new generation (1,104.4 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-969.4 MW), Demand Resource (DR) modifications (1,894.1 MW), Energy Efficiency (EE) modifications (100.8 MW), the EFORd effect due to higher sell offer EFORds (-589.3 MW), and higher Load Management UCAP conversion factor (9.1 MW).
- **Demand.** There was a 16,060.5 MW increase in the RPM reliability requirement from 157,488.5 MW on June 1, 2012, to 173,549.0 MW on June 1, 2013. This increase was primarily due to the inclusion of the ATSI Zone in the preliminary forecast peak load for the 2013/2014 RPM Base Residual Auction. On June 1, 2013, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 72.0 percent, up slightly from 71.9 percent on June 1, 2012.
- **Market Concentration.** In the 2013/2014 RPM Base Residual Auction, 2013/2014 RPM First Incremental Auction, 2013/2014 RPM Second Incremental Auction, 2013/2014 RPM Third Incremental Auction, 2014/2015 RPM First Incremental Auction, 2014/2015 RPM Second Incremental Auction, 2015/2016 RPM Base Residual Auction, 2015/2016 RPM First Incremental Auction, 2016/2017 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[9] In the 2014/2015 RPM Base Residual Auction, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer

7 See 126 FERC ¶ 61,275 (2009) at P 88.

8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

9 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[10, 11, 12]

- **Imports and Exports.** Net exchange increased 715.3 MW from June 1, 2012 to June 1, 2013. Net exchange, which is imports less exports, increased due to an increase in imports of 516.6 MW and a decrease in exports of 198.7 MW.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs increased by 1,371.5 MW from 7,118.5 MW on June 1, 2012 to 8,490.0 MW on June 1, 2013 as a result of an increase in cleared capacity for Demand Resources (2,038.7 MW), an increase in cleared capacity for Energy Efficiency Resources (238.1 MW), and a decrease in replacement capacity for Energy Efficiency Resources (159.9 MW), offset by an increase in replacement capacity for Demand Resources (1,065.2 MW).

Market Conduct

- **2013/2014 RPM Base Residual Auction.** Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). Offer caps of all kinds were calculated for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Second Incremental Auction.** Of the 163 generation resources which submitted offers, unit-specific offer caps were calculated for eight generation resources (4.9 percent). The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Third Incremental Auction.** Of the 410 generation resources which submitted offers, unit-specific offer caps were calculated for zero generation resources (0.0 percent). The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.** Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM First Incremental Auction.** Of the 190 generation resources which submitted offers, unit-specific offer caps were calculated for 21 generation resources (11.1 percent). The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Second Incremental Auction.** Of the 221 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (2.7 percent). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 188 generation resources (16.1 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-

10 See OATT Attachment DD § 6.5.

11 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

12 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

specific offer caps were calculated for 139 generation resources (11.6 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.

Market Performance

- RPM net excess increased 541.8 MW from 5,976.5 MW on June 1, 2012, to 6,518.3 MW on June 1, 2013.
- For the 2013/2014 Delivery Year, RPM annual charges to load totaled approximately $6.7 billion.
- The Delivery Year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.55 per MW-day in 2013/2014.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2013 was 8.0 percent, an increase from the 7.6 percent average PJM EFORd for 2012.[13]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in 2013 was 83.7 percent, a slight decrease from the 84.1 percent PJM aggregate equivalent availability factor for 2012.
- **Outages Deemed Outside Management Control (OMC).** In 2013, 16.8 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

13 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM. Data is for the twelve months ending December 31 as downloaded from the PJM GADS database on January 27, 2014. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Recommendations[14, 15, 16, 17]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18, 19]
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources.
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve.
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model.
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units.
- The MMU recommends that protocols be defined for recalling the energy output of Capacity Resources

14 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports.

15 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

16 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

17 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

18 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000.

19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details.

- The MMU recommends improvements to the incentive requirements of RPM.
- The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical.
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.
- The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market.
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[20]

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in 2013. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in 2013.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[21, 22, 23] In 2012, and 2013, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

20 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

21 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

22 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

23 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

Table 5-2 RPM related MMU reports, 2012 through December, 2013

Date	Name
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligation for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf
November 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20121129.pdf
December 11, 2012	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf
March 29, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130329.pdf
April 19, 2013	IMM Answer and Motion for Leave to Answer re: MOPR No. ER13-535-001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-535-001_20130419.pdf
June 19, 2013	Unit Specific MOPR Review Modeling Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Unit_Specific_MOPR_Review_Modeling_Assumptions_20130619.pdf
June 20, 2013	Capacity Deliverability, Docket No. AD12-16 http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_FERC_Capacity_Deliverability_20130620.pdf
June 28, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130628.pdf
July 23, 2013	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Replacement_Capacity_Activity_Rev_20130723.pdf
August 30, 2013	RPM Unit-Specific Offer Cap Review Process http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Unit-Specific_Offer_Cap_Review_Process_20130830.pdf
September 3, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130903.pdf
September 13, 2013	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf
September 13, 2013	IMM Answer and Motion for Leave to Answer re RPM BRA Deadline Changes No. ER13-2140 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-2140_20130913.pdf
September 24, 2013	Analysis of the 2015/2016 RPM Base Residual Auction Report http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf
November 27, 2013	IMM Answer and Motion for Leave to Answer re Forward Capacity Market Comment Clarification No. ER11-4081-001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_No_ER11-4081-001_20131127.pdf
December 20, 2013	IMM Comments re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_ER14-503-000_20131220.pdf
December 20, 2013	IMM Comments re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_ER14-504-000_20131220.pdf
December 20, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20131220.pdf
January 8, 2014	IMM Comments re Capacity Technical Conference No. AD13-7-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_AD13-7-000_20140109.pdf
January 8, 2014	IMM Answer re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-504-000_20140108.pdf
January 8, 2014	IMM Answer re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-503-000_20140108.pdf

Installed Capacity

On January 1, 2013, PJM installed capacity was 182,011.1 MW (Table 5-3).[24] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 183,095.2 MW on December 31, 2013, an increase of 1,084.1 MW or 0.6 percent over the January 1 level.[25, 26] The 1,084.1 MW increase was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone (2,680.0 MW), an increase in imports (565.0 MW), capacity modifications (395.7 MW), new or reactivated generation (279.4 MW), and a decrease in exports (126.9 MW), offset by deactivations (2,675.0 MW) and derates (287.9 MW).

At the beginning of the new Delivery Year on June 1, 2013, PJM installed capacity was 185,567.9 MW, an increase of 3,531.6 MW or 1.9 percent over the May 31 level.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for Delivery Years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[27] In 2013, a Third Incremental Auction was held in February for the 2013/2014 Delivery Year, a Base Residual Auction was held for the 2016/2017 Delivery Year, a Second Incremental Auction was held in July for the 2014/2015 Delivery Year, and a First Incremental Auction was held in September for the 2015/2016 Delivery Year.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2013

	1-Jan-13		31-May-13		1-Jun-13		31-Dec-13	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,989.2	41.7%	76,055.6	41.8%	77,981.5	42.0%	75,559.6	41.3%
Gas	52,003.2	28.6%	52,106.1	28.6%	53,420.2	28.8%	53,380.0	29.2%
Hydroelectric	7,879.8	4.3%	7,880.4	4.3%	8,091.4	4.4%	8,106.7	4.4%
Nuclear	33,024.0	18.1%	33,024.0	18.1%	33,072.8	17.8%	33,076.7	18.1%
Oil	11,531.2	6.3%	11,361.2	6.2%	11,339.5	6.1%	11,314.2	6.2%
Solar	47.0	0.0%	47.0	0.0%	80.7	0.0%	84.2	0.0%
Solid waste	757.1	0.4%	756.4	0.4%	709.4	0.4%	701.4	0.4%
Wind	779.6	0.4%	805.6	0.4%	872.4	0.5%	872.4	0.5%
Total	182,011.1	100.0%	182,036.3	100.0%	185,567.9	100.0%	183,095.2	100.0%

24 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

25 The capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM Auctions.

26 Wind resources accounted for 872.4 MW of installed capacity in PJM on December 31, 2013. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

27 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2012/2013 Delivery Year. The 21,908.5 MW increase was the result of new Generation Capacity Resources (6,486.4 MW), reactivated Generation Capacity Resources (409.1 MW), uprates (4,223.0 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (2,134.7 MW), a net decrease in capacity exports (2,641.9 MW), offset by deactivations (9,826.7 MW) and derates (2,268.9 MW).

As shown in Table 5-5, total internal capacity increased 14,724.9 MW from 169,953.3 MW on June 1, 2012, to 184,678.2 MW on June 1, 2013. This increase was the result of the integration of capacity resources in the American Transmission Systems, Inc. (ATSI) Zone (13,175.2 MW), new generation (1,104.4 MW), reactivated generation (0.0 MW), net generation capacity modifications (cap mods) (-969.4 MW), Demand Resource (DR) modifications (1,894.1 MW), Energy Efficiency (EE) modifications (100.8 MW), the EFORd effect due to higher sell offer EFORds (-589.3 MW), and higher moad management UCAP conversion factor (9.1 MW). The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

In the 2014/2015, 2015/2016, and 2016/2017 auctions, new generation were 13,342.0 MW; reactivated generation were 759.9 MW and net generation cap mods were -9,484.1 MW. DR and Energy Efficiency (EE) modifications totaled 2,223.3 MW through June 1, 2016. An increase of 1,705.7 MW was due to lower EFORds, and an increase of 101.8 MW was due to a higher Load Management UCAP conversion factor. The integration of the Duke Energy Ohio Kentucky (DEOK) Zone resources added 4,816.8 MW to total internal capacity, and the integration of the East Kentucky Power Cooperative (EKPC) Zone resources added 2,735.7 MW to total internal capacity. A decrease of 31.2 MW was due to a correction in resource modeling. The net effect from June 1, 2013, through June 1, 2016, was an increase in total internal capacity of 16,169.9 MW (8.8 percent) from 184,678.2 MW to 200,848.1 MW.

As shown in Table 5-5 and Table 5-13, in the 2013/2014 auction, the increase of 37 generation resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely Fixed Resource Requirement (FRR) committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generation resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 Delivery Year: four wind resources (66.2 MW).

As shown in Table 5-5 and Table 5-14, in the 2014/2015 auction, the 43 additional generation resources offered consisted of 39 new resources (1,038.5 MW), two additional resources imported (577.6 MW), one reactivated resource (8.1 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource (22.5 MW). The new Generation Capacity Resources consisted of 17 solar resources (30.2 MW), seven wind resources (146.6 MW), seven diesel resources (31.5 MW), five hydroelectric resources (132.7), two CT units (76.7 MW), and one combined cycle unit (620.8 MW). The reactivated Generation Capacity Resources consisted of one diesel resource (8.1 MW). The 61 fewer generation resources offered consisted of 12 deactivated resources (936.8 MW), 12 additional resources excused from offering (1,129.9 MW), 32 additional resources committed fully to FRR (2,175.0 MW), four Planned Generation Capacity Resources not offered (240.0 MW), and one external generation resource not offered (6.6 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2013/2014 BRA: two combustion turbine (CT) units (2.5 MW).

As shown in Table 5-5 and Table 5-15, in the 2015/2016 auction, the 111 additional generation resources offered consisted of 49 new resources (6,221.0 MW), 45 resources that were previously entirely FRR committed (4,803.0 MW), 13 additional resources imported (1,072.2 MW), three resources that were excused and not offered in the 2014/2015 BRA (30.8 MW), and one Duke Energy Ohio and Kentucky (DEOK) integration resource not offered in the 2014/2015 BRA (42.7 MW). The new Generation Capacity Resources consisted of 15 solar resources (13.8 MW), eight CT resources (1,348.4 MW), seven combined cycle resources (4,526.9 MW), six wind resources (104.9 MW), five diesel resources (13.6 MW), five hydroelectric resources (143.6 MW), two fuel cell resources (28.5 MW), and one steam unit (41.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2015/2016 Delivery Year: two CT resources (283.6 MW). The 95 fewer generation resources offered consisted of 49 additional resources excused from offering (3,761.1 MW), 29 deactivated resources (3,713.2 MW), eight additional resources committed fully to FRR (471.8 MW), three less resources resulting from aggregation of RPM resources, three external resources not offered (866.4 MW), one resource that is no longer a PJM capacity resource (1.2 MW), one Planned Generation Capacity Resource not offered (1.5 MW), and one resource unoffered and unexcused (4.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2014/2015 BRA: six steam units (918.5 MW).

As shown in Table 5-5 and Table 5-16, in the 2016/2017 auction, the 99 additional generation resources offered consisted of 36 new resources (4,900.8 MW), 29 additional resources imported (3,026.3 MW), 18 East Kentucky Power Cooperative (EKPC) integration resources not offered in the 2015/2016 BRA (2,537.3 MW), nine resources that were excused and not offered in the 2015/2016 BRA (1,033.9 MW), three repowered resources (920.2 MW), two resources that were previously entirely FRR committed (168.3 MW), one reactivated resource (17.6 MW), and one additional resource resulting from the disaggregation of an RPM resource. The 36 new Generation Capacity Resources consisted of 11 diesel resources (36.1 MW), nine solar resources (32.1 MW), eight combined cycle resources (4,597.2 MW), five wind resources (54.3 MW), two CT resources (159.3 MW), and one steam unit (21.8 MW). In addition, there were new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2016/2017 Delivery Year: one wind resource (12.8 MW) and one diesel resource (5.3 MW). The 68 fewer generation resources offered consisted of 33 additional resources excused from offering (1,706.0 MW), 28 deactivated resources (1,389.6 MW), three fewer resources resulting from aggregation of RPM resources, two additional resources committed fully to FRR (28.7 MW), and two Planned Generation Capacity Resources not offered (934.8 MW). In addition, there were the following retirements of resources that were either exported, excused, or committed to an FRR capacity plan in the 2015/2016 BRA: 25 steam units (2,207.1 MW) and 13 CT resources (245.0 MW).

Table 5-4 Generation capacity changes: 2007/2008 through 2012/2013

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9									
Total		6,486.4	409.1	4,223.0	18,109.0	2,134.7	(2,641.9)	9,826.7	2,268.9	21,908.5

Table 5-5 Internal capacity: June 1, 2012 to June 1, 2016[28]

	UCAP (MW)									
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland
Total internal capacity @ 01-Jun-12	169,953.3	69,003.9	33,667.5	12,430.3	1,498.9	7,431.4	3,745.3	5,416.0		
Correction in resource modeling	0.0	13.0	0.0	0.0	81.3	0.0	28.5	0.0		
Adjusted internal capacity @ 01-Jun-12	169,953.3	69,016.9	33,667.5	12,430.3	1,580.2	7,431.4	3,773.8	5,416.0		
Integration of existing ATSI resources	13,175.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
New generation	1,104.4	172.5	110.3	1.8	0.0	108.8	101.9	1.8		
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Generation cap mods	(969.4)	(1,007.7)	(884.9)	(113.8)	12.4	(180.2)	(180.2)	(11.0)		
DR mods	1,894.1	900.2	689.5	(207.4)	9.7	646.1	431.2	61.8		
EE mods	100.8	(34.9)	(0.3)	(51.9)	(8.1)	3.3	(0.3)	(20.7)		
EFORd effect	(589.3)	27.7	117.5	(292.5)	18.1	26.0	48.3	(159.4)		
DR and EE effect	9.1	4.2	1.0	1.8	0.1	0.2	0.1	0.4		
Total internal capacity @ 01-Jun-13	184,678.2	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9		
Correction in resource modeling	(31.2)	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Adjusted internal capacity @ 01-Jun-13	184,647.0	69,078.9	33,700.6	11,768.3	1,612.4	8,035.6	4,174.8	5,288.9		
Integration of existing DEOK resources	4,816.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
New generation	1,038.5	875.8	697.2	2.7	48.0	6.8	1.5	0.0		
Reactivated generation	8.1	8.1	8.1	0.0	0.0	8.1	0.0	0.0		
Generation cap mods	(991.9)	(175.2)	(102.3)	(242.8)	(161.9)	9.3	(0.5)	(2.8)		
DR mods	6,940.0	6,653.8	2,438.6	2,727.5	241.9	547.0	205.0	681.7		
EE mods	49.4	55.6	1.2	52.0	3.0	(0.6)	(0.6)	7.5		
EFORd effect	(271.7)	(248.0)	(93.5)	54.1	(17.8)	104.8	25.5	106.4		
DR and EE effect	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Total internal capacity @ 01-Jun-14	196,235.8	76,249.0	36,649.9	14,361.8	1,725.6	8,711.0	4,405.7	6,081.7	10,545.2	
New generation	6,786.1	3,486.9	2,523.3	661.0	297.7	801.0	793.9	661.0	843.8	
Reactivated generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Generation cap mods	(5,118.9)	(361.0)	7.0	(372.3)	(2.0)	(138.9)	5.5	(372.3)	74.4	
DR mods	5,441.4	(149.6)	606.9	(1,583.0)	(123.8)	(33.9)	(70.7)	(34.8)	2,729.0	
EE mods	220.1	29.4	25.4	(3.0)	(5.0)	5.1	3.5	12.9	78.2	
EFORd effect	938.4	508.9	229.8	156.4	7.0	170.3	87.9	114.4	133.6	
DR and EE effect	54.4	29.5	12.8	6.2	0.9	4.0	2.0	3.4	3.3	
Total internal capacity @ 01-Jun-15	204,557.3	79,793.1	40,055.1	13,227.1	1,900.4	9,518.6	5,227.8	6,466.3	14,407.5	3,484.3
Integration of existing EKPC resources	2,735.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New generation	5,517.4	2,291.3	606.5	3.6	0.0	30.2	0.0	0.0	767.1	0.0
Reactivated generation	751.8	751.8	751.8	0.0	0.0	17.6	0.0	0.0	0.0	0.0
Generation cap mods	(3,373.3)	(2,385.3)	(1,320.6)	(70.4)	(2.8)	(241.3)	(108.7)	0.0	(92.3)	0.0
DR mods	(10,690.1)	(6,472.2)	(3,268.1)	(1,030.2)	(139.0)	(986.6)	(428.4)	(428.7)	(791.4)	564.7
EE mods	262.5	145.6	28.7	85.6	0.7	3.2	0.7	50.4	131.0	55.7
EFORd effect	1,039.0	575.2	160.5	325.3	6.8	(0.6)	(0.6)	146.4	(101.8)	(69.6)
DR and EE effect	47.8	18.4	7.0	6.8	0.2	2.1	0.8	3.0	5.1	0.0
Total internal capacity @ 01-Jun-16	200,848.1	74,717.9	37,020.9	12,547.8	1,766.3	8,343.2	4,691.6	6,237.4	14,325.2	4,035.1

28 The RTO includes MAAC, EMAAC, SWMAAC, and ATSI. MAAC includes EMAAC and SWMAAC. EMAAC includes DPL South, PSEG and PSEG North. PSEG includes PSEG North. SWMAAC includes Pepco. ATSI includes ATSI Cleveland.

Demand

There was a 16,060.5 MW increase in the RPM reliability requirement from 157,488.5 MW on June 1, 2012, to 173,549.0 MW on June 1, 2013. This increase was primarily due to the inclusion of the ATSI Zone in the preliminary forecast peak load for the 2013/2014 RPM Base Residual Auction.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2013, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 72.0 percent (Table 5-6), up slightly from 71.9 percent on June 1, 2012. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 28.0 percent, down slightly from 28.1 percent on June 1, 2012. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year.

Table 5-6 Capacity market load obligations served: June 1, 2013

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	69,846.4	38,979.5	18,589.5	4,111.9	14,441.1	5,420.6	25,633.7	177,022.6
Percent of total obligation	39.5%	22.0%	10.5%	2.3%	8.2%	3.1%	14.5%	100.0%

Market Concentration

Auction Market Structure

As shown in Table 5-7, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2013/2014 RPM Base Residual Auction, 2013/2014 RPM First Incremental Auction, 2013/2014 RPM Second Incremental Auction, 2013/2014 RPM Third Incremental Auctions, 2014/2015 RPM First Incremental Auction, 2014/2015 RPM Second Incremental Auction, 2015/2016 RPM Base Residual Auction, 2015/2016 RPM First Incremental Auction, 2016/2017 RPM Base Residual Auction.[29] In the 2014/2015 RPM Base Residual Auction, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[30, 31, 32] In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price.[33] The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-7 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

29 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

30 See OATT Attachment DD § 6.5.

31 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

32 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

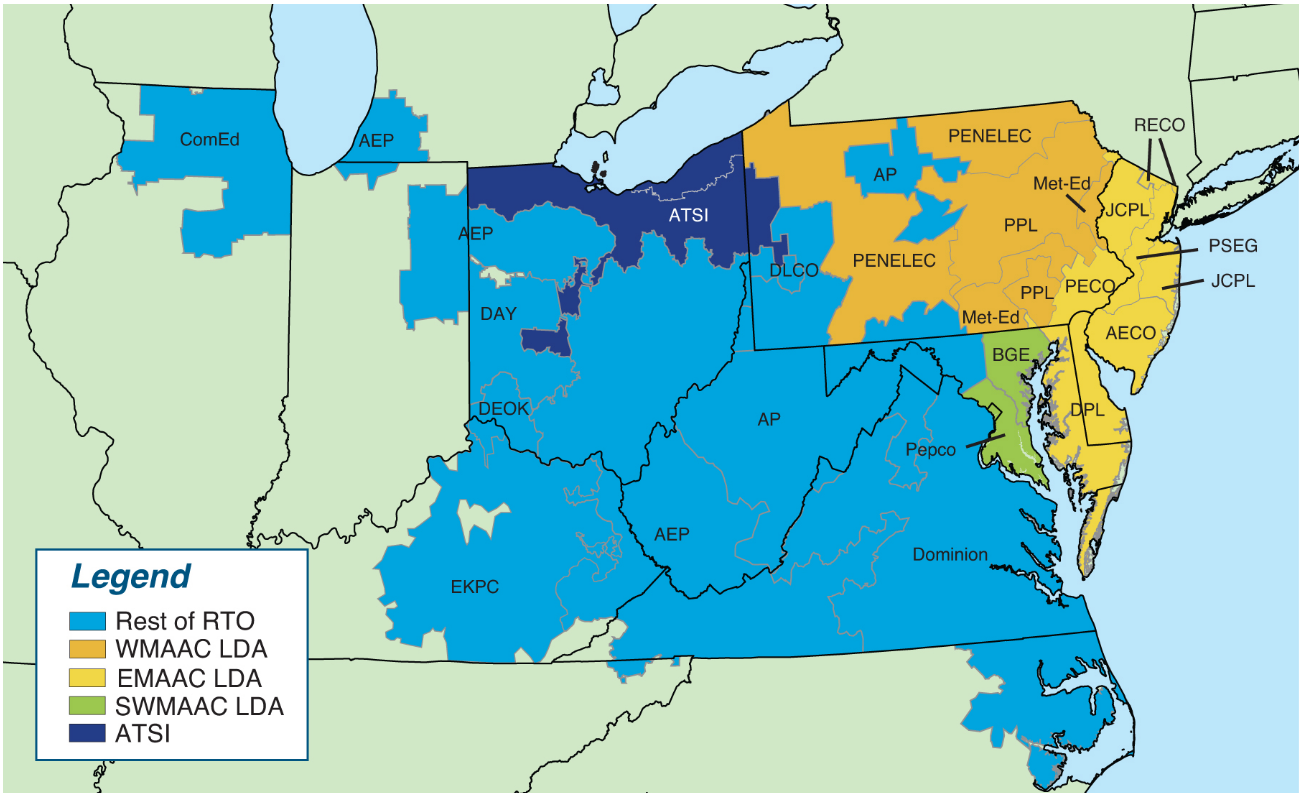
33 Effective November 1, 2009, DR and EE resources are not included in the TPS test. See 129 FERC ¶ 61,081 (2009) at P 31.

Table 5-7 RSI results: 2013/2014 through 2016/2017 RPM Auctions[34]

RPM Markets	RSI1, 1.05	RSI3	Total Participants	Failed RSI3 Participants
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2013/2014 Third Incremental Auction				
RTO	0.60	0.38	60	60
MAAC/SWMAAC/Pepco	0.01	0.02	4	4
EMAAC/PSEG/PSEG North/DPL South	0.38	0.22	7	7
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2014/2015 Second Incremental Auction				
RTO	0.71	0.42	40	40
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.40	0.01	4	4
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2015/2016 First Incremental Auction				
RTO	0.70	0.61	43	43
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.15	0.09	5	5
PSEG/PSEG North	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 BRA				
RTO	0.78	0.59	110	110
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.56	0.38	6	6
PSEG/PSEG North	0.00	0.00	1	1
ATSI/ATSI Cleveland	0.00	0.00	1	1

34 The RSI shown is the lowest RSI in the market.

Figure 5-1 Map of PJM Locational Deliverability Areas



Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[35] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[36] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 and subsequent Delivery Years, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[37]

Locational Deliverability Areas are shown in Figure 5-1, Figure 5-2 and Figure 5-3.

35 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
36 OATT Attachment DD § 5.10 (a) (ii).
37 146 FERC ¶ 61,052 (2014).

Figure 5-2 Map of PJM RPM EMAAC subzonal LDAs

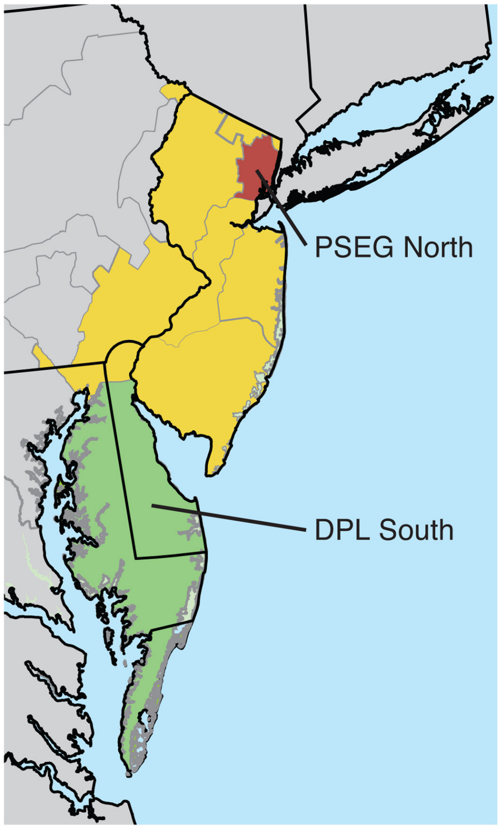
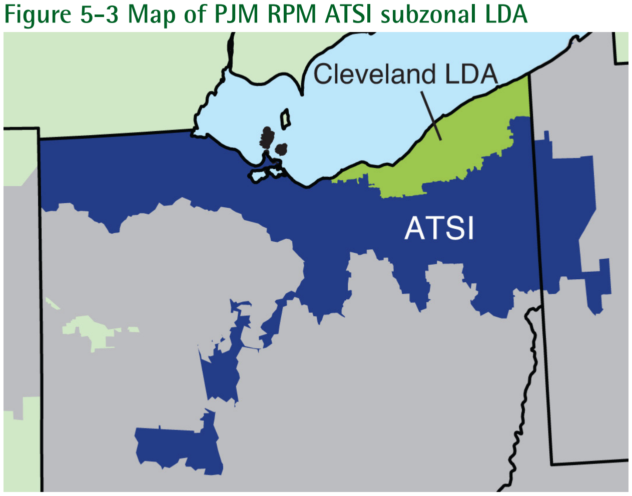


Figure 5-3 Map of PJM RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[38]

As shown in Table 5-8, net exchange increased 715.3 MW from June 1, 2012 to June 1, 2013. Net exchange, which is imports less exports, increased due to an increase in imports of 516.6 MW and a decrease in exports of 198.7 MW.

As shown in Table 5-9, a total of 7,482.7 MW of imports cleared in the 2016/2017 RPM Base Residual Auction. Of these cleared imports, 4,723.1 MW (63.1 percent) were from MISO.

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are required to have pseudo ties to PJM to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM capacity market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

38 OATT Attachment DD § 5.6.6(b).

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM Auction if it meets specific requirements.[39, 40] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point-to-point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; twelve months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[41]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Additionally, external capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[42, 43] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[44] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction.[45]

39 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, " Schedule 9 & 10.

40 See PJM. "Manual 18: PJM Capacity Market," Revision 20 (November 21, 2013), pp. 40-41 & p. 60-61.

41 OATT, Schedule 1, Section 1.10.1A.

42 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Section 1.69A.

43 See PJM. "Manual 18: PJM Capacity Market", Revision 20 (November 21, 2013), pp. 43-44.

44 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

45 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

Exporting Capacity

Non-firm transmission can be used to export capacity from the PJM region. A Generation Capacity Resource located in the PJM region not committed to service of PJM loads may be removed from PJM Capacity Resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[46] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[47]

The MMU evaluates requests submitted by Capacity Market Sellers to export Generation Capacity Resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[48]

When submitting a teal-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

Table 5-8 PJM capacity summary (MW): June 1, 2007 to June 1, 2015[49, 50]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14	01-Jun-15	01-Jun-16
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4	217,829.1	216,671.5
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2	207,738.6	207,578.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6	2.7	0.0
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5	177,184.1	180,332.2
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1	162,777.4	166,127.5
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3	5,855.9	7,185.4
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,055.5	4,395.5	7,941.5
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,228.1)	(1,214.2)	(1,211.6)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	2,827.4	3,181.3	6,729.9
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1
EE cleared						568.9	679.4	822.1	922.5	1,117.3
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6					
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1	356.8	501.9
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1	4,069.4	4,153.2

Table 5-9 RPM imports: 2007/2008 through 2016/2017 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7

46 OATT Attachment DD § 6.6(g).

47 *Id.*

48 OATT Attachment M-Appendix § II.C.2.

49 Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

50 The results for RPM Incremental Auctions are not included in this table.

Demand Resources

There are three basic demand products incorporated in the RPM market design:[51]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the BRA peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[52] The Energy Efficiency (EE) resource type was eligible to be offered in RPM Auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[53]

Effective with the 2014/2015 Delivery Year, there are three types of Demand Resource products incorporated into the RPM market design:[54, 55]

- **Annual DR.** Demand Resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April.
- **Extended Summer DR.** Demand Resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended Summer DR is required to be capable of maintaining each interruption for at least a 10-hour duration during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** Demand Resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for at least a 6-hour duration during the hours of 12:00 p.m. to 8:00 p.m. EPT.

As shown in Table 5-10 and Table 5-12, capacity in the RPM load management programs increased by 1,371.5 MW from 7,118.5 MW on June 1, 2012 to 8,490.0 MW on June 1, 2013 as a result of an increase in cleared capacity for Demand Resources (2,038.7 MW), an increase in cleared capacity for Energy Efficiency Resources (238.1 MW), and a decrease in replacement capacity for Energy Efficiency Resources (159.9 MW), offset by an increase in replacement capacity for Demand Resources (1,065.2 MW). Table 5-11 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

51 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price.

52 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 6, Section M.

53 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

54 134 FERC ¶ 61,066 (2011).

55 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.

Table 5-10 RPM load management statistics by LDA: June 1, 2012 to June 1, 2016[56, 57, 58]

	UCAP (MW)									
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9			
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8			
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1			
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)			
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8			
DR cleared	10,779.6	6,466.6	2,735.7	1,788.8	155.4	1,185.0	534.8	661.9		
EE cleared	904.2	289.9	65.2	149.5	10.7	26.2	9.4	72.7		
DR net replacements	(3,318.8)	(3,016.9)	(1,434.3)	(745.7)	(53.3)	(819.7)	(388.6)	(272.4)		
EE net replacements	125.0	121.8	(11.1)	124.2	2.2	(2.1)	1.4	4.8		
RPM load management @ 01-Jun-13	8,490.0	3,861.4	1,355.5	1,316.8	115.0	389.4	157.0	467.0		
DR cleared	14,401.9	7,343.9	2,939.5	2,253.9	220.9	989.7	468.2	912.1		
EE cleared	1,021.9	291.9	37.3	169.8	8.1	17.0	8.2	51.4		
DR net replacements	(1,297.2)	(815.7)	(404.6)	(249.4)	(32.0)	(97.7)	(0.5)	(157.0)		
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
RPM load management @ 01-Jun-14	14,126.6	6,820.1	2,572.2	2,174.3	197.0	909.0	475.9	806.5		
DR cleared	14,922.1	6,692.2	2,631.3	2,009.1	86.3	797.0	263.3	867.4	1,763.7	
EE cleared	1,009.9	241.8	42.2	159.4	0.0	10.7	3.1	55.8	81.9	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-15	15,932.0	6,934.0	2,673.5	2,168.5	86.3	807.7	266.4	923.2	1,845.6	
DR cleared	12,408.1	5,350.2	2,006.4	1,600.5	105.7	630.7	226.6	663.9	1,811.9	468.7
EE cleared	1,117.3	310.1	51.2	208.4	0.6	11.9	3.1	83.5	196.6	52.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-16	13,525.4	5,660.3	2,057.6	1,808.9	106.3	642.6	229.7	747.4	2,008.5	521.3

Table 5-11 RPM load management cleared capacity and ILR: 2007/2008 through 2016/2017[59, 60]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	13,818.2	14,401.9	982.0	1,021.9	0.0	0.0
2015/2016	14,358.3	14,922.1	973.0	1,009.9	0.0	0.0
2016/2017	11,918.7	12,408.1	1,074.7	1,117.3	0.0	0.0

56 Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

57 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

58 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year include transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

59 For delivery years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

60 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

Table 5-12 RPM load management statistics: June 1, 2007 to June 1, 2016[61, 62]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(3,184.8)	(3,318.8)	120.0	125.0	8,151.8	8,490.0
01-Jun-14	14,800.2	15,423.8	(1,244.5)	(1,297.2)	0.0	0.0	13,555.7	14,126.6
01-Jun-15	15,331.3	15,932.0	0.0	0.0	0.0	0.0	15,331.3	15,932.0
01-Jun-16	12,993.4	13,525.4	0.0	0.0	0.0	0.0	12,993.4	13,525.4

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[63, 64, 65]

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[66] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. Capacity resource owners could provide ACR data by providing their own unit-specific data or by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[67]

The opportunity cost option allows Capacity Market Sellers to input a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the Generation Capacity Resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the Generation Capacity Resource does not clear in the RPM market, it is available to sell in the external market.

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[68] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for combined cycle (CC) and combustion turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[69]

61 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

62 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

63 See OATT Attachment DD § 6.5.

64 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

65 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

66 OATT Attachment DD § 6.8 (b).

67 OATT Attachment DD § 6.8 (a).

68 135 FERC ¶ 61,022 (2011).

69 135 FERC ¶ 61,022 (2011), order on reh'g, 137 FERC ¶ 61,145 (2011).

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[70] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exemption process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the Transmission System; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from constrained LDAs only.

Table 5-13 ACR statistics: 2013/2014 RPM Auctions

	2013/2014 Base Residual Auction		2013/2014 First Incremental Auction		2013/2014 Second Incremental Auction		2013/2014 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	580	49.6%	70	36.5%	55	33.7%	44	10.7%
ACR data input (APIR)	92	7.9%	27	14.1%	8	4.9%	0	0.0%
ACR data input (non-APIR)	15	1.3%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	6	0.5%	0	0.0%	4	2.5%	0	0.0%
Default ACR and opportunity cost	7	0.6%	4	2.1%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	201	49.0%
Uncapped planned uprate and default ACR	NA	NA	3	1.6%	10	6.1%	0	0.0%
Uncapped planned uprate and opportunity cost	NA	NA	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	NA	NA	1	0.5%	5	3.1%	7	1.7%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	20	1.7%	1	0.5%	11	6.7%	2	0.5%
Price takers	450	38.5%	86	44.8%	70	42.9%	156	38.0%
Total Generation Capacity Resources offered	1,170	100.0%	192	100.0%	163	100.0%	410	100.0%

Table 5-14 ACR statistics: 2014/2015 RPM Auctions

	2014/2015 Base Residual Auction		2014/2015 First Incremental Auction		2014/2015 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	544	47.2%	59	31.1%	66	29.9%
ACR data input (APIR)	138	12.0%	21	11.1%	5	2.3%
ACR data input (non-APIR)	3	0.3%	0	0.0%	0	0.0%
Opportunity cost input	7	0.6%	4	2.1%	0	0.0%
Default ACR and opportunity cost	6	0.5%	1	0.5%	1	0.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	11	1.0%	11	5.8%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	6	0.5%	4	2.1%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	22	1.9%	5	2.6%	5	2.3%
Price takers	415	36.0%	85	44.7%	144	65.2%
Total Generation Capacity Resources offered	1,152	100.0%	190	100.0%	221	100.0%

70 143 FERC ¶ 61,090 (2013).

Table 5-15 ACR statistics: 2015/2016 RPM Auctions

	2015/2016 Base Residual Auction		2015/2016 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	449	38.4%	24	18.3%
ACR data input (APIR)	171	14.6%	16	12.2%
ACR data input (non-APIR)	17	1.5%	0	0.0%
Opportunity cost input	4	0.3%	4	3.1%
Default ACR and opportunity cost	4	0.3%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	25	2.1%	1	0.8%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	7	0.6%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	32	2.7%	3	2.3%
Price takers	459	39.3%	83	63.4%
Total Generation Capacity Resources offered	1,168	100.0%	131	100.0%

Table 5-16 ACR statistics: 2016/2017 RPM Auctions

	2016/2017 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	471	39.3%
ACR data input (APIR)	138	11.5%
ACR data input (non-APIR)	1	0.1%
Opportunity cost input	8	0.7%
Default ACR and opportunity cost	5	0.4%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	15	1.3%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	11	0.9%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	31	2.6%
Price takers	519	43.3%
Total Generation Capacity Resources offered	1,199	100.0%

Table 5-17 APIR statistics: 2013/2014 RPM Base Residual Auction[71, 72]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$44.51	$33.30	$79.91	$212.68	$52.57	$115.83
Net revenues	$110.63	$30.53	$12.72	$364.90	$259.34	$199.44
Offer caps	$6.84	$16.36	$68.15	$9.29	$14.30	$14.09
APIR units						
ACR	NA	$49.42	$341.77	$509.95	$305.48	$390.05
Net revenues	NA	$9.18	$63.80	$459.41	$187.40	$292.92
Offer caps	NA	$40.73	$277.96	$112.30	$118.09	$134.44
APIR	NA	$25.28	$243.47	$352.55	$1.69	$268.59
Maximum APIR effect						$1,304.36

71 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.

72 For reasons of confidentiality, the APIR statistics do not include opportunity cost based offer cap data.

Table 5-18 APIR statistics: 2014/2015 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$47.04	$34.61	$84.19	$222.70	$58.86	$110.52
Net revenues	$112.21	$29.80	$14.52	$306.01	$226.46	$152.35
Offer caps	$8.92	$16.34	$74.66	$28.52	$16.68	$25.32
APIR units						
ACR	NA	$65.34	$278.46	$511.79	$330.13	$437.99
Net revenues	NA	$18.24	$55.97	$222.06	$138.36	$182.98
Offer caps	NA	$51.46	$222.49	$313.68	$191.78	$274.45
APIR	NA	$38.99	$185.24	$313.37	$1.67	$268.95
Maximum APIR effect						$744.80

Table 5-19 APIR statistics: 2015/2016 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$50.33	$36.07	$85.46	$232.16	$81.94	$113.51
Net revenues	$160.85	$34.32	$35.86	$248.90	$265.61	$148.07
Offer caps	$5.89	$11.34	$49.70	$26.50	$7.73	$17.86
APIR units						
ACR	$163.25	$334.57	$192.87	$471.60	$41.74	$401.95
Net revenues	$8.33	$17.93	$17.39	$221.10	$57.91	$166.81
Offer caps	$154.94	$316.69	$175.53	$264.18	$8.15	$246.63
APIR	$116.55	$293.45	$87.42	$265.13	$23.35	$238.79
Maximum APIR effect						$776.46

Table 5-20 APIR statistics: 2016/2017 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)					
	CombinedCycle	Combustion Turbine	Oil or Gas Steam	Subcritical/ Supercritical Coal	Other	Total
Non-APIR units						
ACR	$42.11	$33.46	$78.32	$215.57	$75.69	$102.23
Net revenues	$194.19	$56.23	$42.33	$208.04	$228.59	$150.24
Offer caps	$4.80	$7.64	$36.43	$29.03	$4.63	$16.07
APIR units						
ACR	$52.48	$93.23	$188.80	$432.72	$53.20	$352.84
Net revenues	$72.50	$17.49	$16.68	$222.52	$62.15	$177.14
Offer caps	$13.92	$79.12	$167.29	$213.88	$5.91	$180.23
APIR	$14.45	$57.71	$64.90	$236.99	$23.01	$191.19
Maximum APIR effect						$773.08

2013/2014 RPM Base Residual Auction

As shown in Table 5-13, 1,170 generation resources submitted offers in the 2013/2014 RPM Base Residual Auction. Unit-specific offer caps were calculated for 107 generation resources (9.1 percent of all generation resources offered) including 92 generation resources (7.9 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 15 generation resources (1.3 percent) without an APIR component. The MMU calculated offer caps for 700 generation resources (59.9 percent), of which 587 (50.2 percent) were based on the technology specific default (proxy) ACR values. Of the 1,170 generation resources, 20 planned generation resources had uncapped offers (1.7 percent), while the remaining 450 generation resources were price takers (38.4 percent), of which the offers for 441 generation resources were zero and the offers for nine generation resources were set to zero because no data were submitted.

Of the 1,170 generation resources which submitted offers, 92 resources (7.9 percent) included an APIR component. As shown in Table 5-17, the weighted-average gross ACR for resources with APIR ($390.05 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($134.44 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.59 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.37 per MW-day, which is the average APIR ($1.31 per MW-day) for the previously estimated default ACR values in the 2012/2013 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($352.55 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($1,304.36 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2013/2014 RPM First Incremental Auction

As shown in Table 5-13, 192 generation resources submitted offers in the 2013/2014 RPM First Incremental Auction. Unit-specific offer caps were calculated for 27 generation resources (14.1 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 104 generation resources (54.2 percent), of which 77 were based on the technology specific default (proxy) ACR values. Of the 192 generation resources, one Planned Generation Capacity Resource had an uncapped offer (0.5 percent), three generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.6 percent), one generation resource had an uncapped planned uprate along with price taker status for the existing portion (0.5 percent), while the remaining 86 generation resources were price takers (44.8 percent), of which the offers for 86 generation resources were zero and the offers for no generation resources were set to zero because no data were submitted.

2013/2014 RPM Second Incremental Auction

As shown in Table 5-13, 163 generation resources submitted offers in the 2013/2014 RPM Second Incremental Auction. Unit-specific offer caps were calculated for eight generation resources (4.9 percent of all generation resources), all of which included an APIR component. The MMU calculated offer caps for 77 generation resources (47.2 percent), of which 65 were based on the technology specific default (proxy) ACR values. Of the 163 generation resources, 11 Planned Generation Capacity Resources had uncapped offers (6.7 percent), 10 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (6.1 percent), five generation resources had uncapped planned uprates along with price taker status for the existing portion (3.1 percent), while the remaining 70 generation resources were price takers (42.9 percent), of which the offers for 69 generation resources were zero and the offers for one generation resource was set to zero because no data were submitted.

2013/2014 RPM Third Incremental Auction

As shown in Table 5-13, 410 generation resources submitted offers in the 2013/2014 RPM Third Incremental Auction. The MMU calculated offer caps for 44 generation resources (10.7 percent), all of which were based on the technology specific default (proxy) ACR values. Of the 410 generation resources, 201 generation resources elected offer cap option of 1.1 times the BRA clearing price (49.0 percent), two Planned Generation Capacity Resources had uncapped offers (0.5 percent), and seven generation resources had uncapped planned uprates along with price taker status for the existing portion (1.7 percent), while the remaining 156 generation resources were price takers (38.0 percent). Market power mitigation was applied to the sell offers for 17 generation resources.

2014/2015 RPM Base Residual Auction

As shown in Table 5-14, 1,152 generation resources submitted offers in the 2014/2015 RPM Base Residual Auction. Unit-specific offer caps were calculated for 141 generation resources (12.2 percent of all generation resources offered) including 138 generation resources (12.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and three generation resources (0.3 percent) without an APIR component. The MMU calculated offer caps for 709 generation resources (61.5 percent), of which 561 (48.7 percent) were based on the technology specific default (proxy) ACR values. Of the 1,152 generation resources, 22 Planned Generation Capacity Resources had uncapped offers (1.9 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.0 percent), six generation resources had uncapped planned uprates along with price taker status for the existing portion (0.5 percent), while the remaining 415 generation resources were price takers (36.0 percent), of which the offers for 413 generation resources were zero and the offers for two generation resources were set to zero because no data were submitted. The MOPR was applied and the MOPR exception process was applied to two units.

Of the 1,152 generation resources which submitted offers, 138 (12.0 percent) included an APIR component. As shown in Table 5-18, the weighted-average gross ACR for resources with APIR ($437.99 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($274.45 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $268.95 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.42 per MW-day, which is the average APIR ($1.37 per MW-day) for the previously estimated default ACR values in the 2013/2014 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($313.37 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($744.80 per MW/day) is the maximum amount by which an offer cap was increased by APIR.

2014/2015 RPM First Incremental Auction

As shown in Table 5-14, 190 generation resources submitted offers in the 2014/2015 RPM First Incremental Auction. Unit-specific offer caps were calculated for 21 generation resources (11.1 percent of all generation resources offered), all of which included an APIR component. The MMU calculated offer caps for 96 generation resources (50.5 percent), of which 71 (37.4 percent) were based on the technology specific default (proxy) ACR values. Of the 190 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.6 percent), 11 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (5.8 percent), four generation resources had uncapped planned uprates along with price taker status for the existing portion (2.1 percent), while the remaining 85 generation resources were price takers (44.7 percent), of which the offers for 85 generation resources were zero and the offers for no generation resources were set to zero because no data were submitted.

2014/2015 RPM Second Incremental Auction

As shown in Table 5-14, 221 generation resources submitted offers in the 2014/2015 RPM Second Incremental Auction. Unit-specific offer caps were calculated for six generation resources (2.7 percent), including five generation resources (2.3 percent) with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 72 generation resources (32.6 percent), of which 67 (30.3 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, five Planned Generation Capacity Resources had uncapped offers (2.3 percent), while the remaining 144 generation resources were price takers (65.2 percent). Market power mitigation was applied to the sell offers for two generation resources.

2015/2016 RPM Base Residual Auction

As shown in Table 5-15, 1,168 generation resources submitted offers in the 2015/2016 RPM Base Residual Auction. Unit-specific offer caps were calculated for 188 generation resources (16.1 percent) including 171 generation resources (14.6 percent) with an Avoidable Project Investment Recovery Rate (APIR) component and 17 generation resources (1.5 percent) without an APIR component. The MMU calculated offer caps for 670 generation resources, of which 478 were based on the technology specific default (proxy) ACR values. Of the 1,168 generation resources, 32 Planned Generation Capacity Resources had uncapped offers, 25 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion, seven generation resources had uncapped planned uprates along with price taker status for the existing portion, while the remaining 459 generation resources were price takers, of which the offers for 458 generation resources were zero and the offer for one generation resources was set to zero because no data were submitted.

Of the 1,168 generation resources which submitted offers, 171 (14.6 percent) included an APIR component. As shown in Table 5-19, the weighted-average gross ACR for resources with APIR ($401.95 per MW-day) and the weighted-average offer caps, net of net revenues, for resources with APIR ($246.63 per MW-day) were higher than for resources without an APIR component, including resources for which the default ACR value was selected. The APIR component added an average of $238.79 per MW-day to the ACR value of the APIR resources. The default ACR values included an average APIR of $1.48 per MW-day, which is the average APIR ($14.42 per MW-day) for the previously estimated default ACR values in the 2014/2015 BRA escalated using the most recent Handy-Whitman Index value. The highest APIR for a technology ($293.45 per MW-day) was for combustion turbine (CT) units. The maximum APIR effect ($776.46 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2015/2016 RPM First Incremental Auction

As shown in Table 5-15, 131 generation resources submitted offers in the 2015/2016 RPM First Incremental Auction. Unit-specific offer caps were calculated for 20 generation resources (15.3 percent), including 16 generation resources with an Avoidable Project Investment Recovery Rate (APIR). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 (19.1 percent) were based on the technology specific default (proxy) ACR values. Of the 221 generation resources, three Planned Generation Capacity Resources had uncapped offers (2.3 percent), one generation resource had an uncapped planned uprate along with a default ACR based offer cap for the existing portion (0.8 percent), while the remaining 83 generation resources were price takers (63.4 percent). Market power mitigation was applied to the sell offer for one generation resource.

2016/2017 RPM Base Residual Auction

As shown in Table 5-16, 1,199 generation resources submitted offers in the 2016/2017 RPM Base Residual Auction. Unit-specific offer caps were calculated for 139 generation resources (11.6 percent), including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) and one generation resource (0.1 percent) without an APIR component. The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 (41.0 percent) were based on the technology specific default (proxy) ACR values. Of the 1,199 generation resources, 31 Planned Generation Capacity Resources had uncapped offers (2.6 percent), 15 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.3 percent), and 11 generation resources had uncapped planned uprates along with price taker status for the existing portion (0.9 percent), while the remaining 519 generation resources were price takers (43.3 percent). Market power mitigation was applied to the sell offers for 50 generation resources.

Of the 1,199 generation resources which submitted offers, 138 (11.5 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR ($352.84 per MW-day) and the weighted-average offer caps, net of net revenues, for units with APIR ($180.23 per MW-day) decreased from the 2015/2016 BRA values of $401.95 per MW-day and $246.63 per MW-day, due primarily to lower weighted average gross ACRs for combined cycle, combustion turbine, oil and gas steam units, and subcritical/supercritical coal units. The APIR component added an average of $191.19 per MW-day to the ACR value of the APIR units compared to $238.79 per MW-day in the 2015/2016 BRA. The highest APIR for a technology ($236.99 per MW-day) was for subcritical/supercritical coal units. The maximum APIR effect ($773.08 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance[73]

Figure 5-4 presents cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-21 shows RPM clearing prices for all RPM Auctions held through 2013.

Figure 5-5 illustrates the RPM cleared MW weighted average prices for each LDA for the current Delivery Year and all results for future Delivery Years that have been held through 2013.

Table 5-22 shows RPM revenue by resource type for all RPM Auctions held through 2013 with $2.1 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

Table 5-23 shows RPM revenue by calendar year for all RPM Auctions held through 2013.

73 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2013.shtml>.

Table 5-21 Capacity prices: 2007/2008 through 2016/2017 RPM Auctions

		RPM Clearing Price ($ per MW-day)									
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11	
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33	
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29	
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23

Table 5-22 RPM revenue by type: 2007/2008 through 2016/2017[74, 75]

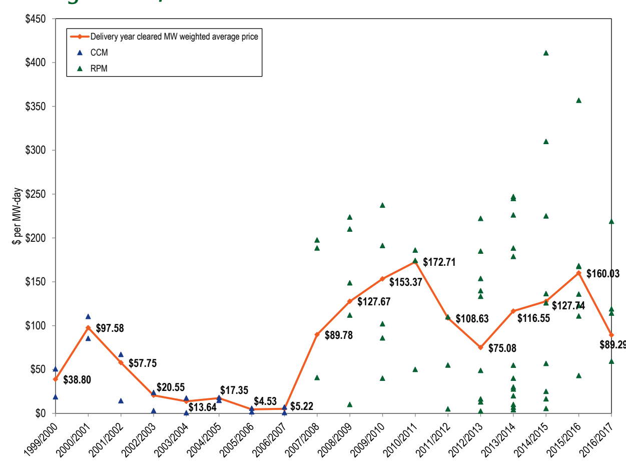
	Demand Resources	Energy Efficiency Resources	Imports	Coal: Existing	Coal: New/repower reactivated	Gas: Existing	Gas: New/repower reactivated	Hydroelectric: Existing	Hydroelectric: New/repower reactivated	Nuclear: Existing	Nuclear: New/repower reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,022,372,301	$0	$1,458,989,006	$3,472,667	$209,490,444	$0	$996,085,233	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,844,120,476	$0	$1,910,349,518	$9,751,112	$287,850,403	$0	$1,322,601,837	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,417,576,805	$1,854,781	$2,275,446,414	$30,168,831	$364,742,517	$0	$1,517,723,628	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,662,434,386	$3,168,069	$2,586,971,699	$58,065,964	$442,429,815	$0	$1,799,258,125	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,595,707,479	$28,330,047	$1,607,317,731	$98,448,693	$278,529,660	$0	$1,079,386,338	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,016,194,603	$7,568,127	$1,079,413,451	$76,633,409	$179,117,975	$11,397	$762,719,550	$0
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,745,438,458	$12,950,135	$1,846,432,716	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0
2014/2015	$672,042,592	$41,075,583	$131,766,080	$1,915,786,864	$57,078,818	$1,977,669,867	$188,665,243	$329,051,834	$6,591,114	$1,460,153,171	$0
2015/2016	$882,512,351	$55,664,349	$190,102,852	$2,779,290,152	$63,163,731	$2,475,378,226	$529,577,871	$385,193,684	$14,880,302	$1,849,263,911	$0
2016/2017	$437,607,477	$35,346,456	$157,012,514	$1,259,270,875	$42,487,007	$1,461,069,582	$498,909,311	$218,627,999	$10,031,353	$1,002,422,494	$0

	Oil: Existing	Oil: New/repower reactivated	Solar: Existing	Solar: New/repower reactivated	Solid waste: Existing	Solid waste: New/repower reactivated	Wind: Existing	Wind: New/repower reactivated	Total revenue
2007/2008	$502,172,373	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$572,259,505	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$715,618,319	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$668,505,533	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$368,084,004	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$423,957,756	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$689,864,789	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$473,230,023	$4,101,872	$0	$3,525,901	$34,529,651	$1,694,126	$1,524,551	$32,682,583	$7,331,169,873
2015/2016	$566,555,231	$5,243,967	$0	$4,526,101	$35,716,918	$4,258,208	$1,829,269	$41,406,297	$9,884,563,419
2016/2017	$327,077,318	$4,026,475	$0	$4,868,047	$28,668,947	$3,780,862	$1,144,873	$20,886,259	$5,513,237,849

Table 5-23 RPM revenue by calendar year: 2007 through 2017[76]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$123.11	158,258.0	365	$7,111,333,803
2015	$146.67	164,609.3	365	$8,812,393,764
2016	$118.67	168,936.9	366	$7,337,483,492
2017	$89.29	169,159.7	151	$2,280,818,946

Figure 5-4 History of PJM capacity prices: 1999/2000 through 2016/2017[77]



74 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

75 The results for the ATSI Integration Auctions are not included in this table.

76 The results for the ATSI Integration Auctions are not included in this table.

77 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2016/2017 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by Delivery Year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent Delivery Years, only the prices for Annual Resources are plotted.

Figure 5-5 Map of RPM capacity prices: 2013/2014 through 2016/2017

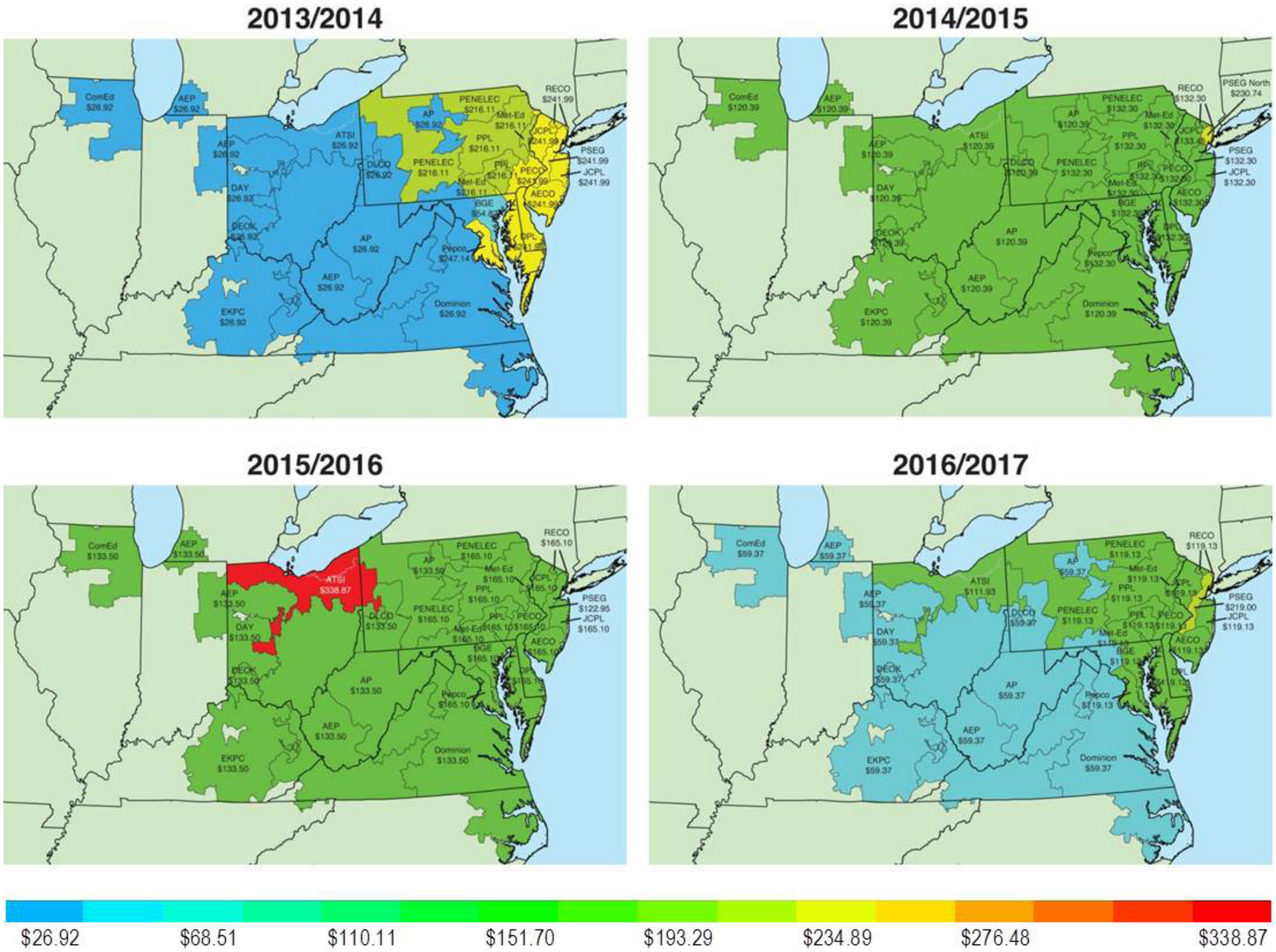


Table 5-24 shows the RPM annual charges to load. For the 2013/2014 Delivery Year, RPM annual charges to load total approximately $6.7 billion.

Table 5-24 RPM cost to load: 2013/2014 through 2016/2017 RPM Auctions[78, 79, 80]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2013/2014			
Rest of RTO	$28.45	80,012.1	$830,802,258
Rest of MAAC	$232.55	14,623.8	$1,241,276,219
EMAAC	$248.30	36,094.7	$3,271,227,460
Rest of SWMAAC	$231.58	7,925.5	$669,900,300
Pepco	$244.94	7,525.2	$672,777,842
Total		146,181.3	$6,685,984,079
2014/2015			
Rest of RTO	$129.28	81,309.3	$3,836,841,975
Rest of MAAC	$138.36	30,331.6	$1,531,762,816
Rest of EMAAC	$138.36	20,118.8	$1,016,059,638
DPL	$146.14	4,593.1	$244,995,176
PSEG	$171.46	11,669.9	$730,342,563
Total		148,022.7	$7,360,002,168
2015/2016			
Rest of RTO	$135.72	83,538.3	$4,149,635,361
Rest of MAAC	$166.40	55,889.0	$3,403,719,326
PSEG	$166.18	11,787.4	$716,915,782
ATSI	$295.97	14,786.2	$1,601,698,117
Total		166,000.8	$9,871,968,586
2016/2017			
Rest of RTO	$59.37	88,722.2	$1,922,615,128
Rest of MAAC	$118.89	57,413.6	$2,491,443,430
PSEG	$177.61	12,055.9	$781,575,871
ATSI	$90.54	15,121.1	$499,720,114
Total		173,312.9	$5,695,354,543

Replacement Capacity

The MMU's review and analysis of replacement capacity activity is the issue source for the problem statement/issue charge which is currently being discussed in the PJM stakeholder process.[81, 82, 83] The MMU proposed a solution package at the Capacity Senior Task Force (CSTF) which includes increasing the Capacity Resource Deficiency Charge; modifying how PJM releases capacity in Incremental Auctions; defining the First and Second Incremental Auction as not mandatory and held due to increases in the Reliability Requirement exceeding certain thresholds; and adding a Market Seller Offer Cap option for First and Second Incremental Auctions, if held, of 1.0 times the Base Residual Auction clearing price. The MMU also recommends that the rules governing the requirement to be a physical resource are enforced and enhanced and that replacement transactions are allowed only for defined qualifying events.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[84]

78 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.

79 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

80 Prior to the 2009/2010 Delivery Year, the final UCAP obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the final UCAP obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the final UCAP obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2014/2015, 2015/2016, and 2016/2017 Net Load Prices are not finalized. The 2014/2015, 2015/2016, and 2016/2017 obligation MW are not finalized.

81 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf> (December 18, 2012).

82 The Replacement Capacity Issue Charge and Problem Statement were presented at the March 6, 2013 MIC meeting. See "Item 04B – Replacement Capacity Issue Charge," <http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-04b-replacement-capacity-issue-charge.ashx>.

83 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

84 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. In 2013, nuclear units had a capacity factor of 93.8 percent, compared to 92.4 percent in 2012. Combined cycle units ran less often, decreasing from a capacity factor of 60.4 percent in 2012 to 51.6 in 2013. The capacity factor for steam units, which are primarily coal fired, increased from 45.5 percent in 2012 to 49.5 percent in 2013.

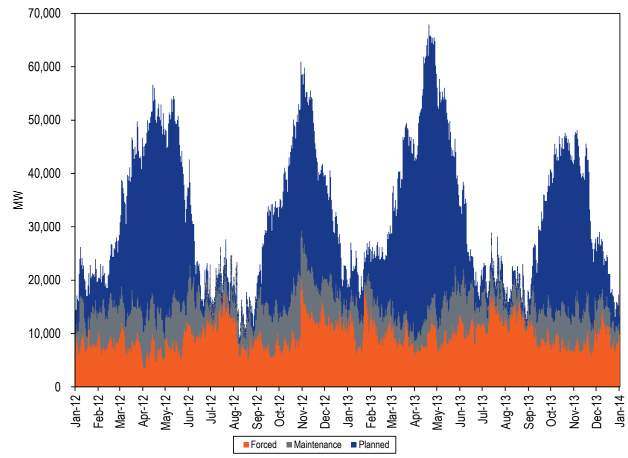
Table 5-25 PJM capacity factor (By unit type (GWh)): 2012 and 2013[85, 86]

	2012		2013	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.3	0.1%	0.7	0.1%
Combined Cycle	136,595.3	60.4%	119,414.7	51.6%
Combustion Turbine	8,023.8	3.0%	7,722.7	2.9%
Diesel	592.5	15.5%	613.2	16.4%
Diesel (Landfill gas)	1,221.0	40.5%	1,380.9	43.5%
Fuel Cell	13.2	57.1%	115.3	43.9%
Nuclear	273,372.2	92.4%	277,277.8	93.8%
Pumped Storage Hydro	6,544.5	13.6%	6,716.2	14.0%
Run of River Hydro	6,105.3	28.8%	7,368.8	34.0%
Solar	233.5	14.3%	355.0	15.8%
Steam	344,755.1	45.5%	361,307.3	49.5%
Wind	12,633.6	25.7%	14,826.9	26.8%
Total	790,090.3	47.2%	797,099.6	48.0%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The amount of MW on outages varies throughout the year. For example, the MW on planned outages are generally highest in the spring and fall, as shown in Figure 5-6, due to restrictions on planned outages during the winter and summer. The effect of seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

Figure 5-6 PJM outages (MW): January 2012 through December 2013



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-7. Metrics by unit type are shown in Table 5-26 through Table 5-29.

85 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.

86 The EKPC Transmission Zone was integrated on June 1, 2013 and is included in the numbers for 2013.

Figure 5-7 PJM equivalent outage and availability factors: 2007 to 2013

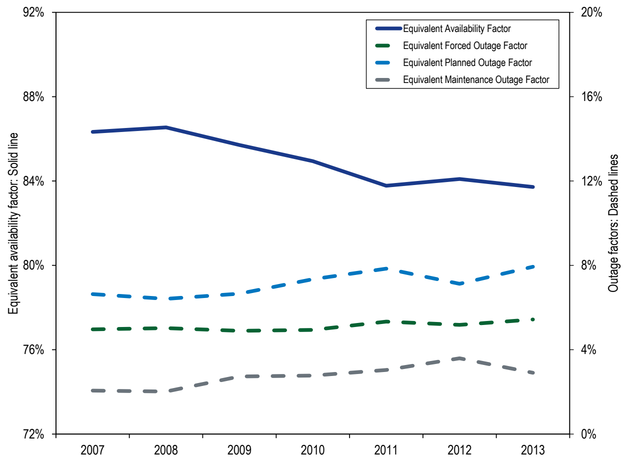


Table 5-26 EAF by unit type: 2007 through 2013

	2007	2008	2009	2010	2011	2012	2013
Combined Cycle	89.7%	90.1%	87.8%	85.9%	85.4%	85.4%	86.1%
Combustion Turbine	90.5%	91.1%	93.3%	93.1%	91.8%	92.4%	89.8%
Diesel	87.4%	88.6%	91.7%	93.9%	94.9%	93.1%	92.6%
Hydroelectric	90.2%	88.8%	86.9%	88.8%	84.6%	88.3%	88.3%
Nuclear	93.1%	92.3%	90.1%	91.8%	90.1%	91.1%	92.2%
Steam	81.3%	81.7%	80.9%	79.0%	78.3%	77.9%	77.0%
Total	86.3%	86.5%	85.7%	84.9%	83.8%	84.1%	83.7%

Table 5-27 EMOF by unit type: 2007 through 2013

	2007	2008	2009	2010	2011	2012	2013
Combined Cycle	2.0%	1.6%	3.0%	3.1%	2.4%	2.7%	2.5%
Combustion Turbine	2.5%	2.2%	2.3%	2.0%	2.4%	1.7%	1.9%
Diesel	1.6%	1.2%	1.1%	1.5%	1.9%	2.4%	1.4%
Hydroelectric	1.4%	2.1%	2.2%	2.0%	1.8%	2.2%	1.8%
Nuclear	0.3%	0.8%	0.6%	0.5%	1.2%	1.1%	0.7%
Steam	2.7%	2.5%	3.7%	3.9%	4.2%	5.5%	4.3%
Total	2.1%	2.0%	2.7%	2.8%	3.0%	3.6%	2.9%

Table 5-28 EPOF by unit type: 2007 through 2013

	2007	2008	2009	2010	2011	2012	2013
Combined Cycle	5.9%	6.0%	6.3%	8.2%	9.7%	8.3%	8.8%
Combustion Turbine	2.5%	4.0%	2.8%	3.0%	3.8%	3.2%	3.3%
Diesel	0.6%	1.0%	0.6%	0.5%	0.1%	0.7%	0.3%
Hydroelectric	7.1%	7.7%	8.4%	8.5%	11.7%	6.5%	7.9%
Nuclear	5.3%	5.1%	5.2%	5.4%	6.1%	6.4%	6.0%
Steam	8.6%	7.7%	8.4%	9.2%	9.1%	8.5%	10.2%
Total	6.6%	6.4%	6.7%	7.3%	7.8%	7.1%	7.9%

Table 5-29 EFOF by unit type: 2007 through 2013

	2007	2008	2009	2010	2011	2012	2013
Combined Cycle	2.3%	2.3%	2.9%	2.7%	2.6%	3.6%	2.6%
Combustion Turbine	4.5%	2.7%	1.6%	1.9%	2.0%	2.8%	4.9%
Diesel	10.3%	9.2%	6.6%	4.2%	3.1%	3.8%	5.7%
Hydroelectric	1.3%	1.4%	2.4%	0.7%	1.8%	3.0%	2.0%
Nuclear	1.3%	1.8%	4.1%	2.3%	2.6%	1.5%	1.1%
Steam	7.5%	8.0%	7.0%	7.9%	8.4%	8.0%	8.5%
Total	5.0%	5.0%	4.9%	4.9%	5.3%	5.2%	5.4%

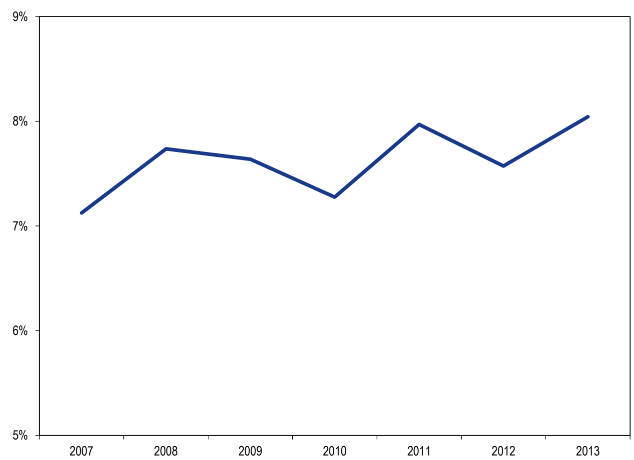
Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[87] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2013 was 8.0 percent, an increase from the 7.6 percent average PJM EFORd for 2012. Figure 5-8 shows the average EFORd since 2007 for all units in PJM.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2013



87 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

Table 5-30 shows the class average EFORd by unit type.

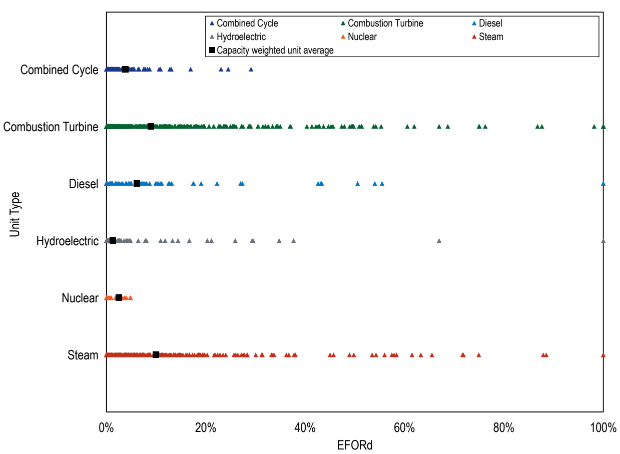
Table 5-30 PJM EFORd data for different unit types: 2007 through 2013

	2007	2008	2009	2010	2011	2012	2013	NERC EFORd 2008 to 2012 Average
Combined Cycle	3.7%	3.8%	4.3%	3.8%	3.5%	4.3%	3.3%	4.6%
Combustion Turbine	11.1%	11.1%	9.8%	8.9%	8.0%	8.2%	10.8%	9.9%/10.7%
Diesel	11.9%	10.4%	9.3%	6.1%	9.2%	5.1%	6.3%	14.2%
Hydroelectric	2.1%	2.1%	3.4%	1.3%	3.1%	4.7%	3.2%	5.4%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	3.9%
Steam	9.3%	10.3%	9.4%	9.9%	11.4%	10.8%	11.6%	8.2%
Total	7.1%	7.7%	7.6%	7.3%	8.0%	7.6%	8.0%	NA

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates within each unit type. The distribution of EFORd by unit type is shown in Figure 5-9. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Combustion turbine units had the greatest variance of EFORd, while nuclear units had the lowest variance in EFORd values in 2013.

Figure 5-9 PJM distribution of EFORd data by unit type: 2013



Other Forced Outage Rate Metrics

There are two additional primary forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours.

The PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations of XEFORd, which are used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market.

The PJM Capacity Market creates an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[88] For NERC, an outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[89] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market.[90] That choice was made by PJM and can be modified without violating any NERC requirements.[91] It is possible to have an OMC outage under the NERC definition, which PJM does not define as an OMC outage for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC.

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 5-31 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 16.8 percent of all forced outages. The third-largest contributor to OMC outages, lack of fuel, was the cause of 17.6 percent of OMC outages and 3.0 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."

The largest contributor to OMC outages, hurricane, affected a number of large units in the early spring. Also contributing to hurricane outages were several units that have been on outage since the 2012 hurricane.

88 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control… There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

89 For a list of these cause codes, see *the Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes" <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

90 For example, the NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules. See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf>. When a generator, energy/capacity limited resource, system resource, intermittent power resource or control area system resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of unforced capacity such installed capacity suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the generator, energy/capacity limited resource, system resource, intermittent power resource or control area system resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as outside management control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

91 It is unclear whether there were member votes taken on this issue prior to PJM's implementation of its approach to OMC outages. It does not appear that PJM has consulted with members for the subsequent changes to its application of OMC outages.

Table 5-31 OMC Outages: 2013

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	41.9%	7.1%
Flood	22.8%	3.8%
Lack of fuel	17.6%	3.0%
Lightning	6.5%	1.1%
Transmission system problems other than catastrophes	5.8%	1.0%
Other switchyard equipment external (OMC)	2.6%	0.4%
Other miscellaneous external problems	1.1%	0.2%
Transmission line (connected to powerhouse switchyard to 1st Substation)	0.3%	0.1%
Transmission equipment at the 1st substation	0.3%	0.0%
Frozen coal	0.2%	0.0%
Transmission equipment beyond the 1st substation	0.2%	0.0%
Switchyard transformers and associated cooling systems external (OMC)	0.2%	0.0%
Lack of water (hydro)	0.2%	0.0%
Switchyard circuit breakers external (OMC)	0.1%	0.0%
Wet coal	0.0%	0.0%
Switchyard system protection devices external (OMC)	0.0%	0.0%
Other fuel quality problems	0.0%	0.0%
Storms	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	16.8%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because, even if the OMC concept were accepted, the lack of fuel reasons are not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[92]

If there were units in a constrained locational deliverability area (LDA) that regularly had a higher rate of OMC outages than other units in the LDA and in PJM, and that cleared in the capacity auctions, the supply and demand in that LDA would be affected. The payments to the high OMC units would be too high and the payments to other units in the LDA would be too low. This market signal, based on the exclusion of OMC outages, favors generating units with high forced outage rates that result from causes classified as OMC, compared to generating units with no OMC outages.

With the OMC rules in place, if a new unit were considering entry into a constrained LDA and had choices about the nature of its fuel supply, the unit would not have an incentive to choose the most reliable fuel source or combination of fuel sources, but simply the cheapest. The OMC outage rules would provide the wrong incentive. While it is up to the generation investor to determine its fuel supply arrangements, the generation investor must also take on the risks associated with its fuel supply decisions rather than being able to shift those risks to other generation owners and to customers, which is exactly what occurs under

92 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

the OMC rules as currently implemented. This issue is especially critical in a time when almost all incremental conventional generation in PJM is gas fired.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that pending elimination of OMC outages, PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[93] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.[94]

PJM EFOF was 5.4 percent in 2013. This means there was 5.4 percent lost availability because of forced outages. Table 5-32 shows that forced outages for boiler tube leaks, at 19.3 percent of the systemwide EFOF, were the largest single contributor to EFOF.

Table 5-32 Contribution to EFOF by unit type by cause: 2013

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	4.4%	0.0%	0.0%	0.0%	0.0%	25.7%	19.3%
Catastrophe	4.8%	54.9%	6.0%	1.8%	17.0%	4.3%	12.0%
Boiler Piping System	5.6%	0.0%	0.0%	0.0%	0.0%	7.1%	5.6%
Electrical	1.6%	5.9%	4.8%	11.6%	7.1%	4.3%	4.6%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%	4.5%
Miscellaneous (Steam Turbine)	4.3%	0.0%	0.0%	0.0%	0.1%	5.3%	4.2%
High Pressure Turbine	26.7%	0.0%	0.0%	0.0%	0.0%	3.0%	3.9%
Economic	0.8%	7.0%	5.6%	2.2%	0.0%	3.7%	3.8%
Feedwater System	0.6%	0.0%	0.0%	0.0%	5.4%	4.6%	3.6%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	3.9%	2.9%
Controls	4.0%	4.4%	0.1%	0.6%	5.7%	1.3%	2.1%
Boiler Internals and Structures	0.9%	0.0%	0.0%	0.0%	0.0%	2.3%	1.8%
Reserve Shutdown	1.8%	4.3%	33.0%	1.1%	0.4%	1.2%	1.7%
Personnel or Procedure Errors	0.4%	0.0%	1.7%	0.0%	1.5%	2.0%	1.5%
Condensing System	0.6%	0.0%	0.0%	0.0%	1.0%	1.9%	1.5%
Circulating Water Systems	1.8%	0.0%	0.0%	0.0%	5.8%	1.5%	1.5%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.4%
Generator	1.5%	0.2%	7.0%	1.9%	18.1%	0.7%	1.3%
Stack Emission	0.3%	1.4%	0.3%	0.0%	0.0%	1.5%	1.3%
All Other Causes	39.8%	21.9%	41.6%	80.9%	38.0%	17.7%	21.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

93 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

94 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-33 shows the categories which are included in the economic category.[95] Lack of fuel that is considered outside management control accounted for 77.9 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[96] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-33 Contributions to Economic Outages: 2013

	Contribution to Economic Reasons
Lack of fuel (OMC)	77.9%
Lack of fuel (Non-OMC)	20.8%
Lack of water (Hydro)	0.8%
Problems with primary fuel for units with secondary fuel operation	0.2%
Fuel conservation	0.2%
Other economic problems	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[97] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market.

Table 5-34 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

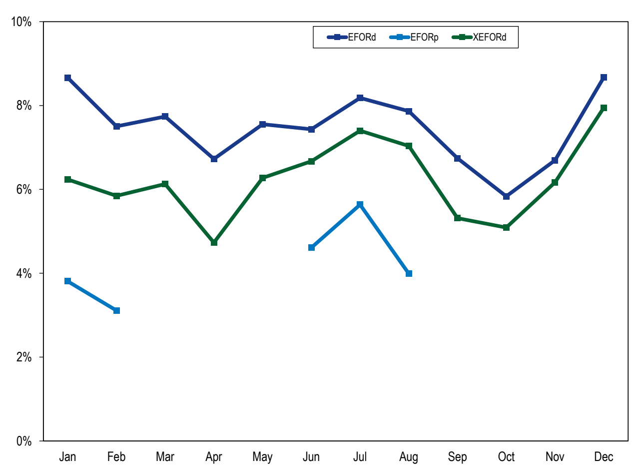
Table 5-34 PJM EFORd, XEFORd and EFORp data by unit type: 2013[98]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.3%	3.0%	1.8%	0.3%	1.5%
Combustion Turbine	10.8%	6.7%	3.6%	4.0%	7.1%
Diesel	6.3%	5.8%	3.2%	0.5%	3.1%
Hydroelectric	3.2%	1.2%	1.4%	2.1%	1.8%
Nuclear	1.2%	1.0%	0.7%	0.2%	0.4%
Steam	11.6%	10.3%	7.3%	1.3%	4.3%
Total	8.0%	6.6%	4.5%	1.4%	3.6%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-10, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

Figure 5-10 PJM EFORd, XEFORd and EFORp: 2013



95 The definitions of these outages are defined by NERC GADS.

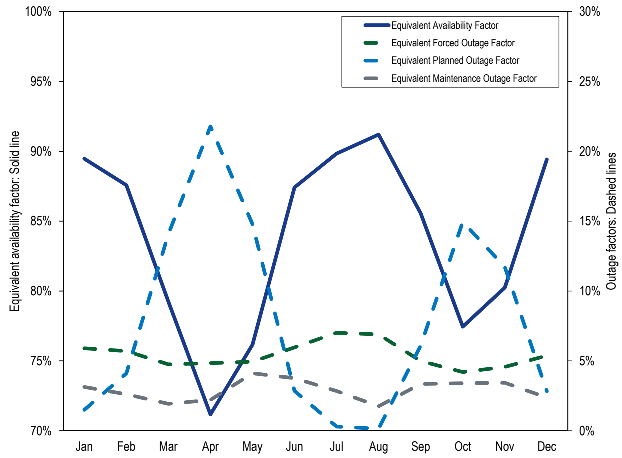
96 The definitions of these outages are defined by NERC GADS.

97 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

98 EFORp is only calculated for the peak months of January, February, June, July and August.

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-11.

Figure 5-11 PJM monthly generator performance factors: 2013



Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Economic program credits decreased by $836,828, from $9,284,118 in 2012 to $8,447,290 in 2013, a 9.0 percent drop. Emergency energy credits increased 250.4 percent to $36.7 million compared to 2012. In 2013, synchronized reserve credits for demand resources (DR) decreased by $1.3 million, or 29.7 percent, compared to 2012, from $4.5 million to $3.2 million in 2013.The capacity market is the primary source of revenue to participants in PJM demand response programs. In 2013, load management (LM) program revenue increased $98.8 million, or 29.9 percent, from $331.1 million in 2012 to $429.9 million in 2013. Demand response credits increased by $122.9 million or 34.6 percent to $478.3 million in 2013 compared to 2012.[1]

  Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Emergency demand response energy costs are not covered by LMP. All demand response energy payments are out of market; demand response payments are a form of uplift.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis when appropriate, but subzonal dispatches are only on a voluntary basis. Beginning with the 2014/2015 Delivery Year, demand resources will be dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency.[2]

- **Emergency Event Day Analysis.** Emergency energy revenue increased by $26.2 million, or 250.4 percent, from $10.4 million in 2012 to $36.7 in 2013. Emergency load management event rules over-calculate a participants' compliance levels. Increases in load for dispatched demand resources, negative reduction MWh values, are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero. Considering all positive and negative reported values, the observed load reduction of the five events in 2013 should have been 4,807.8 MW, rather than the 5,488.5 MW calculated by PJM's method. The correct calculation of compliance is 81.8 percent rather than PJM's calculated 93.3 percent. This does not include locations that did not report their load during the emergency event days.

Recommendations

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program and not an emergency program.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[3]
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[4]
- The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that demand resources measurement and verification be further modified to more accurately reflect compliance.

1 The total credits and MWh numbers for demand resources were calculated as of March 7, 2014 and may change as a result of continued PJM billing updates.

2 If "PJM Interconnection LLC," Docket No. ER14-822-000 (December 24, 2013) is approved by the FERC, mandatory curtailment for subzonal dispatch will be delayed until the 2015/2016 Delivery Year.

3 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

4 *Id* at 1.

- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[5]
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM economic load response program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. That is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs. Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to both emergency and economic programs. Demand resource is used here to refer to both resources participating in the capacity market and resources participating in the energy market.

5 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

Table 6-1 Overview of demand response programs[6]

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.

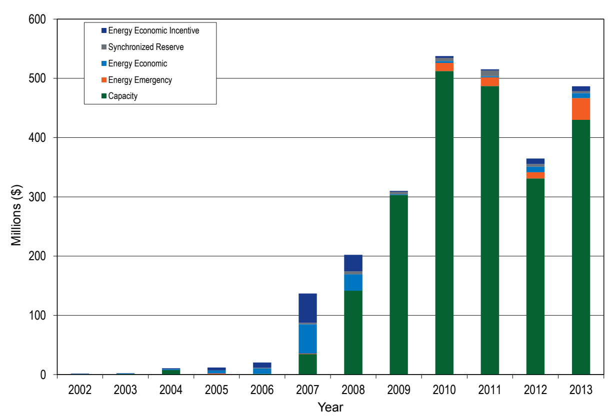
Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefit test (NBT) is met. In 2013, credits and MWh in the economic program decreased compared to 2012, but increased compared to 2009, 2010 and 2011. There were fewer settlements submitted and fewer active participants in 2013 compared to 2012, and credits decreased.

Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through 2013. Since the implementation of the RPM design on June 1, 2007, the Capacity Market has been the primary source of revenue to demand response participants, representing 89.9 percent of all revenue received through demand response programs in 2013. In 2013, total credits under the economic program decreased by $836,828, from $9,284,118 in 2012 to $8,447,290 in 2013. This represents a 9.0 percent decrease in credits. In 2013, capacity revenue represented 89.9 percent of all revenue received by demand response providers, emergency energy revenue represented 7.7 percent, revenue from the economic program represented 1.8 percent and revenue from Synchronized Reserve represented 0.7 percent.

Capacity revenue increased by $98.8 million, or 29.9 percent, from $331.1 million in 2012 to $429.9 million in 2013, primarily due to higher clearing prices in the capacity market for the 2013/2014 Delivery Year. The emergency energy revenue increased by $26.2 million, or 250.4 percent, from $10.5 million in 2012 to $36.7 million in 2013. Emergency energy revenue increased in 2013 as a result of more emergency events called in PJM and an increased offer cap for demand response resources to $1,800 per MWh on June 1, 2013, from $1,000 per MWh. Synchronized reserve credits for demand response resources decreased by $1.3 million, from $4.5 million in 2012 to $3.2 million in 2013, due to lower clearing prices in the Synchronized Reserve Market.

Figure 6-1 Demand response revenue by market: 2002 through 2013



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period 2010 through 2013. The average number of registrations and registered MW increased in 2013. The average monthly registered MW for 2013 increased by 175 MW from 2,200 MW in 2012 to 2,375 MW in 2013. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations increased by 63 from

6 Prior to April 1, 2012, payment for the economic load response program was based on LMP minus the generation and transmission components of the retail rate.

1,071 in 2012 to 1,134 in 2013. The economic program's registered MW have not increased significantly with FERC Order No. 745.

There is a large overlap between economic registrations and emergency registrations. There were 811 registrations that were in both the economic and emergency programs. The registered MW in the economic load response program are not the amount of MW available for dispatch. Economic resources can dispatch more, less or the amount of MW registered in the program.

Table 6-2 Economic program registrations on the last day of the month: 2010 through 2013

	2010		2011		2012		2013	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,321
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,333
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,291
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,341
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,412
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,138
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,473
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,568
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,516
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,387
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,358
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,363
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,134	2,375

Table 6-3 Maximum economic MW dispatched by location per month: 2010 through 2013

	Maximum Dispatched MW by Location			
Month	2010	2011	2012	2013
Jan	233	243	104	193
Feb	121	190	101	119
Mar	115	153	72	127
Apr	111	80	108	133
May	172	98	143	192
Jun	209	561	944	431
Jul	999	561	1,641	1,088
Aug	794	161	980	497
Sep	276	84	451	517
Oct	118	81	242	157
Nov	111	86	165	151
Dec	41	88	99	158
Total	1,209	841	1,956	1,470

Since response by participants in the economic demand response program is optional, not all registrations or registered MW performed each year. Table 6-3 shows the maximum economic MW dispatched by location each month for 2010 through 2013. The maximum dispatched MW for each location were added together for each month to get the maximum economic MW dispatch value. Economic dispatch can occur above, at or below the registered MW amount for each registration. The total maximum MW by location dispatched in 2013 decreased by 485 MW, from 1,956 in 2012 to 1,470 in 2013. Total MW dispatched by location each year has grown with the implementation of FERC Order No. 745. The total MW dispatched by location in July of 2012 was the highest recorded for the last four years at 1,641 maximum MW dispatched by location.

Economic demand response energy costs are assigned to PJM market participants based on real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[7] All demand response energy payments are out of market.

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by \$2.47/MWh in 2013, from \$64.02/MWh in 2012 to \$66.49/MWh in 2013. Curtailed energy for the economic program was 127,045 MWh in 2013 and the total payments were \$8,447,290. Credits for 2013 decreased by \$836,828, or 13 percent, compared to 2012. Economic demand response resources that are dispatched in both the economic and emergency programs are settled under emergency rules. The five emergency events in 2013 reduced the economic load response credits in 2013 during the peak days in PJM.

7 PJM: "Manual 28: Operating Agreement Accounting," Revision 59 (April 22, 2013), p 70.

Table 6-4 Credits paid to the PJM economic program participants excluding incentive credits: 2003 through 2013

Year	Total MWh	Total Credits	$/MWh
2003	19,518	$833,530	$42.71
2004	58,352	$1,917,202	$32.86
2005	157,421	$13,036,482	$82.81
2006	258,468	$10,213,828	$39.52
2007	714,148	$31,600,046	$44.25
2008	452,222	$27,087,495	$59.90
2009	57,157	$1,389,136	$24.30
2010	74,070	$3,088,049	$41.69
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	127,045	$8,447,290	$66.49

Figure 6-2 shows monthly economic demand response credits, for 2009 through 2013. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. For the months of June through August, total economic demand response credits decreased by $2,506,945 from $6,764,613 in 2012 to $4,257,946 in 2013. Both 2012 and 2013 had more economic demand response credits than 2009 through 2011.

Figure 6-2 Economic program credits by month: 2009 through 2013

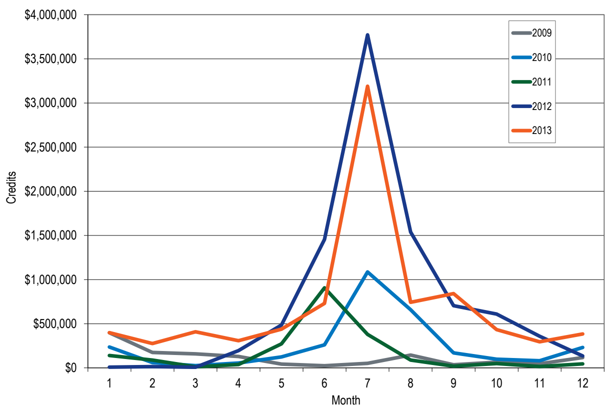


Table 6-5 shows 2012 and 2013 performance in the economic program by control zone and participation type. The Dominion Control Zone accounted for $4,822,827 or 60 percent of all economic program credits, associated with 80,243 MWh or 60.5 percent of total program reductions. The Dominion Control Zone had the highest average MW reductions per registration and average credits per registration.

Table 6-5 PJM Economic program participation by zone: 2012 and 2013[8]

	Credits			MWh Reductions		
Zones	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO, JCPL, PECO, RECO	$884,993	$519,152	(41%)	10,869	3,934	(64%)
AP	$1,068,328	$216,693	(80%)	16,825	3,637	(78%)
AEP, ATSI, ComEd, DAY, DEOK, DLCO, EKPC, PENELEC	$975,265	$1,132,313	16%	17,963	21,342	19%
BGE, DPL, Met-Ed, Pepco	$542,522	$670,416	24%	6,013	3,657	(39%)
Dominion	$4,215,114	$5,113,549	21%	65,688	84,199	28%
PPL	$441,458	$269,602	(39%)	5,076	3,545	(30%)
PSEG	$1,156,438	$525,566	(55%)	22,586	6,731	(70%)
Total	$9,284,118	$8,447,290	(9%)	145,019	127,045	(12%)

Table 6-6 shows total settlements submitted by year for 2008 through 2013. A settlement is counted for every day on which a registration is dispatched in the economic program. Settlements submitted by year in the economic program have decreased from 2008 to 2013. Settlements increased after FERC Order No. 745 in 2012, but decreased in 2013. There were 4,002 less settlements in 2013 than in 2012.

Table 6-6 Settlements submitted by year in the economic program: 2008 through 2013

	2008	2009	2010	2011	2012	2013
Total	32,990	21,605	12,697	4,591	7,894	3,897

Table 6-7 shows the number of distinct curtailment service providers (CSPs) and distinct participants actively submitting settlements by year for the period 2009 through 2013. The number of active participants during 2013 decreased by 229 compared to 2012. The smaller number of active participants in 2013 responded more frequently compared to participants in 2012.

Table 6-7 Distinct participants and CSPs submitting settlements in the Economic Program by year: 2009 through 2013

	2009		2010		2011		2012		2013	
	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	25	747	24	438	20	610	24	520	22	291

Table 6-8 shows MWh reductions and credits in each hour for 2012 and 2013. In 2013, 43.7 percent of the reductions occurred between hour ending 1500 and hour ending 1800, while in 2012, 49.9 percent of hourly reductions occurred during those hours. The majority of reductions occurred between hours ending 1000 and hour ending 1800.

Table 6-8 Hourly frequency distribution of economic program MWh reductions and credits: 2012 and 2013

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2012	2013	Percentage Change	2012	2013	Percentage Change
1	177	168	(5%)	$5,326	$5,867	10%
2	176	156	(12%)	$3,997	$4,009	0%
3	179	144	(20%)	$2,316	$3,226	39%
4	220	136	(38%)	$2,413	$2,377	(1%)
5	227	136	(40%)	$3,338	$2,406	(28%)
6	291	236	(19%)	$6,834	$7,783	14%
7	3,112	5,673	82%	$145,453	$313,467	116%
8	4,635	6,792	47%	$205,997	$400,083	94%
9	5,166	7,036	36%	$200,227	$327,904	64%
10	4,849	6,553	35%	$190,280	$292,944	54%
11	4,477	4,910	10%	$204,828	$229,059	12%
12	5,113	4,434	(13%)	$267,238	$199,568	(25%)
13	8,256	6,635	(20%)	$572,564	$356,923	(38%)
14	12,638	10,174	(19%)	$818,401	$855,745	5%
15	16,987	13,681	(19%)	$1,208,146	$1,014,289	(16%)
16	18,217	14,232	(22%)	$1,460,337	$1,164,466	(20%)
17	18,766	14,221	(24%)	$1,489,493	$1,182,457	(21%)
18	18,373	13,441	(27%)	$1,314,136	$1,010,531	(23%)
19	9,196	10,131	10%	$541,938	$627,836	16%
20	6,522	4,686	(28%)	$335,446	$257,863	(23%)
21	3,736	2,060	(45%)	$179,181	$119,957	(33%)
22	2,044	827	(60%)	$79,851	$43,898	(45%)
23	942	345	(63%)	$27,631	$14,921	(46%)
24	718	240	(67%)	$18,746	$9,713	(48%)
Total	145,019	127,045	(12%)	$9,284,118	$8,447,290	(9%)

8 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

Following the implementation of FERC Order No. 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during the hours they were dispatched, provided that LMP was greater than the net benefits test threshold. The NBT is used to define a price point above which the net benefits of DR are deemed to exceed the cost to load. When the LMP is above the NBT threshold, the demand response resource receives credit for the full LMP. The net benefits test defined an average price of $28.09 for 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the net benefits test price.

Table 6-9 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP.

Total economic program reductions decreased by 17,974 MWh, from 145,019 MWh in 2012 to 127,045 MWh in 2013. Reductions occurred at all price levels. Approximately 80.5 percent of MWh reductions and 58.0 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. MWh reductions in 2013 decreased 12.4 percent compared to 2012.

Table 6-9 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2012 and 2013

	MWh Reductions			Program Credits		
LMP	2012	2013	Percentage Change	2012	2013	Percentage Change
$0 to $25	1,676	362	(78.4%)	$8,893	$13,361	50.2%
$25 to $50	80,848	75,985	(6.0%)	$3,069,793	$3,190,964	3.9%
$50 to $75	31,388	26,237	(16.4%)	$1,905,190	$1,706,528	(10.4%)
$75 to $100	11,427	7,290	(36.2%)	$1,002,933	$690,586	(31.1%)
$100 to $125	6,711	6,293	(6.2%)	$788,302	$860,996	9.2%
$125 to $150	4,179	4,278	2.4%	$568,642	$660,723	16.2%
$150 to $200	2,995	2,483	(17.1%)	$505,094	$395,878	(21.6%)
$200 to $250	3,028	1,905	(37.1%)	$628,775	$324,872	(48.3%)
$250 to $300	1,829	851	(53.5%)	$471,562	$221,550	(53.0%)
> $300	939	1,363	45.1%	$334,934	$381,831	14.0%
Total	145,019	127,045	(12.4%)	$9,284,118	$8,447,290	(9.0%)

Emergency Program

The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources. This will ensure comparability and consistency for demand resources. The MMU also recommends demand resources have an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently at $1,000 per MWh.[9]

Table 6-10 shows zonal monthly capacity credits to demand resources for 2013. Capacity revenue increased in 2013 by $98.8 million, or 29.9 percent, compared to 2012, from $331.1 million to $429.9 million due to higher RPM prices and more DR participation in RPM for the 2013/2014 Delivery Year.[10]

9 See "Complaint and Motion to Consolidate of the Independent Market Monitor," Docket No. EL14-20-000 (January 28, 2014).

10 For more detail on RPM prices see the *2013 State of the Market Report for PJM*, Volume II, Section 5, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml>.

Table 6-10 Zonal monthly capacity credits: 2013

Zone	January	February	March	April	May	June	July	August	September	October	Novemeber	December	Total
AECO	$411,097	$371,313	$411,097	$397,836	$411,097	$1,002,307	$1,035,717	$1,035,717	$1,002,307	$1,035,717	$257,721	$1,035,717	$8,407,643
AEP, EKPC	$425,101	$383,962	$425,101	$411,388	$425,101	$751,158	$776,197	$776,197	$751,158	$776,197	$1,145,576	$776,197	$7,823,329
AP	$185,478	$167,528	$185,478	$179,495	$185,478	$477,348	$493,260	$493,260	$477,348	$493,260	$749,663	$493,260	$4,580,855
ATSI	$19,859	$17,937	$19,859	$19,218	$19,859	$365,564	$377,750	$377,750	$365,564	$377,750	$477,348	$377,750	$2,816,205
BGE	$5,430,108	$4,904,613	$5,430,108	$5,254,943	$5,430,108	$7,487,232	$7,736,807	$7,736,807	$7,487,232	$7,736,807	$365,564	$7,736,807	$72,737,134
ComEd	$405,926	$366,643	$405,926	$392,831	$405,926	$782,114	$808,185	$808,185	$782,114	$808,185	$7,487,232	$808,185	$14,261,452
DAY	$63,670	$57,508	$63,670	$61,616	$63,670	$42,849	$44,278	$44,278	$42,849	$44,278	$782,114	$44,278	$1,355,058
DEOK	$8,185	$7,393	$8,185	$7,921	$8,185	$16,115	$16,653	$16,653	$16,115	$16,653	$42,849	$16,653	$181,557
DLCO	$49,718	$44,907	$49,718	$48,114	$49,718	$143,269	$148,045	$148,045	$143,269	$605,391	$16,115	$605,391	$2,051,701
Dominion	$306,929	$277,226	$306,929	$297,028	$306,929	$585,863	$605,391	$605,391	$585,863	$1,979,013	$585,862	$1,979,013	$8,421,436
DPL	$1,547,049	$1,397,335	$1,547,049	$1,497,145	$1,547,049	$1,915,174	$1,979,013	$1,979,013	$1,915,174	$148,045	$1,915,174	$148,045	$17,535,265
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,447,382	$1,495,628	$2,215,048	$2,288,883	$2,288,883	$2,215,048	$2,288,883	$1,495	$2,288,883	$20,872,275
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,010,595	$1,044,281	$2,174,111	$2,246,581	$2,246,581	$2,174,111	$2,246,581	$2,215,048	$2,246,581	$20,636,256
PECO	$2,660,069	$2,402,643	$2,660,069	$2,574,260	$2,660,069	$5,142,792	$5,314,219	$5,314,219	$5,142,792	$5,314,219	$2,174,111	$5,314,219	$46,673,680
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,107,926	$1,144,857	$2,884,571	$2,980,723	$2,980,723	$2,884,571	$2,980,723	$5,142,792	$2,980,723	$28,411,388
Pepco	$1,906,591	$1,722,082	$1,906,591	$1,845,088	$1,906,591	$4,092,964	$4,229,396	$4,229,396	$4,092,964	$4,229,396	$2,884,571	$4,229,396	$37,275,024
PPL	$3,247,272	$2,933,020	$3,247,272	$3,142,521	$3,247,272	$7,019,745	$7,253,736	$7,253,736	$7,019,745	$7,253,736	$4,092,964	$7,253,736	$62,964,755
PSEG	$2,354,400	$2,126,555	$2,354,400	$2,278,452	$2,354,400	$8,574,172	$8,859,978	$8,859,978	$8,574,172	$8,859,978	$7,019,745	$8,859,978	$71,076,209
RECO	$14,896	$13,454	$14,896	$14,415	$14,896	$249,408	$257,721	$257,721	$249,408	$257,721	$249,408	$257,721	$1,851,664
Total	$22,721,111	$20,522,294	$22,721,111	$21,988,172	$22,721,111	$45,921,805	$47,452,531	$47,452,531	$45,921,805	$47,452,531	$37,605,354	$47,452,531	$429,932,888

Table 6-11 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 and 2013/2014 Delivery Year. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources increased by 63 percent from 631.2 MW in 2012/2013 to 1,029.2 MW in 2013/2014 Delivery Year.

Table 6-11 Energy efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
	2012/ 2013	2013/ 2014	Percentage Change	2012/ 2013	2013/ 2014	Percentage Change
Total	609.8	990.9	62%	631.2	1,029.2	63%

Table 6-12 shows the MW registered by measurement and verification method and by load drop method. Of the DR MW committed, 5.5 percent use the guaranteed load drop (GLD) measurement and verification method, 86.5 percent use firm service level (FSL) method and 8.0 percent use direct load control (DLC).

Table 6-12 Reduction MW by each demand response method: 2013/2014 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other MW	Total	Percentage by type
Firm Service Level	1,887.0	2,164.1	289.3	857.5	3,487.9	123.7	253.0	9,062.5	86.5%
Guaranteed Load Drop	77.1	287.1	1.2	145.9	44.9	0.9	18.8	575.9	5.5%
Non hourly metered sites (DLC)	0.0	770.4	0.0	0.0	0.0	68.9	0.0	839.2	8.0%
Total	1,964.1	3,221.5	290.5	1,003.4	3,532.8	193.5	271.9	10,477.7	100.0%
Percentage by method	18.7%	30.7%	2.8%	9.6%	33.7%	1.8%	2.6%	100.0%	

The program type is submitted as "Other" for 2.6 percent of committed MW, which does not explain how the reduction occurs. The choice of other is no longer a valid option for new registrations as of the 2014/2015 Delivery Year.

Table 6-13 shows the fuel type used in the on-site generators identified in Table 6-12. Of the 18.7 percent of emergency demand response identified as using on-site generation, 81.8 percent of MW are diesel, 5.2 percent are natural gas and 12.9 percent is coal, oil, other or no fuel source.[11]

Table 6-13 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal, Oil, Other	16.5	0.8%
Diesel	1,606.7	81.8%
Natural Gas	102.9	5.2%
None	238.0	12.1%
Total	1,964.0	100.00%

11 Since 2.6 percent of committed MW are registered under the other option, the 18.7 percent of emergency load response resources registered with on-site generation could be conservatively low.

Emergency Event Reported Compliance

In 2013, PJM declared five emergency events in the 2013/2014 Delivery Year, on July 15, July 16, July 18, September 10 and September 11. There were two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of these events occurred within the summer compliance period, all were considered in PJM's compliance assessment. Table 6-14 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM increased from 1.4 percent in the 2011/2012 Delivery Year to 6.7 percent of capacity resources in the 2013/2014 Delivery Year.

Table 6-14 Demand response cleared MW UCAP for PJM: 2011/2012 through 2013/2014 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%

Table 6-15 lists PJM emergency load management events declared by PJM in 2013 and the affected zones. The ATSI Control Zone was called for all five events.

The emergency demand response program currently settles on the average performance by registration for the duration of a demand response event. Demand response should measure compliance based on each hour to accurately report reductions during demand response events. This would be consistent with the rules that apply to generation resources. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.

Table 6-15 PJM declared load management events: 2013

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical Area
15-Jul-13	15:50-18:22	16:00-18:00	32	Long Lead	ATSI
16-Jul-13	13:30-16:30	14:00-16:00	60	Long Lead	ATSI
18-Jul-13	14:40-18:00	15:00-18:00	20	Long Lead	ATSI
	14:40-17:00	15:00-17:00	20	Long Lead	PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	AEP Canton Subzone
10-Sep-13	15:50-21:30	16:00-20:00	100	Long Lead	ATSI
	16:45-21:30	17:00-20:00	115	Long Lead	AEP Canton Subzone
11-Sep-13	13:30-19:30	14:00-19:00	60	Long Lead	AEP
	14:00-20:00	14:00-20:00	0	Long Lead	ATSI
	14:00-17:15	14:00-17:00	15	Short Lead	AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC Pepco, PPL, PSEG, RECO
	14:30-18:30	15:00-18:00	60	Long Lead	Dominion
	15:00-17:00	15:00-17:00	0	Long Lead	AECO, JCPL, PSEG, RECO
	15:00-17:30	15:00-17:30	30	Long Lead	Met-Ed, PECO, PPL
	15:00-18:00	15:00-18:00	0	Long Lead	BGE, DPL, Pepco
	15:00-18:30	15:00-18:00	30	Long Lead	PENELEC, DLCO

PJM deployed both long lead time resources, which require more than one hour but less than two hours notification, and short lead time resources, which require less than an hour notification during the 2013/2014 Delivery Year. Any resource is eligible to be either a short lead time or long lead time resource, and there are no differences in payment for these resources. Approximately 99.4 percent of registrations, accounting for 91.7 percent of registered MW, are designated as long lead time resources. The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources. This will enable quicker response and greater flexibility.

There were two events in 2013, on July 18, 2013 and September 10, 2013, for which PJM requested voluntary subzonal dispatch of emergency demand side resources. While PJM may voluntarily declare load management events for part of a zone, the only locational requirement for the aggregation of multiple participants to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal emergency events is aggregated for each CSP to a zonal level.

Subzonal dispatch by zip code is currently voluntary, but will be mandatory beginning with the 2014/2015 delivery year.[12] More locational deployment of load management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

12 If PJM Interconnection L.L.C., Docket No. ER14-822-000 (December 24, 2013) is approved by the FERC, the mandatory requirement for subzonal dispatch will be delayed until the 2015/2016 Delivery Year.

PJM ignores load increases from demand resources when calculating response and compliance. PJM calculates compliance for demand response events by reducing increases in load, negative compliance values, during an event to a zero MW reduction. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores the negative reduction value and instead replaces the value with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[13] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

Table 6-16 shows the performance for the July 15, 2013, event. The first column shows the nominated value, which is the reduction capability indicated by the participant at registration. The second column shows load management committed MW, which are used to assess RPM compliance. Differences between these two columns reflect, in part, differences between MW offered and cleared for any partially cleared DR. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for demand resources, while the nominated ICAP does not. The third column shows the reported load reduction in MWh, or the reported load drop during the hours of an event. The reported reduction does not include negative reductions, load increases. The reported reduction is as reported by PJM. The fourth column shows the observed load reduction in MWh, which includes all reported reduction values. The observed load reduction is as calculated by the MMU.

Table 6-16 Load management event performance: July 15, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	795.7	683.1	670.8	535.3	135.5	98.2%	78.4%
Total	795.7	683.1	670.8	535.3	135.5	98.2%	78.4%

Table 6-17 Load management event performance: July 16, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	795.7	683.1	637.9	519.7	118.2	93.4%	76.1%
Total	795.7	683.1	637.9	519.7	118.2	93.4%	76.1%

The ATSI Control Zone was called for the event on July 15, 2013. Overall, the PJM reported performance was 98.2 percent, or 670.8 MW out of 683.1 MW committed. The observed performance level was 78.4 percent compliance or 592.2 MW, a difference of 135.5 MW compared to the reported load reduction.

Table 6-17 shows the performance for the July 16, 2013, event. The ATSI Control Zone was called for the event on July 16, 2013. Overall, the PJM reported performance was 93.4 percent, or 637.9 MW out of 683.1 MW committed. The observed performance level was 76.1 percent compliance or 519.7 MW, a difference of 118.2 MW compared to the reported load reduction.

The ATSI Control Zone reduced 15.6 MW less on the July 16 event day compared to the July 15 event day. This reduction is consistent with the hypothesis that the response of demand resources declines when demand response events are called on successive days.

Table 6-18 shows the performance for the July 18, 2012 event. The ATSI, PECO, PPL and AEP Canton subzone zones were called for the event on July 18, 2013. Overall, the PJM reported performance was 93.3 percent, or 1,558.8 MW out of 1,671.7 MW committed. The observed performance level was 83.6 percent compliance or 1,396.9 MW, a difference of 161.9 MW compared to the reported load reduction. The ATSI and PECO zones had 88.9 and 92.2 percent reported compliance. The PPL Control Zone had 99.1 percent reported compliance. The AEP Canton subzone dispatch was not mandatory.

This was the third event for ATSI Control Zone during this week, and the compliance results decreased from an observed 535.3 MW reduction on July 15, 2013, to an observed 519.7 MW reduction on July 16 and an observed 519.5 MW reduction on July 18, 2013.

13 OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

Table 6-18 Load management event performance: July 18, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	796.2	683.1	607.3	519.5	87.8	88.9%	76.1%
PECO	580.0	410.1	378.2	331.3	46.9	92.2%	80.8%
PPL	751.5	578.5	573.4	546.1	27.3	99.1%	94.4%
Total	2,127.7	1,671.7	1,558.8	1,396.9	161.9	93.3%	83.6%

Table 6-19 shows the performance for the September 10, 2013 event. The ATSI and AEP Canton subzone zones were called for the event on September 10, 2013. Overall, the PJM reported performance was 94.1 percent, or 642.5 MW out of the 683.1 MW committed. The observed performance level was 77.9 percent compliance or 532.0 MW, a difference of 110.5 MW compared to the reported load reduction. The AEP Canton subzone dispatch was not mandatory. The event continued past the mandatory compliance period and the hourly data past the compliance period do not count towards the compliance value for PJM. After 2000 (EPT), limited demand response is considered voluntary curtailment.

This was the fourth event in the ATSI Control Zone and the second call for the AEP Canton subzone. The compliance results increased from an observed 519.5 MW reduction on July 18, 2013, to an observed 532.0 MW on September 10.

Table 6-19 Load management event performance: September 10, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
ATSI	799.4	683.1	642.5	532.0	110.5	94.1%	77.9%
Total	799.4	683.1	642.5	532.0	110.5	94.1%	77.9%

Table 6-20 shows the performance for the September 11, 2013 event. The AECO, AEP, ATSI, BGE, DLCO, Dominion, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO zones were called for the event on September 11, 2013. Overall, the PJM reported performance was 92.7 percent, or 5,623.7 MW out of the 6,064.9 MW committed. The observed performance level was 82.7 percent compliance or 5,017.0 MW, a difference of 606.7 MW compared to the reported load reduction. The short lead time resources covered three zones; Met-Ed, PENELEC, and RECO, that did not have any short lead time resources.

The BGE Control Zone performed at 107.3 percent observed compliance, or 672.7 MW. BGE has 787.7 nominated MW to cover their 627.2 committed MW obligation, resulting in the 107.3 percent observed compliance. The BGE Control Zone's performance compared to the committed MW level increased the overall compliance measured for all zones without BGE from 79.9 percent observed compliance to 82.7 percent observed compliance with BGE.

This was the fifth call in the ATSI Control Zone for the 2013/2014 Delivery Year, and its performance decreased to the lowest for all the events at 68.4 percent observed compliance, or 467.2 MW.

Table 6-20 Load management event performance: September 11, 2013

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	114.7	102.5	91.8	86.4	5.4	89.6%	84.3%
AEP	1,576.0	1,252.0	1,243.0	1,131.3	111.7	99.3%	90.4%
ATSI	800.0	683.1	601.4	467.2	134.2	88.0%	68.4%
BGE	787.7	627.2	690.3	672.7	17.6	110.1%	107.3%
BGE Long Lead	715.3	565.6	617.9	600.4	17.6	109.2%	106.1%
BGE Short Lead	72.4	61.6	72.4	72.4	0.0	117.5%	117.5%
DLCO	91.7	69.2	54.3	49.4	4.8	78.4%	71.4%
Dominion	863.1	757.0	683.0	621.4	61.6	90.2%	82.1%
DPL	250.7	220.3	221.8	208.2	13.7	100.7%	94.5%
DPL Long Lead	178.7	154.4	119.2	105.5	13.7	77.2%	68.3%
DPL Short Lead	72.0	65.9	102.7	102.7	0.0	155.8%	155.8%
JCPL	191.0	156.7	145.3	83.4	61.9	92.7%	53.2%
JCPL Lead Lead	171.1	136.8	120.3	58.4	61.9	87.9%	42.7%
JCPL Short Lead	19.9	19.9	25.0	25.0	0.0	125.6%	125.6%
Met-Ed	231.2	173.6	180.0	167.5	12.5	103.5%	96.3%
PECO	563.7	410.3	328.6	276.7	51.9	80.1%	67.4%
PENELEC	322.3	265.1	259.6	236.1	23.5	97.9%	89.1%
Pepco	700.2	372.0	304.9	294.9	10.0	82.0%	79.3%
Pepco Long Lead	203.9	200.3	160.8	150.8	10.0	80.3%	75.3%
Pepco Short Lead	496.3	171.7	144.1	144.1	0.0	83.9%	83.9%
PPL	790.2	621.1	611.7	565.6	46.1	98.5%	91.1%
PPL Long Lead	742.9	578.5	548.0	501.8	46.1	94.7%	86.8%
PPL Short Lead	47.2	42.6	63.8	63.8	0.0	149.6%	149.6%
PSEG	377.9	350.6	203.3	152.4	50.8	58.0%	43.5%
PSEG Long Lead	364.6	346.1	198.4	157.7	40.7	57.3%	45.6%
PSEG Short Lead	13.3	4.4	4.9	(5.3)	10.2	110.9%	(120.0%)
RECO	6.4	4.0	4.8	3.8	1.0	118.1%	93.5%
Total	7,666.7	6,064.9	5,623.7	5,017.0	606.7	92.7%	82.7%

Table 6-21 shows load management event performance for the five event days. RTO wide percent reported compliance was 93.3 percent in 2013 for resources called during emergency events, while observed compliance was 81.8 percent. The reported performance value treated locations showing increases in load, negative performance, as zero performance. The BGE Control Zone reported 110.1 percent compliance and observed 107.3 percent compliance were the highest in PJM, while the DLCO Control Zone observed 71.4 percent compliance and the JCPL Control Zone observed 53.2 percent observed compliance were the lowest.

The BGE Control Zone over performed by 45.5 MW which offset under performance in other zones. The observed compliance for all zones, excluding BGE, was 78.8 percent of the committed MW. The ATSI Control Zone had five calls and had an average 75.4 percent observed compliance. The JCPL Control Zone only had one event called during 2013, and had 53.2 percent observed compliance. Every zone underperformed compared to their nominated ICAP MW. CSPs have more MW registered than are committed in each zone to ensure deliverability at the committed MW level.

Table 6-21 Load management event performance: 2013 Aggregated

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	114.7	102.5	91.8	86.4	5.4	89.6%	84.3%
AEP	1,576.0	1,252.0	1,243.0	1,131.3	111.7	99.3%	90.4%
ATSI	797.4	683.1	625.8	514.7	111.1	91.6%	75.4%
BGE	787.7	627.2	690.3	672.7	17.6	110.1%	107.3%
DLCO	91.7	69.2	54.3	49.4	4.8	78.4%	71.4%
Dominion	863.1	757.0	683.0	621.4	61.6	90.2%	82.1%
DPL	250.7	220.3	221.8	208.2	13.7	100.7%	94.5%
JCPL	191.0	156.7	145.3	83.4	61.9	92.7%	53.2%
Met-Ed	231.2	173.9	180.0	167.5	12.5	103.5%	96.3%
PECO	571.8	410.3	353.4	304.0	49.4	86.1%	74.1%
PENELEC	322.3	265.1	259.6	236.1	23.5	97.9%	89.1%
Pepco	700.2	372.0	304.9	294.9	10.0	82.0%	79.3%
PPL	770.8	621.5	592.5	555.8	36.7	95.4%	89.5%
PSEG	377.9	350.6	203.3	152.4	50.8	58.0%	43.5%
RECO	6.4	4.0	4.8	3.8	1.0	118.1%	93.5%
Weighted Total	7,652.9	6,064.9	5,660.7	4,958.7	571.7	93.3%	81.8%

Table 6-22 Distribution of participant event days and nominated MW across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period

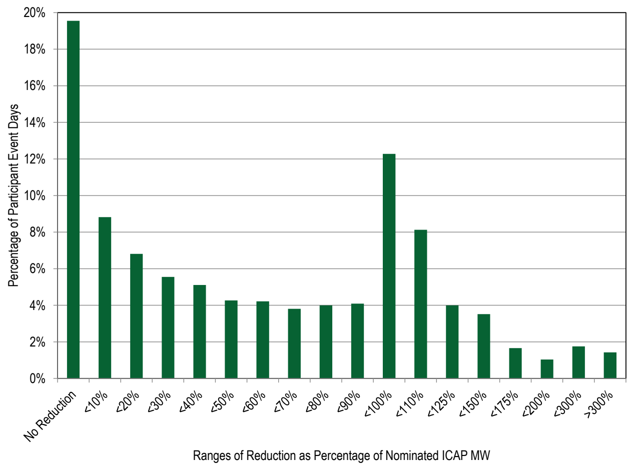
Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of Nominated MW
0%, load increase, or no reporting	2,974	20%	1,102	9%
0% - 10%	1,342	9%	790	6%
10% - 20%	1,036	7%	909	7%
20% - 30%	844	6%	435	4%
30% - 40%	777	5%	376	3%
40% - 50%	649	4%	323	3%
50% - 60%	641	4%	331	3%
60% - 70%	579	4%	523	4%
70% - 80%	608	4%	332	3%
80% - 90%	622	4%	479	4%
90% - 100%	1,868	12%	875	7%
100% - 110%	1,236	8%	3,411	28%
110% - 125%	608	4%	1,194	10%
125% - 150%	535	4%	631	5%
150% - 175%	252	2%	243	2%
175% - 200%	157	1%	155	1%
200% - 300%	267	2%	138	1%
> 300%	217	1%	136	1%
Total	15,212	100%	12,383	100%

Performance for specific customers varied significantly. Table 6-22 shows the distribution of participant event days across various levels of performance for July 15, July 16, July 18, September 10 and September 11, 2013, events in the 2013/2014 compliance period. Table 6-22 includes the participation for subzonal and zonal dispatch. For these events, 20 percent of participant event days showed no reduction, load increased or participants did not report data. Approximately 50 percent of participant event days provided less than half of their nominated MW, while 32 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, approximately 78 percent, provided less than 100 percent reduction compared to their nominated MW, while 52 percent of the nominated MW provided less than 100 percent reduction.

Figure 6-3 shows the data in Table 6-22.[14] The distribution includes high frequencies of both under performing and over performing registrations.

14 Participant event days, shown in Figure 6-3 shows the data in Table 6-22. The distribution includes high frequencies of both under performing and over performing registrations. Figure 6-3, and Table 6-22, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant event day. The load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Figure 6-3 Distribution of participant event days across ranges of performance levels across the event in the 2013/2014 Delivery Year compliance period



Testing of Emergency Resources

Load management must be tested if no emergency event is called in a specific zone by August 15 of the delivery year. All of a provider's committed emergency demand response resources in the same zone are required to test at the same time for a one hour period between 1200 (EPT) to 2000 (EPT) on a non-holiday weekday between June 1 and September 30. The resource provider must notify PJM of the intent to test 48 hours in advance.[15]

Depending on initial test results, multiple tests may be conducted. If a curtailment service provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

Table 6-23 Load management test results and compliance by zone for the 2013/2014 Delivery Year

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AP	1,375.8	511.2	1,241.9	1,209.6	32.3	242.9%	236.6%
ComEd	2,439.0	810.6	2,119.6	2,105.1	14.5	261.5%	259.7%
DAY, DEOK, EKPC	416.6	185.3	330.5	324.5	6.0	178.4%	175.1%
Total	4,359.4	1,623.8	3,970.9	3,927.4	43.5	244.5%	241.9%

There were 1,623.8 committed MW not deployed in an event during the compliance period for the 2013/2014 Delivery Year and thus required to perform testing.

Load management test results are shown in Table 6-23. Overall test results showed an observed 3,927.4 MW load reduction, or 241.9 percent compliance. There were an additional 2,735.6 MW nominated in the test zones compared to the committed MW, allowing for a higher potential compliance.

Load management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to a baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. Given prior warning of a test event, customers have time to prepare to drop load, unlike in a real emergency event in which a customer will only have one to two hours' notice before an event begins. Customers can test on any day in the summer period between the hours of 1200 (EPT) and 2000 (EPT). The baseline day must occur within the limited demand response resource window of June 1 to October 1 to establish comparability between the baseline day and test day.

The MMU recommends that the testing program be modified to require verification of test methods and results. Tests should be initiated by PJM without prior scheduling by CSPs in order to more accurately model demand response during an emergency event.

15 For more information, see PJM, "Manual 18, PJM Capacity Market," Revision 20 (November 21, 2013), Section 8.6.

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. Load management event rules allow over-compliance to be reported when there is no actual over-compliance. Settlement locations with a negative load reduction value (load increase) are not netted within registrations or a demand response portfolio. For example, if a registration had two locations, one with a 50 MWh load increase, and another with a 75 MWh load reduction, compliance for that registration is calculated at a 75 MWh load reduction for that event hour. Settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would show a 0 MWh reduction in hour one and a 30 MWh reduction in hour two and an average hourly 15 MWh load reduction for that two hour event. Reported compliance is less than actual compliance, as locations with load increases, negative reductions, are treated as zero for compliance purposes. Overall, 14 percent of event hours demonstrated negative reductions or no reduction in load.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 6.8 percent of locations were not submitted to PJM for compliance purposes. While the performance of these resources is not known, it is reasonable to assume, given the incentives to report reductions, that these locations had negative compliance (load increases relative to baseline), further skewing reported compliance values and performance penalties. Registrations with negative compliance are treated as zero for the purposes of imposing penalties and reporting.

Table 6-24 shows the number of locations that did not report during 2013 event days. In total, 6.8 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 3.2 percent of all nominated MW for those events. It is likely that these locations were not responding to the emergency event and had loads greater than their committed MW for those locations, and the corresponding registrations.

Table 6-24 Non-reporting locations and nominated ICAP on 2013 event days

	Locations Not Reporting	Percent Non Reporting	Nominated ICAP Not Reporting	Percent Non Reporting
Total	1,231	6.8%	420	3.2%

Emergency Energy Payments

For any PJM declared load management event in 2013, participants registered under the full option of the emergency load response program that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The emergency energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800 per MWh. The maximum offer increases to $2,100 per MWh for the 2014/2015 Delivery Year and $2,700 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[16]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-25 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices. The majority of participants, 65.9 percent, have a minimum dispatch price of $1,000 per MWh, 1.5 percent of participants have a dispatch price of $1,001 per MWh to $1,799 per MWh and 17.7 percent of participants have a dispatch price of $1,800 per MWh, which is the maximum price allowed for the 2013/2014 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2013/2014 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $500 to $800 strike prices had the highest average at $3,262.88 per location.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) recently approved changes in Manual 15 to eliminate shutdown costs for demand response resources participating in the

16 139 FERC ¶ 61,057 (2012).

Synchronized Reserve Market, but not the emergency or economic demand response program.[17]

Table 6-25 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices effective for the 2013/2014 Delivery Year[18]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	694	4.7%	1,036.5	9.8%	$0.00
$1-$200	1,204	8.2%	539.3	5.1%	$409.39
$200-$500	179	1.2%	107.2	1.0%	$171.23
$500-$800	66	0.4%	84.0	0.8%	$3,262.88
$800-$999	56	0.4%	52.9	0.5%	$622.59
1000	9,719	65.9%	6,685.6	63.1%	$28.14
$1,001-$1,799	219	1.5%	250.0	2.4%	$879.68
1800	2,619	17.7%	1,833.4	17.3%	$0.00
Total	14,756	100.0%	10,588.9	100.0%	$84.03

Table 6-26 shows emergency credits for each event in 2013 by zone. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market.[19] Emergency demand response energy costs are not covered by LMP. All demand response energy payments and shutdown costs are out of market payments. These payments are a form of uplift.

LMP in the ATSI Control Zone was $1,705.04 per MWh on average during the July 18, 2013, event, resulting in total emergency demand response costs in the ATSI Control Zone of $1.8 million. Total emergency credits for the emergency event days were $36,730,878.23.

Table 6-26 Emergency credits by event by zone: 2013

Event	Zone	Total
15-Jul-13	ATSI	$1,599,802.92
16-Jul-13	ATSI	$1,827,507.29
18-Jul-13	AEP	$696,926.40
	ATSI	$1,766,836.50
	PECO	$1,374,163.36
	PPL	$2,185,842.11
10-Sep-13	AEP	$845,091.99
	ATSI	$878,740.70
11-Sep-13	AECO	$209,208.82
	AEP	$9,166,436.46
	ATSI	$838,112.95
	BGE	$3,666,790.23
	DLCO	$259,868.34
	Dominion	$2,804,228.14
	DPL	$684,296.56
	JCPL	$315,112.76
	Met-Ed	$884,050.38
	PECO	$1,606,267.08
	PENELEC	$1,144,191.49
	Pepco	$639,505.99
	PPL	$2,622,194.49
	PSEG	$704,086.18
	RECO	$11,617.09
Total		$36,730,878.23

Energy payments in the emergency program differ significantly from energy payments in the economic program and from capacity payments through the emergency load response program in that they are not based on or tied to any market price signal. Once an event is called in a zone, these payments are guaranteed if a resource is determined to have responded.

17 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.

18 In this analysis nominated MW does not include capacity only resources, which do not receive energy market revenue.

19 PJM. "Manual 28: Operating Agreement Accounting," Revision 59 (April 22, 2013), p. 65.

Limited Demand Resource Penalty Charge

Limited demand response resources are required to be available for only 10 times during the months of June through September in a delivery year on weekdays other than PJM holidays from 1200 (EPT)to 2000 (EPT) and be capable of maintaining an interruption for a minimum of two hours to maximum of six hours. Limited demand response resources have one or two hours to reduce load once PJM initiates an event. When a provider under complies based on their committed MW, a penalty is charged. The penalty is based on the amount of under compliance, the number of events called during the DY and the cost per MW day for that provider. DR penalties are only assessed for PJM initiated events, after a compliance review is complete.

Subzonal dispatch was voluntary, so there were no penalties assessed based on the AEP Canton Subzone dispatch. The penalties are assessed daily and have increased by $6,371,193.23 from $1,194,706.36 in June through December of the 2012/2013 Delivery Year compared to $7,565,899.59 of the same period in the 2013/2014 Delivery Year. Table 6-27 shows penalty charges by zone for June through September of the 2012/2013 and 2013/2014 Delivery Year. The PECO Control Zone had the highest penalty amount, due to the clearing prices in EMAAC and a reported performance at 93.2 percent of the committed MW.[20] The penalty charges represent 2.4 percent of the capacity credits for the 2013/2014 Delivery Year and 0.8 percent of the capacity credits for the 2012/2013 Delivery Year.

Table 6-27 Penalty charges per zone: June through September 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$53.50	$47,916.54
AEP	$84,134.10	$217,538.25
AP	$0.00	$0.00
ATSI	$0.00	$501,318.87
BGE, Met-Ed, Pepco	$372,156.70	$909,172.89
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$34,603.80	$113,197.17
DPL	$434,306.58	$284,574.63
DLCO	$0.00	$28,433.82
EKPC	$0.00	$0.00
JCPL	$3,126.54	$220,683.18
PECO	$234,171.64	$2,747,982.66
PENELEC	$25,836.22	$159,393.87
PPL	$348.82	$1,571,637.36
PSEG, RECO	$5,968.46	$764,050.35
Total	$1,194,706.36	$7,565,899.59

20 Refer to Section 5: Capacity, Table 5-11 for complete listing of capacity prices.

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Fuel prices and energy prices were higher in 2013 than in 2012 and capacity market prices were higher in 2013 in 10 eastern zones and lower in six western zones, AEP, AP, ComEd, DAY, DLCO, and Dominion.
- In 2013, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone. But the net revenue results for a new CT bifurcate the zones into two groups with very different results. There are ten eastern zones in which net revenues cover more than 75 percent of levelized fixed costs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six western zones net revenues cover less than 30 percent of levelized fixed costs with the lowest zone at 18 percent. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets. Covering 75 percent of levelized fixed costs would result in a rate of return slightly less than half the rate of return included in the calculation of levelized fixed costs.
- In 2013, the net revenue results for a new CC also bifurcate the zones into two groups with very different results. There are ten eastern zones in which net revenues cover more than 95 percent of levelized fixed costs. These are the same ten zones with higher net revenues for CTs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six western zones net revenues cover less than 65 but more than 33 percent of levelized fixed costs. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets.
- In 2013, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone. The results for CPs are relatively uniform. A new CP would not have received sufficient net revenue to cover more than 30 percent of levelized fixed costs in any zone. However, the results for CPs in 2013 are better than they were in 2012 based on higher energy market net revenues in all but one zone and higher capacity market revenues in ten zones. These are the same ten eastern zones that increased the net revenue results for both CTs and CCs. All but two zones showed increases in the coverage of fixed costs by CPs in 2013.
- In 2013, a new nuclear plant in the western AEP zone would not have received sufficient net revenue to cover levelized fixed costs. The combination of lower energy market revenues and lower capacity market revenues in the AEP zone, similar to the other western zones, than in the eastern zones resulted in a covering only 30 percent of the annual fixed costs for a nuclear power plant.
- In 2013, actual net revenues covered more than 75 percent of the annual levelized fixed costs of a new entrant wind installation and over 200 percent of the annual levelized fixed costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for more than 40 percent of the net revenue of a wind installation and more than 75 percent of the net revenue of a solar installation.
- In 2013, a substantial portion of units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM capacity market in providing incentives for continued operation and investment. Capacity market revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM, with the exception of some coal units and some oil or gas steam units.
- The actual net revenue results mean that 14,597 MW of capacity in PJM are at risk of retirement in addition to the 24,933 MW that are currently planning to retire.

Conclusion

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

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. The actual net revenue results illustrate that a significant amount of generation in PJM relies on the capacity market to cover the gap between energy market net revenues and avoidable costs. Capacity market revenues are critical to covering total costs including fixed costs.

The net revenue results also demonstrate the significance of capacity market design. Capacity market prices have been suppressed by a number of market design factors. These factors, including an inappropriate definition of capacity imports has led to especially low capacity market prices in the western part of the system. The impacts of this are clearly shown in the bifurcation of net revenue results between the eastern and western zones in PJM.

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

Net Revenue

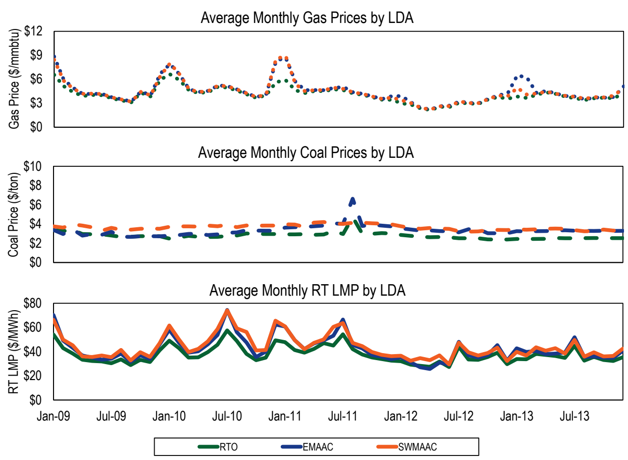
When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators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

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

Operating reserve (uplift) payments are included when the analysis is based on the peak-hour, economic dispatch model and when the analysis uses actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 9.7 percent higher in 2013 than in 2012, $38.66 per MWh versus $35.23 per MWh. Comparing fuel prices in 2013 to 2012, the price of Northern Appalachian coal was 1.0 percent higher; the price of Central Appalachian coal was 0.3 percent higher; the price of Powder River Basin coal was 20.0 percent higher; the price of eastern natural gas was 40.0 percent higher; and the price of western natural gas was 32.0 percent higher.

Figure 7-1 Energy Market net revenue factor trends: 2009 through 2013



Theoretical Energy Market Net Revenue

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

Analysis of energy market net revenues for a new entrant includes eight power plant configurations:

- The CT plant has an installed capacity of 410.2 MW and consists of two GE Frame 7FA.05 CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 655.7 MW and consists of two GE Frame 7FA.05 CTs equipped with evaporative cooling, duct burners a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.[2]
- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology.
- The wind installation consists of twenty GE 2.5 MW wind turbines totaling 50 MW installed capacity.
- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[3,4] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included

1 The peak-hour, economic dispatch model is a realistic representation of market outcomes that considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

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

3 Hourly ambient conditions supplied by Schneider Electric.

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

in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[5]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[6] Each CT, CC, CP, and DS plant was also given a continuous 14 day planned annual outage in the fall season. Ancillary service revenues for the provision of synchronized reserve service for all four plant types are set to zero. Ancillary service revenues for the provision of regulation service were calculated for the CP only. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour. No black start service capability is assumed for any of the unit types.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 30 or fewer operating years.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[7] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[8] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[9]

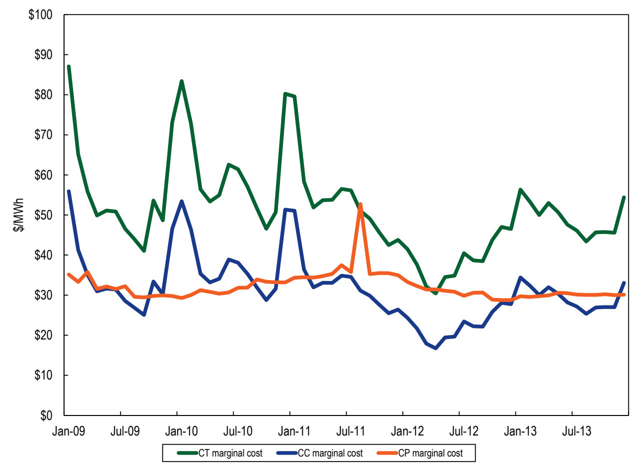
Operating costs are the marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[10] Average zonal operating costs in 2013 are shown in Table 7-1.

Table 7-1 Average zonal operating costs

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$49.10	10,241	$8.59
CC	$29.34	7,127	$1.50
CP	$29.98	9,250	$3.32
DS	$220.21	9,660	$12.50

Increasing gas prices caused the average zonal operating cost of a CC to rise above the average zonal operating cost of a CP by the end of the 2013 as shown in Figure 7-2.

Figure 7-2 Average zonal operating costs: 2009 through 2013



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

5 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
6 Outage figures obtained from the PJM eGADS database.
7 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
8 Gas daily cash prices obtained from Platts.
9 Coal prompt prices obtained from Platts.
10 VOM rates provided by Pasteris Energy, Inc.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2013 includes five months of the 2012/2013 RPM auction clearing price and seven months of the 2013/2014 RPM auction clearing price.[11] These capacity revenues are adjusted for the yearly, system wide forced outage rate.

Table 7-2 Capacity revenue by PJM zones (Dollars per MW-year): 2009 through 2013[12]

Zone	2009	2010	2011	2012	2013	Average
AECO	$58,586	$61,406	$45,938	$43,138	$67,616	$55,336
AEP	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
AP	$53,440	$61,406	$45,938	$18,730	$7,743	$37,451
ATSI	NA	NA	NA	NA	NA	NA
BGE	$76,236	$67,851	$45,938	$41,878	$63,023	$58,985
ComEd	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
DAY	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
DEOK	NA	NA	NA	NA	$7,743	$7,743
DLCO	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
Dominion	$35,789	$48,898	$45,938	$18,730	$7,743	$31,419
DPL	$58,586	$62,251	$46,530	$48,399	$71,305	$57,414
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$58,586	$61,406	$45,938	$43,138	$67,616	$55,336
Met-Ed	$53,440	$61,406	$45,938	$41,878	$63,023	$53,137
PECO	$58,586	$61,406	$45,938	$43,138	$67,616	$55,336
PENELEC	$53,440	$61,406	$45,938	$41,837	$62,994	$53,123
Pepco	$76,236	$67,851	$45,938	$41,878	$67,154	$59,811
PPL	$53,440	$61,406	$45,938	$41,878	$63,023	$53,137
PSEG	$58,586	$61,406	$45,938	$46,223	$69,779	$56,386
RECO	NA	NA	NA	NA	NA	NA
PJM	$48,385	$56,226	$45,956	$30,354	$33,657	$42,916

New Entrant Combustion Turbine

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

Table 7-3 PJM-wide net revenue for a CT under economic dispatch by market (Dollars per installed MW-year): 2009 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$9,945	$48,385	$0	$0	$887	$59,216
2010	$32,781	$56,226	$0	$0	$4,320	$93,327
2011	$36,103	$45,956	$0	$0	$3,587	$85,647
2012	$23,240	$30,354	$0	$0	$891	$54,485
2013	$19,004	$33,657	$0	$0	$1,296	$53,958

Table 7-4 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through 2013[13]

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$12,421	$40,037	$46,156	$25,015	$20,835	(17%)
AEP	$3,696	$11,575	$20,838	$16,262	$12,535	(23%)
AP	$11,136	$32,494	$32,958	$21,028	$17,091	(19%)
ATSI	NA	NA	NA	$18,295	$15,402	(16%)
BGE	$15,126	$52,411	$48,640	$36,305	$29,602	(18%)
ComEd	$2,445	$9,446	$15,081	$13,780	$10,381	(25%)
DAY	$3,313	$11,701	$21,704	$18,572	$12,559	(32%)
DEOK	NA	NA	NA	$16,003	$12,036	(25%)
DLCO	$4,471	$17,525	$24,178	$18,772	$14,499	(23%)
Dominion	$15,253	$42,922	$38,944	$25,374	$20,253	(20%)
DPL	$13,886	$40,530	$44,338	$32,585	$24,545	(25%)
EKPC	NA	NA	NA	NA	$10,507	NA
JCPL	$11,994	$39,409	$44,967	$24,115	$25,778	7%
Met-Ed	$11,083	$39,409	$40,800	$25,395	$20,492	(19%)
PECO	$10,611	$38,311	$45,852	$25,882	$19,688	(24%)
PENELEC	$6,986	$24,309	$32,089	$22,461	$21,779	(3%)
Pepco	$17,798	$50,906	$44,232	$32,009	$27,977	(13%)
PPL	$10,045	$33,649	$42,870	$22,816	$19,895	(13%)
PSEG	$10,079	$37,626	$37,927	$24,080	$20,872	(13%)
RECO	$8,717	$35,022	$32,177	$22,807	$23,363	2%
PJM	$9,945	$32,781	$36,103	$23,240	$19,004	(18%)

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

12 No resources in ATSI cleared in the relevant auctions. There are no capacity resources in the EKPC or RECO zones.

13 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

Table 7-5 Zonal combined net revenue from all markets for a CT under economic dispatch (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$71,894	$105,763	$95,680	$69,044	$89,747	30%
AEP	$40,371	$64,793	$70,363	$35,882	$21,573	(40%)
AP	$65,464	$98,220	$82,483	$40,648	$26,129	(36%)
ATSI	NA	NA	NA	NA	NA	NA
BGE	$92,249	$124,583	$98,165	$79,074	$93,921	19%
ComEd	$39,120	$62,665	$64,605	$33,400	$19,420	(42%)
DAY	$39,989	$64,919	$71,229	$38,193	$21,597	(43%)
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$41,146	$70,743	$73,702	$38,393	$23,537	(39%)
Dominion	$51,928	$96,141	$88,469	$44,994	$29,292	(35%)
DPL	$73,358	$107,101	$94,455	$81,876	$97,146	19%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$71,466	$105,135	$94,491	$68,144	$94,690	39%
Met-Ed	$65,410	$105,135	$90,325	$68,164	$84,811	24%
PECO	$70,083	$104,037	$95,377	$69,911	$88,599	27%
PENELEC	$61,314	$90,035	$81,614	$65,189	$86,068	32%
Pepco	$94,921	$123,078	$93,756	$74,778	$96,427	29%
PPL	$64,372	$99,375	$92,395	$65,585	$84,214	28%
PSEG	$69,552	$103,352	$87,452	$71,194	$91,948	29%
RECO	NA	NA	NA	NA	NA	NA
PJM	$59,216	$93,327	$85,647	$54,485	$53,958	(1%)

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. For this economic dispatch scenario, it was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs.[14] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day ahead or real time block.

New entrant CC plant energy market net revenues were generally lower in 2013 as a result of the interaction between the relative costs of gas and coal and energy market prices.

Table 7-6 PJM-wide net revenue for a CC under economic dispatch by market (Dollars per installed MW-year): 2009 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$52,260	$48,385	$0	$0	$1,641	$102,286
2010	$89,027	$56,226	$0	$0	$762	$146,014
2011	$106,616	$45,956	$0	$0	$964	$153,536
2012	$97,259	$30,354	$0	$0	$1,608	$129,221
2013	$81,012	$33,657	$0	$0	$269	$114,939

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

Table 7-7 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$62,063	$106,643	$126,866	$101,147	$87,580	(13%)
AEP	$29,759	$47,591	$82,321	$87,906	$67,040	(24%)
AP	$59,052	$91,032	$113,559	$100,496	$80,861	(20%)
ATSI	NA	NA	NA	$94,384	$78,928	(16%)
BGE	$70,571	$124,665	$130,803	$123,364	$105,312	(15%)
ComEd	$20,613	$33,906	$46,291	$61,752	$42,434	(31%)
DAY	$27,904	$46,647	$82,064	$93,514	$70,151	(25%)
DEOK	NA	NA	NA	$82,041	$69,498	(15%)
DLCO	$27,649	$51,180	$81,639	$89,178	$64,735	(27%)
Dominion	$68,932	$116,873	$114,527	$103,607	$84,077	(19%)
DPL	$64,321	$106,245	$123,597	$114,805	$93,469	(19%)
EKPC	NA	NA	NA	NA	$47,065	NA
JCPL	$61,477	$105,474	$124,875	$100,383	$95,950	(4%)
Met-Ed	$55,400	$97,665	$111,650	$96,015	$83,610	(13%)
PECO	$57,843	$99,951	$121,801	$98,148	$81,262	(17%)
PENELEC	$48,876	$80,773	$109,045	$106,233	$104,603	(2%)
Pepco	$71,959	$121,952	$121,141	$115,688	$100,910	(13%)
PPL	$52,285	$87,314	$111,108	$91,724	$81,294	(11%)
PSEG	$57,910	$101,819	$114,948	$96,614	$88,596	(8%)
RECO	$51,808	$93,724	$96,232	$90,921	$92,865	2%
PJM	$52,260	$89,027	$106,616	$97,259	$81,012	(17%)

Table 7-8 Zonal combined net revenue from all markets for a CC under economic dispatch (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$122,290	$168,811	$173,768	$145,892	$155,464	7%
AEP	$67,189	$97,252	$129,223	$108,243	$75,051	(31%)
AP	$114,134	$153,200	$160,460	$120,834	$88,873	(26%)
ATSI	NA	NA	NA	NA	NA	NA
BGE	$148,448	$193,279	$177,704	$166,850	$168,604	1%
ComEd	$58,043	$83,567	$93,193	$82,089	$50,446	(39%)
DAY	$65,333	$96,308	$128,966	$113,852	$78,163	(31%)
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$65,078	$100,841	$128,541	$109,515	$72,747	(34%)
Dominion	$106,362	$166,534	$161,429	$123,945	$92,089	(26%)
DPL	$124,547	$169,258	$171,090	$164,812	$165,043	0%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$121,704	$167,642	$171,777	$145,129	$163,835	13%
Met-Ed	$110,482	$159,833	$158,551	$139,501	$146,902	5%
PECO	$118,069	$162,119	$168,703	$142,894	$149,146	4%
PENELEC	$103,957	$142,941	$155,947	$149,678	$167,866	12%
Pepco	$149,836	$190,565	$168,042	$159,174	$168,333	6%
PPL	$107,366	$149,481	$158,010	$135,211	$144,586	7%
PSEG	$118,137	$163,986	$161,850	$144,446	$158,645	10%
RECO	NA	NA	NA	NA	NA	NA
PJM	$102,286	$146,014	$153,536	$129,221	$114,939	(11%)

New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 7-9 PJM-wide net revenue for a CP by market (Dollars per installed MW-year): 2009 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$62,062	$48,385	$0	$2,213	$286	$112,945
2010	$119,478	$56,226	$0	$898	$601	$177,203
2011	$73,178	$45,956	$0	$1,025	$272	$120,431
2012	$34,410	$30,354	$0	$1,154	$117	$66,034
2013	$61,339	$33,657	$0	$2,187	$2,876	$100,059

Table 7-10 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$87,901	$149,022	$75,325	$23,302	$41,305	77%
AEP	$19,251	$56,227	$72,858	$41,246	$77,765	89%
AP	$49,303	$98,671	$99,020	$54,555	$89,641	64%
ATSI	NA	NA	NA	$47,276	$90,238	91%
BGE	$46,299	$80,689	$56,940	$23,391	$50,867	117%
ComEd	$42,738	$106,599	$94,493	$53,815	$57,925	8%
DAY	$27,905	$77,082	$65,842	$43,029	$91,857	113%
DEOK	NA	NA	NA	$36,521	$81,303	123%
DLCO	$22,971	$76,395	$47,075	$43,906	$20,885	(52%)
Dominion	$46,756	$144,290	$77,310	$17,548	$106,130	505%
DPL	$38,833	$147,279	$94,908	$29,103	$42,291	45%
EKPC	NA	NA	NA	NA	$32,142	NA
JCPL	$74,389	$147,559	$71,437	$30,519	$47,574	56%
Met-Ed	$57,888	$139,228	$61,703	$38,563	$38,916	1%
PECO	$78,602	$142,542	$74,834	$24,475	$37,354	53%
PENELEC	$77,650	$122,426	$95,440	$52,899	$103,732	96%
Pepco	$70,058	$160,627	$73,476	$23,707	$47,769	101%
PPL	$71,601	$114,549	$76,697	$18,080	$37,379	107%
PSEG	$171,879	$124,533	$47,550	$22,590	$63,026	179%
RECO	$71,025	$143,410	$59,111	$29,259	$68,678	135%
PJM	$62,062	$119,478	$73,178	$34,410	$61,339	78%

Table 7-11 Zonal combined net revenue from all markets for a CP (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$148,766	$211,834	$122,803	$68,057	$114,314	68%
AEP	$57,769	$106,816	$120,002	$60,960	$90,366	48%
AP	$105,209	$161,578	$146,086	$74,196	$102,069	38%
ATSI	NA	NA	NA	NA	NA	NA
BGE	$125,422	$150,436	$104,233	$66,784	$119,146	78%
ComEd	$81,344	$157,093	$141,510	$73,666	$70,859	(4%)
DAY	$66,301	$127,524	$112,974	$62,727	$104,310	66%
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$61,485	$126,935	$94,132	$63,737	$34,689	(46%)
Dominion	$85,174	$194,621	$124,773	$37,890	$118,355	212%
DPL	$100,379	$210,936	$142,910	$78,990	$119,042	51%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$135,346	$210,360	$118,692	$74,961	$120,469	61%
Met-Ed	$113,865	$202,056	$108,848	$81,612	$107,399	32%
PECO	$139,510	$205,362	$121,945	$69,115	$110,468	60%
PENELEC	$133,259	$185,220	$142,324	$95,700	$171,249	79%
Pepco	$148,753	$229,888	$120,561	$67,029	$120,239	79%
PPL	$127,425	$177,453	$123,816	$61,532	$105,906	72%
PSEG	$232,222	$187,396	$95,621	$70,346	$137,820	96%
RECO	NA	NA	NA	NA	NA	NA
PJM	$112,945	$177,203	$120,431	$66,034	$100,059	52%

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

Table 7-12 PJM-wide net revenue for a DS by market (Dollars per installed MW-year): 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$2,914	$48,385	$0	$0	$0	$51,298
2010	$6,491	$56,226	$0	$0	$0	$62,716
2011	$4,391	$45,956	$0	$0	$0	$50,348
2012	$1,579	$30,354	$0	$0	$0	$31,932
2013	$2,368	$33,657	$0	$0	$0	$36,026

Table 7-13 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$3,778	$10,802	$6,783	$1,586	$1,122	(29%)
AEP	$392	$490	$1,725	$844	$503	(40%)
AP	$2,081	$1,743	$2,019	$1,087	$771	(29%)
ATSI	NA	NA	NA	$1,109	$23,776	2,044%
BGE	$5,594	$13,673	$7,961	$2,619	$2,758	5%
ComEd	$107	$473	$817	$928	$399	(57%)
DAY	$375	$545	$1,906	$971	$535	(45%)
DEOK	NA	NA	NA	$708	$477	(33%)
DLCO	$758	$2,882	$2,180	$941	$1,269	35%
Dominion	$5,265	$10,589	$4,172	$1,700	$1,600	(6%)
DPL	$4,926	$9,548	$5,842	$2,431	$1,125	(54%)
EKPC	NA	NA	NA	NA	$297	NA
JCPL	$3,829	$8,364	$6,681	$1,741	$2,083	20%
Met-Ed	$3,343	$8,422	$5,093	$1,866	$1,292	(31%)
PECO	$3,300	$8,266	$5,446	$1,967	$1,024	(48%)
PENELEC	$829	$1,102	$2,671	$2,167	$1,141	(47%)
Pepco	$5,955	$12,838	$6,149	$2,046	$2,332	14%
PPL	$3,079	$7,428	$5,380	$1,782	$1,088	(39%)
PSEG	$3,187	$7,142	$5,519	$1,730	$1,302	(25%)
RECO	$2,733	$6,038	$4,310	$1,771	$2,469	39%
PJM	$2,914	$6,491	$4,391	$1,579	$2,368	50%

Table 7-14 Zonal combined net revenue from all markets for a DS (Dollars per installed MW-year): 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AECO	$62,363	$72,207	$52,721	$44,724	$69,860	56%
AEP	$36,180	$49,388	$47,662	$19,573	$8,749	(55%)
AP	$55,521	$63,149	$47,957	$19,816	$9,284	(53%)
ATSI	NA	NA	NA	NA	NA	NA
BGE	$81,830	$81,524	$53,899	$44,498	$65,781	48%
ComEd	$35,895	$49,371	$46,755	$19,658	$8,141	(59%)
DAY	$36,163	$49,443	$47,844	$19,700	$8,277	(58%)
DEOK	NA	NA	NA	NA	NA	NA
DLCO	$36,546	$51,781	$48,118	$19,671	$9,011	(54%)
Dominion	$41,054	$59,488	$50,110	$20,429	$9,342	(54%)
DPL	$63,511	$71,799	$52,372	$50,830	$72,431	42%
EKPC	NA	NA	NA	NA	NA	NA
JCPL	$62,415	$69,770	$52,618	$44,878	$69,699	55%
Met-Ed	$56,784	$69,828	$51,031	$43,744	$64,315	47%
PECO	$61,885	$69,672	$51,384	$45,105	$68,639	52%
PENELEC	$54,269	$62,508	$48,609	$44,003	$64,135	46%
Pepco	$82,191	$80,689	$52,087	$43,924	$69,486	58%
PPL	$56,519	$68,834	$51,317	$43,660	$64,111	47%
PSEG	$61,772	$68,547	$51,456	$47,953	$71,081	48%
RECO	NA	NA	NA	NA	NA	NA
PJM	$51,298	$62,716	$50,348	$31,932	$36,026	13%

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant located in the AEP Zone was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

Table 7-15 PJM-wide net revenue for a nuclear plant by market (Dollars per installed MW-year): 2012 through 2013

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
2009	$218,504	$35,789	$0	$0	$0	$254,293
2010	$261,098	$48,898	$0	$0	$0	$309,996
2011	$270,022	$45,938	$0	$0	$0	$315,960
2012	$201,658	$18,730	$0	$0	$0	$220,387
2013	$233,502	$7,743	$0	$0	$0	$241,244

Table 7-16 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2012 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AEP	$218,504	$261,098	$270,022	$201,658	$233,502	16%

Table 7-17 Zonal combined net revenue from all markets for a nuclear plant (Dollars per installed MW-year): 2012 through 2013

Zone	2009	2010	2011	2012	2013	Change in 2013 from 2012
AEP	$254,293	$309,996	$315,960	$220,387	$241,244	9%

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power. Capacity revenue was calculated using a 13 percent capacity factor. Wind net revenues include both production tax credits and RECs.

Table 7-18 ComEd net revenue for a wind installation by market (Dollars per installed MW-year): 2012 through 2013

ComEd	Energy	Credits	Capacity	Total	Change (%)
2012	$67,294	$57,709	$2,435	$127,438	NA
2013	$82,934	$62,837	$1,007	$146,777	15.2%

Table 7-19 PENELEC net revenue for a wind installation by market (Dollars per installed MW-year): 2012 through 2013

PENELEC	Energy	Credits	Capacity	Total	Change (%)
2012	$68,913	$58,450	$5,439	$132,802	NA
2013	$87,404	$66,885	$8,189	$162,479	22.3%

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG Zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power. Capacity revenue was calculated using a 38 percent capacity factor. Solar net revenues include SRECs.

Table 7-20 PSEG net revenue for a solar installation by market (Dollars per installed MW-year): 2012 through 2013

PSEG	Energy	Credits	Capacity	Total	Change (%)
2012	$50,363	$314,530	$17,565	$382,458	NA
2013	$81,813	$428,449	$26,516	$536,778	40.3%

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-21 includes new entrant levelized total costs for selected technologies. The levelized total costs of both the combined cycle and combustion turbine decreased in 2013 from 2012 as a result of competitive pressures in the equipment market.

Net revenue includes net revenue from the PJM Energy Market, from the PJM Capacity Market and from any applicable ancillary service plus production tax credits and RECs for wind installations and SRECs for solar installations.

Levelized Fixed Costs

Table 7-21 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year)): 2009 through 2013[15, 16]

	20-Year Levelized Fixed Cost				
	2009	2010	2011	2012	2013
Combustion Turbine	$128,705	$131,044	$110,589	$113,027	$109,731
Combined Cycle	$173,174	$175,250	$153,682	$155,294	$150,654
Coal Plant	$446,550	$465,455	$474,692	$480,662	$491,240
Diesel Plant	$153,143	$153,143	$153,143	$153,143	$153,143
Nuclear Plant	$801,100	$801,100	$801,100	$801,100	$801,100
Wind Installation (with 1603 grant)				$196,186	$196,148
Solar Installation (with 1603 grant)				$394,855	$263,824

New Entrant Combustion Turbine

In 2013, a new CT would not have received sufficient net revenue to cover levelized fixed costs in any zone. But the results bifurcate the zones into two groups with very different results. This separation is also illustrated in Figure 7-4. There are ten zones in which net revenues cover more than 75 percent of levelized fixed costs. These ten zones are in the eastern part of PJM. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. In the remaining six zones net revenues cover less than 30 percent of levelized fixed costs with the lowest zone at 18 percent. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets. Covering 75 percent of levelized fixed costs would result in a rate of return slightly less than half the rate of return included in the calculation of levelized fixed costs. (See Table 7-29.)

15 Levelized fixed costs provided by Pasteris Energy, Inc.

16 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and Wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

Table 7-22 Percent of 20-year levelized fixed costs recovered by CT energy and capacity net revenue (Dollars per installed MW-year): 2009 through 2013

Zone	2009	2010	2011	2012	2013
AECO	56%	81%	87%	61%	82%
AEP	31%	49%	64%	32%	20%
AP	51%	75%	75%	36%	24%
ATSI	NA	NA	NA	NA	NA
BGE	72%	95%	89%	70%	86%
ComEd	30%	48%	58%	30%	18%
DAY	31%	50%	64%	34%	20%
DEOK	NA	NA	NA	NA	NA
DLCO	32%	54%	67%	34%	21%
Dominion	40%	73%	80%	40%	27%
DPL	57%	82%	85%	72%	89%
EKPC	NA	NA	NA	NA	NA
JCPL	56%	80%	85%	60%	86%
Met-Ed	51%	80%	82%	60%	77%
PECO	54%	79%	86%	62%	81%
PENELEC	48%	69%	74%	58%	78%
Pepco	74%	94%	85%	66%	88%
PPL	50%	76%	84%	58%	77%
PSEG	54%	79%	79%	63%	84%
RECO	NA	NA	NA	NA	NA
PJM	49%	73%	78%	52%	60%

Figure 7-3 compares zonal net revenue for a new entrant CT to the 2013 levelized fixed cost. Figure 7-4 shows zonal net revenue for the new entrant CT by LDA with the applicable annual levelized fixed cost.

Figure 7-3 New entrant CT net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

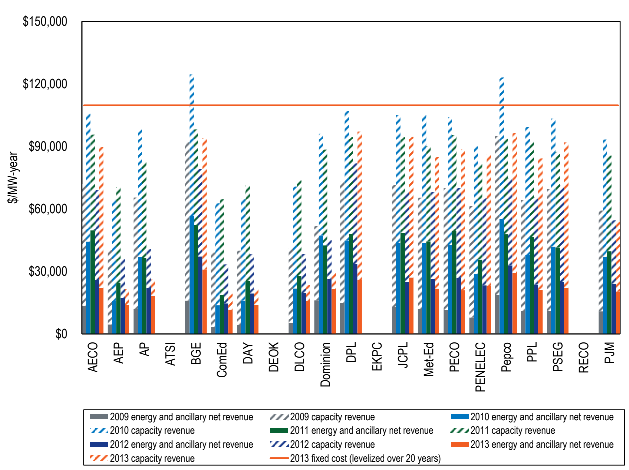


Figure 7-4 New entrant CT net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013

New Entrant Combined Cycle

In 2013, a new CC would have received net revenue sufficient to cover levelized fixed costs in seven zones. The results bifurcate the zones into two groups with very different results. This separation is also illustrated in Figure 7-6. There are ten zones in which net revenues cover more than 95 percent of levelized fixed costs. These are the same ten zones with higher net revenues for CTs. The higher net revenues in these zones reflect higher capacity market revenues offsetting lower energy market net revenues. These ten zones are in the eastern part of PJM. In the remaining six zones net revenues cover less than 65 but more than 33 percent of levelized fixed costs. The lower net revenues in these zones result from reductions in net revenues from both capacity and energy markets.

Table 7-23 Percent of 20-year levelized fixed costs recovered by CC energy and capacity net revenue: 2009 through 2013

Zone	2009	2010	2011	2012	2013
AECO	71%	96%	113%	94%	103%
AEP	39%	55%	84%	70%	50%
AP	66%	87%	104%	78%	59%
ATSI	NA	NA	NA	NA	NA
BGE	86%	110%	116%	107%	112%
ComEd	34%	48%	61%	53%	33%
DAY	38%	55%	84%	73%	52%
DEOK	NA	NA	NA	NA	NA
DLCO	38%	58%	84%	71%	48%
Dominion	61%	95%	105%	80%	61%
DPL	72%	97%	111%	106%	110%
EKPC	NA	NA	NA	NA	NA
JCPL	70%	96%	112%	93%	109%
Met-Ed	64%	91%	103%	90%	98%
PECO	68%	93%	110%	92%	99%
PENELEC	60%	82%	101%	96%	111%
Pepco	87%	109%	109%	102%	112%
PPL	62%	85%	103%	87%	96%
PSEG	68%	94%	105%	93%	105%
RECO	NA	NA	NA	NA	NA
PJM	61%	84%	100%	87%	85%

Figure 7-5 compares zonal net revenue for a new entrant CC to the 2013 levelized fixed cost. Figure 7-6 shows zonal net revenue for the new entrant CC for by LDA with the applicable yearly levelized fixed cost.

Figure 7-5 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

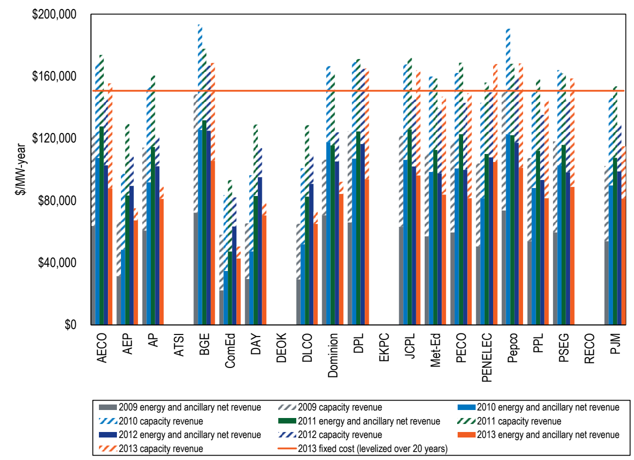
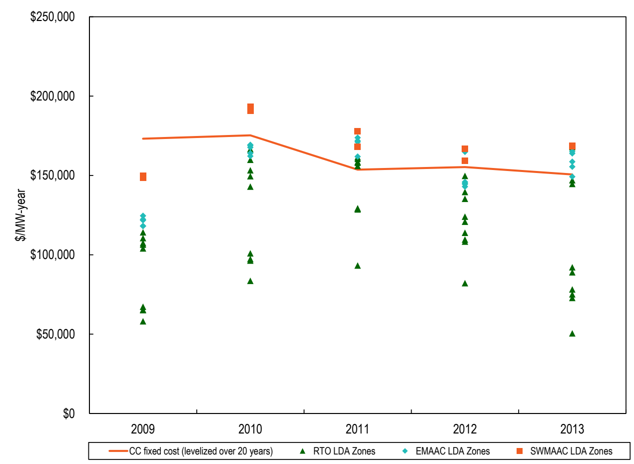


Figure 7-6 New entrant CC net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013



New Entrant Coal Plant

In 2013, a new CP would not have received sufficient net revenue to cover levelized fixed costs in any zone. The results for CPs are relatively uniform. A new CP would not have received sufficient net revenue to cover more than 30 percent of levelized fixed costs in any zone. However, the results for CPs in 2013 are better than they were in 2012 based on higher energy market net revenues in all but one zone and higher capacity market revenues in ten zones. These are the same ten eastern zones that increased the net revenue results for both CTs and CCs. All but two zones showed increases in the coverage of fixed costs by CPs in 2013. This improvement is also illustrated in Figure 7-8.

Table 7-24 Percent of 20-year levelized fixed costs recovered by CP energy and capacity net revenue: 2009 through 2013

Zone	2009	2010	2011	2012	2013
AECO	33%	46%	26%	14%	23%
AEP	13%	23%	25%	13%	18%
AP	24%	35%	31%	15%	21%
ATSI	NA	NA	NA	NA	NA
BGE	28%	32%	22%	14%	24%
ComEd	18%	34%	30%	15%	14%
DAY	15%	27%	24%	13%	21%
DEOK	NA	NA	NA	NA	NA
DLCO	14%	27%	20%	13%	7%
Dominion	19%	42%	26%	8%	24%
DPL	22%	45%	30%	16%	24%
EKPC	NA	NA	NA	NA	NA
JCPL	30%	45%	25%	16%	25%
Met-Ed	25%	43%	23%	17%	22%
PECO	31%	44%	26%	14%	22%
PENELEC	30%	40%	30%	20%	35%
Pepco	33%	49%	25%	14%	24%
PPL	29%	38%	26%	13%	22%
PSEG	52%	40%	20%	15%	28%
RECO	NA	NA	NA	NA	NA
PJM	26%	38%	26%	14%	22%

Figure 7-7 compares zonal net revenue for a new entrant CP to the 2012 levelized fixed cost. Figure 7-8 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed cost.

Figure 7-7 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

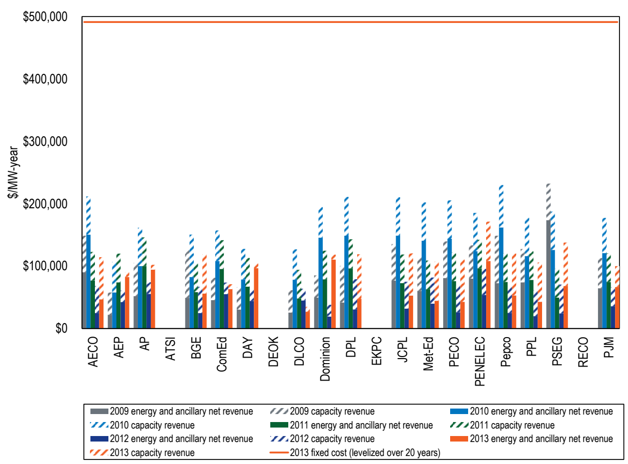
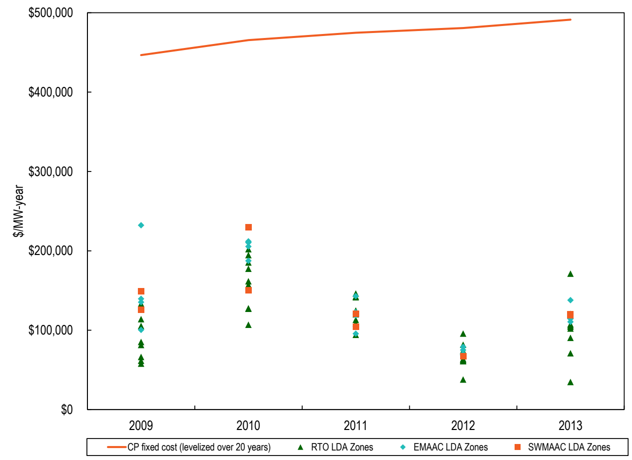


Figure 7-8 New entrant CP net revenue and 20-year levelized fixed cost by LDA (Dollars per installed MW-year): 2009 through 2013



New Entrant Nuclear Plant

In 2013, a new nuclear plant in the western AEP zone would not have received sufficient net revenue to cover levelized fixed costs. The combination of lower energy market revenues and lower capacity market revenues in the AEP zone, similar to the other western zones, than in the eastern zones resulted in a low level of coverage of fixed costs for a nuclear power plant.

Table 7-25 Percent of 20-year levelized fixed costs recovered by nuclear energy and capacity net revenue

Zone	2009	2010	2011	2012	2013
AEP	32%	39%	39%	28%	30%

Figure 7-9 compares net revenue for a new entrant nuclear plant to the 2013 levelized fixed cost.

Figure 7-9 New entrant nuclear plant net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013

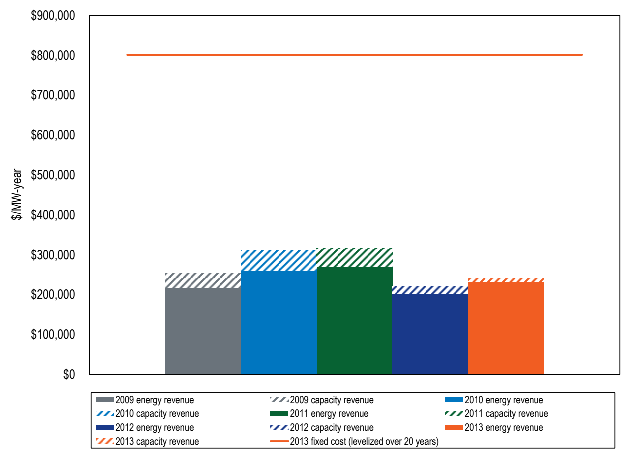
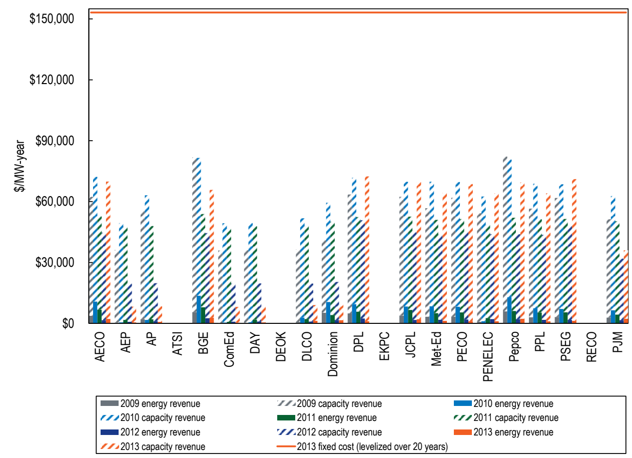


Figure 7-10 compares zonal net revenue for a new entrant DS plant to the 2013 levelized fixed cost.

Figure 7-10 New entrant DS plant net revenue and 20-year levelized fixed cost (Dollars per installed MW-year): 2009 through 2013



New Entrant Diesel Plant

In 2013, a new diesel plant would not have received sufficient net revenue to cover levelized fixed costs in any zone. The highest net revenues were in the 10 eastern zones with higher capacity prices than in the six western zones. Energy market revenues were very low for the diesel plant across all zones as diesels were economically dispatched in very few hours.

Table 7-26 Percent of 20-year levelized fixed costs recovered by DS energy and capacity net revenue

Zone	2009	2010	2011	2012	2013
AECO	41%	47%	34%	29%	46%
AEP	24%	32%	31%	13%	6%
AP	36%	41%	31%	13%	6%
ATSI	NA	NA	NA	NA	NA
BGE	53%	53%	35%	29%	43%
ComEd	23%	32%	31%	13%	5%
DAY	24%	32%	31%	13%	5%
DEOK	NA	NA	NA	NA	NA
DLCO	24%	34%	31%	13%	6%
Dominion	27%	39%	33%	13%	6%
DPL	41%	47%	34%	33%	47%
EKPC	NA	NA	NA	NA	NA
JCPL	41%	46%	34%	29%	46%
Met-Ed	37%	46%	33%	29%	42%
PECO	40%	45%	34%	29%	45%
PENELEC	35%	41%	32%	29%	42%
Pepco	54%	53%	34%	29%	45%
PPL	37%	45%	34%	29%	42%
PSEG	40%	45%	34%	31%	46%
RECO	NA	NA	NA	NA	NA
PJM	33%	41%	33%	21%	24%

New Entrant Wind Installation

In 2013, a new wind installation would not have received sufficient net revenue to cover levelized fixed costs.

Table 7-27 Percent of 20-year levelized fixed costs recovered by wind energy and capacity net revenue and wind credits

Zone	2012	2013
ComEd	65%	75%
PENELEC	68%	83%

New Entrant Solar Installation

In 2013, a new solar installation would have received sufficient net revenue to cover 203 percent of levelized fixed costs. Net revenues from the energy market, SRECs and the capacity market all increased substantially. Net revenues from SRECs are the reason for the high solar net revenues. Net revenues from SRECs were 79.8 percent of total net revenues in 2013 and 82.2 percent of total net revenues in 2012.

Table 7-28 Percent of 20-year levelized fixed costs recovered by solar energy and capacity net revenue and solar credits

Zone	2012	2013
PSEG	97%	203%

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2013, the yearly average operating cost of the CC was lower than the average operating costs of the CP for seven out of twelve months, driven by the relative cost of gas versus coal although that relationship reversed toward the end of the year. (See Figure 7-2.)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy cost units and therefore tend to be marginal in the energy market, when load requires them, and set prices in the energy market, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2013, zonal energy net revenues decreased for most CCs and CTs, while capacity market prices increased in ten zones and decreased in six zones. As a result, there are ten zones in which net revenues covered more than 95 percent of levelized fixed costs for CCs. These are the same ten zones with higher net revenues for CTs. These ten zones are in the eastern part of PJM. The lower net revenues in these zones resulted from reductions in net revenues from both capacity and energy markets.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. The same is true when efficient CCs are on the margin. However, when CTs or less efficient coal units are on the margin net revenues are higher for more efficient coal units.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 7-21 The results are shown in Table 7-29.[17]

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

Table 7-29 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$117,231	13.8%	$160,654	13.7%	$521,240	13.6%
Base Case	$109,731	12.0%	$150,654	12.0%	$491,240	12.0%
Sensitivity 2	$102,231	10.1%	$140,654	10.2%	$461,240	10.3%
Sensitivity 3	$94,731	8.1%	$130,654	8.3%	$431,240	8.6%
Sensitivity 4	$87,231	5.9%	$120,654	6.3%	$401,240	6.8%
Sensitivity 5	$79,731	3.5%	$110,654	4.1%	$371,240	4.9%
Sensitivity 6	$72,231	0.5%	$100,654	1.7%	$341,240	2.8%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-30 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-30 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percentage of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$116,792	$159,857
Sensitivity 2	55%	$113,262	$155,255
Base Case	50%	$109,731	$150,654
Sensitivity 3	45%	$106,201	$146,052
Sensitivity 4	40%	$102,671	$141,450
Sensitivity 5	35%	$99,140	$136,849
Sensitivity 6	30%	$95,610	$132,247

Table 7-31 shows the levelized annual revenue requirements associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

Table 7-31 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$98,680	$136,249
Sensitivity 2	25	$102,856	$141,693
Base Case	20	$109,731	$150,654
Sensitivity 3	15	$115,508	$158,183
Sensitivity 4	10	$123,167	$168,166

Table 7-32 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-32 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$106,246	$0	0.0%	$146,885
Sensitivity 2	$4,998	1.6%	$107,988	$7,990	1.2%	$148,769
Base Case	$9,996	3.2%	$109,731	$15,981	2.5%	$150,654
Sensitivity 3	$14,994	4.8%	$111,474	$23,971	3.7%	$152,538
Sensitivity 4	$19,992	6.4%	$113,217	$31,962	4.9%	$154,422
Sensitivity 5	$24,990	8.0%	$114,959	$39,952	6.2%	$156,306
Sensitivity 6	$29,988	9.6%	$116,702	$47,943	7.4%	$158,190
Sensitivity 7	$50,953	16.4%	$123,679	$50,953	7.9%	$158,675
Sensitivity 8	$76,430	24.6%	$132,396	$76,430	11.8%	$164,571
Sensitivity 9	$101,906	32.8%	$141,113	$101,906	15.7%	$170,466

Actual Net Revenue

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

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

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

Actual energy net revenues include day-ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, spinning reserves and black start service, in addition to actual or class average reactive revenues from actual FERC filings.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2012/2013 and 2013/2014 RPM Auctions.[18] For units that did not submit ACR data, the default ACR was used.

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2012/2013 and 2013/2014 delivery years, reflecting commitments made in Base Residual Auctions (BRA) and subsequent Incremental Auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM Markets in 2013. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[19] For units exporting capacity, the applicable Base Residual Auction (BRA) clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the RPM. The underlying analysis was done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Table 7-33 provides a summary of results by technology class, as well as the total installed capacity associated with each technology analyzed.

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

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

Table 7-33 Class average net revenue from energy and ancillary markets and associated recovery of class average avoidable costs and total revenue from all markets and associated recovery of class average avoidable costs[20]: 2013

Technology	Total Installed Capacity (ICAP)	Class average energy and ancillary net revenue ($/MW-year)	Class average energy net revenue and capacity revenue ($/MW-year)	Class average avoidable costs ($/MW-year)
CC - NUG Cogeneration Frame B or E Technology	1,787	$49,306	$114,076	$42,719
CC - Two on Three on One Frame F Technology	13,731	$25,764	$58,454	$17,592
CT - First & Second Generation Aero (P&W FT 4)	3,073	$4,312	$62,711	$9,513
CT - First & Second Generation Frame B	3,324	$1,046	$58,231	$10,883
CT - Second Generation Frame E	9,334	$12,281	$46,215	$9,237
CT - Third Generation Aero	3,543	$11,990	$58,351	$17,074
CT - Third Generation Frame F	8,051	$22,098	$44,014	$8,889
Diesel	490	($3,904)	$36,716	$8,521
Hydro and Pumped Storage	5,409	$136,938	$183,775	$24,887
Nuclear	29,884	$218,245	$253,956	$801,100
Oil or Gas Steam	8,556	$15,589	$68,266	$32,542
Sub-Critical Coal	29,649	$29,835	$59,184	$59,827
Super Critical Coal	19,186	$55,265	$89,076	$56,987

The actual unit specific energy and ancillary net revenues, avoidable costs and capacity revenues underlying the class averages shown in Table 7-33 represent a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis and are used to present the range of data while avoiding the influence of outliers. The three break points between the four quartiles are presented. Table 7-34 shows average energy and ancillary service net revenues by quartile for select technology classes.

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

Table 7-34 Energy and ancillary service net revenue by quartile for select technologies for 2013

	Energy and ancillary net revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$2,970	$16,579	$33,988
CC - Two on Three on One Frame F Technology	$5,682	$14,400	$50,241
CT - First & Second Generation Aero (P&W FT 4)	($935)	$542	$3,496
CT - First & Second Generation Frame B	($2,111)	($60)	$2,353
CT - Second Generation Frame E	$769	$6,143	$13,046
CT - Third Generation Aero	$2,008	$13,700	$25,528
CT - Third Generation Frame F	$6,387	$21,064	$32,756
Diesel	($1,771)	$0	$3,255
Hydro and Pumped Storage	$51,469	$106,000	$194,111
Nuclear	$179,256	$237,779	$253,598
Oil or Gas Steam	($5,260)	$442	$4,586
Sub-Critical Coal	$3,589	$18,677	$42,227
Super Critical Coal	$40,395	$54,870	$61,442

Table 7-35 shows capacity market net revenues by quartile for select technology classes.

Table 7-35 Capacity revenue by quartile for select technologies for 2013

	Capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$64,169	$67,515	$72,084
CC - Two on Three on One Frame F Technology	$8,018	$8,346	$66,414
CT - First & Second Generation Aero (P&W FT 4)	$58,500	$64,490	$70,175
CT - First & Second Generation Frame B	$38,435	$63,168	$67,793
CT - Second Generation Frame E	$8,105	$8,438	$68,206
CT - Third Generation Aero	$8,157	$64,571	$73,158
CT - Third Generation Frame F	$8,010	$8,255	$8,936
Diesel	$8,046	$24,461	$75,993
Hydro and Pumped Storage	$8,338	$63,941	$68,535
Nuclear	$8,319	$8,603	$68,358
Oil or Gas Steam	$7,832	$68,136	$72,245
Sub-Critical Coal	$7,478	$8,227	$64,194
Super Critical Coal	$4,222	$24,502	$64,590

20 20-year levelized fixed cost used in place of Nuclear ACR.

Table 7-36 shows total net revenues by quartile for select technology classes.

Table 7-36 Combined revenue from all markets by quartile for select technologies for 2013

	Energy, ancillary, and capacity revenue ($/MW-year)		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	$67,140	$84,094	$106,072
CC - Two on Three on One Frame F Technology	$13,700	$22,746	$116,655
CT - First & Second Generation Aero (P&W FT 4)	$57,565	$65,032	$73,671
CT - First & Second Generation Frame B	$36,325	$63,107	$70,146
CT - Second Generation Frame E	$8,875	$14,580	$81,252
CT - Third Generation Aero	$10,165	$78,272	$98,686
CT - Third Generation Frame F	$14,396	$29,319	$41,692
Diesel	$6,275	$24,461	$79,248
Hydro and Pumped Storage	$59,807	$169,940	$262,646
Nuclear	$187,574	$246,382	$321,957
Oil or Gas Steam	$2,572	$68,578	$76,831
Sub-Critical Coal	$11,067	$26,904	$106,421
Super Critical Coal	$44,617	$79,372	$126,032

Table 7-37 shows the avoidable cost recovery from PJM energy and ancillary services markets by quartiles. In 2013, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. Although there is not good public data on nuclear unit avoidable costs, the table includes the total annualized costs for a new nuclear unit as a rough proxy for the avoidable costs of an existing nuclear unit. This is only an approximation to provide a rough benchmark for avoidable cost results.

Table 7-37 Avoidable cost recovery by quartile from energy and ancillary net revenue for select technologies for 2012

	Recovery of avoidable costs from energy and ancillary net revenue		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	28%	50%	205%
CC - Two on Three on One Frame F Technology	50%	79%	208%
CT - First & Second Generation Aero (P&W FT 4)	NA	8%	35%
CT - First & Second Generation Frame B	NA	0%	37%
CT - Second Generation Frame E	22%	57%	85%
CT - Third Generation Aero	4%	68%	114%
CT - Third Generation Frame F	64%	213%	312%
Diesel	NA	NA	0%
Hydro and Pumped Storage	308%	462%	740%
Nuclear	22%	27%	31%
Oil or Gas Steam	NA	1%	11%
Sub-Critical Coal	11%	37%	68%
Super Critical Coal	56%	76%	137%

Table 7-38 shows the avoidable cost recovery from all PJM markets by quartiles. While the net revenues from all markets cover avoidable costs for most technology types, sub-critical coal units are the exception. The total annualized costs for a new nuclear unit is used as a rough proxy for the avoidable costs of an existing nuclear unit. This is only an approximation to provide a rough benchmark for avoidable cost results.

Table 7-38 Avoidable cost recovery by quartile from all PJM Markets for select technologies for 2013

	Recovery of avoidable costs from all markets		
Technology	First quartile	Second quartile	Third quartile
CC - NUG Cogeneration Frame B or E Technology	181%	215%	461%
CC - Two on Three on One Frame F Technology	133%	246%	624%
CT - First & Second Generation Aero (P&W FT 4)	576%	664%	734%
CT - First & Second Generation Frame B	478%	630%	698%
CT - Second Generation Frame E	154%	196%	814%
CT - Third Generation Aero	143%	200%	815%
CT - Third Generation Frame F	291%	393%	822%
Diesel	NA	87%	532%
Hydro and Pumped Storage	567%	793%	1,134%
Nuclear	23%	32%	39%
Oil or Gas Steam	71%	220%	267%
Sub-Critical Coal	54%	92%	131%
Super Critical Coal	117%	150%	180%

Table 7-39 and Table 7-40 show the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. Since 2009, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units in PJM, with the exception of coal and oil or gas steam units.

Table 7-39 Proportion of units recovering avoidable costs from energy and ancillary markets : 2009 to 2013

	Units with full recovery from energy and ancillary services markets				
Technology	2009	2010	2011	2012	2013
CC - NUG Cogeneration Frame B or E Technology	64%	77%	60%	65%	61%
CC - Two on Three on One Frame F Technology	71%	73%	70%	64%	54%
CT - First & Second Generation Aero (P&W FT 4)	44%	35%	25%	15%	20%
CT - First & Second Generation Frame B	32%	32%	31%	23%	15%
CT - Second Generation Frame E	63%	54%	72%	67%	48%
CT - Third Generation Aero	50%	53%	77%	78%	52%
CT - Third Generation Frame F	45%	64%	72%	81%	75%
Diesel	77%	77%	72%	57%	53%
Hydro and Pumped Storage	98%	98%	95%	98%	97%
Nuclear	0%	0%	0%	0%	0%
Oil or Gas Steam	44%	52%	48%	41%	44%
Sub-Critical Coal	80%	81%	59%	40%	51%
Super Critical Coal	87%	87%	74%	48%	53%

Table 7-40 Proportion of units recovering avoidable costs from all markets: 2009 to 2013

	Units with full recovery from all markets				
Technology	2009	2010	2011	2012	2013
CC - NUG Cogeneration Frame B or E Technology	95%	95%	96%	90%	100%
CC - Two on Three on One Frame F Technology	100%	95%	98%	92%	85%
CT - First & Second Generation Aero (P&W FT 4)	95%	90%	90%	90%	86%
CT - First & Second Generation Frame B	99%	99%	95%	94%	91%
CT - Second Generation Frame E	100%	100%	100%	100%	100%
CT - Third Generation Aero	99%	99%	99%	97%	89%
CT - Third Generation Frame F	100%	100%	100%	94%	96%
Diesel	97%	98%	91%	85%	73%
Hydro and Pumped Storage	100%	100%	100%	100%	100%
Nuclear	0%	0%	0%	0%	0%
Oil or Gas Steam	97%	95%	85%	75%	81%
Sub-Critical Coal	93%	95%	88%	55%	69%
Super Critical Coal	100%	100%	91%	68%	89%

Units At Risk

Units that have either already started the deactivation process or are expected to request deactivation are excluded from the at-risk analysis.[21]

Units' revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover avoidable costs from total market revenues, including capacity market revenues, may be at risk of retirement. In addition, units that failed to clear the most recent capacity auction(s) may be at risk of retirement. The profile of units falling into these categories is shown in Table 7-41. These units are considered at risk of retirement.

21 This analysis excludes nuclear units due to a lack of data and is based in part on information provided to PJM at its request by generation owners indicating their plans for retirements, retrofits, and related retrofits outage schedules to the extent they were known and understood by generation owners following the issuance of the final MATS rule.

These results mean that 14,597 MW of capacity in PJM are at risk of retirement in addition to the 24,933 MW that are currently planning to retire.

While the evidence is not complete on whether nuclear units are covering avoidable costs, total market revenues are not covering the total annualized costs of nuclear units in any part of PJM. Further analysis is required in order to determine whether any nuclear units are at risk in PJM.

Table 7-41 Profile of units that did not recover avoidable costs from total market revenues or did not clear the 15/16 BRA or 16/17 BRA but cleared in previous auctions

Technology	No. Units	ICAP (MW)	Avg. 2013 Run Hrs	Avg. Heat Rate	Avg. Unit Age (Yrs)
CT	30	1,195	393	13,454	31
Coal	22	8,650	6,808	10,577	45
Diesel	16	161	1,641	11,288	24
Oil or Gas Steam	11	2,542	2,076	11,502	33
Other	8	2,049	5,600	5,954	35
Total	87	14,597	3,197	11,391	34

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The Mercury and Air Toxics Standards Rule (MATS) requires significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal emissions. The EPA has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The most recent interstate emissions rule, the Cross-State Air Pollution Rule (CSAPR), would if implemented, also require investments for some fossil-fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions. New Jersey's high electric demand day (HEDD) rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from RGGI affect some unit offers in the PJM energy market. The investments required for environmental compliance have resulted in higher offers in the capacity market, and when units do not clear, in the retirement of units.

Renewable energy mandates and associated incentives by state and federal governments have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have potentially significant impacts on PJM wholesale markets.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[2] The rule establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[3]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4] The Clean Air Interstate Rule (CAIR) is in effect but CAIR is subject to remand to the EPA due to the a finding of the U.S. Court of Appeals for the District of Columbia Circuit.[5]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[6] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency

1 For quantification of the economics of new entrant wind and solar installations, see the *2013 State of the Market Report for PJM*, Volume II, Section 7, "Net Revenue."

2 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

3 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

4 CAA § 110(a)(2)(D)(i)(I).

5 See 550 F.3d 1176, 1177 (2008).

6 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

demand response programs include Demand Resources in RPM.

- Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics in those jurisdictions.[7]
- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[8] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[9]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[10] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[11]
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were an average of $2.92 per ton, above the price floor for 2013. The clearing price is equivalent to a price of $3.22 per metric tonne, the unit used in other carbon markets.

Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. On December 31, 2013, 68.6 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 96.6 percent of coal steam MW had some type of particulate control, and 91.2 percent of fossil fuel fired capacity in PJM had NO_x emission control technology in place.

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. The out of market payments in the form of RECs and federal production tax credits mean that these units have an incentive to generate MWh until the LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to

7 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

8 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Propose Rule, EPA-HQ-OAR-2013-0495.

9 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).

10 N.J.A.C. § 7:27–19.

11 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).

make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are not transparent. Data on RECs prices and markets are not publicly available. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and certain area sources of emissions.[12, 13] The EPA actions have and are expected to continue to affect the cost to build and operate generating units in PJM which in turn affects wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the Clean Water Act (CWA) affects generating plants that rely on water drawn from jurisdictional water bodies.[14]

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources.

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[15] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[16]

Air Quality Standards: Control of NO_x, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_x, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as "SIPs." Standards for each

12 42 U.S.C. § 7401 et seq. (2000).

13 The EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

14 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see Rapanos v. U.S., et al., 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.

15 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

16 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and periodically revised accordingly.

Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[17]

The Clean Air Interstate Rule (CAIR) is in effect but CAIR is subject to remand to the EPA due to the a finding of the U.S. Court of Appeals for the District of Columbia Circuit.[18]

The EPA attempted to replace CAIR with another transport rule, the Cross-State Air Pollution Rule (CSAPR). On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[19] The Supreme Court granted the EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. The Supreme Court will decide whether CSAPR replaces CAIR or the EPA must develop another replacement rule.

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[20] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[21]

17 CAA § 110(a)(2)(D)(i)(I).

18 See 550 F.3d 1176, 1177 (2008).

19 See EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

20 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("Final NESHAP RICE Rule").

21 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295, codified at 40 CFR Part 60 Subpart JJJJ.

The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition).

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[22] The proposed rule allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The MMU objected to the proposed rule, as it had to similar provisions in a related proposed settlement released for comment, explaining that it was not required for participation by demand resources in the PJM markets, nor for reliability.[23] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[24] Otherwise a 15-hour exception applies.[25] The exempted emergency demand response programs include demand resources in RPM.

Pending initiatives in Pennsylvania and New Jersey would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics in those jurisdictions.[26] The MMU and PJM have stated that these state measures would not, if enacted, have any harmful impact on system reliability.[27] The MMU has also explained that such measures would improve markets.[28]

22 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines*; New Source Performance Standards for Stationary Internal Combustion Engines, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

23 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA–HQ–OGC–2011–1030 (February 16, 2012).

24 Final NESHAP RICE Rule at 31–24.

25 *Id.* at 31.

26 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

27 *See* Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-0708 (August 9, 2012); Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012); Market Monitor, Comments of the Independent Market Monitor for PJM, Supporting Testimony before the Pennsylvania House of Representatives Environmental and Energy Committee re House Bill 1699, An Act Providing for the Regulation of Certain Reciprocal Internal Combustion Engines (November 20, 2013), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_to_PA_CERE_1699_20131120.pdf>; Letter from Terry Boston, President & CEO, PJM to Hon. Chris Ross re Pennsylvania House Bill 1999 (November 11, 2013) ("With regards to your inquiry of potential impacts to grid reliability, PJM does not anticipate the emergence of system reliability issues, should HB 1699 become law."); Letter from Terry Boston, President & CEO, PJM to Hon. Mary M. Cheh re District of Columbia Bill 20-569 (December 19, 2013).

28 *Id.*

Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare.[29] On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[30] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[31]

On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[32] The standards would require advanced technologies like efficient natural gas units and efficient coal units implementing partial carbon capture and storage (CCS). The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[33]

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the CWA.[34] A settlement in a federal court, as modified, obligates the EPA to issue a final rule no later than April 17, 2014.[35]

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[36] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[37]

Table 8-1 shows the HEDD emissions limits applicable to each unit type. Emissions limits for coal units became effective December 15, 2012.[38] Emissions limits for other unit types will become effective May 1, 2015.[39]

Table 8-1 HEDD maximum NOx emission rates[40]

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple cycle gas CT	1.00
Simple cycle oil CT	1.60
Combined cycle gas CT	0.75
Combined cycle oil CT	1.20
Regenerative cycle gas CT	0.75
Regenerative cycle oil CT	1.20

29 Massachusetts v. EPA, 549 U.S. 497.

30 *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009).

31 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

32 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency ("June 25, 2013); Presidential Memorandum–Power Section Caron Pollution Standards (June 25, 2013) (June 25th Presidential Memorandum").

33 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660, 79 Fed. Reg. 1352 (January 8, 2014).

34 *EPA, National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule*, Docket No. EPA-HQ-OW-2008-0667, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).

35 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010, *modified*, Fifth Amendment to Settlement Agreement among the Environmental Protection Agency, the Plaintiffs in Conin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and the Plaintiffs in Riverkeeper, et al. v. EPA, 06 Civ. 12987 (PKC) (SDNY), etc.

36 N.J.A.C. § 7:27-19.

37 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).

38 N.J.A.C. § 7:27-19.4.

39 N.J.A.C. § 7:27-19.5.

40 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[41, 42]

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional auctions for the 2012-2014 compliance period held as of December 31, 2013. Prices for auctions held in 2013 for the 2012-2014 compliance period were from $2.80 to $3.21 per allowance (equal to one ton of CO_2), which is above the current price floor for RGGI auctions.[43] The RGGI clearing prices ranged from $1.86 to $1.93 per ton from June 2010 through December 2012. In 2013, the clearing price in June 2013 rose to $3.21 per ton, the highest price since June 2009. The last auction in 2013 on December 4 cleared at $3.00 per ton. The average spot price in 2013 for a 2012-2014 compliance period allowance was $2.98 per ton, $0.96 higher than the average of 2012. Monthly average spot prices for the 2012-2014 compliance period ranged from $1.99 per ton in January to $3.42 per ton in April. Table 8-3 converts the RGGI CO_2 clearing prices and quantities to metric tonnes for comparison to other CO_2 markets.

Figure 8-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In 2013, NO_x prices were 5.3 percent higher than in 2012. SO_2 prices were 17.2 percent lower in 2013 compared to 2012. Figure 8-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware and Maryland.

Figure 8-1 Spot monthly average emission price comparison: 2012 and 2013

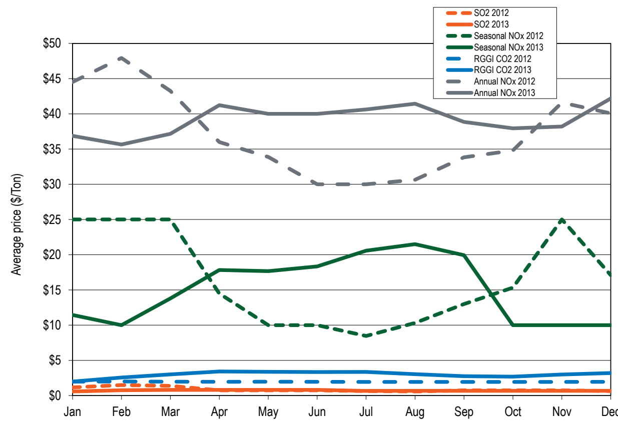


Table 8-2 RGGI CO2 allowance auction prices and quantities in short tons: 2009-2011 and 2012-2014 Compliance Periods[44]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000
March 14, 2012	$1.93	34,843,858	21,559,000
June 6, 2012	$1.93	36,426,008	20,941,000
September 5, 2012	$1.93	37,949,558	24,589,000
December 5, 2012	$1.93	37,563,083	19,774,000
March 13, 2013	$2.80	37,835,405	37,835,405
June 5, 2013	$3.21	38,782,076	38,782,076
September 4, 2013	$2.67	38,409,043	38,409,043
December 4, 2013	$3.00	38,329,378	38,329,378

41 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

42 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

43 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

44 See "Regional Greenhouse Gas Initiative: Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 20, 2014).

Table 8-3 RGGI CO2 allowance auction prices and quantities in metric tonnes: 2009-2011 and 2012-2014 Compliance Periods[45]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.38	11,399,131	11,399,131
December 17, 2008	$3.73	28,581,678	28,581,678
March 18, 2009	$3.87	28,588,815	28,588,815
June 17, 2009	$3.56	28,020,786	28,020,786
September 9, 2009	$2.41	25,772,169	25,772,169
December 2, 2009	$2.26	25,937,960	25,937,960
March 10, 2010	$2.28	36,842,967	36,842,967
June 9, 2010	$2.07	36,909,352	36,909,352
September 10, 2010	$2.05	41,363,978	31,213,514
December 1, 2010	$2.05	39,166,486	22,457,365
March 9, 2011	$2.08	38,097,972	38,097,972
June 8, 2011	$2.08	38,132,781	11,373,378
September 7, 2011	$2.08	38,273,849	7,118,681
December 7, 2011	$2.08	38,993,970	24,759,800
March 14, 2012	$2.13	31,609,825	19,558,001
June 6, 2012	$2.13	33,045,128	18,997,361
September 5, 2012	$2.13	34,427,270	22,306,772
December 5, 2012	$2.13	34,076,665	17,938,676
March 13, 2013	$3.09	34,323,712	34,323,712
June 5, 2013	$3.54	35,182,518	35,182,518
September 4, 2013	$2.94	34,844,108	34,844,108
December 4, 2013	$3.31	34,771,837	34,771,837

Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2023. As shown in Table 8-4, New Jersey will require 23.0 percent of load to be served by renewable resources in 2023, the most stringent standard of all PJM jurisdictions. Renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction. For example, Illinois only requires utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are out of market revenues for PJM resources and are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit per MWh from generation from "alternative energy resources" including waste coal and pumped-storage hydroelectric, and allows two credits per MWh of electricity generated by "renewable energy resources," which include wind, solar, and run of river hydroelectric. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits.

45 See "Regional Greenhouse Gas Initiative: Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed January 20, 2014).

Table 8-4 Renewable standards of PJM jurisdictions to 2023[46, 47]

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	20.00%	20.00%
Michigan	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	9.64%	10.48%	11.31%	12.15%	12.99%	14.83%	16.68%	18.53%	20.38%	22.50%	22.50%
North Carolina	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%
Ohio	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%
Pennsylvania	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%
Washington, D.C.	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%
West Virginia			10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%	15.00%

REC prices are required to be disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are difficult to determine. Few sources provide public REC price data. Table 8-5 has the Pennsylvania weighted average price and price range for 2010 through 2013 delivery years. The weighted average price of solar credits in Pennsylvania decreased from $325.00 in the 2010/2011 Delivery Year by $215.77 to $109.23 in the 2013/2014 Delivery Year. Tier I credits increased from $4.77 in the 2010/2011 Delivery Year to $8.31 in the 2013/2014 Delivery Year, while Tier II resources only dropped $0.10 from $0.32 in the 2010/2011 Delivery Year to $0.22 in the 2013/2014 Delivery Year.[48]

Table 8-5 Pennsylvania weighted average price and price range for 2010 to 2013 Delivery Years[49]

	2010/2011 Delivery Year		2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
Pennsylvania	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range
Solar AEC	$325.00	$235.00-$415.00	$247.82	$25.00-$653.00	$180.39	$10.00-$675.00	$109.23	$5.50-$600.00
Tier I	$4.77	$0.50-$24.15	$3.94	$0.14-$50.00	$5.23	$0.20-$23.00	$8.31	$0.13-$100.00
Tier II	$0.32	$0.01-$1.75	$0.22	$0.01-$20.00	$0.17	$0.01-$5.00	$0.22	$0.01-$20.00

Many PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the standards shown in Table 8-4 but must be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have requirements for the proportion of load served by solar units by 2023.[50] Indiana, Michigan, Virginia, and West Virginia have no specific solar standards. In 2013, New Jersey had the most stringent standard in PJM, requiring that 0.75 percent of load be served by solar resources. As Table 8-6 shows, by 2023, New Jersey will continue to have the most stringent standard, requiring that at least 3.65 percent of load be served by solar resources.

46 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

47 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

48 Tier I resources are solar photovoltaic and thermal energy, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, biomass and coal mine methane. Tier II resources are waste coal, distributed generation, demand-side management, large-scale hydropower, municipal solid waste and integrated combined coal gasification technology.

49 See PAPUC. Pennsylvania AEPS Alternative Energy Credit Program, "Pricing," <http://paaeps.com/credit/pricing.do> (Accessed February 25, 2014).

50 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement.

Table 8-6 Solar renewable standards of PJM jurisdictions to 2023

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.25%	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%
North Carolina	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%
Pennsylvania	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%
West Virginia	No Solar Standard										

Some PJM jurisdictions have also added other specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-7 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind resources, increasing from 5.25 percent of load served in 2013 to 15.38 percent in 2023. Maryland, New Jersey, Pennsylvania and Washington D.C. all have "Tier II" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits.[51] North Carolina also requires that 0.2 percent of power be generated using swine waste and poultry waste to fulfill their renewable portfolio standards by 2018 (Table 8-7).

Table 8-7 Additional renewable standards of PJM jurisdictions to 2023

Jurisdiction		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Illinois	Wind Requirement	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433
North Carolina	Swine Waste	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	170	700	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%

PJM jurisdictions include various methods for complying with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey, solar alternative compliance payments are $641 per MWh.[52] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. Alternative resources include solar, wind energy, organic biomass, and hydro power not requiring new construction. Burning waste wood, garbage, or other forms of solid waste do not qualify as alternative resources. Table 8-8 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

51 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

52 See "New Jersey Renewables Portfolio Standard," <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed January 20, 2013).

Table 8-8 Renewable alternative compliance payments in PJM jurisdictions: 2013[53]

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$641.00
North Carolina	No specific penalties		
Ohio	$45.00		$350.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 8-9 shows renewable generation by jurisdiction and resource type in 2013. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 16,083.8 GWh of 27,777.4 Tier I GWh, or 57.9 percent, in the PJM footprint. As shown in Table 8-9, 54,662.5 GWh were generated by resources that were renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 50.8 percent. Landfill gas, solid waste, and waste coal were 22,995.0 GWh of renewable generation or 42.1 percent of the total Tier I and Tier II.

Table 8-10 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[54] This capacity includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 27.1 percent of the total renewable capacity. West Virginia allows coal technology, coal bed methane, waste coal and fuel produced by a coal gasification facility to be counted as alternative energy resources. New Jersey has the largest amount of solar capacity in PJM, 186.8 MW, or 75.1 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,707.6 MW, or 56.6 percent of the total wind capacity.

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS), a system operated by PJM EIS. This includes solar capacity of 1,354.3 MW of which 895.8 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 8-11 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind-the-meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Table 8-9 Renewable generation by jurisdiction and renewable resource type (GWh): 2013

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	108.1	0.0	0.0	0.0	0.0	0.0	0.0	108.1	216.1
Illinois	171.8	0.0	0.0	0.0	0.0	0.0	6,070.1	6,241.9	6,241.9
Indiana	0.0	0.0	88.8	0.0	0.0	0.0	3,308.9	3,397.6	3,397.6
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	102.4	0.0	1,713.6	62.0	936.0	0.0	507.6	2,385.6	3,321.7
Michigan	23.4	0.0	122.4	0.0	0.0	0.0	0.0	145.7	145.7
New Jersey	339.2	533.2	17.7	223.4	1,450.7	0.0	9.0	589.3	2,573.1
North Carolina	0.0	0.0	600.9	0.0	0.0	0.0	0.0	600.9	600.9
Ohio	352.0	0.0	215.4	0.7	0.0	0.0	1,101.9	1,669.9	1,669.9
Pennsylvania	1,013.7	1,890.8	2,795.6	1.3	1,656.4	9,727.7	3,581.3	7,391.9	20,666.7
Tennessee	0.0	0.0	0.0	0.0	336.6	0.0	0.0	0.0	336.6
Virginia	563.8	4,148.7	1,426.8	0.0	1,589.1	3,575.9	0.0	1,990.6	11,304.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	8.2	0.0	1,742.5	0.0	0.0	1,040.2	1,505.2	3,255.9	4,296.1
Total	2,682.5	6,572.6	8,723.6	287.5	5,968.7	14,343.7	16,083.8	27,777.4	54,662.5

53 See "Program Information," <http://www.pjm-eis/program-information.aspx> (Accessed February 25, 2014)

54 PJM GATS.

Table 8-10 PJM renewable capacity by jurisdiction (MW), on December 31, 2013

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	13.8	0.0	0.0	0.0	0.0	0.0	0.0	1,857.2
Illinois	0.0	78.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,454.4	2,553.3
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,253.2	1,261.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	70.0
Maryland	60.0	28.7	129.0	31.9	0.0	581.0	40.1	109.0	0.0	120.0	1,099.8
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	186.8	189.1	0.0	7.5	873.9
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	94.0	0.0	0.0	409.0
Ohio	5,021.8	52.3	125.5	225.0	0.0	178.0	1.1	0.0	0.0	500.0	6,103.7
Pennsylvania	35.0	222.0	2,370.7	0.0	1,505.0	682.3	18.0	247.0	1,422.2	1,365.6	7,867.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	63.0	121.6	80.0	7.0	3,588.0	457.1	2.7	215.0	0.0	0.0	4,534.4
West Virginia	8,539.0	2.0	450.0	0.0	0.0	243.1	0.0	0.0	130.0	663.5	10,027.6
PJM Total	13,718.8	603.9	4,990.5	277.7	5,493.0	2,551.5	248.8	924.1	1,552.2	6,549.2	36,909.6

Table 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS[55, 56] (MW), on December 31, 2013

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	2.1	48.8
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	60.0
Illinois	0.0	6.6	91.8	0.0	0.0	0.0	34.5	0.0	302.5	435.4
Indiana	0.0	0.0	49.7	0.0	679.1	0.0	1.2	0.0	0.0	730.0
Kentucky	600.0	2.0	16.0	0.0	0.0	0.0	0.6	88.0	0.0	706.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	95.2	1.2	0.3	103.7
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	39.9	0.0	0.0	23.3	895.8	0.0	0.4	959.4
New York	0.0	146.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	147.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	8.0
Ohio	0.0	1.0	39.8	52.6	67.0	1.0	85.1	109.3	17.4	373.2
Pennsylvania	0.0	37.0	40.6	4.8	86.2	0.3	170.9	0.0	3.2	342.9
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.9	318.1	0.0	351.4
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	1.7
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	7.7	0.0	0.0	7.7
Total	655.0	214.8	301.1	57.4	832.4	24.6	1,354.3	621.2	472.0	4,532.8

55 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
56 See "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed January 20, 2013).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. Many PJM units burning fossil fuels have installed emission control technology.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low SO_2 emission rates. Of the current 80,762.4 MW of coal steam capacity in PJM, 55,443.3 MW of capacity, 68.6 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-12 shows SO_2 emission controls by unit type, of fossil fuel units in PJM.[57]

Table 8-12 SO_2 emission controls (FGD) by unit type (MW), as of December 31, 2013

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	55,443.3	25,319.1	80,762.4	68.6%
Combined Cycle	0.0	27,565.3	27,565.3	0.0%
Combustion Turbine	0.0	32,320.1	32,320.1	0.0%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	0.0	8,735.4	8,735.4	0.0%
Total	55,443.3	94,311.0	149,754.3	37.0%

NO_x emission control technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 136,502.6 MW, 91.2 percent, of 149,754.3 MW of capacity in PJM, have emission controls for NO_x. Table 8-13 shows NO_x emission controls by unit type in PJM. While most units in PJM have NO_x emission controls, many of these controls will likely need to be upgraded in order to meet each state's emission compliance standards. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 8-13 NO_x emission controls by unit type (MW), as of December 31, 2013

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	78,004.8	2,757.6	80,762.4	96.6%
Combined Cycle	27,362.3	203.0	27,565.3	99.3%
Combustion Turbine	26,764.7	5,555.4	32,320.1	82.8%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	4,370.8	4,364.6	8,735.4	50.0%
Total	136,502.6	13,251.7	149,754.3	91.2%

Most coal steam units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter from coal steam units. In PJM, 78,878.4 MW, 97.7 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 8-14 shows particulate emission controls by unit type in PJM. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet each state's emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which 213 of 295 coal steam units have not installed.

Table 8-14 Particulate emission controls by unit type (MW), as of December 31, 2013

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	78,878.4	1,884.0	80,762.4	97.7%
Combined Cycle	0.0	27,565.3	27,565.3	0.0%
Combustion Turbine	0.0	32,320.1	32,320.1	0.0%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	3,047.0	5,688.4	8,735.4	34.9%
Total	81,925.4	67,828.9	149,754.3	54.7%

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 8-15 shows the estimated emissions from units in PJM in 2013. It is estimated that over 644 million tons of CO_2, 2.1 million tons of SO_2, and 786 thousand tons of NO_x were emitted in 2013 by PJM units.

57 See EPA.gov "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed January 20, 2014)

Table 8-15 CO_2, SO_2 and NO_x emissions by month (tons), by PJM units, 2013

	Tons of CO_2	Tons of SO_2	Tons of NO_x
January	53,840,466.5	156,310.9	70,054.9
February	50,824,445.9	132,912.3	64,118.8
March	51,431,851.0	145,765.1	65,220.0
April	43,713,069.2	135,825.4	55,220.0
May	49,126,344.5	141,085.2	58,020.0
June	57,062,540.2	180,387.6	67,620.4
July	67,139,573.0	246,611.5	81,327.6
August	59,629,357.3	207,311.2	72,095.7
September	54,602,220.5	186,715.2	65,215.9
October	49,672,720.2	185,384.6	58,921.4
November	49,743,758.5	180,507.9	58,937.0
December	57,984,181.1	213,005.1	70,009.8
Total	644,770,527.8	2,111,822.0	786,761.3

Wind Units

Table 8-16 shows the capacity factor of wind units in PJM. In 2013, the capacity factor of wind units in PJM was 28.5 percent. Wind units that were capacity resources had a capacity factor of 28.5 percent and an installed capacity of 4,888 MW. Wind units that were classified as energy only had a capacity factor of 27.8 percent and an installed capacity of 1,476 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the capacity market, and energy only resources are not included in the capacity market.[58]

Table 8-16 Capacity factor of wind units in PJM: 2013[59]

Type of Resource	Capacity Factor	Capacity Factor by Cleared MW	Installed Capacity (MW)
Energy-Only Resource	27.8%	NA	1,476
Capacity Resource	28.5%	146.7%	4,888
All Units	28.3%	146.7%	6,364

Figure 8-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,868.51 MW, occurred in November, and the lowest average hour, 413.6 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-2 Average hourly real-time generation of wind units in PJM: 2013

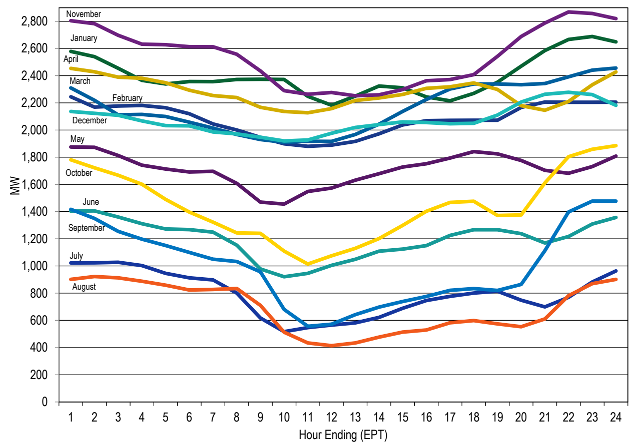


Table 8-17 shows the generation and capacity factor of wind units in each month of 2012 and 2013.

Table 8-17 Capacity factor of wind units in PJM by month, 2012 and 2013

	2012		2013	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,608,349.8	41.9%	1,784,359.3	40.3%
February	1,167,011.9	32.4%	1,397,468.3	35.4%
March	1,416,278.0	35.6%	1,606,248.3	36.5%
April	1,345,643.3	34.7%	1,639,590.9	37.8%
May	885,583.1	21.6%	1,271,272.4	28.5%
June	882,597.0	22.2%	862,532.2	19.8%
July	546,676.9	13.3%	588,174.8	13.4%
August	415,544.2	10.1%	510,448.5	12.0%
September	677,039.5	16.9%	719,196.4	16.7%
October	1,213,664.0	27.7%	1,070,829.4	23.5%
November	1,022,628.8	22.9%	1,833,051.6	41.2%
December	1,452,588.7	31.1%	1,543,685.2	34.2%
Annual	12,633,605.2	25.7%	14,826,857.3	28.3%

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 8-3 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

58 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

59 Capacity factor does not include external resources which only offer in the Day-Ahead Market. Capacity factor is calculated based on online date of the resource. Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

Figure 8-3 Average hourly day-ahead generation of wind units in PJM: 2013

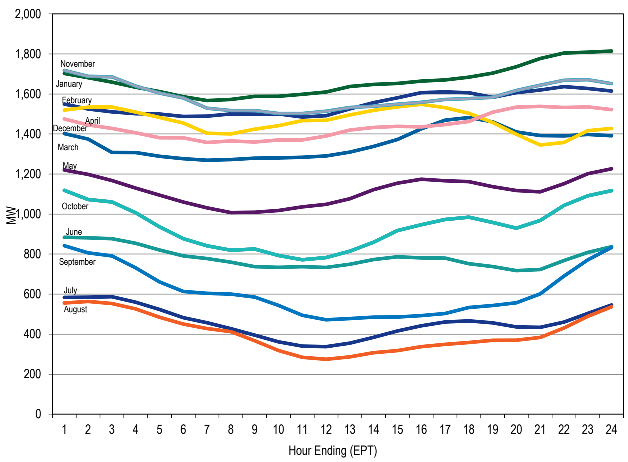
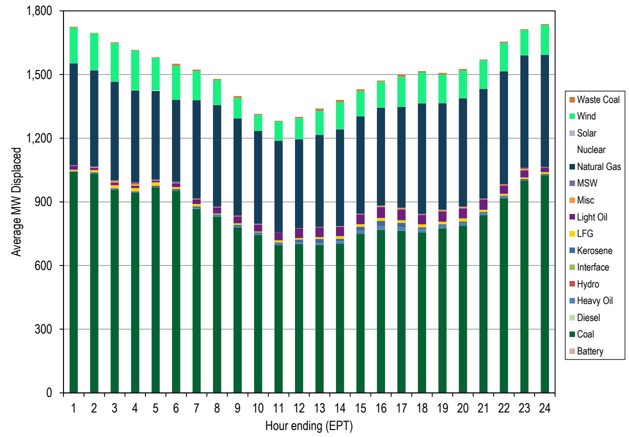


Figure 8-4 Marginal fuel at time of wind generation in PJM: 2013

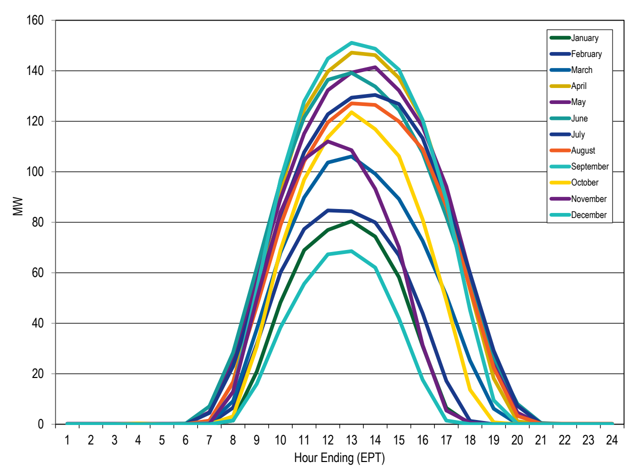


Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation in 2013. Figure 8-4 shows potentially displaced marginal unit MW by fuel type in 2013. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-5 shows the average hourly real-time generation of solar units in PJM, by month. On average, solar generation was highest in September, the month with the highest average hour, 150.5 MW, compared to 248.8 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-5 Average hourly real-time generation of solar units in PJM: January through December 2013



Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and non-market balancing authorities.

Overview

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.
- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2013, PJM was a net importer of energy in the Real-Time Energy Market in January through August, and November, and a net exporter of energy in the remaining months of 2013.[1] In 2013, the real-time net interchange of 4,867.1 GWh was greater than net interchange of 2,770.9 GWh for 2012.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2013, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. In 2013, the total day-ahead net interchange of -17,603.2 GWh was greater than net interchange of -12,548.4 GWh for 2012.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2013, gross imports in the Day-Ahead Energy Market were 147.4 percent of gross imports in the Real-Time Energy Market (364.4 percent for 2012), gross exports in the Day-Ahead Energy Market were 210.3 percent of the gross exports in the Real-Time Energy Market (415.8 percent for 2012).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2013, in the Real-Time Energy Market, there were net scheduled exports at ten of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2013, in the Real-Time Energy Market, there were net scheduled exports at eleven of PJM's 18 interface pricing points eligible for real-time transactions.[2]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2013, in the Day-Ahead Energy Market, there were net scheduled exports at eleven of PJM's 21 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2013, in the Day-Ahead Energy Market, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2013, in the Day-Ahead Market, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 45.0 percent of hours in 2013.
- **PJM and New York ISO Interface Prices.** In 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 54.1 percent of the hours in 2013.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2013, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow in 2013 was -365 MW.[4] (The negative sign means that the flow was an export

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

3 In 2013, there were 1,702 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $41.69 while the NYISO LMP at the Neptune Bus during non-zero flows was $60.38, a difference of $18.69.

4 The average hourly flow in 2013, ignoring hours with no flow, on the Neptune DC Tie line was -453 MW.

from PJM to NYISO.) The flows were consistent with price differentials in 67.7 percent of the hours in 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In 2013, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[5] The average hourly flow in 2013 was -131 MW.[6] The flows were consistent with price differentials in 65.8 percent of the hours in 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. In the first seven months of operations, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[7] The average hourly flow during the first seven months of operation was -52 MW.[8] The flows were consistent with price differentials in 66.6 percent of the hours between June 3, 2013 and December 31, 2013.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at one or more specific interfaces.

- **In 2013, net scheduled interchange was 2,848 GWh and net actual interchange was 3,101 GWh, a difference of 253 GWh.** In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 49 TLRs of level 3a or higher in 2013, compared to 37 TLRs issued in 2012.

- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 110,306 bids per day, with an average cleared volume of 1,238,361 MWh per day, in 2013, compared to an average of 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012. (Figure 9-13).

Recommendations

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement..
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

5 In 2013, there were 1,865 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $40.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.02, a difference of $7.40.

6 The average hourly flow in 2013, ignoring hours with no flow, on the Linden VFT line was -166 MW.

7 In its seven months of operation, there were 3,528 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $47.29 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.17, a difference of $7.88.

8 The average hourly flow during the first seven months of operations, ignoring hours with no flow, on the Hudson line was -171 MW.

- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non-market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial congestion offsets (FTRs and auction revenue rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly net importer of energy in the Real-Time Energy Market in January through August, and November, and a net exporter of energy in the remaining months of 2013 (Figure 9-1).[9] In 2013, the total real-time net interchange of 4,867.1 GWh was greater than the net interchange of 2,770.9 GWh during for 2012. In 2013, the peak month for net importing interchange was July, 1,464.4 GWh; in 2012 it was November, 1,152.7 GWh. Gross monthly export volumes during in 2013 averaged 3,282.2 GWh compared to 3,671.3 GWh for 2012, while gross monthly imports in 2013 averaged 3,687.8 GWh compared to 3,902.2 GWh for 2012.

In 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In 2013, the total day-ahead net interchange of -17,603.2 GWh was greater than the net interchange of -12,548.4 GWh for 2012. In 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was October, -2,696.6 GWh. Gross monthly export volumes in 2013 averaged 6,903.6 GWh compared to 15,265.8 GWh for 2012, while gross monthly imports in 2013 averaged 5,436.6 GWh compared to 14,220.1 GWh for 2012.

The large decreases in gross import and export volumes in the Day-Ahead Energy Market were the result of the rule change on November 1, 2012, which permitted up-to congestion transactions to be submitted between two internal buses. Prior to the rule change, up-to congestion transactions were required to have the source at an interface (modeled as an import) or the sink at an interface (modeled as an export).[10]

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net Day-Ahead Energy Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 9-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In 2013, gross imports in the Day-Ahead Energy Market were 147.4 percent of gross imports in the Real-Time Energy Market (364.4 percent for 2012), gross exports in the Day-Ahead Energy Market were 210.3 percent of gross exports in the Real-Time Energy Market (415.8 percent for 2012). In 2013, net interchange was -17,603.2 GWh in the Day-Ahead Energy Market and 4,867.1 GWh in the Real-Time Energy Market compared to -12,548.4 GWh in the Day-Ahead Energy Market and 2,770.9 GWh in the Real-Time Energy Market for 2012.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based

9 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

10 See "*Up-To Congestion Transaction Enhancements*," (October 10, 2012) <https://pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-11-up-to-congestion-transactions.ashx>.

on differences between the transaction MW and price differences in the Day-Ahead and Real-Time Energy Markets.[11] In 2013, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: 2013

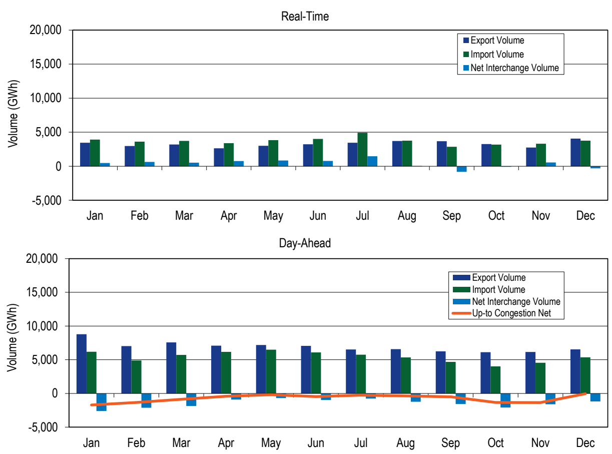
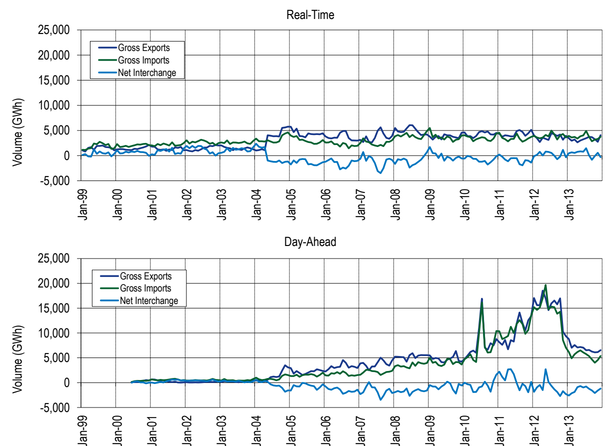


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through December, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows began to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Energy Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased. While the gross import and export volumes in the Day-Ahead Energy Market have decreased, the net direction of power flows has remained predominantly in the export direction.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 2013



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. See Table 9-16 for a list of active interfaces during 2013. Figure 9-3 shows the approximate geographic location of the interfaces. In 2013, PJM had 21 interfaces with neighboring balancing authorities.[12] While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are nine separate interfaces that make up the MISO Interface between the PJM and MISO balancing authorities. Table 9-1 through Table 9-3 show the Real-Time Energy Market interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Energy Market is shown by interface for 2013

11 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

12 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

in Table 9-1, while gross imports and exports are shown in Table 9-2 and Table 9-3.

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(30.6)	(38.3)	(48.4)	(33.1)	(25.3)	188.1	206.8	211.8	(52.7)	(20.2)	(14.2)	(24.0)	319.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
DUK	175.2	122.7	148.1	80.9	294.6	221.9	263.2	134.0	(49.5)	(22.2)	(171.9)	77.2	1,274.2
EKPC	(149.7)	(139.9)	(152.7)	(152.2)	(108.8)								(703.3)
LGEE	281.5	272.0	302.2	182.9	204.3	253.5	312.2	263.2	206.7	254.8	341.0	362.3	3,236.6
MEC	(484.1)	(390.8)	(158.9)	(421.4)	(509.1)	(464.2)	(492.5)	(478.1)	(465.7)	(483.1)	(468.9)	(259.4)	(5,076.2)
MISO	283.1	518.3	572.6	622.4	103.4	62.0	690.9	(318.8)	(442.3)	(299.4)	338.5	(364.9)	1,766.1
ALTE	(306.7)	(176.9)	(239.3)	(214.3)	(454.5)	(449.7)	(370.3)	(474.7)	(420.9)	(363.1)	(122.8)	(251.4)	(3,844.8)
ALTW	(9.0)	(4.5)	(3.0)	(3.8)	(25.3)	(40.2)	(1.8)	(33.8)	(17.9)	(18.4)	(5.6)	(96.5)	(259.6)
AMIL	181.7	153.6	181.5	150.2	170.1	12.0	340.6	(76.7)	(145.2)	(99.3)	(94.7)	129.7	903.5
CIN	253.3	285.4	349.7	272.0	129.6	350.0	376.1	315.0	165.9	98.6	174.8	(94.3)	2,676.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(43.4)	48.1	63.8	74.5	(29.2)	128.7	239.6	50.6	(10.8)	43.2	273.9	8.2	847.2
MECS	322.3	298.9	322.5	433.4	529.0	291.8	205.0	24.1	130.0	273.9	306.0	132.3	3,269.1
NIPS	(22.9)	(12.5)	(22.0)	(25.6)	(71.6)	(5.0)	9.3	(7.7)	(6.2)	(8.6)	(9.1)	35.8	(146.0)
WEC	(92.1)	(73.8)	(80.5)	(64.0)	(144.7)	(225.6)	(107.6)	(115.6)	(137.1)	(225.7)	(184.0)	(228.7)	(1,679.4)
NYISO	(1,047.1)	(1,018.0)	(1,100.9)	(313.3)	(216.5)	(608.4)	(977.3)	(897.7)	(820.5)	(537.9)	(292.8)	(1,303.5)	(9,133.9)
HUDS						(24.8)	(31.6)	(17.7)	(7.8)	(6.6)	(46.8)	(130.7)	(265.9)
LIND	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(73.0)	(71.9)	(85.2)	(33.1)	(61.2)	(216.5)	(1,145.5)
NEPT	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(409.3)	(415.2)	(223.8)	(261.9)	(228.9)	(385.4)	(3,198.0)
NYIS	(611.0)	(622.3)	(770.1)	(1.3)	(37.0)	(360.0)	(463.3)	(392.9)	(503.7)	(236.3)	44.1	(570.9)	(4,524.5)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	985.5	825.5	685.2	854.9	715.3	928.9	9,255.1
TVA	643.8	600.0	383.6	249.0	392.2	217.6	475.5	297.6	119.5	164.3	110.9	274.7	3,928.7
Total	470.4	639.5	530.6	757.9	846.7	778.9	1,464.4	37.5	(819.3)	(88.8)	557.9	(308.7)	4,867.1

In the Real-Time Energy Market, in 2013, there were net scheduled exports at ten of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 65.3 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 24.7 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 22.0 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.7 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 44.4 percent of the total net PJM exports in the Real-Time Energy Market. Ten PJM interfaces had net scheduled imports, with three importing interfaces accounting for 64.0 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.0 percent, PJM/Tennessee Valley Authority (TVA) with 15.3 percent and PJM/Michigan Electric Coordinated System (MECS) with 12.7 percent of the net import volume.[13]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by load serving entities or their affiliates within the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 70 percent of the generation output into the PJM footprint.[14] OVEC itself does not serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

13 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

14 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed January 23, 2014).

Table 9-2 Real-time scheduled gross import volume by interface (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	1.4	0.1	1.6	0.0	2.0	219.4	236.8	227.4	0.0	0.0	0.0	2.8	691.4
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
DUK	225.0	190.6	157.0	137.4	320.4	265.8	301.2	202.6	70.7	94.0	91.3	194.8	2,250.8
EKPC	4.4	1.5	25.6	21.8	33.0		0.0	0.0	0.0	0.0	0.0	0.0	86.3
LGEE	299.0	272.4	302.2	186.0	205.0	255.4	318.3	264.2	223.2	258.8	342.2	362.4	3,289.0
MEC	0.2	48.2	320.6	6.2	0.0	0.0	3.9	3.3	1.1	0.8	0.0	228.6	613.0
MISO	1,026.7	971.1	1,110.5	1,199.0	1,264.4	1,193.4	1,596.0	998.0	896.6	859.4	1,062.1	855.3	13,032.4
ALTE	0.0	1.1	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	1.5	0.0	6.2
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	207.0	177.1	215.1	198.2	213.8	79.0	386.4	98.4	107.6	46.9	35.6	287.1	2,052.3
CIN	374.5	394.7	455.5	438.9	358.2	519.7	518.4	493.0	361.8	259.1	323.5	297.4	4,794.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	95.9	76.5	101.6	101.3	70.4	176.3	289.3	103.6	62.7	115.8	336.2	87.6	1,617.3
MECS	349.1	321.6	338.3	458.2	621.9	418.4	383.5	302.8	362.5	437.6	365.4	141.1	4,500.5
NIPS	0.2	0.0	0.0	2.4	0.0	0.0	14.7	0.2	1.9	0.0	0.0	42.1	61.3
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	871.0	782.0	820.7	1,037.6	857.5	895.0	984.2	914.4	834.0	921.2	957.0	856.9	10,731.5
HUDS						0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.6	10.4	7.5	13.5	7.8	10.2	19.7	9.0	8.1	16.8	21.9	0.0	125.5
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	870.5	771.6	813.2	1,024.1	849.7	884.8	964.5	905.4	825.9	904.4	935.1	856.9	10,606.0
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	985.6	825.5	685.2	854.9	715.3	928.9	9,280.6
TVA	689.8	630.0	399.1	261.5	431.9	265.9	493.8	313.8	146.9	184.1	143.6	317.9	4,278.3
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	4,919.6	3,749.2	2,857.7	3,173.3	3,311.4	3,747.6	44,253.4

Table 9-3 Real-time scheduled gross export volume by interface (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	31.9	38.4	50.0	33.1	27.3	31.3	30.0	15.7	52.7	20.2	14.2	26.9	371.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	49.8	67.9	8.9	56.5	25.8	43.9	37.9	68.6	120.2	116.2	263.2	117.6	976.6
EKPC	154.0	141.4	178.3	174.0	141.8		0.0	0.0	0.0	0.0	0.0	0.0	789.6
LGEE	17.5	0.4	0.0	3.1	0.7	1.8	6.1	1.1	16.5	4.0	1.1	0.1	52.3
MEC	484.4	439.0	479.6	427.6	509.1	464.2	496.4	481.4	466.8	483.9	468.9	488.0	5,689.2
MISO	743.5	452.8	537.9	576.7	1,161.0	1,131.4	905.0	1,316.7	1,338.8	1,158.8	723.6	1,220.2	11,266.3
ALTE	306.7	178.0	239.3	214.3	454.5	449.7	374.0	474.7	420.9	363.1	124.3	251.4	3,851.1
ALTW	9.0	4.5	3.0	3.8	25.3	40.2	1.8	33.8	17.9	18.4	5.6	96.5	259.6
AMIL	25.3	23.5	33.6	48.0	43.7	67.0	45.7	175.2	252.8	146.1	130.3	157.5	1,148.8
CIN	121.2	109.3	105.8	166.9	228.6	169.7	142.3	178.0	195.9	160.5	148.7	391.6	2,118.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	139.3	28.4	37.8	26.8	99.7	47.6	49.7	53.0	73.5	72.7	62.3	79.3	770.1
MECS	26.8	22.7	15.8	24.8	93.0	126.6	178.6	278.7	232.6	163.7	59.3	8.9	1,231.4
NIPS	23.0	12.5	22.0	28.0	71.6	5.0	5.4	7.8	8.1	8.6	9.1	6.2	207.3
WEC	92.1	73.8	80.5	64.0	144.7	225.6	107.6	115.6	137.1	225.7	184.0	228.7	1,679.4
NYISO	1,918.1	1,800.1	1,921.6	1,351.0	1,074.0	1,503.4	1,961.4	1,812.1	1,654.6	1,459.1	1,249.8	2,160.4	19,865.5
HUDS						24.8	31.6	17.7	7.8	6.6	46.8	130.7	265.9
LIND	165.8	160.3	99.1	78.5	84.8	66.1	92.7	80.9	93.3	49.9	83.1	216.5	1,271.0
NEPT	270.9	245.9	239.2	247.1	102.5	167.8	409.3	415.2	223.8	261.9	228.9	385.4	3,198.0
NYIS	1,481.5	1,393.9	1,583.3	1,025.4	886.6	1,244.7	1,427.8	1,298.3	1,329.7	1,140.7	891.0	1,427.7	15,130.5
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	0.0	0.0	0.0	0.0	0.0	0.0	25.4
TVA	46.0	30.0	15.6	12.5	39.7	48.3	18.3	16.1	27.4	19.8	32.7	43.3	349.6
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.0	3,455.2	3,711.7	3,677.0	3,262.1	2,753.5	4,056.3	39,386.2

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[15] An interface pricing point defines the price at which transactions are priced, and

15 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[16]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[17] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. According to the PJM Interface Price Definition Methodology, dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[18] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. Table 9-17 presents the interface pricing points used in 2013.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified by PJM only occasionally.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[19]

In the Real-Time Energy Market, in 2013, there were net scheduled exports at eleven of PJM's 18 interface pricing points eligible for real-time transactions.[20] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 72.4 percent of the total net exports: PJM/MISO with 59.0 percent, and PJM/NYIS with 13.4 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 31.6 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net

16 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

17 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

18 See "PJM Interface Pricing Definition Methodology," (September 29, 2006) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx>.

19 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.

20 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

imports, with two importing interface pricing points accounting for 71.4 percent of the total net imports: PJM/SouthIMP with 41.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 30.4 percent of the net import volume.

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS						(24.8)	(31.6)	(17.7)	(7.8)	(6.6)	(46.8)	(130.7)	(265.9)
IMO	592.6	395.0	556.4	547.2	668.7	584.3	616.2	516.6	522.7	617.0	557.5	357.5	6,531.6
LINDENVFT	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(73.0)	(71.9)	(85.2)	(33.1)	(61.2)	(216.5)	(1,145.5)
MISO	(1,015.3)	(686.3)	(699.3)	(709.9)	(1,444.8)	(1,513.8)	(1,146.5)	(1,683.6)	(1,675.8)	(1,569.7)	(1,131.7)	(1,635.8)	(14,912.6)
NEPTUNE	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(409.3)	(415.2)	(223.8)	(261.9)	(228.9)	(385.4)	(3,198.0)
NORTHWEST	(3.6)	(3.3)	(5.9)	(5.0)	(5.5)	(2.7)	(1.2)	(0.3)	(3.9)	(4.8)	(1.1)	(1.5)	(38.9)
NYIS	(603.2)	(572.1)	(706.3)	62.9	28.4	(230.2)	(289.9)	(271.6)	(402.6)	(177.9)	215.0	(435.9)	(3,383.4)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	985.5	825.5	685.2	854.9	715.3	928.9	9,255.1
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	1,909.4	1,260.0	591.9	659.8	863.2	1,402.7	14,629.1
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	230.0	222.8	0.0	0.0	0.0	0.0	672.2
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	136.7	58.7	28.4	38.7	34.8	56.8	937.4
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	62.1	48.5	17.6	10.1	26.9	79.9	544.1
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	1,480.5	930.0	545.9	611.0	801.5	1,265.9	12,475.5
SOUTHEXP	(303.9)	(283.9)	(255.9)	(291.0)	(238.9)	(129.7)	(95.1)	(104.2)	(220.0)	(166.5)	(323.4)	(191.9)	(2,604.4)
CPLEEXP	(31.3)	(33.4)	(47.6)	(32.0)	(26.7)	(30.8)	(29.7)	(15.2)	(49.7)	(20.2)	(13.9)	(16.6)	(347.1)
DUKEXP	(27.1)	(45.2)	(0.9)	(32.9)	(11.8)	(29.9)	(27.3)	(44.4)	(45.3)	(51.8)	(223.5)	(79.9)	(619.9)
NCMPAEXP	0.0	(0.1)	0.0	(0.2)	0.0	(1.5)	0.0	0.0	0.0	0.0	(0.2)	0.0	(1.9)
SOUTHWEST	(4.5)	(5.7)	(3.0)	(11.7)	(3.6)	(4.4)	(2.4)	(2.3)	(2.8)	(6.0)	(11.9)	(4.1)	(62.3)
SOUTHEXP	(241.0)	(199.6)	(204.5)	(214.2)	(196.9)	(63.1)	(35.6)	(42.3)	(122.2)	(88.5)	(73.9)	(91.3)	(1,573.2)
Total	470.4	639.5	530.6	757.9	846.7	778.9	1,464.4	37.5	(819.3)	(88.8)	557.9	(308.7)	4,867.1

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS						0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IMO	594.6	403.2	562.5	549.8	669.9	584.7	621.6	522.0	533.1	620.1	562.2	368.4	6,592.0
LINDENVFT	0.6	10.4	7.5	13.5	7.8	10.2	19.7	9.0	8.1	16.8	21.9	0.0	125.5
MISO	204.4	196.3	309.1	277.5	215.9	74.6	250.9	110.3	116.3	60.4	47.1	65.0	1,927.9
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.1	0.0	0.0	0.8
NYIS	876.3	813.6	870.9	1,085.7	914.0	1,014.1	1,132.5	1,021.6	923.1	961.1	1,101.8	982.7	11,697.5
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	985.6	825.5	685.2	854.9	715.3	928.9	9,280.6
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	1,909.4	1,260.0	591.9	659.8	863.2	1,402.7	14,629.1
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	230.0	222.8	0.0	0.0	0.0	0.0	672.2
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	136.7	58.7	28.4	38.7	34.8	56.8	937.4
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	62.1	48.5	17.6	10.1	26.9	79.9	544.1
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	1,480.5	930.0	545.9	611.0	801.5	1,265.9	12,475.5
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	4,919.6	3,749.2	2,857.7	3,173.3	3,311.4	3,747.6	44,253.4

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS						24.8	31.6	17.7	7.8	6.6	46.8	130.7	265.9
IMO	2.0	8.2	6.1	2.6	1.3	0.4	5.3	5.4	10.3	3.1	4.7	10.9	60.5
LINDENVFT	165.8	160.3	99.1	78.5	84.8	66.1	92.7	80.9	93.3	49.9	83.1	216.5	1,271.0
MISO	1,219.7	882.6	1,008.4	987.4	1,660.7	1,588.4	1,397.5	1,794.0	1,792.1	1,630.1	1,178.8	1,700.8	16,840.4
NEPTUNE	270.9	245.9	239.2	247.1	102.5	167.8	409.3	415.2	223.8	261.9	228.9	385.4	3,198.0
NORTHWEST	3.6	3.3	5.9	5.0	5.5	2.7	1.2	1.0	3.9	4.9	1.1	1.5	39.7
NYIS	1,479.5	1,385.8	1,577.2	1,022.8	885.6	1,244.3	1,422.4	1,293.2	1,325.7	1,139.0	886.8	1,418.5	15,080.9
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	0.0	0.0	0.0	0.0	0.0	0.0	25.4
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	303.9	283.9	255.9	291.0	238.9	129.7	95.1	104.2	220.0	166.5	323.4	191.9	2,604.4
CPLEEXP	31.3	33.4	47.6	32.0	26.7	30.8	29.7	15.2	49.7	20.2	13.9	16.6	347.1
DUKEXP	27.1	45.2	0.9	32.9	11.8	29.9	27.3	44.4	45.3	51.8	223.5	79.9	619.9
NCMPAEXP	0.0	0.1	0.0	0.2	0.0	1.5	0.0	0.0	0.0	0.0	0.2	0.0	1.9
SOUTHWEST	4.5	5.7	3.0	11.7	3.6	4.4	2.4	2.3	2.8	6.0	11.9	4.1	62.3
SOUTHEXP	241.0	199.6	204.5	214.2	196.9	63.1	35.6	42.3	122.2	88.5	73.9	91.3	1,573.2
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.0	3,455.2	3,711.7	3,677.0	3,262.1	2,753.5	4,056.3	39,386.2

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[21] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up-to congestion; and dispatchable.[22]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 9-7, Table 9-8 and Table 9-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow.

Table 9-7 through Table 9-9 show the day-ahead interchange totals at the individual interfaces. Net

21 Effective September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

22 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

interchange in the Day-Ahead Energy Market is shown by interface for 2013 in Table 9-7, while gross imports and exports are shown in Table 9-8 and Table 9-9.

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(33.4)	(28.5)	(41.2)	(30.5)	(24.1)	172.0	208.7	215.4	(47.1)	(18.8)	(11.2)	(15.7)	345.4
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	149.9	80.9	22.3	24.0	46.6	113.9	1,017.1
EKPC	(36.6)	(33.6)	(37.2)	(36.0)	(37.2)		0.0	0.0	0.0	0.0	0.0	0.0	(180.5)
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	0.0	0.0	0.0	4.4	70.0	55.2	378.0
MEC	(483.0)	(435.7)	(477.7)	(423.0)	(484.7)	(462.9)	(463.0)	(472.9)	(454.9)	(481.0)	(468.2)	(484.1)	(5,591.1)
MISO	(242.1)	(52.6)	(48.7)	(34.3)	(324.7)	(302.2)	(204.9)	(419.6)	(343.7)	(370.4)	(71.0)	(470.9)	(2,885.1)
ALTE	(177.8)	(79.5)	(119.1)	(99.9)	(238.2)	(267.3)	(289.0)	(318.5)	(296.3)	(229.6)	(51.3)	(168.4)	(2,334.7)
ALTW	(7.6)	(2.5)	0.0	0.0	(2.5)	(35.8)	0.0	(24.0)	(6.8)	(14.7)	0.0	(36.7)	(130.5)
AMIL	8.7	5.2	26.3	13.5	(0.9)	(1.2)	1.9	(5.0)	(38.2)	(39.9)	(21.6)	0.0	(51.1)
CIN	7.9	45.9	37.1	32.3	18.3	44.4	41.6	37.1	61.9	57.9	(10.1)	(186.4)	187.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(0.9)	(5.9)	(1.6)	0.0	0.0	33.9	117.5	54.5	0.0	0.0	0.0	0.0	197.6
MECS	23.4	45.8	102.9	93.1	97.9	36.9	8.9	(55.8)	72.2	(22.8)	118.1	51.1	571.9
NIPS	(22.2)	(12.5)	(21.5)	(27.8)	(70.7)	0.0	0.6	0.0	(0.2)	0.0	0.0	0.0	(154.3)
WEC	(73.7)	(49.2)	(72.8)	(45.5)	(128.8)	(113.1)	(86.4)	(107.9)	(136.4)	(121.4)	(106.1)	(130.6)	(1,171.8)
NYISO	(833.6)	(874.4)	(944.3)	(459.5)	(386.6)	(707.5)	(968.7)	(910.2)	(777.0)	(587.7)	(373.5)	(1,056.7)	(8,879.7)
HUDS					(32.5)	(36.6)	(18.4)	(12.1)	(7.9)	(2.7)	(28.3)	(97.8)	(236.5)
LIND	(15.3)	(14.3)	(2.6)	0.1	0.0	0.1	0.0	0.0	0.0	0.0	(9.4)	(34.1)	(75.6)
NEPT	(278.5)	(255.2)	(248.7)	(253.1)	(101.5)	(193.7)	(420.0)	(425.6)	(236.7)	(275.7)	(237.6)	(394.3)	(3,320.7)
NYIS	(539.7)	(604.9)	(693.0)	(206.5)	(252.6)	(477.2)	(530.3)	(472.4)	(532.3)	(309.2)	(98.1)	(530.5)	(5,246.9)
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	691.9	598.5	498.0	607.0	529.4	693.9	6,574.8
TVA	32.7	3.6	(3.6)	41.2	92.4	18.6	71.9	47.0	42.9	60.2	26.6	25.1	458.6
Total without Up-To Congestion	(898.1)	(790.9)	(987.2)	(494.9)	(494.1)	(509.7)	(514.3)	(860.9)	(1,059.5)	(762.2)	(251.2)	(1,139.4)	(8,762.3)
Up-To Congestion	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(252.3)	(374.2)	(505.0)	(1,331.0)	(1,346.8)	(44.9)	(8,840.9)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(766.5)	(1,235.0)	(1,564.5)	(2,093.3)	(1,598.0)	(1,184.3)	(17,603.2)

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	0.0	0.0	0.0	0.0	0.0	202.5	237.7	228.5	0.0	0.0	0.0	0.0	668.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	149.9	80.9	24.2	27.4	47.7	116.3	1,026.0
EKPC	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	0.0	0.0	0.0	4.4	70.0	55.2	378.0
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	75.2	115.2	196.6	184.4	231.6	229.4	270.8	213.2	235.3	187.0	167.2	61.1	2,167.1
ALTE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	8.7	5.2	26.3	13.5	3.9	1.9	1.9	0.0	7.9	0.0	0.0	0.0	69.5
CIN	21.5	64.2	58.4	77.7	61.9	52.0	41.6	41.5	62.7	59.7	1.2	10.0	552.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	5.6	0.0	0.0	0.0	0.0	33.9	117.5	54.5	0.0	0.0	0.0	0.0	211.6
MECS	39.3	45.8	111.9	93.1	165.8	141.6	109.2	117.1	164.6	127.3	166.0	51.1	1,333.0
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.6
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	726.2	650.4	717.7	768.3	601.6	726.7	755.8	749.1	696.8	740.8	723.9	705.2	8,562.4
HUDS					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.1	9.3	2.9	0.1	0.0	0.1	0.0	0.0	0.0	0.0	1.4	0.0	13.8
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	726.2	641.1	714.8	768.2	601.6	726.6	755.8	749.1	696.8	740.8	722.5	705.2	8,548.6
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	691.9	598.5	498.0	607.0	529.4	693.9	6,574.8
TVA	41.7	13.6	3.6	42.7	102.8	21.5	74.1	47.0	50.1	63.5	35.4	36.9	532.7
Total without Up-To Congestion	1,540.9	1,409.5	1,483.5	1,442.6	1,606.8	1,952.4	2,180.1	1,917.2	1,504.4	1,630.0	1,573.5	1,668.7	19,909.7
Up-To Congestion	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	3,571.1	3,422.3	3,183.9	2,387.3	2,972.8	3,692.9	45,329.9
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	5,751.2	5,339.5	4,688.3	4,017.3	4,546.4	5,361.6	65,239.6

In the Day-Ahead Energy Market in 2013, there were net scheduled exports at eleven of PJM's 21 interfaces.[23] The top three net exporting interfaces in the Real-Time Energy Market accounted for 77.6 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 30.6 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 28.7 percent, and PJM/NEPT with 18.2 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 48.6 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 15.8 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net scheduled imports, with three importing interfaces accounting for 83.9 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 67.6 percent, PJM/DUK with 10.5 percent and PJM/Michigan Electric Coordinated Systems (MECS) with 5.9 percent of the net import volume.[24]

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Energy Market interchange totals at the individual interface pricing points. In 2013, up-to congestion transactions accounted for 69.5 percent of all scheduled import MW transactions, 65.4 percent of all scheduled export MW transactions and 50.2 percent of the net interchange volume in the Day-Ahead Energy Market. Net interchange in the Day-Ahead Energy Market, including up-to congestion transactions, is shown by interface pricing point in 2013 in Table 9-10. Up-to congestion transactions by interface pricing point in 2013 are shown in Table 9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Energy Market are shown in Table 9-12 and Table 9-14, while gross import up-to congestion transactions are show in Table 9-13 and gross export up-to congestion transactions are shown in Table 9-15.

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	33.4	28.5	41.2	30.5	24.1	30.5	29.0	13.1	47.1	18.8	11.2	15.7	323.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	3.3	1.1	2.4	8.8
EKPC	36.6	33.6	37.2	36.0	37.2		0.0	0.0	0.0	0.0	0.0	0.0	180.5
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	483.0	435.7	477.7	423.0	484.7	462.9	463.0	472.9	454.9	481.0	468.2	484.1	5,591.1
MISO	317.3	167.9	245.4	218.6	556.4	531.6	475.7	632.8	579.0	557.4	238.2	532.0	5,052.2
ALTE	177.8	79.5	119.1	99.9	238.2	267.3	289.0	318.5	296.3	229.6	51.3	168.4	2,334.7
ALTW	7.6	2.5	0.0	0.0	2.5	35.8	0.0	24.0	6.8	14.7	0.0	36.7	130.5
AMIL	0.0	0.0	0.0	0.0	4.8	3.2	0.0	5.0	46.1	39.9	21.6	0.0	120.6
CIN	13.7	18.3	21.3	45.5	43.5	7.6	0.0	4.4	0.8	1.7	11.3	196.4	364.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	6.5	5.9	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.0
MECS	15.9	0.0	9.1	0.0	67.9	104.7	100.3	172.9	92.5	150.1	47.8	0.0	761.1
NIPS	22.2	12.5	21.5	27.8	70.7	0.0	0.0	0.0	0.2	0.0	0.0	0.0	154.9
WEC	73.7	49.2	72.8	45.5	128.8	113.1	86.4	107.9	136.4	121.4	106.1	130.6	1,171.8
NYISO	1,559.8	1,524.8	1,662.1	1,227.8	988.2	1,434.2	1,724.5	1,659.3	1,473.8	1,328.4	1,097.3	1,761.9	17,442.1
HUDS					32.5	36.6	18.4	12.1	7.9	2.7	28.3	97.8	236.5
LIND	15.4	23.6	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.8	34.1	89.4
NEPT	278.5	255.2	248.7	253.1	101.5	193.7	420.0	425.6	236.7	275.7	237.6	394.3	3,320.7
NYIS	1,265.9	1,246.0	1,407.8	974.7	854.2	1,203.9	1,286.1	1,221.6	1,229.1	1,050.0	820.6	1,235.7	13,795.5
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	9.0	10.0	7.2	1.5	10.4	2.9	2.2	0.0	7.1	3.2	8.7	11.8	74.1
Total without Up-To Congestion	2,439.0	2,200.5	2,470.7	1,937.5	2,100.9	2,462.2	2,694.4	2,778.1	2,563.9	2,392.2	1,824.8	2,808.0	28,672.0
Up-To Congestion	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	3,823.4	3,796.4	3,688.9	3,718.4	4,319.6	3,737.9	54,170.8
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	6,517.8	6,574.5	6,252.8	6,110.6	6,144.4	6,545.9	82,842.8

23 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

24 In the Day-Ahead Energy Market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created prior to the integration of all balancing authorities into MISO. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the integration, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created at the NIPSCO Interface prior to the integration.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The Southeast pricing point also remains eligible to receive the real-time interface price only through the reserve sharing agreement with VACAR. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.

In the Day-Ahead Energy Market, in 2013, there were net scheduled exports at ten of PJM's 19 interface pricing points eligible for day-ahead. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 56.7 percent of the total net exports: PJM/SouthEXP with 20.9 percent, PJM/NIPSCO with 19.4 percent and PJM/Neptune with 16.3 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 28.1 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net imports, with three importing interface pricing points accounting for 78.5 percent of the total net imports: PJM/SouthIMP with 35.0 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 23.1 percent, and PJM/Southeast with 20.5 percent of the net import volume.[25]

In the Day-Ahead Energy Market, in 2013, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 75.4 percent of the total net up-to congestion exports: PJM/SouthEXP with 27.7 percent, PJM/NIPSCO with 26.7 percent and PJM/Southwest with 21.0 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 7.3 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 7.3 percent). The PJM/NYIS, PJM/LIND and the PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Seven PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 68.0 percent of the total net up-to congestion imports: PJM/MISO with 26.7 percent, PJM/Northwest with 21.3 percent and PJM/Southeast with 19.9 percent of the net import volume.[26]

25 In the Day-Ahead Energy Market, one PJM interface pricing point had a net interchange of zero (PJM/DUKEXP).

26 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS					(32.5)	(36.6)	116.2	(49.5)	64.8	106.3	(20.0)	166.6	315.3
IMO	27.4	235.1	206.5	104.5	100.1	37.8	42.5	27.4	87.8	74.8	142.9	194.4	1,281.1
LINDENVFT	102.2	14.5	(14.6)	(16.8)	(68.7)	(13.6)	33.3	(95.6)	(48.1)	(48.9)	19.1	65.6	(71.6)
MISO	192.7	130.5	453.0	228.8	(434.9)	(207.4)	(305.0)	(174.3)	(265.1)	(274.5)	(176.3)	(796.7)	(1,628.8)
NEPTUNE	(335.1)	(381.7)	(398.9)	(473.6)	(341.6)	(302.0)	(541.9)	(541.5)	(338.8)	(453.0)	(299.1)	(505.1)	(4,912.4)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(221.9)	(145.1)	(166.9)	(411.4)	(712.3)	(755.0)	(5,824.2)
NORTHWEST	(744.5)	(810.7)	(646.6)	199.5	520.7	128.3	(9.0)	(176.0)	(309.3)	(560.1)	(475.9)	(58.1)	(2,941.7)
NYIS	(662.2)	(576.6)	(506.4)	208.5	10.8	(312.0)	(346.8)	(432.6)	(465.7)	(225.3)	154.9	(318.0)	(3,471.4)
OVEC	254.6	210.5	438.4	269.4	92.5	142.3	247.3	69.1	64.0	(38.7)	188.2	859.6	2,797.1
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	1,547.2	1,389.6	886.3	653.2	826.1	973.3	12,620.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	231.5	227.2	0.0	0.0	0.0	0.0	661.2
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	63.1	17.0	2.0	2.5	0.7	11.2	221.4
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	62.1	42.4	16.8	8.1	28.9	76.6	441.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	446.4	340.8	257.3	173.8	199.9	387.3	3,627.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	187.2	287.8	257.4	3,426.2
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	496.7	394.3	322.8	281.5	308.9	240.8	4,243.8
SOUTHEXP	(1,766.4)	(1,094.4)	(1,527.3)	(1,809.8)	(1,518.9)	(1,370.0)	(1,328.6)	(1,106.6)	(1,073.4)	(915.6)	(1,245.7)	(1,011.0)	(15,767.7)
CPLEEXP	(32.4)	(27.8)	(40.7)	(29.6)	(22.8)	(29.5)	(27.4)	(12.7)	(46.8)	(18.5)	(10.6)	(15.0)	(313.6)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	(1.0)	(0.8)	(0.5)	(0.9)	(1.3)	(1.1)	(1.6)	(0.5)	(0.4)	(0.3)	(0.6)	(0.8)	(9.7)
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(190.9)	(59.8)	(50.3)	(69.9)	(155.7)	(52.9)	(1,139.5)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(480.0)	(605.4)	(675.2)	(551.6)	(644.1)	(497.7)	(8,011.2)
SOUTHEXP	(771.5)	(501.6)	(659.5)	(638.4)	(628.2)	(582.0)	(628.8)	(428.3)	(300.8)	(275.2)	(434.7)	(444.7)	(6,293.8)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(766.5)	(1,235.0)	(1,564.5)	(2,093.3)	(1,598.0)	(1,184.3)	(17,603.2)

Table 9-11 Up-to congestion scheduled net interchange volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS					0.0	0.0	134.7	(37.4)	72.7	109.0	(4.3)	264.5	539.1
IMO	(11.9)	189.4	94.5	18.0	(62.6)	(92.8)	(55.8)	(79.2)	(76.9)	(51.0)	(23.0)	143.3	(8.0)
LINDENVFT	117.5	28.8	(12.0)	(16.9)	(68.7)	(13.7)	33.3	(95.6)	(48.1)	(48.9)	28.5	99.8	4.0
MISO	500.7	288.8	660.8	422.2	117.7	323.4	164.1	458.2	305.6	282.0	61.4	(265.0)	3,319.9
NEPTUNE	(56.5)	(126.5)	(150.2)	(220.6)	(240.1)	(108.3)	(121.9)	(115.9)	(102.1)	(177.3)	(61.5)	(110.8)	(1,591.6)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(221.9)	(145.1)	(166.9)	(411.4)	(712.3)	(755.0)	(5,824.2)
NORTHWEST	(261.6)	(375.0)	(168.9)	622.5	1,004.7	591.2	454.0	296.9	145.6	(79.1)	(7.7)	426.0	2,648.7
NYIS	(121.9)	25.3	185.7	415.0	264.0	165.2	183.5	40.1	65.1	83.9	265.7	210.0	1,781.7
OVEC	(306.9)	(281.8)	31.4	(55.2)	(430.3)	(502.5)	(444.6)	(529.4)	(432.1)	(645.7)	(341.3)	168.2	(3,770.3)
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	919.7	926.7	749.3	497.7	672.3	755.3	9,240.8
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	181.0	440.7	338.9	256.8	173.8	199.9	387.3	3,617.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	187.2	287.8	257.4	3,426.2
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	231.7	219.9	205.1	136.6	184.6	110.6	2,197.3
SOUTHEXP	(1,687.4)	(1,022.2)	(1,441.8)	(1,741.8)	(1,447.2)	(1,336.7)	(1,297.4)	(1,093.5)	(1,017.1)	(890.2)	(1,224.7)	(981.1)	(15,181.0)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(190.9)	(59.8)	(50.3)	(69.9)	(155.7)	(52.9)	(1,139.5)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(480.0)	(605.4)	(675.2)	(551.6)	(644.1)	(497.7)	(8,011.2)
SOUTHEXP	(725.9)	(457.9)	(615.1)	(600.9)	(580.6)	(579.2)	(626.6)	(428.3)	(291.6)	(268.7)	(424.9)	(430.5)	(6,030.3)
Total Interfaces	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(252.3)	(374.2)	(505.0)	(1,331.0)	(1,346.8)	(44.9)	(8,840.9)
INTERNAL	22,906.0	23,311.1	27,439.6	32,152.2	34,779.0	34,935.1	29,883.4	29,207.9	26,044.7	28,243.6	32,437.9	38,150.1	359,490.7
Total	21,201.2	21,974.3	26,564.6	31,731.0	34,587.4	34,477.8	29,496.5	28,871.1	25,467.1	26,803.6	31,095.4	37,840.7	350,110.7

Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS					0.0	0.0	159.7	32.4	116.9	136.9	224.9	378.4	1,049.2
IMO	268.0	322.5	310.8	285.5	376.4	341.5	316.0	290.3	375.6	342.0	331.2	274.2	3,834.2
LINDENVFT	292.4	210.2	188.5	130.0	145.1	119.8	143.7	37.3	40.2	46.8	101.4	134.2	1,589.7
MISO	719.6	516.2	809.8	770.8	470.0	591.0	429.1	624.6	438.5	390.4	288.4	248.3	6,296.6
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	27.4	6.7	1.7	2.9	6.0	22.9	276.7
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	136.6	120.4	60.6	38.1	32.9	70.2	907.1
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	561.9	507.2	337.1	196.6	265.0	636.1	5,967.1
NYIS	1,097.0	1,031.5	1,130.2	1,260.6	991.5	1,046.5	1,103.7	966.1	898.1	991.8	1,125.0	1,005.8	12,647.8
OVEC	2,096.0	1,643.5	2,137.2	1,858.8	2,029.3	1,879.4	1,325.7	1,364.9	1,533.3	1,218.4	1,345.5	1,618.1	20,050.2
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	1,547.2	1,389.6	886.3	653.2	826.1	973.3	12,620.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	231.5	227.2	0.0	0.0	0.0	0.0	661.2
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	63.1	17.0	2.0	2.5	0.7	11.2	221.4
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	62.1	42.4	16.8	8.1	28.9	76.6	441.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	446.4	340.8	257.3	173.8	199.9	387.3	3,627.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	187.2	287.8	257.4	3,426.2
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	496.7	394.3	322.8	281.5	308.9	240.8	4,243.8
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	5,751.2	5,339.5	4,688.3	4,017.3	4,546.4	5,361.6	65,239.6

Table 9-13 Up-to congestion scheduled gross import volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS					0.0	0.0	159.7	32.4	116.9	136.9	224.9	378.4	1,049.2
IMO	228.7	276.6	198.9	199.1	213.8	210.9	217.7	183.7	211.0	216.3	165.2	223.1	2,545.0
LINDENVFT	292.4	200.9	185.5	129.9	145.1	119.8	143.7	37.3	40.2	46.8	100.1	134.2	1,575.9
MISO	710.9	505.8	772.2	745.5	466.1	590.2	422.5	624.3	430.5	389.5	287.9	247.9	6,193.2
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	27.4	6.7	1.7	2.9	6.0	22.9	276.7
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	136.6	120.4	60.6	38.1	32.9	70.2	907.1
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	561.9	507.2	337.1	196.6	265.0	636.1	5,967.1
NYIS	370.9	388.3	414.4	492.4	389.9	319.8	347.9	217.3	199.5	251.1	402.5	298.1	4,092.0
OVEC	1,534.5	1,151.2	1,730.2	1,534.2	1,506.5	1,234.6	633.9	766.4	1,037.2	611.4	816.0	926.6	13,482.9
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	919.7	926.7	749.3	497.7	672.3	755.3	9,240.8
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	181.0	440.7	338.9	256.8	173.8	199.9	387.3	3,617.3
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	247.3	367.9	287.3	187.2	287.8	257.4	3,426.2
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	231.7	219.9	205.1	136.6	184.6	110.6	2,197.3
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	3,571.1	3,422.3	3,183.9	2,387.3	2,972.8	3,692.9	45,329.9

Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS					32.5	36.6	43.4	81.9	52.1	30.7	244.9	211.8	733.9
IMO	240.6	87.4	104.4	181.1	276.4	303.7	273.5	262.9	287.9	267.3	188.3	79.8	2,553.1
LINDENVFT	190.2	195.7	203.1	146.7	213.8	133.4	110.4	132.9	88.3	95.7	82.3	68.6	1,661.2
MISO	526.9	385.6	356.8	541.9	904.9	798.4	734.1	798.8	703.5	664.9	464.6	1,045.0	7,925.4
NEPTUNE	462.2	413.9	410.4	490.9	352.4	312.1	569.3	548.2	340.5	455.9	305.2	528.0	5,189.0
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	358.5	265.5	227.6	449.5	745.1	825.2	6,731.3
NORTHWEST	1,032.4	1,025.5	876.4	618.5	663.8	600.0	570.8	683.1	646.4	756.7	740.9	694.2	8,908.8
NYIS	1,759.2	1,608.1	1,636.5	1,052.1	980.7	1,358.5	1,450.5	1,398.7	1,363.8	1,217.1	970.1	1,323.8	16,119.2
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	1,078.5	1,295.8	1,469.3	1,257.2	1,157.3	758.5	17,253.1
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,766.4	1,094.4	1,527.3	1,809.8	1,518.9	1,370.0	1,328.6	1,106.6	1,073.4	915.6	1,245.7	1,011.0	15,767.7
CPLEEXP	32.4	27.8	40.7	29.6	22.8	29.5	27.4	12.7	46.8	18.5	10.6	15.0	313.6
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	1.0	0.8	0.5	0.9	1.3	1.1	1.6	0.5	0.4	0.3	0.6	0.8	9.7
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	190.9	59.8	50.3	69.9	155.7	52.9	1,139.5
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	480.0	605.4	675.2	551.6	644.1	497.7	8,011.2
SOUTHEXP	771.5	501.6	659.5	638.4	628.2	582.0	628.8	428.3	300.8	275.2	434.7	444.7	6,293.8
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	6,517.8	6,574.5	6,252.8	6,110.6	6,144.4	6,545.9	82,842.8

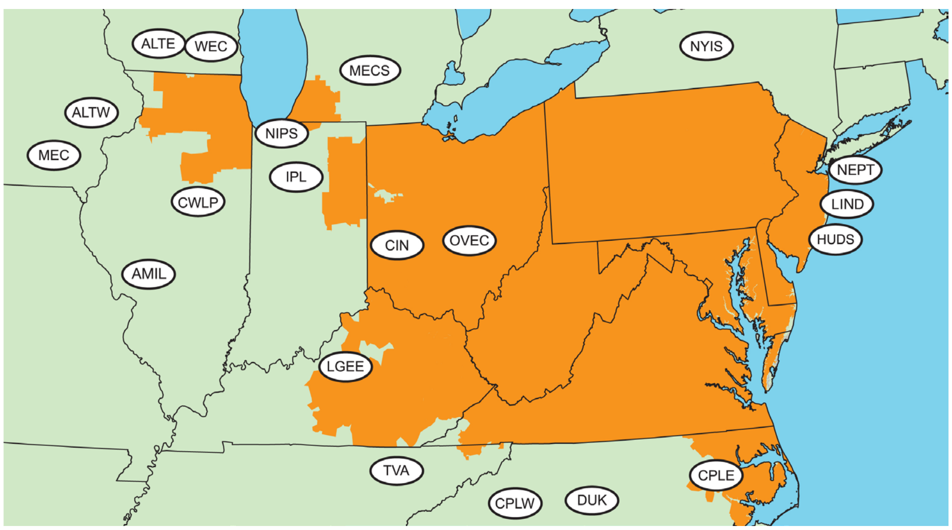
Table 9-15 Up-to congestion scheduled gross export volume by interface pricing point (GWh): 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
HUDS					0.0	0.0	25.0	69.8	44.2	28.0	229.2	113.9	510.1
IMO	240.6	87.3	104.4	181.1	276.4	303.7	273.5	262.9	287.9	267.3	188.3	79.8	2,553.0
LINDENVFT	174.8	172.1	197.6	146.7	213.8	133.4	110.4	132.9	88.3	95.7	71.5	34.4	1,571.8
MISO	210.2	217.0	111.4	323.3	348.4	266.7	258.4	166.1	124.9	107.5	226.4	513.0	2,873.3
NEPTUNE	183.7	158.7	161.7	237.8	250.9	118.4	149.3	122.6	103.8	180.2	67.6	133.7	1,868.3
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	358.5	265.5	227.6	449.5	745.1	825.2	6,731.3
NORTHWEST	549.4	589.8	398.7	195.5	179.8	137.1	107.8	210.2	191.6	275.7	272.7	210.1	3,318.4
NYIS	492.8	362.9	228.7	77.4	126.0	154.6	164.4	177.1	134.3	167.2	136.8	88.1	2,310.3
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	1,078.5	1,295.8	1,469.3	1,257.2	1,157.3	758.5	17,253.1
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,687.4	1,022.2	1,441.8	1,741.8	1,447.2	1,336.7	1,297.4	1,093.5	1,017.1	890.2	1,224.7	981.1	15,181.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	190.9	59.8	50.3	69.9	155.7	52.9	1,139.5
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	480.0	605.4	675.2	551.6	644.1	497.7	8,011.2
SOUTHEXP	725.9	457.9	615.1	600.9	580.6	579.2	626.6	428.3	291.6	268.7	424.9	430.5	6,030.3
Total	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	3,823.4	3,796.4	3,688.9	3,718.4	4,319.6	3,737.9	54,170.8

Table 9-16 Active interfaces: 2013[27,28,29]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	
EKPC	Active	Active	Active	Active	Active							
HUDS						Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external interfaces



27 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

28 On June 1, 2013, East Kentucky Power Cooperative (EKPC) integrated with PJM, resulting in the elimination of the EKPC Interface.

29 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDS Interface.

Table 9-17 Active pricing points: 2013[30]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS						Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[31]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market based price differentials that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs.

PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both MISO's border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows). In 2013, there were net scheduled flows of 3,393 GWh through MISO that received an interface pricing point associated with the southern border. Conversely, in 2013, there were net scheduled flows of 134 GWh across the southern border that received the MISO interface pricing point.

30 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDSONTP Interface Pricing Point.

31 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In 2013, net scheduled interchange was 2,848 GWh and net actual interchange was 3,101 GWh, a difference of 253 GWh. In 2012, net scheduled interchange was 898 GWh and net actual interchange was 672 GWh, a difference of 226 GWh.[32] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[33]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): 2013

	Actual	Net Scheduled	Difference (GWh)
CPLE	7,419	149	7,270
CPLW	(1,580)	0	(1,580)
DUK	192	1,274	(1,082)
EKPC	957	(569)	1,526
LGEE	2,371	3,237	(866)
MEC	(2,582)	(5,068)	2,486
MISO	(12,926)	1,396	(14,322)
ALTE	(6,486)	(3,845)	(2,641)
ALTW	(2,510)	(260)	(2,251)
AMIL	10,404	903	9,501
CIN	(5,413)	2,440	(7,854)
CWLP	(471)	0	(471)
IPL	441	713	(272)
MECS	(9,316)	3,269	(12,585)
NIPS	(5,276)	(146)	(5,130)
WEC	5,702	(1,679)	7,381
NYISO	(9,143)	(9,331)	188
HUDS	(266)	(266)	0
LIND	(1,146)	(1,146)	0
NEPT	(3,198)	(3,198)	0
NYIS	(4,533)	(4,722)	188
OVEC	13,149	9,255	3,894
TVA	5,244	2,505	2,738
Total	3,101	2,848	253

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[34] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-19 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (13,570 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 10,432 GWh).

32 The "Net Scheduled" values shown in Table 9-18 include dynamic schedules. Dynamic schedules are commonly used for scheduling generation from one another balancing authority area to another. As defined by NERC, a dynamic schedule is a telemetered reading or value from such a generating unit that is updated in real time and used as a schedule in the AGC/ACE equation of the BA to which it is scheduled. The hourly integrated values of dynamic schedules are treated as a schedule for interchange accounting purposes. Table 9-1 through Table 9-6 represent block scheduled transactions, submitted through the Enhanced Energy Scheduling (EES) application and tagged through the NERC e-tag process only. As a result, the net interchange in Table 9-18 does not match the interchange values shown in Table 9-1 through Table 9-6.

33 See PJM. "M-12: Balancing Operations," Revision 30 (December 1, 2013).

34 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of GCA and LCA after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model," <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008.)

The IMO Interface Pricing Point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-19 Net scheduled and actual PJM flows by interface pricing point (GWh): 2013

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(266)	(266)	0
IMO	0	6,532	(6,532)
LINDENVFT	(1,146)	(1,146)	0
MISO	(11,969)	(15,148)	3,179
NEPTUNE	(3,198)	(3,198)	0
NORTHWEST	(2,582)	(31)	(2,552)
NYIS	(4,533)	(3,581)	(953)
OVEC	13,149	9,255	3,894
SOUTHIMP	13,646	13,035	610
CPLEIMP	0	672	(672)
DUKIMP	0	937	(937)
NCMPAIMP	0	544	(544)
SOUTHWEST	0	0	0
SOUTHIMP	13,646	10,882	2,764
SOUTHEXP	0	(2,605)	2,605
CPLEEXP	0	(347)	347
DUKEXP	0	(620)	620
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(63)	63
SOUTHEXP	0	(1,573)	1,573
Total	3,101	2,848	253

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2013

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(266)	(266)	0
LINDENVFT	(1,146)	(1,146)	0
MISO	(11,969)	(8,579)	(3,390)
NEPTUNE	(3,198)	(3,198)	0
NORTHWEST	(2,582)	(31)	(2,552)
NYIS	(4,533)	(3,618)	(915)
OVEC	13,149	9,255	3,894
SOUTHIMP	13,646	13,035	610
CPLEIMP	0	672	(672)
DUKIMP	0	937	(937)
NCMPAIMP	0	544	(544)
SOUTHWEST	0	0	0
SOUTHIMP	13,646	10,882	2,764
SOUTHEXP	0	(2,605)	2,605
CPLEEXP	0	(347)	347
DUKEXP	0	(620)	620
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(63)	63
SOUTHEXP	0	(1,573)	1,573
Total	3,101	2,848	253

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loops flows would be reduced.

The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce. unscheduled loop flows.

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): 2013

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(6,486)	(3,845)	(2,641)	HUDS		(266)	(266)	0
	MISO	(6,486)	(3,845)	(2,640)		HUDSONTP	(266)	(266)	0
	NORTHWEST	0	(2)	2	IPL		441	713	(272)
	SOUTHIMP	0	2	(2)		IMO	0	943	(943)
ALTW		(2,510)	(260)	(2,251)		MISO	441	(842)	1,282
	MISO	(2,510)	(259)	(2,251)		SOUTHEXP	0	(2)	2
AMIL		10,404	903	9,501		SOUTHIMP	0	613	(613)
	MISO	10,404	460	9,944	LGEE		2,371	3,237	(866)
	NORTHWEST	0	(1)	1		SOUTHEXP	0	(52)	52
	SOUTHIMP	0	507	(507)		SOUTHIMP	2,371	3,289	(918)
	SOUTHWEST	0	(63)	63	LIND		(1,146)	(1,146)	0
CIN		(5,413)	2,440	(7,854)		LINDENVFT	(1,146)	(1,146)	0
	IMO	0	1,932	(1,932)	MEC		(2,582)	(5,068)	2,486
	MISO	(5,413)	(2,078)	(3,335)		MISO	0	(5,651)	5,651
	NORTHWEST	0	(35)	35		NORTHWEST	(2,582)	8	(2,591)
	NYIS	0	1,103	(1,103)		SOUTHIMP	0	575	(575)
	SOUTHIMP	0	1,519	(1,519)	MECS		(9,316)	3,269	(12,585)
CPLE		7,419	149	7,270		IMO	0	3,694	(3,694)
	CPLEEXP	0	(347)	347		MISO	(9,316)	(1,199)	(8,117)
	CPLEIMP	0	672	(672)		SOUTHIMP	0	775	(775)
	DUKEXP	0	(10)	10	NEPT		(3,198)	(3,198)	0
	DUKIMP	0	4	(4)		NEPTUNE	(3,198)	(3,198)	0
	SOUTHEXP	0	(15)	15	NIPS		(5,276)	(146)	(5,130)
	SOUTHIMP	7,419	(156)	7,574		MISO	(5,276)	(188)	(5,088)
CPLW		(1,580)	0	(1,580)		SOUTHIMP	0	42	(42)
	SOUTHIMP	(1,580)	0	(1,580)	NYIS		(4,533)	(4,722)	188
CWLP		(471)	0	(471)		IMO	0	(38)	38
	MISO	(471)	0	(471)		NYIS	(4,533)	(4,684)	151
DUK		192	1,274	(1,082)	OVEC		13,149	9,255	3,894
	DUKEXP	0	(610)	610		OVEC	13,149	9,255	3,894
	DUKIMP	0	933	(933)	TVA		5,244	2,505	2,738
	NCMPAEXP	0	(2)	2		SOUTHEXP	0	(350)	350
	NCMPAIMP	0	544	(544)		SOUTHIMP	5,244	2,855	2,389
	SOUTHEXP	0	(365)	365	WEC		5,702	(1,679)	7,381
	SOUTHIMP	192	774	(581)		MISO	5,702	(1,679)	7,381
EKPC		957	(569)	1,526	Grand Total		3,101	2,848	253
	MISO	957	134	822					
	SOUTHEXP	0	(790)	790					
	SOUTHIMP	0	86	(86)					

Table 9-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the Interface Pricing Points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 9-21 shows that in 2013, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area of the Ontario Independent Electricity System Operator (IMO), and thus actual flows were assigned the IMO Interface Pricing point (1,932 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO Interface, and thus were assigned the MISO Interface Pricing point (2,078 GWh).

Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-22 shows that in 2013, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO Interface Pricing Point, had market paths that entered the PJM Energy Market at the MECS Interface (3,694 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO Interface Pricing Point, had market paths that exited the PJM Energy Market at the NYIS Interface (38 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): 2013

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(347)	347	NEPTUNE		(3,198)	(3,198)	0
	CPLE	0	(347)	347		NEPT	(3,198)	(3,198)	0
CPLEIMP		0	672	(672)	NORTHWEST		(2,582)	(31)	(2,552)
	CPLE	0	672	(672)		ALTE	0	(2)	2
DUKEXP		0	(620)	620		AMIL	0	(1)	1
	CPLE	0	(10)	10		CIN	0	(35)	35
	DUK	0	(610)	610		MEC	(2,582)	8	(2,591)
DUKIMP		0	937	(937)	NYIS		(4,533)	(3,581)	(953)
	CPLE	0	4	(4)		CIN	0	1,103	(1,103)
	DUK	0	933	(933)		NYIS	(4,533)	(4,684)	151
HUDSONTP		(266)	(266)	0	OVEC		13,149	9,255	3,894
	HUDS	(266)	(266)	0		OVEC	13,149	9,255	3,894
IMO		0	6,532	(6,532)	SOUTHEXP		0	(1,573)	1,573
	CIN	0	1,932	(1,932)		CPLE	0	(15)	15
	IPL	0	943	(943)		DUK	0	(365)	365
	MECS	0	3,694	(3,694)		EKPC	0	(790)	790
	NYIS	0	(38)	38		IPL	0	(2)	2
LINDENVFT		(1,146)	(1,146)	0		LGEE	0	(52)	52
	LIND	(1,146)	(1,146)	0		TVA	0	(350)	350
MISO		(11,969)	(15,148)	3,179	SOUTHIMP		13,646	10,882	2,764
	ALTE	(6,486)	(3,845)	(2,640)		ALTE	0	2	(2)
	ALTW	(2,510)	(259)	(2,251)		AMIL	0	507	(507)
	AMIL	10,404	460	9,944		CIN	0	1,519	(1,519)
	CIN	(5,413)	(2,078)	(3,335)		CPLE	7,419	(156)	7,574
	CWLP	(471)	0	(471)		CPLW	(1,580)	0	(1,580)
	EKPC	957	134	822		DUK	192	774	(581)
	IPL	441	(842)	1,282		EKPC	0	86	(86)
	MEC	0	(5,651)	5,651		IPL	0	613	(613)
	MECS	(9,316)	(1,199)	(8,117)		LGEE	2,371	3,289	(918)
	NIPS	(5,276)	(188)	(5,088)		MEC	0	575	(575)
	WEC	5,702	(1,679)	7,381		MECS	0	775	(775)
NCMPAEXP		0	(2)	2		NIPS	0	42	(42)
	DUK	0	(2)	2		TVA	5,244	2,855	2,389
NCMPAIMP		0	544	(544)	SOUTHWEST		0	(63)	63
	DUK	0	544	(544)		AMIL	0	(63)	63
					Grand Total		3,101	2,848	253

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange transactions then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[35,36]

In 2013, questions were raised in the PJM/MISO Joint and Common Market (JCM) Initiative meetings whether the existing interface definitions utilized by PJM and MISO were accurately reflecting the value of congestion applied to interchange transactions when a M2M constraint is binding in either footprint.

When a M2M constraint binds, PJM's LMP calculations at the nine selected buses that make up PJM's MISO interface pricing point is determined based on the PJM model's distribution factors of those selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint.

PJM's MISO interface pricing point is a weighted aggregate price of the selected bus LMPs. Because PJM's MISO interface pricing point was calculated based on buses located within the MISO footprint (and in particular to the west of all M2M flowgtes), PJM's calculated LMP at those buses may include a congestion component of the M2M flowgates located inside the MISO footprint.

MISO's calculated LMPs at those same buses also include the congestion component as determined based on the MISO model's distribution factors and the calculated MISO shadow price of the same binding M2M constraint. The MISO's PJM interface pricing point is a weighted aggregate price of the selected buses' LMPs. MISO's PJM interface pricing point includes all PJM generator buses located within the PJM footprint.

The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. By modifying interface price definitions in this manner, the congestion components of the bus LMPs that make up the interface prices in the individual RTOs would accurately reflect the value of congestion on M2M constraints to either RTO and therefore facilitate convergence through efficient price signals.

Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In 2013, the PJM average hourly locational marginal price (LMP) at the PJM/MISO border was $30.18 while the MISO LMP at the border was $30.79, a difference of $0.61. While the average hourly LMP difference at the PJM/MISO border was only $0.61, the average of the absolute values of the hourly differences was $8.36. The average hourly flow in 2013 was -1,475 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) The direction of flow was consistent with price differentials in only 45.0 percent of hours in 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $10.71. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $6.68. In 2013, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from PJM to MISO, the average price difference was $10.42. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $15.40. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from MISO to PJM, the average price difference was $15.60. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from PJM to MISO, the average price difference was $5.73.

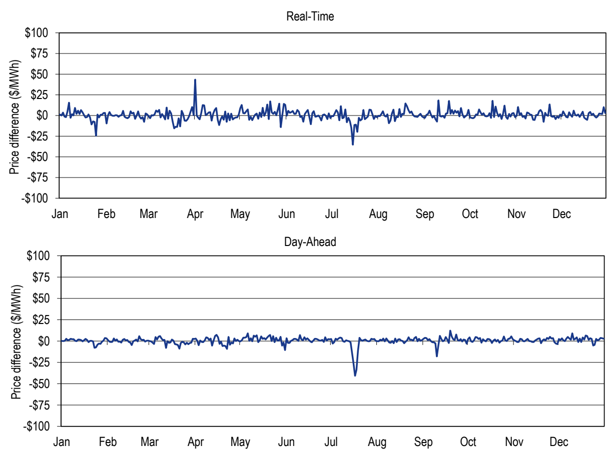
In 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $30.83 while the MISO LMP at the border was $31.32, a difference of $0.49 per MWh.

35 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed January 23, 2014). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

36 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010) (Accessed January 23, 2014).

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

Table 9-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	4,818	100.0%	3,942	100.0%
$1.00	4,166	86.5%	3,393	86.1%
$5.00	1,628	33.8%	2,027	51.4%
$10.00	702	14.6%	1,211	30.7%
$15.00	403	8.4%	823	20.9%
$20.00	251	5.2%	549	13.9%
$25.00	171	3.5%	390	9.9%
$50.00	34	0.7%	118	3.0%
$75.00	14	0.3%	55	1.4%
$100.00	7	0.1%	31	0.8%
$200.00	2	0.0%	5	0.1%
$300.00	0	0.0%	4	0.1%
$400.00	0	0.0%	1	0.0%
$500.00	0	0.0%	1	0.0%

In 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface price differentials in 3,942 hours (45.0 percent of all hours), and was inconsistent with price differentials in 4,818 hours (55.0 percent of all hours). Table 9-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 4,818 hours where flows were uneconomic, 4,166 of those hours (86.5 percent) had a price difference greater than or equal to $1.00 and 1,628 of all uneconomic hours (33.8 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $293.46. Of the 3,942 hours where flows were economic, 3,393 of those hours (86.1 percent) had a price difference greater than or equal to $1.00 and 2,027 of all economic hours (51.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $887.50.

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[37]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 2013, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In 2013, the PJM average hourly LMP at the PJM/NYISO

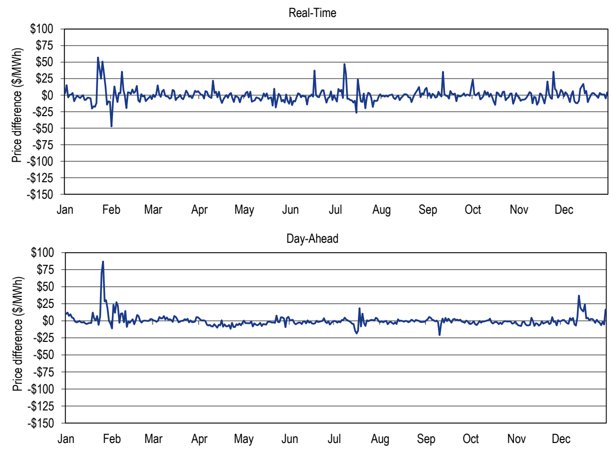
37 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

border was $40.58 while the NYISO LMP at the border was $40.17, a difference of $0.41. While the average hourly LMP difference at the PJM/NYISO border was only $0.41, the average of the absolute value of the hourly difference was $13.30. The average hourly flow in 2013 was -499 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flow was consistent with price differentials in 54.1 percent of the hours in 2013. In 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.61. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $13.04. In 2013, when the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from PJM to NYISO, the average price difference was $13.19. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from NYISO to PJM, the average price difference was $16.44. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $12.09. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $13.35.

In 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $41.53 while the NYIS LMP at the border was $41.59, a difference of $0.06.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 9-6).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): 2013



Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

In 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,737 (54.1 percent of all hours), and was inconsistent with price differences in 4,023 hours (45.9 percent of all hours). Table 9-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 4,023 hours where flows were uneconomic, 3,643 of those hours (90.6 percent) had a price difference greater than or equal to $1.00 and 2,376 of all uneconomic hours (59.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $476.36. Of the 4,737 hours where flows were economic, 4,337 of those hours (91.6 percent) had a price difference greater than or equal to $1.00 and 2,739 of all economic hours (57.8 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $812.91.

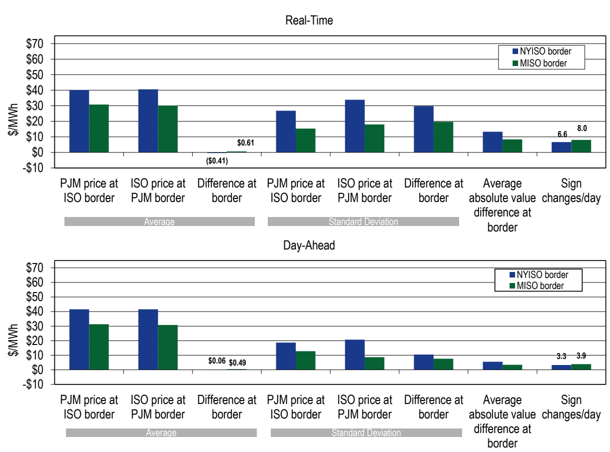
Table 9-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	4,023	100.0%	4,737	100.0%
$1.00	3,643	90.6%	4,337	91.6%
$5.00	2,376	59.1%	2,739	57.8%
$10.00	1,427	35.5%	1,482	31.3%
$15.00	937	23.3%	943	19.9%
$20.00	668	16.6%	649	13.7%
$25.00	523	13.0%	468	9.9%
$50.00	227	5.6%	209	4.4%
$75.00	110	2.7%	122	2.6%
$100.00	51	1.3%	85	1.8%
$200.00	10	0.2%	16	0.3%
$300.00	3	0.1%	5	0.1%
$400.00	1	0.0%	2	0.0%
$500.00	0	0.0%	2	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 9-6, including average prices and measures of variability.

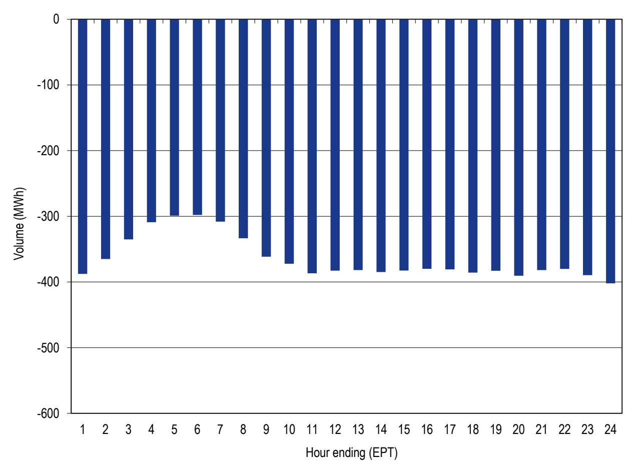
Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: 2013



Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In 2013, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In 2013, the PJM average hourly LMP at the Neptune Interface was $40.56 while the NYISO LMP at the Neptune Bus was $61.02, a difference of $20.46.[38] While the average hourly LMP difference at the PJM/Neptune border was $20.46, the average of the absolute value of the hourly difference was $31.75. The average hourly flow during 2013 was -365 MW.[39] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 67.7 percent of the hours in 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $36.68. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $19.11.

Figure 9-7 Neptune hourly average flow: 2013



Linden Variable Frequency Transformer (VFT) facility

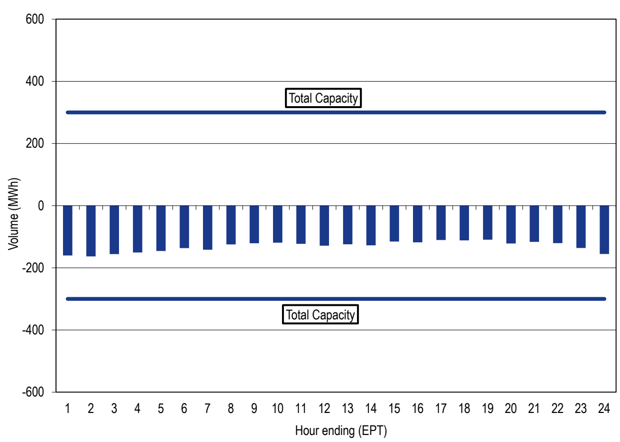
The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). In 2013,

38 In 2013, there were 1,702 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $41.69 while the NYISO LMP at the Neptune Bus during non-zero flows was $60.38, a difference of $18.69.

39 The average hourly flow in 2013, ignoring hours with no flow, on the Neptune DC Tie line was -453 MW.

the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In 2013, the PJM average hourly LMP at the Linden Interface was $40.20 while the NYISO LMP at the Linden Bus was $47.89, a difference of $7.69.[40] While the average hourly LMP difference at the PJM/Linden border was $7.69, the average of the absolute value of the hourly difference was $17.60. The average hourly flow in 2013 was -131 MW.[41] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 65.8 percent of the hours in 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $18.98. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $14.87.

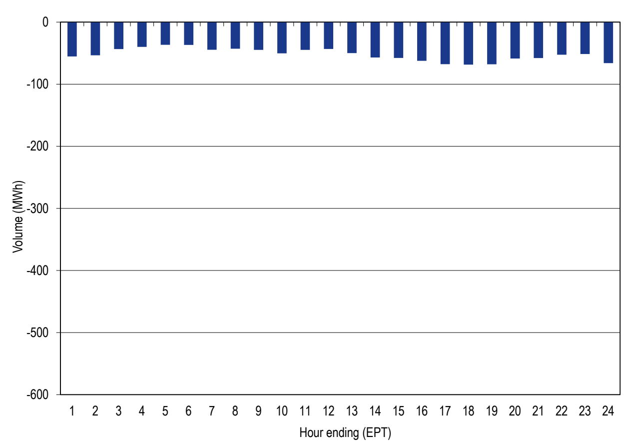
Figure 9-8 Linden hourly average flow: 2013[42]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). In the first seven months of operations, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus. The PJM average hourly LMP at the Hudson Interface was $40.72 while the NYISO LMP at the Hudson Bus was $44.37, a difference of $3.65.[43] While the average hourly LMP difference at the PJM/Hudson border was $3.65, the average of the absolute value of the hourly difference was $14.77. The average hourly flow during the first seven months of operations was -52 MW.[44] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 66.6 percent of the hours in the first seven months of operations. When the NYISO/Hudson Interface price was greater than the PJM/HUDS Interface price, the average hourly price difference was $20.99. When the PJM/HUDS Interface price was greater than the NYISO/Hudson Interface price, the average price difference was $18.32.

Figure 9-9 Hudson hourly average flow: 2013



40 In 2013, there were 1,865 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $40.62 while the NYISO LMP at the Neptune Bus during non-zero flows was $48.02, a difference of $7.40.

41 The average hourly flow in 2013, ignoring hours with no flow, on the Linden VFT line was -166 MW.

42 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.

43 In the first seven months of operations, there were 3,528 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $47.29 while the NYISO LMP at the Hudson Bus during non-zero flows was $55.17, a difference of $7.88.

44 The average hourly flow during the first seven months of operations, ignoring hours with no flow, on the Hudson line was -171 MW.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with MISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

PJM and MISO Joint Operating Agreement[45]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[46]

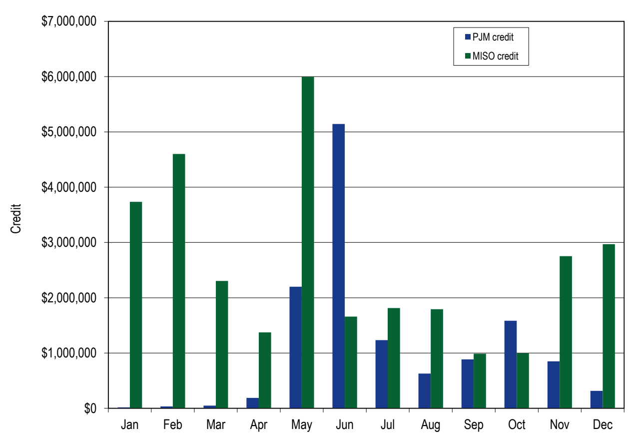
Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.[47]

Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of August 6, 2013, PJM had 166 flowgates eligible for M2M (Market to Market) coordination. Between August 6, 2013 and December 31, 2013, PJM added 19 and deleted 26 flowgates, leaving 159 flowgates eligible for M2M coordination as of December 31, 2013. As of August 6, 2013, MISO had 269 flowgates eligible for M2M coordination. Between August 6, 2013 and December 31, 2013, MISO added 82 and deleted 86 flowgates, leaving 265 flowgates eligible for M2M coordination as of December 31, 2013. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

In 2013, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 Credits for coordinated congestion management: 2013[48]



45 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed January 23, 2014).

46 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.

47 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

48 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[49]

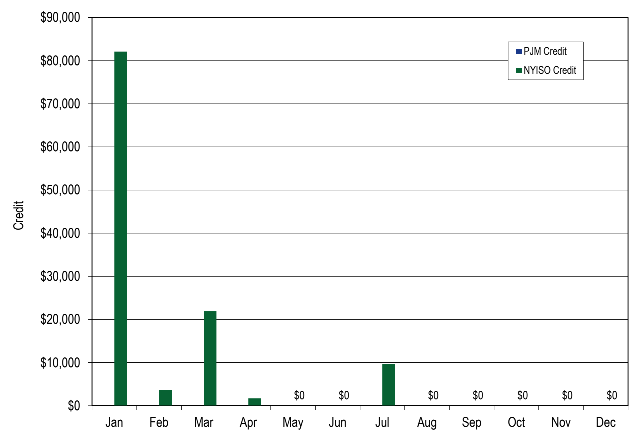
The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/MISO Interface pricing point LMP while The NYISO calculates the PJM Interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

In 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The firm flow entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

In 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (flowgates): 2013[50]



The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the NYISO – PJM Interface. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[51] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-

49 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed January 23, 2014).

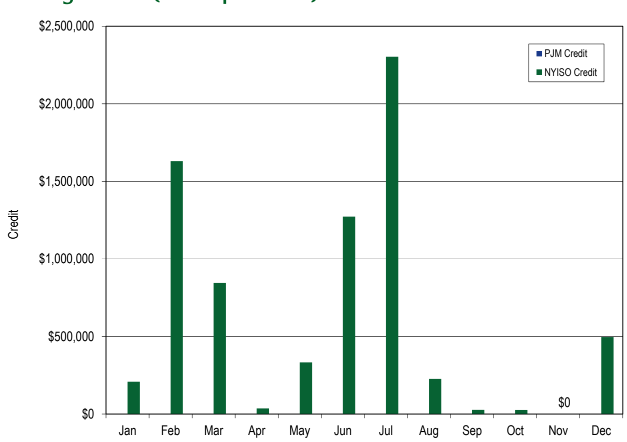
50 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

51 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed January 23, 2014).

time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In 2013, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

The PJM/NYISO JOA includes a provision that allows either party to suspend M2M operations when daily congestion charges exceed $500,000. On July 8, 2013, M2M congestion charges exceeded $500,000. These congestion charges were the result of its inability to meet the Ramapo PAR target values during thunderstorm alerts (TSA) called by the NYISO. During times when actual or anticipated severe weather conditions exist in the New York City area, the NYISO issues a TSA and operates in a more conservative manner, by reducing transmission transfer limits, which affects PJM's ability to meet the PAR targets. On July 12, 2013, PJM requested the suspension of M2M coordination for all TSA flowgates. PJM and NYISO are working together to develop additional operating and coordination procedures to ensure M2M processes continue to produce a just and reasonable result.

Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): 2013[52]



52 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a yearly basis, and, in 2013, there were no developments. The agreement continued to be in effect in 2013.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[53] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[54] The existing JOA depended on the specific characteristics of PEC as a standalone company. The merged company has not engaged in discussions with PJM on this topic. The existing JOA does not apply to the merged company and should be terminated. The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

53 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

54 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[55] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

Table 9-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$33.12	$33.74	$33.20	$33.20	($0.08)	$0.54
PEC	$33.48	$34.46	$33.20	$33.20	$0.28	$1.26
NCMPA	$33.44	$33.54	$33.20	$33.20	$0.24	$0.34

Table 9-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.33	$34.81	$34.09	$34.00	$0.24	$0.81
PEC	$34.69	$35.21	$34.09	$34.00	$0.60	$1.21
NCMPA	$33.20	$33.35	$32.67	$32.63	$0.53	$0.72

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey including lines controlled by PJM.[56] This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001.[57]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[58] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[59] The settlement defined ConEd's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[60] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement

55 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

56 See "Section 4 – Energy Market Uplift" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.

57 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

58 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

59 132 FERC ¶ 61,221 (2010).

60 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

data as shown in Table 9-27 below reflecting those charges effective May 1, 2012.

Table 9-27 Con Edison and PSE&G wheeling agreement data: 2013

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$9,033,280	($43,597)	$8,989,683	$0	$0	$0
Congestion Credit			$3,716,588			$0
Adjustments and Transmission Charges			($36,197,498)			$2,290
Net Charge			$41,470,593			($2,290)

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM issued 49 TLRs of level 3a or higher in 2013, compared to 37 TLRs issued in 2012. The number of different flowgates for which PJM declared TLRs increased from 13 in 2012 to 25 in 2013. The total MWh of transaction curtailments increased by 16.0 percent from 125,783 MWh in 2012 to 145,964 MWh in 2013.

MISO called more TLRs of level 3a or higher in 2013 than in 2012. MISO TLRs increased from 159 in 2012 to 370 in 2013.

NYISO called fewer TLRs of level 3a or higher in 2013 than in 2012. NYISO TLRs decreased from 60 in 2012 to 3 in 2013.

Table 9-28 PJM MISO, and NYISO TLR procedures: January, 2010 through December, 2013[61]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-10	6	23	20	3	5	4	18,393	13,387	60,427
Feb-10	1	9	19	1	7	3	1,249	13,095	69,569
Mar-10	6	18	21	3	10	6	2,376	27,412	78,366
Apr-10	15	40	14	7	11	2	26,992	29,832	59,041
May-10	11	20	7	4	12	4	22,193	54,702	10,463
Jun-10	19	19	13	6	8	6	64,479	183,228	23,969
Jul-10	15	25	4	8	8	3	44,210	169,667	2,262
Aug-10	12	22	0	9	7	0	32,604	189,756	0
Sep-10	11	15	1	7	7	1	82,066	32,782	232
Oct-10	4	26	1	3	12	1	2,305	29,574	0
Nov-10	1	25	0	1	10	0	59	66,113	0
Dec-10	9	7	4	6	5	1	18,509	5,972	4,224
Jan-11	7	8	29	5	5	4	75,057	14,071	156,508
Feb-11	6	7	10	5	4	2	6,428	23,796	27,649
Mar-11	0	14	28	0	5	3	0	10,133	57,472
Apr-11	3	23	12	3	9	3	8,129	44,855	15,761
May-11	9	15	15	4	7	4	18,377	36,777	24,857
Jun-11	15	14	24	7	6	9	17,865	19,437	31,868
Jul-11	7	8	17	4	7	7	18,467	3,697	20,645
Aug-11	4	6	4	4	4	2	3,624	11,323	12,579
Sep-11	7	17	7	6	7	3	6,462	25,914	11,445
Oct-11	4	16	5	2	6	1	16,812	27,392	3,665
Nov-11	0	10	2	0	5	2	0	22,672	484
Dec-11	0	5	8	0	3	2	0	8,659	26,523
Jan-12	1	9	5	1	6	2	4,920	6,274	8,058
Feb-12	4	6	16	2	6	2	0	5,177	35,451
Mar-12	1	11	10	1	6	2	398	31,891	26,761
Apr-12	0	14	11	0	7	1	0	8,408	29,911
May-12	2	17	12	1	10	5	3,539	30,759	21,445
Jun-12	0	24	0	0	7	0	0	31,502	0
Jul-12	11	19	1	5	4	1	34,197	46,512	292
Aug-12	8	13	0	1	6	0	61,151	13,403	0
Sep-12	2	5	0	1	4	0	21,134	12,494	0
Oct-12	3	9	0	2	6	0	0	12,317	0
Nov-12	4	10	5	2	6	2	444	24,351	6,250
Dec-12	1	22	0	1	12	0	0	17,761	0
Jan-13	4	42	2	3	17	1	13,453	103,463	1,045
Feb-13	4	26	0	3	10	0	14,609	66,086	0
Mar-13	0	39	0	0	13	0	0	53,122	0
Apr-13	1	45	0	1	20	0	84	64,938	0
May-13	10	29	0	7	14	0	879	20,778	0
Jun-13	4	25	1	1	11	1	5,036	76,240	4,102
Jul-13	12	28	0	2	9	0	88,623	80,328	0
Aug-13	4	19	0	4	8	0	3,469	38,608	0
Sep-13	6	33	0	5	14	0	7,716	90,188	0
Oct-13	2	42	0	1	20	0	534	72,121	0
Nov-13	2	27	0	2	8	0	11,561	52,508	0
Dec-13	0	16	0	0	5	0	0	20,257	0

Table 9-29 Number of TLRs by TLR level by reliability coordinator: 2013

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2013	ICTE	0	0	0	0	0	0	0
	MISO	119	48	2	128	73	0	370
	NYIS	3	0	0	0	0	0	3
	ONT	7	0	0	0	0	0	7
	PJM	25	22	0	1	1	0	49
	SOCO	0	0	0	0	0	0	0
	SWPP	342	114	0	76	24	0	556
	TVA	29	26	2	5	5	0	67
	VACS	5	7	0	0	0	0	12
Total		530	217	4	210	103	0	1,064

On February 9, 2013, PJM issued a TLR level 5a. A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour

61 The curtailment volume for PJM TLRs was taken from the individual NERC TLR history reports as posted in the interchange distribution calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLRs was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx> (Accessed January 23, 2014).

only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.[62] The TLR 5a, issued on February 9, 2013, was required to address system operating limits on the Bridgewater to Middlesex 230 kV line for the loss of the Smithburg to East Windsor 230 kV line in northern New Jersey. This constraint was caused by unusual weather conditions, in combination with construction outages in the Northern Public Service area and the unplanned failure of one of the Ramapo PAR transformers. At this time, there were no additional internal generation redispatch options and no additional non-cost options available to PJM system operators to relieve the constraint. As a result, firm transmission curtailments were required and PJM issued a TLR level 5a. This TLR resulted in the curtailment of 223 MWh of transactions utilizing firm transmission.

On September 11, 2013, PJM issued a TLR level 5b. A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL. The TLR 5b, issued on September 11, 2013, was required to address system operating limits on the Bridgewater to Middlesex 230 kV line for the loss of Red Oak A and B units in northern New Jersey. This constraint was caused by unusual weather conditions. At this time, there were no additional internal generation redispatch options and no additional non-cost options available to PJM system operators to relieve the constraint. As a result, firm transmission curtailments were required, and PJM issued a TLR level 5b. This TLR resulted in the curtailment of 1,480 MWh of transactions utilizing firm transmission.

Between January 1, 2003, and February 9, 2013, PJM had only issued 20 TLR's of level 5a or 5b, and none since 2008.

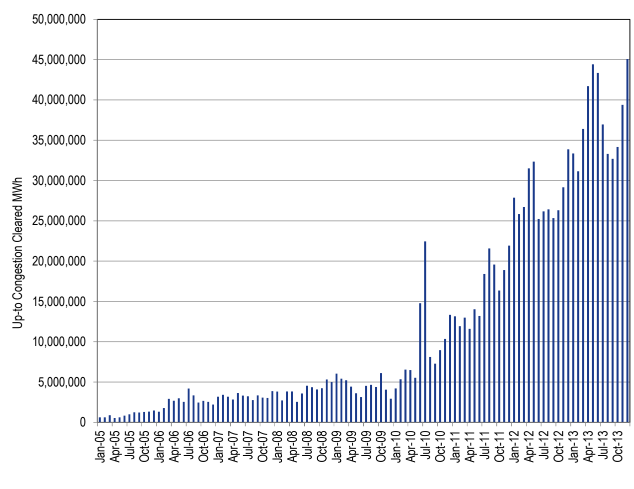
Up-To Congestion

The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[63]

Following elimination of the requirement to procure transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 110,306 bids per day, with an average cleared volume of 1,238,361 MWh per day, in 2013, compared to an average of 67,295 bids per day, with an average cleared volume of 920,307 MWh per day, in 2012 (See Figure 9-13).

Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding. The FTR forfeiture rule does not currently apply to UTCs.

Figure 9-13 Monthly up-to congestion cleared bids in MWh: 2005 through 2013



62 See the *2013 State of the Market Report for PJM*, Volume II, "Appendix E - Interchange Transactions," for a discussion on all TLR levels and the historical volumes of TLR's initiated by PJM and all other reliability coordinators in the Eastern Interconnection.

63 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Table 9-30 Monthly volume of cleared and submitted up-to congestion bids: 2009 through 2013

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	4,218,910	5,787,961	319,122	-	10,325,993	90,277	74,826	6,042	-	171,145
Feb-09	3,580,115	4,904,467	318,440	-	8,803,022	64,338	70,874	6,347	-	141,559
Mar-09	3,649,978	5,164,186	258,701	-	9,072,865	64,714	72,495	5,531	-	142,740
Apr-09	2,607,303	5,085,912	73,931	-	7,767,146	47,970	67,417	2,146	-	117,533
May-09	2,196,341	4,063,887	106,860	-	6,367,088	40,217	54,745	1,304	-	96,266
Jun-09	2,598,234	3,132,478	164,903	-	5,895,615	47,625	44,755	2,873	-	95,253
Jul-09	3,984,680	3,776,957	296,910	-	8,058,547	67,039	56,770	5,183	-	128,992
Aug-09	3,551,396	4,388,435	260,184	-	8,200,015	64,652	64,052	3,496	-	132,200
Sep-09	2,948,353	4,179,427	156,270	-	7,284,050	51,006	64,103	2,405	-	117,514
Oct-09	3,172,034	6,371,230	154,825	-	9,698,089	46,989	100,350	2,217	-	149,556
Nov-09	3,447,356	3,851,334	103,325	-	7,402,015	53,067	61,906	1,236	-	116,209
Dec-09	2,323,383	2,502,529	66,497	-	4,892,409	47,099	47,223	1,430	-	95,752
Jan-10	3,794,946	3,097,524	212,010	-	7,104,480	81,604	55,921	3,371	-	140,896
Feb-10	3,841,573	3,937,880	316,150	-	8,095,603	80,876	80,685	2,269	-	163,830
Mar-10	4,877,732	4,454,865	277,180	-	9,609,777	97,149	74,568	2,239	-	173,956
Apr-10	3,877,306	5,558,718	210,545	-	9,646,569	67,632	85,358	1,573	-	154,563
May-10	3,800,870	5,062,272	149,589	-	9,012,731	74,996	78,426	1,620	-	155,042
Jun-10	9,126,963	9,568,549	1,159,407	-	19,854,919	95,155	89,222	6,960	-	191,337
Jul-10	12,818,141	11,526,089	5,420,410	-	29,764,640	124,929	106,145	18,948	-	250,022
Aug-10	8,231,393	6,767,617	888,591	-	15,887,601	115,043	87,876	10,664	-	213,583
Sep-10	7,768,878	7,561,624	349,147	-	15,679,649	184,697	161,929	4,653	-	351,279
Oct-10	8,732,546	9,795,666	476,665	-	19,004,877	189,748	154,741	7,384	-	351,873
Nov-10	11,636,949	9,272,885	537,369	-	21,447,203	253,594	170,470	9,366	-	433,430
Dec-10	17,769,014	12,863,875	923,160	-	31,556,049	307,716	215,897	15,074	-	538,687
Jan-11	20,275,932	11,807,379	921,120	-	33,004,431	351,193	210,703	17,632	-	579,528
Feb-11	18,418,511	13,071,483	800,630	-	32,290,624	345,227	226,292	17,634	-	589,153
Mar-11	17,330,353	12,919,960	749,276	-	30,999,589	408,628	274,709	15,714	-	699,051
Apr-11	17,215,352	9,321,117	954,283	-	27,490,752	513,881	265,334	17,459	-	796,674
May-11	21,058,071	11,204,038	2,937,898	-	35,200,007	562,819	304,589	24,834	-	892,242
Jun-11	20,455,508	12,125,806	395,833	-	32,977,147	524,072	285,031	12,273	-	821,376
Jul-11	24,273,892	16,837,875	409,863	-	41,521,630	603,519	338,810	13,781	-	956,110
Aug-11	23,790,091	21,014,941	229,895	-	45,034,927	591,170	403,269	8,278	-	1,002,717
Sep-11	21,740,208	18,135,378	232,626	-	40,108,212	526,945	377,158	7,886	-	911,989
Oct-11	20,240,161	19,476,556	333,077	-	40,049,794	540,877	451,507	8,609	-	1,000,993
Nov-11	27,007,141	28,994,789	507,788	-	56,509,718	594,397	603,029	13,379	-	1,210,805
Dec-11	34,990,790	34,648,433	531,616	-	70,170,839	697,524	655,222	14,187	-	1,366,933
Jan-12	38,906,228	36,928,145	620,448	-	76,454,821	745,424	689,174	16,053	-	1,450,651
Feb-12	37,231,115	36,736,507	323,958	-	74,291,580	739,200	724,477	8,572	-	1,472,249
Mar-12	38,824,528	39,163,001	297,895	-	78,285,424	802,983	842,857	8,971	-	1,654,811
Apr-12	42,085,326	44,565,341	436,632	-	87,087,299	884,004	917,430	12,354	-	1,813,788
May-12	44,436,245	43,888,405	489,938	-	88,814,588	994,735	885,319	10,294	-	1,890,348
Jun-12	38,962,548	32,828,393	975,776	-	72,766,718	872,764	684,382	21,781	-	1,578,927
Jul-12	45,565,682	41,589,191	855,676	-	88,010,549	1,077,721	911,300	27,173	-	2,016,194
Aug-12	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366
Oct-12	35,567,607	42,489,970	1,415,992	-	79,473,570	908,200	1,048,029	46,802	-	2,003,031
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,829	1,631,255	2,832,425
Dec-12	22,597,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519
Apr-13	14,538,907	17,419,505	1,337,680	105,927,107	139,223,200	358,245	364,008	47,048	2,275,846	3,045,147
May-13	16,565,868	17,640,682	1,640,097	115,572,648	151,419,296	431,892	389,254	54,873	2,660,793	3,536,812
Jun-13	16,698,203	18,904,971	1,337,373	128,595,957	165,536,504	452,145	433,010	48,007	3,384,811	4,317,973
Jul-13	15,436,914	16,428,662	1,473,144	116,673,912	150,012,631	430,120	387,969	49,712	3,075,624	3,943,425
Aug-13	12,332,984	14,354,140	1,370,624	89,306,595	117,364,344	328,835	326,637	40,325	2,223,269	2,919,066
Sep-13	10,767,257	11,322,974	729,332	75,686,010	98,505,573	264,095	262,486	21,968	1,976,741	2,525,290
Oct-13	9,081,257	11,106,943	853,397	86,857,535	107,899,131	280,821	338,374	31,031	2,524,127	3,174,353
Nov-13	9,219,216	15,052,563	1,307,989	98,027,480	123,607,248	267,704	394,031	39,095	3,167,638	3,868,468
Dec-13	9,934,234	16,089,101	1,696,981	118,916,149	146,636,465	286,295	404,788	42,367	3,691,770	4,425,220
TOTAL	1,014,463,097	995,260,209	49,331,334	1,304,439,071	3,363,493,711	23,015,284	20,937,699	1,136,926	35,252,543	80,342,452

Table 9-30 Monthly volume of cleared and submitted up-to congestion bids: 2009 through 2013 (continued)

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	2,591,211	3,242,491	202,854	-	6,036,556	56,132	45,303	4,210	-	105,645
Feb-09	2,374,734	2,836,344	203,907	-	5,414,985	42,101	44,423	4,402	-	90,926
Mar-09	2,285,412	2,762,459	178,507	-	5,226,378	42,408	42,007	4,299	-	88,714
Apr-09	1,797,302	2,582,294	48,478	-	4,428,074	32,088	35,987	1,581	-	69,656
May-09	1,496,396	2,040,737	77,553	-	3,614,686	26,274	29,720	952	-	56,946
Jun-09	1,540,169	1,500,560	88,723	-	3,129,452	28,565	23,307	1,522	-	53,394
Jul-09	2,465,891	1,902,807	163,129	-	4,531,826	41,924	31,176	2,846	-	75,946
Aug-09	2,278,431	2,172,133	194,415	-	4,644,978	41,774	34,576	2,421	-	78,771
Sep-09	1,774,589	2,479,898	128,344	-	4,382,831	31,962	40,698	1,944	-	74,604
Oct-09	2,060,371	3,931,346	110,646	-	6,102,363	31,634	70,964	1,672	-	104,270
Nov-09	2,065,813	1,932,595	51,929	-	4,050,337	33,769	32,916	653	-	67,338
Dec-09	1,532,579	1,359,936	34,419	-	2,926,933	31,673	28,478	793	-	60,944
Jan-10	2,250,689	1,789,018	161,977	-	4,201,684	49,064	33,640	2,318	-	85,022
Feb-10	2,627,101	2,435,650	287,162	-	5,349,913	50,958	48,008	1,812	-	100,778
Mar-10	3,209,064	3,071,712	263,516	-	6,544,292	60,277	48,596	2,064	-	110,937
Apr-10	2,622,113	3,690,889	170,020	-	6,483,022	42,635	54,510	1,154	-	98,299
May-10	2,366,149	3,049,405	112,700	-	5,528,253	47,505	48,996	1,112	-	97,613
Jun-10	6,863,803	6,850,098	1,072,759	-	14,786,660	59,733	55,574	5,831	-	121,138
Jul-10	8,971,914	8,237,557	5,241,264	-	22,450,734	73,232	60,822	16,526	-	150,580
Aug-10	4,430,832	2,894,314	785,726	-	8,110,871	62,526	40,485	8,884	-	111,895
Sep-10	3,915,814	3,110,580	256,039	-	7,282,433	63,405	45,264	3,393	-	112,062
Oct-10	4,150,104	4,564,039	246,594	-	8,960,736	76,042	65,223	3,670	-	144,935
Nov-10	5,765,905	4,312,645	275,111	-	10,353,661	112,250	71,378	4,045	-	187,673
Dec-10	7,851,235	5,150,286	337,157	-	13,338,678	136,582	93,299	7,380	-	237,261
Jan-11	7,917,986	4,925,310	315,936	-	13,159,232	151,753	91,557	8,417	-	251,727
Feb-11	6,806,039	4,879,207	248,573	-	11,933,818	151,003	99,302	8,851	-	259,156
Mar-11	7,104,642	5,603,583	275,682	-	12,983,906	178,620	124,990	7,760	-	311,370
Apr-11	7,452,366	3,797,819	351,984	-	11,602,168	229,707	113,610	8,118	-	351,435
May-11	8,294,422	4,701,077	1,031,519	-	14,027,018	261,355	143,956	11,116	-	416,427
Jun-11	7,632,235	5,361,825	198,482	-	13,192,543	226,747	132,744	6,363	-	365,854
Jul-11	9,585,027	8,617,284	205,599	-	18,407,910	283,287	186,866	7,008	-	477,161
Aug-11	10,594,771	10,875,384	103,141	-	21,573,297	274,398	208,593	3,648	-	486,639
Sep-11	10,219,806	9,270,121	82,200	-	19,572,127	270,088	185,585	3,444	-	459,117
Oct-11	8,376,208	7,853,947	126,718	-	16,356,873	255,206	198,778	4,236	-	458,220
Nov-11	9,064,570	9,692,312	131,670	-	18,888,552	254,851	256,270	5,686	-	516,807
Dec-11	11,738,910	10,049,685	137,689	-	21,926,284	281,304	248,008	6,309	-	535,621
Jan-12	13,610,725	14,120,791	145,773	-	27,877,288	289,524	304,072	5,078	-	598,674
Feb-12	12,883,355	12,905,553	54,724	-	25,843,632	299,055	276,563	2,175	-	577,793
Mar-12	13,328,968	13,306,689	89,262	-	26,724,918	320,210	320,252	3,031	-	643,493
Apr-12	15,050,798	16,297,303	171,252	-	31,519,354	369,273	355,669	4,655	-	729,597
May-12	17,416,386	14,733,838	189,667	-	32,339,891	434,919	343,872	4,114	-	782,905
Jun-12	12,675,852	12,311,609	250,024	-	25,237,485	355,731	295,911	6,891	-	658,533
Jul-12	13,001,225	12,823,361	348,946	-	26,173,532	399,135	321,062	9,958	-	730,155
Aug-12	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
Oct-12	11,969,576	13,949,871	392,286	-	26,311,733	345,788	376,513	14,089	-	736,390
Nov-12	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	5,116,607	6,350,080	454,289	21,958,089	33,879,065	180,592	224,830	24,459	820,991	1,250,872
Jan-13	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Apr-13	4,413,047	4,834,302	315,867	32,152,243	41,715,459	145,860	157,031	16,315	892,562	1,211,768
May-13	4,556,277	4,747,887	333,677	34,778,962	44,416,803	144,444	144,482	16,317	944,116	1,249,359
Jun-13	3,823,166	4,280,538	312,158	34,935,141	43,351,002	143,223	151,603	17,518	1,116,318	1,428,662
Jul-13	3,250,706	3,502,990	320,374	29,883,430	36,957,500	131,535	127,032	17,948	957,260	1,233,775
Aug-13	2,862,764	3,232,565	309,069	26,900,995	33,305,393	111,715	122,061	16,299	848,490	1,098,565
Sep-13	2,962,619	3,467,611	221,329	26,044,742	32,696,300	102,984	107,604	10,233	792,766	1,013,587
Oct-13	2,201,219	3,532,253	186,113	28,243,584	34,163,168	108,189	145,667	11,551	1,002,832	1,268,239
Nov-13	2,640,001	3,986,788	332,814	32,437,908	39,397,511	112,850	154,379	13,958	1,238,589	1,519,776
Dec-13	3,189,261	3,234,196	503,666	38,150,077	45,077,200	119,954	122,683	14,318	1,382,736	1,639,691
TOTAL	371,405,212	364,254,443	21,054,330	393,624,552	1,150,338,536	9,504,561	8,609,275	470,449	12,607,082	31,191,367

In 2013, the cleared MW volume of up-to congestion transactions was comprised of 9.0 percent imports, 11.0 percent exports, 1.0 percent wheeling transactions and 79.0 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real- Time Energy Market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load which can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.

Elimination of Ontario Interface Pricing Point

An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy.

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[64] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control Area as specified on the NERC Tag. Transactions between PJM and external balancing authorities need to be priced at the PJM border.

The IMO Interface Pricing Point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO Interface Pricing Points. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

The IMO Interface Pricing Point is defined as the LMP at the Bruce bus, which is located in IESO. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The non-contiguous nature of the Ontario Interface Pricing Point creates over payments or additional credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. Of the 6,607 GWh of the net scheduled transactions between PJM and IESO, 6,569 GWh wheeled through MISO in 2013 (see Table 9-22).

The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.[65]

PJM and NYISO Coordinated Interchange Transaction Proposal

The coordinated transaction scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's intermediate term

64 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed January 23, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

65 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price from the ITSCED results with the NYISO. The NYISO compares the PJM/NYISO Interface Price with its RTC calculated NYISO/PJM Interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

On December 13, 2013, PJM submitted proposed revisions to the PJM Operating Agreement, and parallel provisions of the PJM Tariff, to implement CTS.[66] This filing requested that the Commission issue an order accepting the proposed revisions by no later than February 13, 2014 to allow for adequate time to develop the infrastructure necessary to implement CTS in November, 2014. The Commission issued an order conditionally accepting the tariff revisions on February 20, 2014, for implementation on the later of November, 2014, or the date that CTS becomes operational, subject to the submission of an informational filing informing the Commission of the acceptance of ITSCED forecasting accuracy standards, and an additional revised tariff no later than fourteen days prior to the official implementation date of CTS.[67]

CTS transactions are evaluated based on the spread bid, which limits the amount price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to proceed with the development of the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

Elimination of Sources and Sinks

The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets. On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

Total uncollected congestion charges in 2013 were -$2,860, compared to -$11,789 in 2012 (Table 9-31). If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case for the net uncollected congestion charges in 2013. In other words, when market participants utilize the not willing to pay congestion product, it also means that they are not willing to receive congestion credits when the LMP

66 See PJM Interconnection, L.L.C., OA Schedule 1 and Attachment K Revisions, Docket No. ER14-623-000. (December 13, 2013).

67 146 FERC ¶ 61,096 (2014).

at the source is greater than the LMP at the sink. The fact that there was a total negative congestion collection in 2013, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations mostly addresses these concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be necessary in the future to address this exposure.

Table 9-31 Monthly uncollected congestion charges: 2010 through 2013

Month	2010	2011	2012	2013
Jan	$148,764	$3,102	$0	$5
Feb	$542,575	$1,567	($15)	$249
Mar	$287,417	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)
May	$41,025	$0	($27)	$0
Jun	$169,197	$1,354	$78	$0
Jul	$827,617	$1,115	$0	$0
Aug	$731,539	$37	$0	$0
Sep	$119,162	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0
Nov	$30,843	($795)	($4,678)	$0
Dec	$127,176	($659)	($209)	$0
Total	$3,314,018	($20,955)	($11,789)	($2,860)

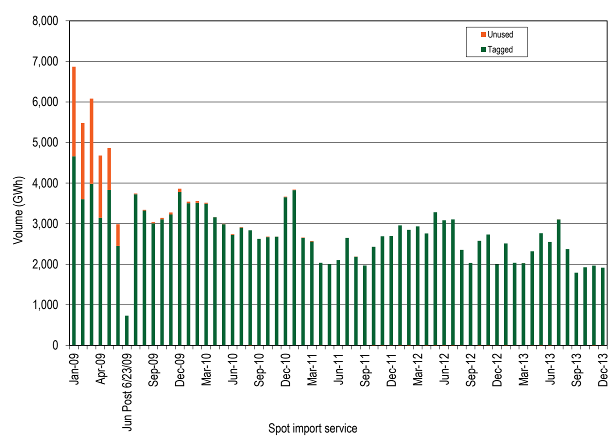
Spot Imports

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[68] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding.

The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

Figure 9-14 Spot import service utilization: 2009 through 2013



68 See "Modifications to the Practices of Non-Firm and Spot Market Import Service," (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (Accessed January 23, 2014).

Real-Time Dispatchable Transactions

Real-time dispatchable transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted in 2013.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service.[1] PJM provides scheduling, system control and dispatch and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for 2013.

Table 10-1 The Regulation Market results were competitive for 2013

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

- Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 90 percent of the hours in 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for 2013 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

Table 10-2 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, 12 percent of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Regulation Market

The PJM Regulation Market is a single market for the RTO. PJM jointly optimizes Regulation with Synchronized Reserve and energy to provide all three of these services at least cost.

Market Structure

- **Supply.** In 2013, the supply of offered and eligible regulation in PJM was stable, but the average daily offer decreased from 6,551 MW in 2012 to 4,166 MW in 2013 (a decrease of 36.4 percent) and the average hourly eligible regulation decreased from 3,253 MW in 2012 to 1,642 MW in 2013 (a decrease of 50.1 percent).
- **Demand.** The average hourly regulation demand was 753 MW in 2013. This is a 177 MW decrease (19.0 percent) in the average hourly regulation demand of 930 MW in the same period of 2012.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 3.40. This is a 5.8 percent decrease from 2012 when the ratio was 3.61.
- **Market Concentration.** In 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2115 which is classified as highly concentrated. In 2013, the three pivotal supplier test was failed in 90 percent of hours. In 2012, the three pivotal supplier test was failed in 40 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[3] As of December 31, 2013, there were 26 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $30.14/MW of regulation in 2013, an increase of $9.79/MW of regulation, or 48.1 percent, from 2012. The cost of regulation in 2013 was $34.57/MW of regulation, an $8.16/MW of regulation, or 30.9 percent, increase from 2012.

Synchronized Reserve Market

The Tier 2 Synchronized Reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Zone (MAD). The MAD subzone is designed to ensure that transmission constraints will not prevent adequate synchronized reserves from being available in MAD when called. PJM has the right to define new zones or subzones "as needed for system reliability."[4]

Market Structure

- **Supply.** In 2013, the supply of offered and eligible synchronized reserve was both stable and adequate.
- **Demand.** When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. The Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012. Requirement synchronized reserve requirement remained at 1,300 MW. The integration of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone.
- **Supply and Demand.** All on-line generation resources are required to offer synchronized reserve. The 2013 ratio of on-line synchronized reserve to synchronized reserve required was 1.29.
- **Market Concentration.** In 2013, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 4205

3 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."
4 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 66.

which is classified as highly concentrated. In 2013, 56 percent of hours had a maximum market share greater than 40 percent.

The MMU concludes from these results that the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each generating unit and each demand resource. The offers are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) Subzone was $6.98 per MW in 2013, a $1.04 decrease from 2012. The total cost of tier 2 synchronized reserves per MW in MAD in 2013 was $13.07, a three percent increase from the $12.71 cost of synchronized reserve in 2012. The market clearing price was 53 percent of the total synchronized reserve cost per MW in 2013, down from 63 percent in 2012.
- **Supply and Demand.** A synchronized reserve shortage occurs when the combination of tier 1 and tier 2 synchronized reserve supply is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a synchronized reserve shortage in 2013. The spinning event of September 10 raised concerns that the current method for estimating Tier 1 is incorrect leading to an overall synchronized reserve deficit.

Day-Ahead Scheduling Reserve (DASR)

The purpose of the DASR Market is to satisfy secondary supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[5] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

The MMU has identified problems with the definition and dispatchability of DASR and recommends solutions.

Market Structure

- **Concentration.** The MMU calculates that in 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Supply.** DASR resources comprise of all those resources that can provide reserve capability that can be fully converted into energy within 30 minutes as requested by PJM dispatchers. MMU recommends that scheduling reserve be more definitively defined and satisfied by a real-time market.
- **Demand.** In 2013, the required DASR was 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero, but there is an opportunity cost associated with providing DASR. As of December 31, 2013, 12 percent of offers reflected economic withholding (defined as cost offers above $5.00). All units with reserve capability that can be converted into energy within 30 minutes are required to offer in the DASR Market.[6] Units that do not offer have their offers set to zero.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in 2013 was $0.70 per MW. This is a 23 percent increase from 2012.

5 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

6 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 137.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[7]

In 2013, black start charges were $107.5 million (compared to $50.2 million in 2012). Black start zonal charges in 2013 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $126,644) to $9.71 per MW-day in the AEP Zone (total charges were $82,588,453).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In 2013, total reactive service charges were $616.6 million compared to $368.3 million in 2012.[8] Total charges in 2013 ranged from $340.0 thousand in the RECO Zone to $76.8 million in the ATSI Zone.

Ancillary Services Costs per MW of Load: 2002 - 2013

Table 10-4 History of ancillary services costs per MW of Load: 2002 through 2013

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2002	$0.45	$0.53	$0.21	$0.07	$0.63	$1.90
2003	$0.50	$0.61	$0.24	$0.14	$0.83	$2.32
2004	$0.50	$0.60	$0.25	$0.13	$0.90	$2.38
2005	$0.79	$0.47	$0.26	$0.11	$0.93	$2.57
2006	$0.53	$0.48	$0.29	$0.08	$0.43	$1.81
2007	$0.63	$0.47	$0.29	$0.06	$0.58	$2.02
2008	$0.68	$0.40	$0.31	$0.08	$0.59	$2.06
2009	$0.34	$0.32	$0.37	$0.05	$0.48	$1.56
2010	$0.34	$0.38	$0.41	$0.07	$0.73	$1.93
2011	$0.32	$0.34	$0.42	$0.10	$0.77	$1.95
2012	$0.26	$0.40	$0.43	$0.04	$0.79	$1.92
2013	$0.24	$0.39	$0.80	$0.04	$0.59	$2.08

Table 10-4 shows PJM ancillary services costs for 2002 through 2013, on a per-MW of load basis. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. Supplementary operating reserve includes day-ahead operating reserve; balancing operating reserve; and synchronous condensing.

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
  - The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.
  - The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.
  - The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

7 OATT Schedule 1 § 1.3BB.

8 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the benefits factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be paid a different amount per effective MW than effective MW provided by RegA resources. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012.[9]

Regulation Market Changes for Performance Based Regulation

On October 20, 2011, the FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to include fast and slow response regulation resources."[10]

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with slow resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the fast and slow resources be purchased in a single market, with compensation for both capacity (MW) and miles (ΔMW).[11] Regulation miles are calculated as the sum of the absolute value of a given regulation resource's movement (up and down) in response to a regulation signal.

The performance based Regulation Market requires that resource owners provide two-part offers for their regulation resources, an offer for regulation capability in terms of \$/MW and a regulation performance offer in terms of \$/MW (based on \$ per ΔMW times ΔMW/MW). The two parts of the offer are combined to provide a total regulation offer in terms of \$/MW.

9 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.
10 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."
11 Id. at PP 99, 131 & 177.

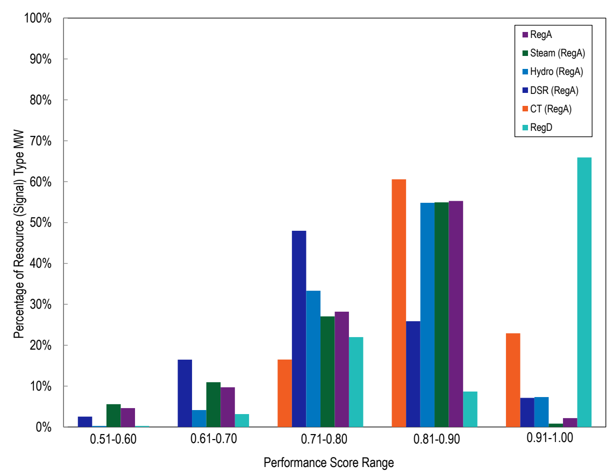
Prior to October 1, 2012, regulation consisted of generation and demand resources responding within five minutes to a single PJM-generated signal (RegA) that directed these resources to increase or decrease output or load. On October 1, 2012, PJM introduced a single market that included resources following two signals: RegA and RegD. Resources responding to either signal help moderate ACE. RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. Resources must qualify to follow the RegA and RegD signals. Resources must qualify for one signal or both signals, but will be assigned by the market clearing engine to follow only one signal within a given market hour.

While resources following RegA and RegD can both provide regulation service in PJM's regulation market, PJM's joint optimization is designed to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD resources into common units of measure via a marginal benefits factor (MBF). The marginal benefits factor is a measure of the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The marginal benefits factor and the performance score of the resource, are used to convert RegA and RegD resource regulation capability MW into comparable units, termed Effective MW. Effective MW, supplied from RegA or RegD resources, are defined in terms of RegA MW. Except where expressly referred to as Effective MW or effective regulation MW, MW means unadjusted regulation capability MW.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[12] An hourly performance score is calculated and multiplied by the MW cleared when calculating payment.

Figure 10-1 shows the average performance score by resource type and signal followed. Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. Resources following the RegD signal follow the RegD signal more closely than resources following the RegA signal follow the RegA signal. That is, RegD resources tend to have higher performance scores. As the figure shows, 65.9 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 2.2 percent of RegA resources have average performance scores within that range.

Figure 10-1 Average performance score by unit type and regulation signal type: 2013



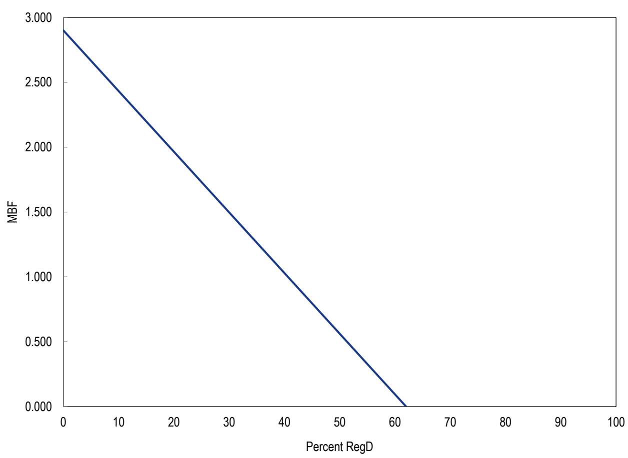
Issues Related to the Marginal Benefits Factor

In a market defined in terms of units of RegA equivalent regulation service, the marginal benefits factor of all units following the RegA signal is one, while the marginal benefits factor of a resource following the RegD signal depends on how much RegD following resources are used. As of December 31, 2013, PJM uses an affine function to determine the marginal benefits factor of RegD resource MW. Two points (percent RegD in Regulation Market, Marginal Benefits Factor) define this

12 PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

function: (0, 2.9) and (62, 0.0001). Its equation is MBF = 2.9 – 0.05 x (percent of RegD in Regulation Market). The marginal benefits factor is therefore a function of the proportion of RegD and RegA resources employed in the market solution. The greater the proportion of RegD to RegA in the market solution, the lower the marginal benefits factor of the last RegD resource MW in that solution. PJM can modify the function based on the observed effect that RegD resources have on satisfying NERC requirements (CPS and BAAL). The relevant portion of the graph of this function is shown in Figure 10-2. As shown in Figure 10-2, if the regulation requirement were 10 MW and there were one RegD resource providing 1 MW of regulation, then the marginal benefits factor would be 2.432.

Figure 10-2 Marginal benefits factor function graph



The FERC's November 16, 2012, order only partially accepted the market design in PJM's August 15, 2012, filing. The order fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment, but not for the market clearing and optimization process. This created a dichotomy in the PJM Regulation Market between the marginal value of RegD resources in the dispatch, and the resulting market price and payments to resources in the settlement process in PJM's regulation market through the third quarter of 2013.

On October 2, 2013, the FERC issued an Order Granting Rehearing.[13] The order removed the marginal benefits factor entirely from the performance and capability credit settlements calculation of RegD resources. Instead, the order directed that the mileage ratio be used in place of the marginal benefits factor as a performance multiplier for RegD performance credits. No similar adjustment is to be applied to the capability credits settlement. This change was implemented for all Regulation Market settlements from November 1, 2013, through December 31, 2013. Retroactive adjustments to Regulation Market settlements from October 1, 2012, through October 31, 2013, will be made by PJM in the first half of 2014.

The resulting market design is flawed. The mileage ratio is not a substitute for the marginal benefits factor. Unlike the marginal benefits factor, the mileage ratio of RegD to RegA provides no information regarding the relative value of RegD and RegA resources in the optimized market solution. The failure to use the marginal benefits factor in the performance and capability credit settlements process creates an inconsistency among the marginal value of the regulation resources as acted upon in the joint optimization, the posted prices for regulation and the compensation of the regulation resources.

From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefits factor be fixed at one for settlement calculations only. As Figure 10-3 shows, the true marginal benefits factor, as used in the optimization and commitment process for Regulation in 2013, was always higher than one. This caused resources following the RegD signal to be underpaid. Resources following the RegD signal should have been paid the true marginal benefits factor times the amount that they were actually paid. This scalar should have been applied to the capability and the performance payments of RegD resources.

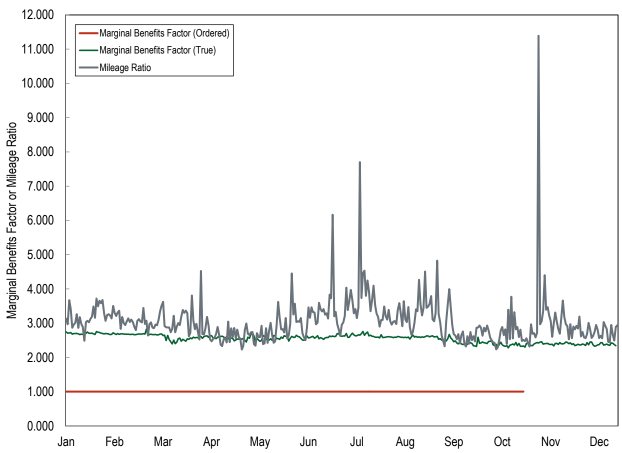
On October 2, 2013, FERC directed PJM to eliminate the use of the marginal benefits factor completely from settlement calculations of the capability and performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[14] As Figure 10-3 demonstrates, the RegD to RegA mileage ratio is generally higher than the true marginal benefits factor and much more variable. The mileage multiplier has not brought total payment of RegD resources in line with RegA resources on a dollar per effective MW basis. This is, in part, due to the fact

13 145 FERC ¶ 61,011 (2013).

14 145 FERC ¶ 61,011 (2013).

that the performance related price per MW of capability, which is multiplied by the mileage ratio, is a relatively small portion of the total price per MW of capability. It is also due to the fact that the mileage ratio is not a substitute for the marginal benefits factor.

Figure 10-3 Daily average marginal benefit factor and mileage ratio: 2013



Unlike the marginal benefits factor, the mileage ratio of RegD to RegA provides no information regarding the relative value of RegD and RegA resources in the optimized market solution. A marginal benefits factor of 2.5 for a RegD resource means that for every 1 MW of regulation capability the RegD resource provides, it is replacing 2.5 MW of regulation capability of a RegA resource. The RegD to RegA mileage ratio simply captures how much PJM wanted RegD resources to change their output over time relative to the signal sent to RegA resources and has nothing to do with the rate of substitution between RegD and RegA resources.

The following two examples illustrate the issues caused by the use of the RegD to RegA mileage ratio and the inconsistent application of the marginal benefits factor in PJM's settlement of the regulation market.

Table 10-5 illustrates the issues that resulted when FERC required the marginal benefits factor to be set at one.

Table 10-5 Regulation payment example (1 of 3)

Problem: MBF = 1	RegA Resource	RegD Resource
Regulation MW	4	4
Performance Score	100%	100%
Marginal Benefits Factor (Actual)	2	2
Mileage Ratio (RegD:RegA)	3	3
RMCCP ($/MW)	$5.00	$5.00
RMPCP ($/MW)	$1.00	$1.00
RMCP ($/MW)	$6.00	$6.00
RMCCP Credit ($)	$20.00	$20.00
RMCCP Credit Should Be ($)	$20.00	$40.00
RMPCP Credit ($)	$4.00	$4.00
RMPCP Credit Should Be ($)	$4.00	$8.00
RMCP Credit ($)	$24.00	$24.00
RMCP Credit Should Be ($)	$24.00	$48.00

It is assumed that each resource provides 4 MW of regulation capability, has a 100 percent performance score, the marginal benefits factor is 2.0, the mileage ratio is 3.0, the RMCCP is $5.00/MW, the RMPCP is $1.00/MW and the RMCP is $6.00/MW.

The RMCCP Credit is calculated as MW of regulation capability times performance score times marginal benefits factor times RMCCP. The RMPCP Credit is calculated as MW of regulation capability times performance score times marginal benefits factor times RMPCP. The RMCP Credit is calculated as RMCCP Credit plus RMPCP Credit.

For the RegA resource, the RMCCP Credit is equal to $20.00 (4 MW x 100 percent x $5.00/MW). The RMPCP Credit is equal to $4.00 (4 MW x 100 percent x $1.00/MW). The total RMCP Credit is $24.00. The FERC marginal benefit factor of one does not affect the settlement of the RegA resources, as the benefit factor of a RegA resource is always one by design.

For the RegD resource, the RMCCP Credit is equal to $20.00 (4 MW x 100 percent x 1.0 (FERC MBF) x $5.00/MW). Since the marginal benefits factor is 2.0, the RMCCP Credit should be equal to $40.00 (4 MW x 100 percent x 2.0 (MBF) x $5.00/MW). The impact of using the marginal benefit factor of 1.0 is to provide only half the RMCCP credits awarded in settlement compared to what they should be with the use of the actual marginal benefit factor.

For the RegD resource, the RMPCP Credit is equal to $4.00 (4 MW x 100 percent x 1.0 (FERC MBF) x $1.00/MW). However, since the marginal benefits factor is 2.0, the RMPCP Credit should be equal to $8.00 (4 MW x 100 percent x 2 (MBF) x $1.00/MW). That is, the RMPCP should be 2.0 (the marginal benefits factor) times the erroneous calculation actually used. For the RegD resource, the total RMCP Credit is equal to $24.00 ($20.00 + $4.00). The RMCP Credit should be equal to $48.00 ($40.00 + $8.00). Again, twice as high due to the failure to include the correct marginal benefits factor in settlement.

Table 10-6 illustrates the issues that resulted when FERC required that the RegD to RegA mileage ratio be applied in the calculation of RMPCP Credits instead of the correct application of the marginal benefits factor to the allocation of both the RMCCP and RMPCP Credits.

Table 10-6 Regulation payment example (2 of 3)

Problem: Mileage Ratio	RegA Resource	RegD Resource
Regulation MW	4	4
Performance Score	100%	100%
Marginal Benefits Factor (Actual)	2	2
Mileage Ratio (RegD:RegA)	3	3
RMCCP ($/MW)	$5.00	$5.00
RMPCP ($/MW)	$1.00	$1.00
RMCP ($/MW)	$6.00	$6.00
RMCCP Credit ($)	$20.00	$20.00
RMCCP Credit Should Be ($)	$20.00	$40.00
RMPCP Credit ($)	$4.00	$12.00
RMPCP Credit Should Be ($)	$4.00	$8.00
RMCP Credit ($)	$24.00	$32.00
RMCP Credit Should Be ($)	$24.00	$48.00

In this example, it is assumed that each resource provides 4 MW of regulation capability, has a 100 percent performance score, the marginal benefits factor is actually 2.0, the mileage ratio is 3.0, the RMCCP is $5.00/MW, the RMPCP is $1.00/MW and the RMCP is $6.00/MW.

In this example, the RMCCP Credit is calculated as MW of regulation capability times performance score times RMCCP. The RMPCP Credit is calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. The RMCP Credit is calculated as RMCCP Credit plus RMPCP Credit.

For the RegA resource, the RMCCP Credit is 4 MW x 100 percent x $5.00/MW = $20.00. The RMPCP Credit is 4 MW x 100 percent x $1.00/MW = $4.00. The total RMCP Credit is $20.00 + $4.00 = $24.00. The assumption does not affect the RegA resources credit calculations.

For the RegD resource, the RMCCP Credit is equal to $20.00 (4 MW x 100 percent x $5.00/MW). However, since the marginal benefits factor is 2.0, the RMCCP Credit should be equal to $40.00 (4 MW x 100 percent x 2 (MBF) x $5.00/MW). That is, the RMCCP should be 2.0 (the marginal benefits factor) times the erroneous calculation actually used. For the RegD resource, the RMPCP Credit is equal to $12.00 (4 MW x 100 percent x 3 (RegD:RegA mileage ratio) x $1.00/MW). However, since the marginal benefits factor is 2.0, the RMPCP Credit should be equal to $8.00 (4 MW x 100 percent x 2 (MBF) x $1.00/MW). That is, the RMPCP should be 2.0 (the marginal benefits factor) divided by 3.0 (the mileage ratio) times the calculation actually used. For the RegD resource, the total RMCP Credit is equal to $32.00 ($20.00 + $12.00). However, the total RMCP Credit should be equal to $48.00 ($40.00 + $8.00).

In this example, the use of the mileage ratio reduces the difference between PJM's current calculation of the RMCP Credit and the correct calculation of RMCP using the consistent application of the marginal benefits factor. But the use of the mileage ratio does not, and it cannot, resolve the issue. The mileage ratio based calculation is incorrect.

The MMU recommends that the current mileage rate based calculation be replaced with the consistent application of the marginal benefits factor.

Posted Regulation Prices Do Not Reflect Actual Clearing Payments

PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in what are termed to be dollars per unadjusted regulation capability MW. The Regulation Market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The five-minute RMCP is the sum of the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

The posted prices for regulation are misleading, as resource payment is not made to resources on an unadjusted capability MW basis. Instead posted prices are adjusted in settlement by multiplying by a resource's regulation capability MW by its performance score. The RMPCP (performance price) paid to RegD resources is further adjusted by multiplying performance related price (RMPCP) by the RegD to RegA mileage ratio for the hour.

Due to the performance score and mileage ratio adjustments, realized regulation payments per capability MW are, on a dollar per capability basis, not the same across resources. The RMCP paid per capability MW, for example, varies by the resource's performance score. The closer a resource's performance score is to 1.0 (100 percent), the closer the realized price is to the posted RMCP per capability MW. Even absent variations in the performance score across resources, the use of the mileage ratio to adjust the realized price of performance (RMPCP) per capability MW of RegD causes the RMPCP price per MW of capability to vary across resource types.

This variation between posted and realized price per MW is problematic because it reduces the transparency of the market. Price transparency is a key feature of efficient markets, as the more reflective the price is of the underlying fundamentals of the market at the margin, the greater the efficiency of the purchase, provision and investment decisions that are dependent on that price. The market design should result in prices that reflect the marginal value and cost of the resource or service being provided, and that price should be provided in a clear and common per unit metric across providers of that product or service.

The hypothetical example in Table 10-7 illustrates the issue.

Table 10-7 Regulation payment example (3 of 3)

Problem: Differing RMCP Credits	Resource 1	Resource 2
Regulation Capability MW	4	4
Performance Score	100%	75%
Marginal Benefits Factor (Actual)	1	1
Mileage Ratio (RegD:RegA)	1	1
Effective MW	$4.00	$3.00
RMCCP ($/MW)	$5.00	$5.00
RMPCP ($/MW)	$1.00	$1.00
RMCP ($/MW)	$6.00	$6.00
RMCCP Credit	$20.00	$15.00
RMPCP Credit	$4.00	$3.00
RMCP Credit	$24.00	$18.00
RMCP Credit per Regulation Capability MW	$6.00	$4.50
RMCP Credit per Effective MW	$6.00	$6.00

In this example, assume that two resources cleared 4 MW of regulation capability, but within the hour, one resource (Resource 1) had a 100 percent performance score and the other (Resource 2) had a 75 percent performance score. Further assume that the RMCCP was $5.00/MW, the RMPCP was $1.00/MW, and the RMCP was $6.00/MW. To simplify, it is also assumed that the marginal benefits factor for the hour was 1.0 and that the mileage ratio was also 1.0. These assumptions limit the differences between the resources in the optimization and the settlement calculations in the example.

Under these assumptions, Resource 1 provided 4 effective MW, due to its 100 percent performance score and Resource 2 supplied only 3 effective MW because it had a performance score of 75 percent. The RMCCP Credit for Resource 1 is equal to $20.00 (4 MW x 100 percent x $5.00/MW) and for Resource 2 is equal to $15.00 (4 MW x 75 percent x $5.00/MW). The RMPCP Credit for Resource 1 is equal to $4.00 (4 MW x 100 percent x $1.00/MW) and for Resource 2 is equal to $3.00 (4 MW x 75 percent x $1.00/MW). Finally, the RMCP Credit for Resource 1 is equal to $24.00 ($20.00 + $4.00) and for Resource 2 is equal to $18.00 ($15.00 + $3.00).

For every 1 MW of regulation capability MW offered and cleared by Resource 1, Resource 1 earned $6.00. However, for every 1 MW of regulation capability offered and cleared by Resource 2, Resource 2 earned only $4.50, due to its 75 percent performance score. As is shown in the last column of Table 10-7, the credit earned per effective MW is $6.00 for both resources.

The MMU recommends that regulation prices be presented in terms of dollars per effective MW, with RegA or RegD resources receiving the same payment per Effective MW. This can only be achieved through the consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.

Market Structure

Supply

Table 10-8 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in 2013, to 8,617 MW from 9,413 MW in 2012.

Table 10-8 PJM regulation capability, daily offer[15] and hourly eligible: 2012 and 2013[16]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2012	9,413	6,551	70%	3,253	35%
2013	8,617	4,166	48%	1,624	19%

Coal units on average provided only 15.5 percent of regulation in 2013. This is a significant decline from the 30.1 percent of regulation provided by coal units in 2012. Coal unit revenues in 2013 were about half of what they were in 2012 ($31.4 million in 2013 versus $62.3 million in 2012). Table 10-9 provides monthly data of the number of coal units providing regulation, the scheduled regulation in MW provided by coal units, the total scheduled regulation in MW provided by all resources, the percent of scheduled regulation provided by coal units, and the total credits received by coal units.

The supply of regulation can be affected by regulating units retiring from service. Table 10-10 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

Although the marginal benefits factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in 2013 because the average performance score was less than 1.00 (Figure 10-4). For 2013, the MW-weighted average RegA performance score was 0.80 and as of December 31, 2013, there were 265 resources following the RegA signal.

Table 10-9 PJM regulation provided by coal units

Year	Month	Number of Coal Units Providing Regulation	Scheduled Regulation from Coal Units (MW)	Scheduled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2012	Jan	94	256,512	739,753	34.7%	$4,730,792
2012	Feb	93	184,650	677,217	27.3%	$2,868,974
2012	Mar	97	174,768	641,655	27.2%	$3,509,174
2012	Apr	93	195,207	572,397	34.1%	$3,301,602
2012	May	105	198,348	658,008	30.1%	$5,031,604
2012	Jun	127	203,402	745,156	27.3%	$4,211,652
2012	Jul	127	309,048	903,024	34.2%	$10,675,726
2012	Aug	122	258,372	824,350	31.3%	$6,144,214
2012	Sep	106	184,365	648,809	28.4%	$4,657,407
2012	Oct	92	130,970	451,710	29.0%	$6,484,144
2012	Nov	105	156,250	479,188	32.6%	$7,307,279
2012	Dec	93	120,276	487,749	24.7%	$3,378,357
2013	Jan	117	121,466	494,253	24.6%	$5,376,657
2013	Feb	102	99,850	453,803	22.0%	$3,071,883
2013	Mar	96	67,580	459,421	14.7%	$2,473,951
2013	Apr	80	40,636	381,510	10.7%	$1,559,309
2013	May	97	42,190	414,053	10.2%	$1,856,919
2013	Jun	105	62,914	475,647	13.2%	$2,332,995
2013	Jul	109	106,367	552,699	19.2%	$5,659,885
2013	Aug	95	83,448	510,342	16.4%	$2,652,089
2013	Sep	89	60,920	414,200	14.7%	$2,118,200
2013	Oct	62	54,575	381,009	14.3%	$1,688,471
2013	Nov	67	56,945	401,553	14.2%	$1,372,687
2013	Dec	81	50,706	413,104	12.3%	$1,208,075

15 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

16 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 10-10 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, 2013	Settled MW, 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
309	6,583,490	33	66,664	1.01%

Figure 10-4 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation: 2013

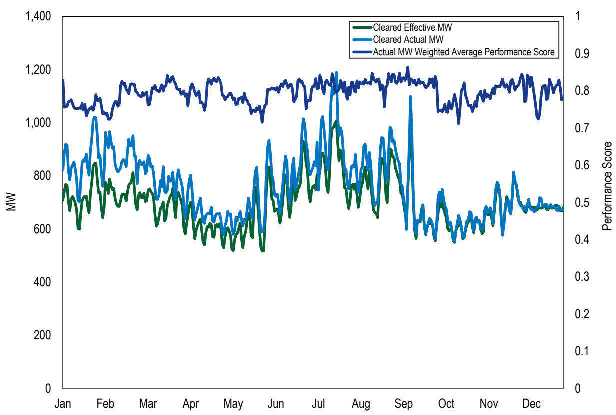
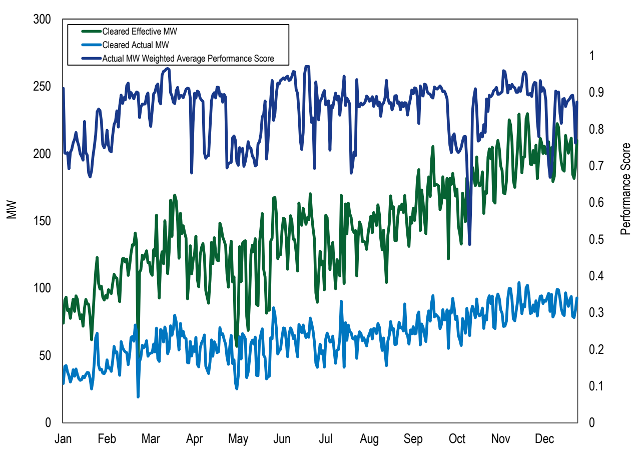


Figure 10-5 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only: 2013



For RegD resources, the effective MW are higher than the actual MW because their marginal benefits factor at current participation levels is significantly greater than 1.0. In 2013, the marginal benefit factor for cleared RegD following resources ranged from 1.743 to 2.899 with an average over all hours of 2.543. For 2013, the MW-weighted average RegD resource performance score was 0.90 and as of December 31, 2013, there were 26 resources following the RegD signal.

The cost of each unit is calculated using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type they choose to follow, modified by resource benefit factor and historic performance score.

As of October 1, 2012, a regulation resource's total offer is equal to the sum of its total capability ($/MW) and performance offer ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the opportunity cost and any applicable benefits factor, of the most expensive cleared regulation resource in each interval.

Since the implementation of regulation performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012, (Table 10-17). Throughout 2013, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for 2013 was $30.14/MW. The regulation cost for 2013 was $34.57/MW. The ratio of price to cost is significantly higher at 87 percent (compared with 77 percent in 2012), meaning that more of the cost of regulation is incorporated in the price.

Figure 10-3 shows the average marginal benefit factor by day compared to the average mileage ratio by day.

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 1, 2013, it was reduced to 700 MW of effective regulation during peak hours and 525 effective MW during off peak hours.

Table 10-11 shows the average hourly required regulation by month and its relationship to the supply of regulation.

Table 10-11 PJM Regulation Market required MW and ratio of eligible supply to requirement: 2012 and 2013

Month	Average Required Regulation (MW), 2012	Average Required Regulation (MW), 2013	Ratio of Supply to Requirement, 2012	Ratio of Supply to Requirement, 2013
Jan	1,005	851	3.29	3.66
Feb	979	870	3.45	4.65
Mar	876	766	3.14	4.86
Apr	826	656	3.19	2.55
May	918	678	3.26	3.91
Jun	1,055	801	3.21	4.34
Jul	1,246	911	2.94	1.66
Aug	1,134	832	2.97	2.60
Sep	941	693	3.33	4.80
Oct	772	633	4.28	1.18
Nov	708	674	4.63	2.29
Dec	701	672	5.60	4.31

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[17]

Market Concentration

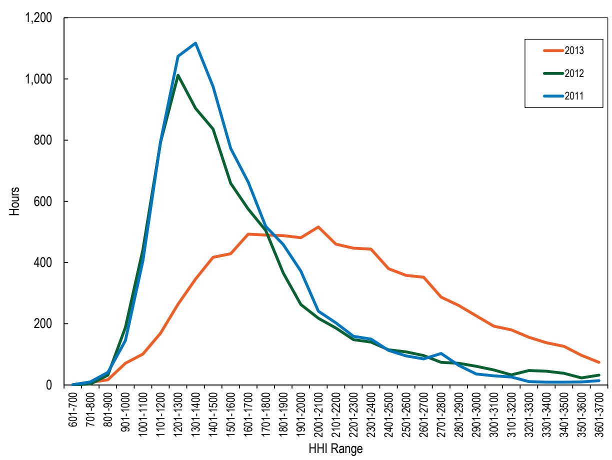
Table 10-12 shows Herfindahl-Hirschman Index (HHI) results for 2012 and 2013. The average HHI of 2115 is classified as highly concentrated and is higher than the HHI for the same period in 2012.

Table 10-12 PJM cleared regulation HHI: 2011 through 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2011	818	1630	4005
2012	788	1735	4962
2013	650	2115	5650

Figure 10-6 compares the 2013 HHI distribution curves with distribution curves for 2012 and 2011. The weighted average HHI in 2013 of 2115 is 380 points higher than the HHI in 2012 of 1735 and 485 points higher than the HHI in 2011 of 1630.

Figure 10-6 PJM Regulation Market HHI distribution: 2011, 2012, and 2013



17 See the *2013 State of the Market Report for PJM*, Appendix F: Ancillary Services.

For 2013, the weighted-average HHI of RegD resources was 4952 (highly concentrated).

Table 10-13 includes a monthly summary of three pivotal supplier results. In 2013, 90 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-8).

The MMU concludes from these results that the PJM Regulation Market in 2013 was characterized by structural market power in 90 percent of hours.

Table 10-13 Regulation market monthly three pivotal supplier results: 2011, 2012 and 2013

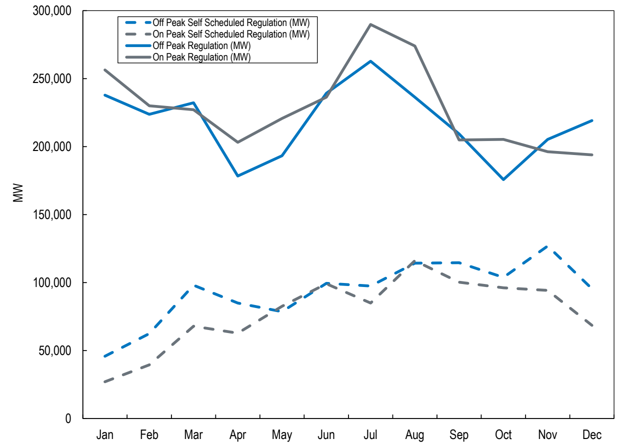
	2011	2012	2013
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	95%	71%	83%
Feb	93%	67%	82%
Mar	94%	64%	97%
Apr	97%	41%	88%
May	95%	37%	93%
Jun	89%	40%	95%
Jul	89%	13%	94%
Aug	83%	32%	92%
Sep	87%	35%	90%
Oct	67%	19%	83%
Nov	46%	18%	89%
Dec	50%	40%	95%

Market Conduct

Offers

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other providers bilaterally, or self-schedule regulation to satisfy their obligation (Table 10-14).[18] Figure 10-6 compares total regulation and self-scheduled regulation during on-peak and off-peak hours.

Figure 10-7 Off peak and on peak regulation levels: 2013



Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in 2013, 57.7 percent was purchased in the spot market, 38.5 percent was self-scheduled, and 3.8 percent was purchased bilaterally (Table 10-14). From 2008 through 2013, Table 10-15 shows the yearly total regulation by spot regulation, self-scheduled regulation, and bilateral regulation. Total regulation MW decreased significantly in 2013.

18 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60, (June 1, 2013); para 4.1, pp 15.

Table 10-14 Regulation sources: spot market, self-scheduled, bilateral purchases: 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)	RegA Regulation (MW)	RegD Regulation (MW)
2012	Jan	553,686	164,806	21,261	739,753	NA	NA
2012	Feb	481,004	175,757	20,456	677,217	NA	NA
2012	Mar	477,564	144,408	19,683	641,655	NA	NA
2012	Apr	426,564	124,750	21,083	572,397	NA	NA
2012	May	542,585	97,574	17,849	658,008	NA	NA
2012	Jun	582,078	140,769	22,309	745,156	NA	NA
2012	Jul	819,897	63,415	19,711	903,024	NA	NA
2012	Aug	710,715	95,949	17,687	824,350	NA	NA
2012	Sep	515,732	113,351	19,726	648,809	NA	NA
2012	Oct	287,616	162,555	1,539	451,710	435,764	15,946
2012	Nov	369,075	104,386	5,727	479,188	469,343	9,845
2012	Dec	385,468	95,903	6,378	487,749	478,367	9,382
2013	Jan	413,304	72,880	8,070	494,253	486,959	7,294
2013	Feb	338,990	102,005	12,808	453,803	444,689	9,113
2013	Mar	275,880	165,987	17,554	459,421	441,000	18,421
2013	Apr	219,793	147,858	13,860	381,510	365,856	15,654
2013	May	235,849	161,270	16,934	414,053	397,020	17,033
2013	Jun	254,215	198,617	22,816	475,647	456,494	19,153
2013	Jul	349,047	182,452	21,201	552,699	536,188	16,512
2013	Aug	258,550	230,441	21,351	510,342	488,951	21,391
2013	Sep	181,609	214,945	17,647	414,200	387,397	26,803
2013	Oct	167,857	200,079	13,073	381,009	351,915	29,094
2013	Nov	161,126	221,180	19,248	401,553	370,938	30,616
2013	Dec	229,317	164,088	19,699	413,104	387,434	25,671

Table 10-15 Regulation sources by year: 2008 through 2013

Year	Spot Regulation (MW)	Spot Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)
2009	6,437,619	86.6%	885,675	11.9%	112,129	1.5%	7,435,423
2010	6,195,368	82.2%	1,162,072	15.4%	175,489	2.3%	7,532,929
2011	6,433,365	81.8%	1,226,492	15.6%	207,421	2.6%	7,867,278
2012	6,151,984	78.6%	1,483,624	19.0%	193,409	2.5%	7,829,016
2013	3,085,535	57.7%	2,061,801	38.5%	204,259	3.8%	5,351,595

Demand resources (DR) offered and cleared regulation for the first time in November, 2011. In April 2012, a tariff change allowing DR to offer regulation in increments as small as 0.1 MW facilitated participation by DR. In 2013, DR provided an average of 2.46 MW of regulation per hour. Generating units supplied an average of 804.36 MW of regulation per hour.

Market Performance

Price

The weighted average RMCP for 2013 was $30.14/MW. This is the average price per capability MW, not effective MW. This is a 48.1 percent increase from the 2012 weighted average RMCP of $20.35/MW. Figure 10-8 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 10-8 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2013

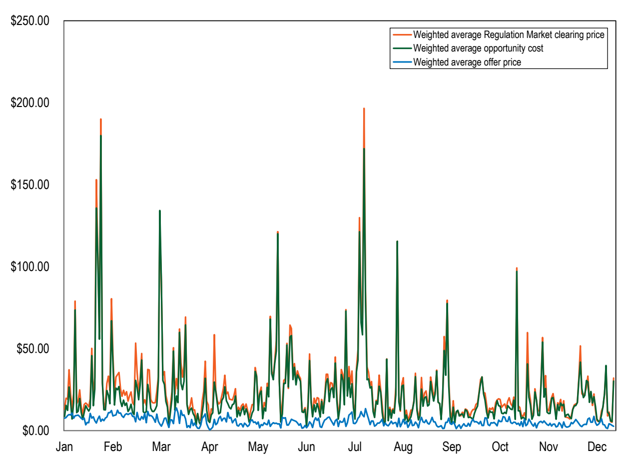


Table 10-16 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

Table 10-16 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): 2013

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$39.94	$7.72	$39.62
Feb	$29.51	$9.37	$23.01
Mar	$31.64	$5.02	$27.10
Apr	$26.49	$5.07	$14.48
May	$33.42	$4.32	$30.52
Jun	$29.81	$4.41	$20.18
Jul	$50.12	$5.97	$32.98
Aug	$27.60	$4.30	$20.75
Sep	$25.98	$3.71	$17.44
Oct	$23.30	$5.12	$16.99
Nov	$21.45	$3.84	$15.62
Dec	$22.43	$4.20	$18.18

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-17.

Table 10-17 Total regulation charges: 2013 and 2012

Year	Month	Scheduled Regulation (MW)	RegA Charges	RegD Charges	Total Regulation Charges	Weighted Average Regulation Market Price	Cost of Regulation (per MW Regulation)	Price as Percentage of Cost
2012	Jan	739,753	$13,338,201	NA	$13,338,201	$13.41	$18.03	74%
2012	Feb	677,217	$10,108,296	NA	$10,108,296	$11.89	$14.93	80%
2012	Mar	641,655	$11,109,763	NA	$11,109,763	$12.61	$17.31	73%
2012	Apr	572,397	$9,038,430	NA	$9,038,430	$13.01	$15.79	82%
2012	May	658,008	$16,248,950	NA	$16,248,950	$17.44	$24.69	71%
2012	Jun	745,156	$14,181,461	NA	$14,181,461	$14.91	$19.03	78%
2012	Jul	903,024	$29,228,039	NA	$29,228,039	$20.73	$32.37	64%
2012	Aug	824,350	$18,273,264	NA	$18,273,264	$15.86	$22.17	72%
2012	Sep	648,809	$13,593,245	NA	$13,593,245	$14.41	$20.95	69%
2012	Oct	451,710	$21,360,986	$728,584	$22,089,570	$39.80	$48.90	81%
2012	Nov	479,188	$24,103,561	$804,645	$24,908,205	$42.71	$51.98	82%
2012	Dec	487,749	$14,346,214	$624,134	$14,970,348	$27.39	$30.69	89%
2013	Jan	494,253	$22,013,590	$857,101	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$14,668,673	$604,931	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$15,933,732	$744,677	$16,678,410	$31.64	$36.30	87%
2013	Apr	381,510	$11,334,101	$595,998	$11,930,098	$26.49	$31.27	85%
2013	May	414,053	$14,914,435	$685,056	$15,599,491	$33.42	$37.68	89%
2013	Jun	475,647	$15,360,763	$638,914	$15,999,677	$29.81	$33.64	89%
2013	Jul	552,699	$30,411,682	$975,050	$31,386,733	$50.12	$56.79	88%
2013	Aug	510,342	$15,230,247	$635,871	$15,866,117	$27.60	$31.09	89%
2013	Sep	414,200	$11,472,333	$731,501	$12,203,834	$25.98	$29.46	88%
2013	Oct	381,009	$9,279,497	$875,974	$10,155,471	$23.30	$26.65	87%
2013	Nov	401,553	$8,772,784	$1,235,308	$10,008,092	$21.45	$24.92	86%
2013	Dec	413,104	$9,624,420	$1,563,940	$11,188,360	$22.43	$27.08	83%

The capability, performance, and opportunity cost components of the cost of regulation into it are shown in Table 10-18.

Table 10-18 Components of regulation cost: 2013

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	494,253	$33.74	$6.25	$6.28	$46.27
Feb	453,803	$25.50	$4.10	$4.06	$33.66
Mar	459,421	$28.31	$3.46	$4.53	$36.30
Apr	381,510	$23.21	$3.36	$4.69	$31.27
May	414,053	$30.44	$3.01	$4.22	$37.68
Jun	475,647	$26.80	$3.09	$3.74	$33.64
Jul	552,699	$46.08	$4.11	$6.59	$56.79
Aug	510,342	$22.93	$4.76	$3.40	$31.09
Sep	414,200	$22.02	$4.05	$3.40	$29.46
Oct	381,009	$19.33	$4.02	$3.30	$26.65
Nov	401,553	$17.66	$4.77	$2.49	$24.92
Dec	413,104	$16.43	$7.58	$3.07	$27.08

A comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources in 2013 is shown in Figure 10-9. On November 1, 2013, PJM removed the marginal benefits factor from all settlement calculations. In its place, PJM inserted the mileage ratio for the performance credit only. In Figure 10-9, the RegA RMCP Credit per effective MW is, on average, 2.58 times higher than the RegD RMCP Credit per effective MW from January through October 2013. However, in November and December 2013, the RegA RMCP Credit per effective MW is only 1.68 times higher than the RegD RMCP Credit per effective MW. Were the marginal benefit factor correctly applied to settlements, the RegA RMCP Credit per effective MW would be equal to the RegD RMCP credit per effective MW.

Figure 10-9 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: 2013

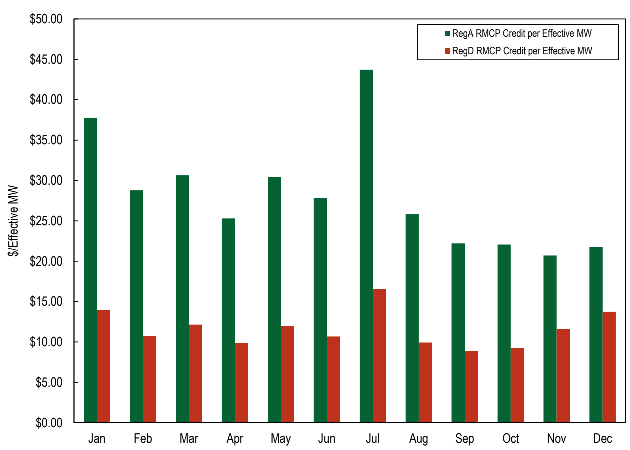


Table 10-19 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in 2013 than it was in 2012. This is an improvement which resulted from the use of actual within-hour five-minute LOC based on real-time LMP instead of forecast LMP as was done prior to the implementation of shortage pricing on October 1, 2012.

Table 10-19 Comparison of average price and cost for PJM Regulation, 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$16.21	$29.28	55%
2012	$20.35	$26.41	77%
2013	$30.14	$34.57	87%

Primary Reserve

Reserves are sources of energy that can be made available within a defined time for the purpose of correcting an imbalance between supply and demand. The PJM markets have three types of reserves to satisfy three classes of imbalance. Regulation is short-term reserve that can be adjusted up or down following either a slow or fast signal to keep the ACE within defined bounds. Primary Reserve is ten minute reserve which can be sustained for up to thirty minutes to correct a disturbance.[19,20]

PJM utilizes two products, synchronized reserve and non-synchronized reserve, to provide primary reserve, both of which are available within ten minutes. Synchronized reserve is on line and synchronized to the grid. Non-synchronized reserve may be provided by any unit not synchronized to the grid but capable of

19 NERC uses the term contingency reserves, which are reserves available within 15 minutes and that may be on line or off line. PJM criteria require response within 10 minutes. PJM meets the NERC requirements through primary reserves.

20 The NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12. Balancing Operations" Revision 30. Attachment D. "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

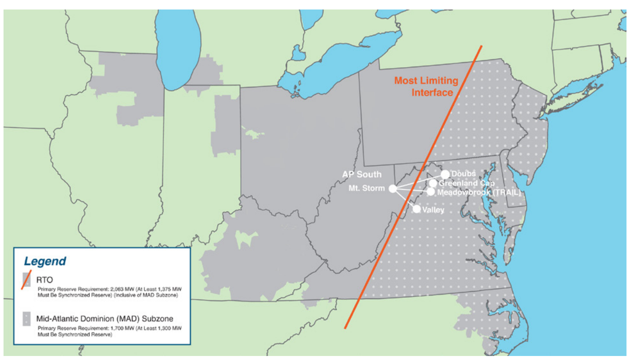
providing energy within ten minutes, for example run of river hydro, pumped hydro, CTs, some CCs and diesels.

Requirements

For the RTO Reserve Zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint. The primary reserve requirement for the RTO is currently 2,063 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The actual hourly average RTO primary reserve requirement was 2,085 MW in 2013.

PJM recognizes that transmission constraints limit the deliverability of reserves within the RTO, and therefore creates a subzone within the RTO called the Mid-Atlantic Dominion (MAD) Subzone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone (Figure 10-10).

Figure 10-10 PJM RTO geography and primary reserve requirement



Of 2,063 MW of primary reserve, PJM requires that at least 1,375 MW be on line and synchronized to the grid. The synchronized reserve requirement is 100 percent of the largest contingency. Of the 1,375 MW of synchronized reserve requirement for the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone.

The Mid-Atlantic Dominion Reserve Subzone is defined dynamically by the most limiting constraint. In approximately 58 percent of hours in 2013, that constraint was the Bedington–Black Oak Figure 10-10 transfer interface constraint. Between January 1, 2013, and May 31, 2013, the reserve interface was defined by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the Bedington–Black Oak constraint. From June 1, 2013, through December 31, 2013, PJM determined the most limiting interface in real time.[21] The changes to the reserve interface increased the supply of tier 1 synchronized reserve available in the Mid-Atlantic Dominion Subzone thereby decreasing the amount of tier 2 synchronized reserve required (Figure 10-11).

The components of the Mid-Atlantic Dominion Primary Reserve Zone primary reserve solution in order of increasing cost are: tier 1 synchronized reserve available within the Mid-Atlantic Dominion Primary Reserve Zone; tier 1 synchronized reserve available across the most limiting constraint from the west as seen by the short term market solution; demand response which is tier 2 synchronized reserve; inflexible tier 2 generation reserve scheduled and priced economically by the hourly solution; and flexible tier 2 synchronized reserve scheduled by the short term market solution intra-hour if needed.

Figure 10-11 Components of Mid-Atlantic Dominion Subzone primary reserve and reserve clearing prices (Daily Averages): 2013

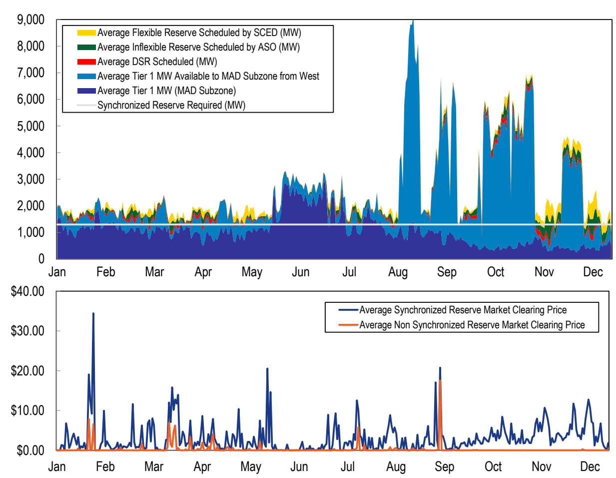


Figure 10-11 shows that tier 1 synchronized reserve remains the major contributor to satisfying the reserve requirements and tier 1 synchronized reserve available inside the subzone from the RTO Zone is a major contributor to satisfying the Mid-Atlantic Dominion (MAD) subzone synchronized reserve requirement.

21 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 62 (January 6, 2014), p. 66.

On October 1, 2012, PJM created a new Non-Synchronized Reserve Market and established a requirement that all on-line, non-emergency, generation capacity resources must offer tier 2 synchronized reserve in accordance with the resources' capability to provide these reserves.[22]

If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line non-emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[23] This rule ensures that short-term and intermediate-term market software solutions will be able to make accurate estimates of the amount of primary reserve available.

Synchronized Reserve Market

PJM operates a Synchronized Reserve Market in the RTO Synchronized Reserve Zone. The Synchronized Reserve Market clears Tier 2 synchronized reserve to satisfy the synchronized reserve requirement minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units synchronized to the grid.

Tier 2 synchronized reserve units can be flexible or inflexible. Inflexible units are scheduled by the hourly market solution sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus LOC (demand response resources are paid SRMCP). Flexible units can be assigned to either synchronized reserve or to energy depending on the economic solution.

Market Structure

Supply

For 2013, the supply of offered and eligible tier 2 synchronized reserve was stable and adequate in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. The contribution of demand resources to the Tier 2 Synchronized Reserve Market was significant. On December 6, 2012, PJM increased the DR limit from 25 percent to 33 percent of the total synchronized reserve requirement.

The Tier 2 Synchronized Reserve Market cleared an hourly average 153.8 MW in 2013. The DR share of the total Tier 2 Synchronized Reserve Market increased from 29.8 percent in 2012 to 48.1 percent in 2013.[24] A change to the way the most limiting constraint was calculated and the integration of the EKPC zone on June 1, 2013 made more Tier 1 reserve available to the MAD subzone (Figure 10-11).

Between October 1, 2013 and December 31, 2013, PJM implemented several changes in the way tier 1 available MW is estimated.[25] The effect of these changes was to reduce the estimates of tier 1 and to increase the amount of tier 2 MW cleared (Figure 10-11). The changes included: capping the tier 1 estimate at the lesser of a generator's economic maximum or its spinning maximum value (spinning maximum is a parameter defined as the maximum output a unit can attain within ten minutes); excluding hydro units from tier 1 estimates; excluding combined cycle units from tier 1 estimates unless they have a spinning maximum value less than their economic maximum value; and excluding any unit requiring manual dispatch. The impact of these changes can be seen in Figure 10-11.

Demand

The default hourly required synchronized reserve requirement is 1,375 MW and the requirement for the MAD subzone is 1,300 MW.[26]

Table 10-20 Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through December 2013

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010		1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

Exceptions to the requirement can occur when grid maintenance or outages change the largest contingency. Exceptions in 2013 are listed in Table 10-21.

22 FERC Order 755, p. 195.

23 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 64, (January 6, 2014), p. 63.

24 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

25 PJM Operating Committee Meeting, November 5, 2013. http://www.pjm.com/~/media/committees-groups/committees/oc/20131105/20131105-item-10-oc-tier-1-changes.ashx.

26 NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12: Balancing Operations" Revision 30, Attachment D, "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

Table 10-21 Exceptions to RTO Zone Synchronized Reserve requirement: 2013

From Day	To Day	Temporary Synchronized Reserve Requirement (MW)
2-Feb	3-Feb	1,780
4-Sep	8-Sep	1,650
25-Sep	27-Sep	2,572
22-Oct	23-Oct	2,572
26-Oct	27-Oct	1,725
11-Nov	18-Nov	2,140
18-Nov	20-Nov	1,761
20-Nov	23-Nov	2,320
16-Dec	21-Dec	2,640

The market demand for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone is determined by subtracting the amount of forecast tier 1 synchronized reserve available in the subzone plus the amount of tier 1 available from the RTO Zone from the subzone's requirement each five-minute period. Market demand is also reduced by subtracting the amount of self-scheduled tier 2 resources.

Figure 10-12 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled in 2013, for the Mid-Atlantic Dominion Reserve Market.

Supply and Demand

In the RTO Synchronized Reserve Zone 14.5 percent of hours cleared a synchronized reserve market in 2013 averaging 251.6 MW. The change to the estimates of tier 1 had a significant impact on the frequency of clearing an RTO Synchronized Reserve Market. An RTO Tier 2 Synchronized Reserve Zone Market was cleared in fewer than 3.0 percent of hours from January through September but in 49.6 percent of the hours from October 1 through December 31.

In the Mid-Atlantic Dominion Subzone a Tier 2 Synchronized Reserve Market was cleared in 45.9 percent of hours at an average of 153.8 MW for cleared hours. This is a reduction from the average of 448.0 MW cleared in all of 2012. The change to the estimates of tier 1 had a significant impact on the frequency of clearing an RTO Synchronized Reserve Market. An RTO Tier 2 Synchronized Reserve Zone Market was cleared in 33.5 percent of hours from January through September but in 83.2 percent of hours from October through December.

In 2013, the average Tier 2 Synchronized Reserve Market Clearing Price in the RTO Zone for all cleared hours was $7.98. In 2013 the average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $6.98.

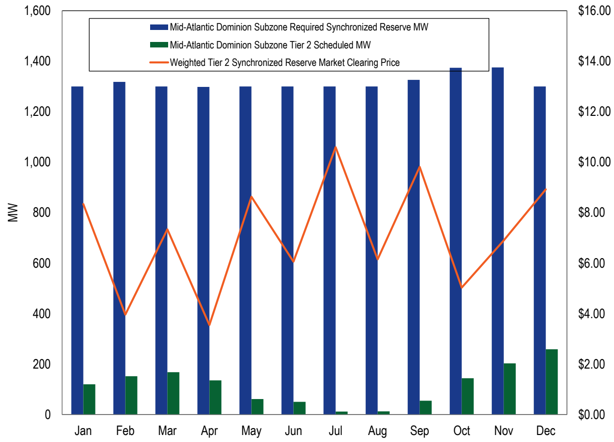
A synchronized reserve shortage occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. No synchronized reserve shortages were identified by PJM in 2013. A primary reserve shortage occurs when the combination of tier 1, tier 2, and non-synchronized reserve is not adequate to meet the primary reserve requirement. No primary reserve shortages were identified by PJM in 2013.

The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.29 for the Mid-Atlantic Dominion subzone for 2013, a decrease from the 1.40 ratio in 2012.

In late May and early June, PJM made several changes to the Tier 2 Synchronized Reserve Market which increased the reserve available in the RTO Zone, the tier 1 available across the interface into the MAD subzone, and the available tier 2 inside the MAD subzone. The reserve interface was made dynamic with the most limiting constraint calculated in real time. The calculation of the interface limit was changed from calculating the effect of all units with a three percent or greater raise help on the constrained side of the interface to calculating the effect from all units. The EKPC Region was integrated into the RTO Zone on June 1, 2013.

In 58 percent of hours in 2013, Bedington-Black Oak was the most limiting interface. In 38 percent of hours, AP South was the most limiting interface. In 4 percent of hours, the Western Interface was the most limiting interface.

Figure 10-12 Mid-Atlantic Dominion Reserve Subzone average hourly synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: 2013



Market Concentration

The HHI for settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market for 2013 was 4205, which is defined as highly concentrated. The HHI for 2012 for the Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market was 3570, which is also defined as highly concentrated. The largest hourly market share was 100 percent and 56 percent of all hours had a maximum market share greater than or equal to 40 percent, unchanged from 2012. Most Tier 2 synchronized reserve is provided by inflexible scheduled resources.[27] When there is not enough Tier 2 during the market hour or when the intermediate or short term market solution identifies a need, flexible reserve units are assigned spinning. The amount of flexible synchronized reserve assigned is 12.2 percent of all tier 2 synchronized reserve in the MAD subzone in 2013. The hourly average HHI in 2013 was 8743 for flexible resources actually assigned during the hour.

The market structure results indicate that the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

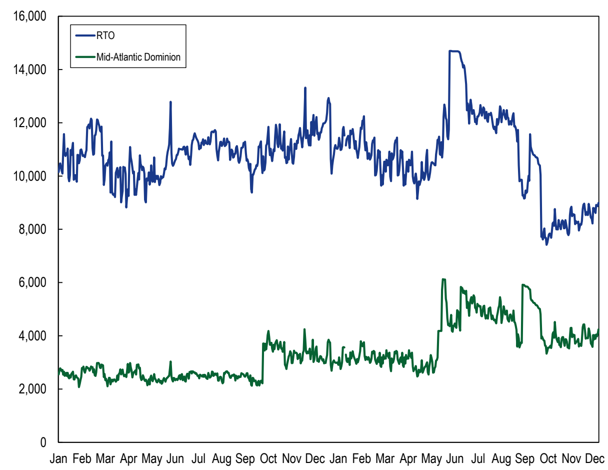
Market Behavior

Offers

Daily cost based offer prices are submitted for each unit by the unit owner. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. Figure 10-13 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

After October 1, 2012, PJM adopted a new rule making synchronized reserve a must-offer requirement for all generation that is on-line, non-emergency, and available to produce energy. Compliance with this rule has been slow. As of late December 2013, approximately 13.7 percent of eligible resources do not comply with this requirement.

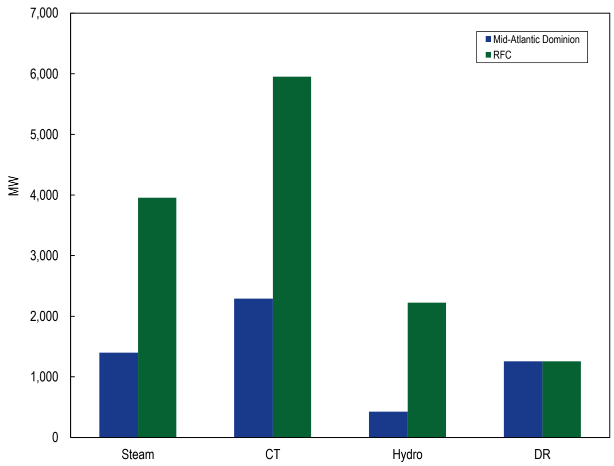
Figure 10-13 Tier 2 synchronized reserve daily average offer volume (MW): January 2012 through December 2013



Synchronized reserve is offered by steam, CT, hydroelectric and DR resources. Figure 10-14 shows average offer MW volume by market and unit type.

27 See the *2013 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT-SCED runs.

Figure 10-14 Average daily tier 2 synchronized reserve offer by unit type (MW): 2013



DR

Demand resources are a significant part of the Synchronized Reserve Market. In 2013, DR was 38 percent of all cleared Tier 2 synchronized reserves, compared to 36 percent for 2012.

Market Performance

Price

Figure 10-15 shows the weighted average tier 2 price and the cost per MW to meet synchronized reserve demand in the Mid-Atlantic Dominion subzone. The price of tier 2 synchronized reserve is the synchronized reserve market clearing price (SRMCP).

Table 10-22 shows the monthly weighted average SRMCP, all credits including LOC credits, credits paid to tier 1 resources when the Non Synchronized Reserve Market Clearing Price is above $0, MW scheduled by PJM, MW self scheduled, and MW added by either the intermediate or short term market solution software for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion subzone 2013 was $6.98 while the cost of synchronized reserve was $13.07. The price for synchronized reserve in 2012 was $8.02 while the cost was $12.71.

The RTO Reserve Zone synchronized reserve requirement was satisfied by Tier 1 in 97 percent all hours of January through September 2013. In October through December, 2013, after the change to the calculation of estimated tier 1 synchronized reserve, the RTO Reserve Zone requirement was satisfied by tier 1 in only 52 percent of hours. The MAD reserve subzone synchronized reserve requirement was satisfied by tier 1 in 54 percent of hours in January through September of 2013. In October through December, 2013 after the change to the calculation of estimated tier 1 synchronized reserve, the MAD reserve subzone synchronized reserve requirement was satisfied by tier 1 in only 16 percent of hours.

For all of 2013, in the MAD subzone, in the tier 2 synchronized reserve market the average synchronized reserve market clearing price was $6.98. The maximum synchronized reserve market clearing price was $210.07.

In 9.5 percent of the hours in which synchronized reserve was cleared, all cleared MW were DR. In the hours when

Table 10-22 Mid-Atlantic Dominion Subzone weighted synchronized reserve market clearing prices, credits, and MWs: 2013

Year	Month	Weighted Tier 2 Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Credits	Tier 1 Credits When NSR Prices are Above $0	PJM Tier 2 and DSR Scheduled Synchronized Reserve (MW)	Flexible Tier 2 Synchronized Reserve Added by SCED (MW)	Self Scheduled Tier 2 Synchronized Reserve MW
2013	Jan	$8.34	$1,241,545	$1,201,252	66,682	15,270	102
2013	Feb	$3.96	$1,237,024	$264,087	86,561	41,251	598
2013	Mar	$7.34	$2,303,326	$2,408,969	124,913	14,727	0
2013	Apr	$3.55	$981,153	$1,208,482	103,897	3,362	165
2013	May	$8.63	$783,952	$696,039	45,746	5,815	140
2013	Jun	$6.06	$354,786	$293,787	22,207	3,432	0
2013	Jul	$10.59	$1,798,168	$2,523,518	70,652	7,029	0
2013	Aug	$6.15	$817,829	$1,213,299	61,389	4,649	291
2013	Sep	$9.81	$1,444,831	$2,071,443	79,412	13,660	892
2013	Oct	$5.03	$1,683,055	$136,521	150,382	26,727	14,478
2013	Nov	$6.90	$2,570,725	$6,459	165,272	15,816	100,888
2013	Dec	$8.92	$2,781,599	$112,207	156,749	5,355	158,239
Total		$6.98	$17,997,993	$12,136,062	1,133,862	157,093	275,793

all cleared MW were DR, the weighted average SRMCP was $1.21. The weighted average SRMCP for all cleared hours was $6.98.

Table 10-23 Weighted average 2013 SRMCP with and without DR: Mid-Atlantic Dominion Sub-zone

Year	Month	Average SRMCP for all cleared hours	Average SRMCP when all Cleared synchronized reserve is DR	Percent of cleared hours all synchronized reserve is DR
2013	Jan	$8.34	$0.14	17%
2013	Feb	$3.96	$0.07	10%
2013	Mar	$7.34	$0.06	19%
2013	Apr	$3.55	$0.00	19%
2013	May	$8.63	$0.46	23%
2013	Jun	$6.06	$0.00	8%
2013	Jul	$10.59	$0.07	6%
2013	Aug	$6.15	$0.70	29%
2013	Sep	$9.81	$1.90	25%
2013	Oct	$5.03	$2.44	36%
2013	Nov	$6.90	$2.43	15%
2013	Dec	$8.92	NA	0%

Shortage pricing rules require that tier 1 synchronized reserve be paid the tier 2 synchronized reserve clearing price when the non-synchronized reserve clearing price is above $0. Tier 1 synchronized reserve has always been available to respond optionally to spinning events, but now it is also paid when the non-synchronized reserve price rises above zero. Payment for tier 1 synchronized reserve that responds to a spinning event is compensated at the average of the five-minute energy LMPs plus $50/MWh.[28] This rule significantly increases the cost of tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not actually reserving any tier 1, but simply paying substantially more for the same product without any additional performance requirements.

Table 10-24 Comparison of yearly weighted average price and cost for PJM Tier 2 Synchronized Reserve, 2005 through 2013

Year	Weighted Average Tier 2 Synchronized Reserve Market Price	Weighted Average Tier 2 Synchronized Reserve Cost	Weighted Average Tier 2 Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010	$10.55	$14.41	73%
2011	$11.81	$15.48	76%
2012	$8.02	$12.71	63%
2013	$6.98	$13.07	53%

Although tier 1 synchronized reserve adds no cost in most hours, PJM's shortage pricing filing resulted in extremely large charges for tier 1 reserves for a small number of hours. The rule change requires paying all Tier 1 reserves the full Tier 2 synchronized reserve clearing price in the hours when the non-synchronized reserve market clearing price is greater than zero. In 2013, 40.3 percent of payments for tier 1 synchronized reserve were paid for tier 1 synchronized reserve when it was not needed (Table 10-22). This is a windfall payment to Tier 1 reserves.

When more tier 2 was cleared after the late September change in the tier 1 calculation, there were fewer hours in which non-synchronized reserve prices rose above $0. Payments to spinning resources for Tier 1 declined in October through December 2013, because there were few spinning events and few hours in which non-synchronized reserve was cleared.

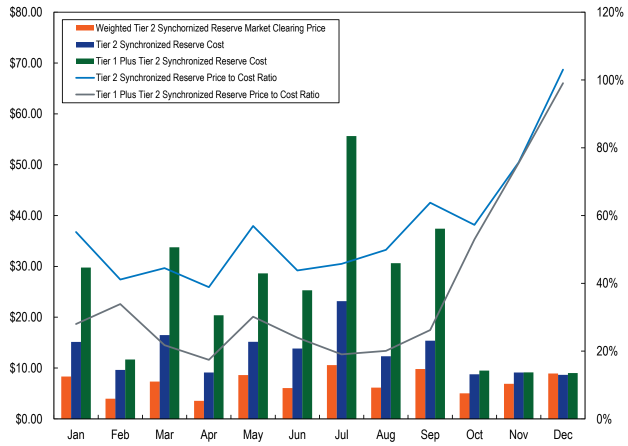
The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. Table 10-24 shows the price and cost history of the Tier 2 Synchronized Reserve Market since 2005.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient synchronized reserve market design. In the Mid-Atlantic Dominion Subzone of the RFC Tier 2 Synchronized Reserve Market for 2013, the price of Tier 2 synchronized reserves was 56 percent of the cost. In 2012, the price to cost ratio was 63 percent. There was a significant improvement in the price to cost ratio in the MAD Tier 2 Synchronized Reserve Market in October through December, 2013 (Figure 10-15).

28 See PJM Manual 28: Operating Agreement Accounting, rev.62, 10/1/2012, p. 62.

Figure 10-15 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): 2013



Tier 1 Bias

Each market clearing engine (hour ahead, intermediate and short term) can have its tier 1 estimate biased. Biasing means modifying the demand for synchronized reserve from the level defined by the market software. Negative tier 1 estimate biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much tier 2 MW to schedule. A negative bias reduces the amount of tier 1 estimated to be available and therefore increases the amount of tier 2 which must be purchased. Tier 1 biasing can be used by PJM dispatchers to compensate for uncertainty in short term load forecasting, generator performance, constraint binding, or uncertainly in the accuracy of the tier 1 estimate of the market solution.

PJM reduced its use of tier 1 biasing in 2013 (Figure 10-16). From July through October 2013, Tier 1 estimate was biased in 39 hours. Tier 1 biasing was not used in November or December. In 33 hours of the 39 hours it was biased negatively averaging -217 MW. In the remaining six hours it was biased positively averaging 47 MW. During the hours of negative bias the SRMCP averaged $28.22. The average SRMCP was $2.77 during all hours between July 1 and October 31.

A negative tier 1 bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. The increased inflexible tier 2 resources need to be compensated for their LOC and they must be paid even if they are not needed in real time (Figure 10-17).

Figure 10-16 Use of hourly market solution tier 1 estimate biasing in the Middle Atlantic Dominion sub-zone: 2013

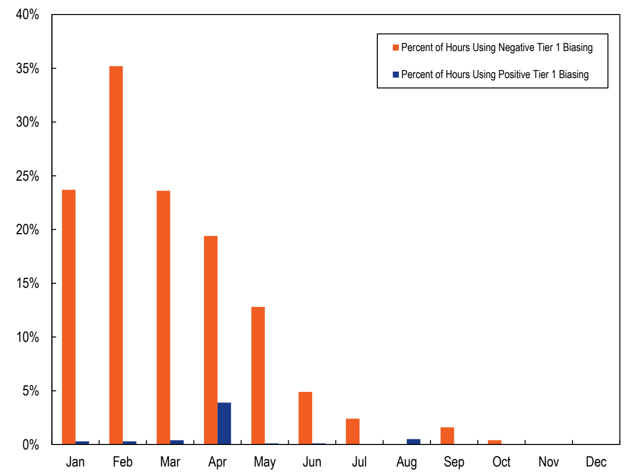
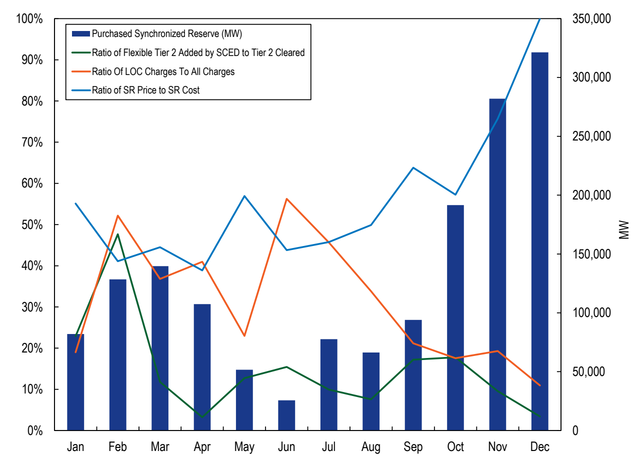


Figure 10-17 Impact of flexible tier 2 synchronized reserve added to the Mid-Atlantic Dominion Subzone Tier 2 Market: 2013



The MMU recommends that PJM be more explicit about why tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

Compliance

Non-compliance in the Tier 2 Synchronized Reserve Market remains a problem. Non-compliance has two major components: failure to deliver scheduled tier 2 Synchronized Reserve MW during spinning events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has identified the issue of noncompliance by tier 2 synchronized reserve resources during spinning events since 2011.[29] When synchronized reserve resources clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has reported a wide range of spinning event response levels and recommended PJM take action to increase compliance rates. In May 2013, PJM initiated an effort to increase the penalty for non-compliance of scheduled synchronized reserve resources during spinning events. An enhanced penalty structure was approved by the PJM Operations Committee on September 30, 2013. PJM filed with the FERC and the new penalty structure was approved December 17. Penalties can be assessed for any spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In 2013, eight spinning events occurred that met these criteria.

Table 10-25 Synchronized reserve events greater than 10 minutes, Mid-Atlantic Dominion Tier 2 Response Compliance 2013

2013 Qualifying Spinning Events (DD-MON-YYYY HR)	Event Duration (minutes)	MAD Synchronized Reserve Market Clearing Price	Tier 2 plus DR Cleared MW	Tier 2 plus DR Added MW	Percent Tier 2 Penalized for Non Compiance	Percent DR Penalized for Non Compiance	Overall Percent of Synchronized Reserve Penalty for Non Compliance
25-JAN-2013 15	19	$150.85	34	444	20%	0%	20%
17-FEB-2013 23	13	$2.08	587	0	47%	69%	54%
17-APR-2013 01	11	$0.00	516	0	44%	48%	46%
30-JUN-2013 01	10	$5.89	689	0	37%	33%	36%
03-JUL-2013 20	13	$11.79	476	264	38%	49%	41%
15-JUL-2013 18	29	$7.49	361	0	14%	62%	35%
10-SEP-2013 19	68	$0.00	67	0	98%	73%	97%
28-OCT-2013 11	33	$3.00	264	163	0%	58%	35%

For the eight qualifying spinning events that occurred in 2013, 37 percent of all scheduled Tier 2 synchronized reserve MW were not delivered and were penalized. Of the 4,126 MW of committed synchronized reserve, 1,542 MW of failed to perform during spinning events.

The new penalty structure will increase the number of consecutive days that an underperforming resource is penalized from three days to the average number of days between spinning events. The average number of days between spinning events is currently 15 days. In addition, a resource will be penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the spinning event.[30]

A second compliance issue is failure to comply with the must offer requirement. The shortage pricing changes introduced on October 1, 2012, included a must offer requirement for Tier 2 synchronized for most generators under normal conditions, and an expanded set of generators under well-defined conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and they must have an offer and be available for reserve. When PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all other non-emergency, off-line available generation capacity resources must have an offer and be available for reserve. As of December 31, 2013, the MMU estimates that 13.7 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

29 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

30 M-28 Operating Agreement Accounting Rev. 63, December 19, 2013, p. 43. See PJM "Energy & Ancillary Services Market Operations," rev. 64, January 6, 2014, pg. 74.

History of Spinning Events

Spinning events (Table 10-26) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[31] PJM also calls spinning events for non-disturbance events, which it characterizes as low ACE. The reserve remains loaded until system balance is recovered. From 2010 through 2013, PJM experienced 116 spinning events, or between two and three events per month. Spinning events had an average length of 13.3 minutes.

Table 10-26 Spinning events, 2010 through 2013

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

The spinning event of September 10, called by PJM due to low ACE, lasted 68 minutes, which is the longest spinning event in the last five years. PJM's systems did not anticipate the event, clearing low levels of tier 2 synchronized reserve as a result of overestimating the amount of tier 1 available. When the event was called, resources estimated to have available tier 1 did not respond as expected and did not resolve the imbalance. During the day of September 10, tier 2 synchronized reserve and non-synchronized reserve prices were $0.00 for 22 hours. The event spanned two market hours, 1600 and 1700. The event began in hour 1600 when the MAD SRMCP was $0, and 1700 when the SRMCP was $3.18. Low ACE that is not the result of a generator outage or transmission interruption indicates a problem with short-term load forecasting, dispatch solution, reserve measurement and/or generator compliance with instructions. Tier 1 response to the September 10 spinning event was low, approximately 20 percent. PJM has created an Energy/Reserve Pricing & Interchange Volatility (ERPIV) study group charged with understanding this event and similar hot day spinning events, reserves, and interchange behavior in the last two quarters of 2013 and recommending solutions to ensure adequate reserve response and prevent load shedding.

Analysis of spinning events similar to the 68 minute event of September 10 (RTO-wide, hot days, and longer than 12 minutes) show that the tier 1 response of September 10 was not unusual (Table 10-27).

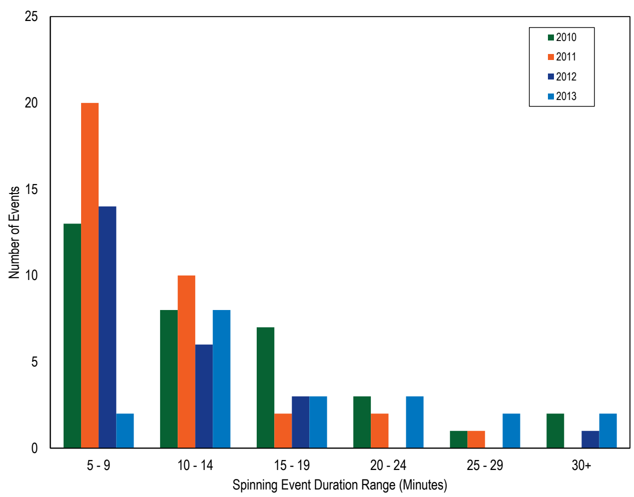
31 See PJM. "Manual 12, Balancing Operations," Revision 30 (December 1, 2013), pp. 36-37.

Table 10-27 Tier 1 Response to spinning events July 3, July 15, September 10, October 28

Market Hour	Duration (Minutes)	MAD Synchronized Reserve Market Clearing Price	RTO Synchronized Reserve Market Clearing Price	MAD Tier 1 Estimate	RTO Available Tier 1 Estimate	RTO Total Tier 1 Available	RTO Total Tier 1 Response	Percent of Tier 1 Capability Responded
July 3, 2013 Hr. 17	13	$11.79	$0.00	582	118	1837	360	20%
July 15, 2013 Hr. 15	17	$7.49	$0.00	805	530	7377	3237	44%
July 15, 2013 Hr. 16	12	$1.00	$0.00	799	543	7223	2076	29%
July 10, 2013 Hr. 16	12	$0.00	$0.00	843	388	6124	355	6%
July 10, 2013 Hr. 17	56	$3.18	$3.18	701	520	6278	1555	25%
October 28, 2013 Hr. 9	16	$2.17	$0.00	511	536	4528	902	20%
October 28, 2013 Hr. 10	17	$3.00	$0.00	508	353	4702	908	19%

September 10 was part of a three day period of high demand for energy and reserves, September 9 through September 11. The day following the spinning event, September 11, 2013, was also a hot day. Although PJM Dispatch used tier 1 estimate biasing in only 1.5 percent of hours from July 1 through September 30, on September 11 PJM Dispatch used it for 9 contiguous hours from 1200 to 2000 inclusive, averaging -241 MW. During this period, prices for both tier 2 synchronized reserve and non-synchronized reserve increased to $210.07, prices for tier 2 synchronized reserve averaged $50.83, and prices for non-synchronized reserve averaged $46.89.

Figure 10-18 Spinning events duration distribution curve, 2010 to 2013



Non-Synchronized Reserve Market

Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. PJM specifies that 1,300 MW of synchronized reserve must be available in the Mid-Atlantic Dominion Reserve Zone. The balance of primary reserve can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[32]

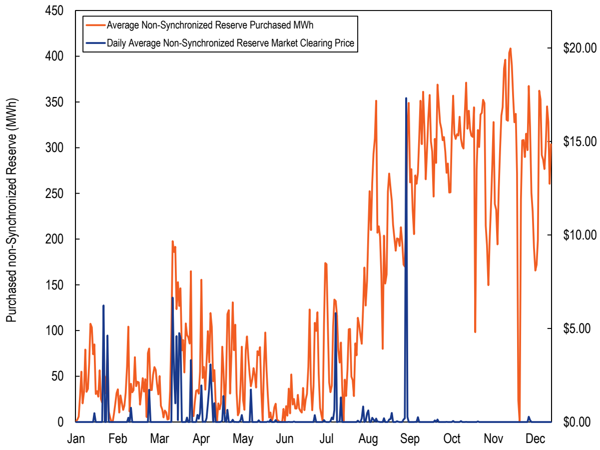
Almost all non-synchronized reserve enabled resources are CTs, with some diesels. Startup time for these units is not subject to testing. There is no non-synchronized reserve offer price. Prices are determined by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. In most hours the non-synchronized reserve clearing price is zero.

Figure 10-19 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market had a clearing price greater than zero in 228 hours in 2013 at an average price of $9.71 and a maximum of $210.07 on September 11, 2013. The non-synchronized reserve market clearing price for the RTO Reserve Zone cleared in 73 hours in 2013 at an average price of $1.81 with a maximum clearing price of $9.40 on August 24, 2013.

In 228 hours in 2013, the Non-Synchronized Reserve Market for the Mid-Atlantic Dominion Subzone cleared at greater than $0.00, averaging $9.71 with a maximum clearing price of $210.07 on September 11. Non-synchronized reserve only clears when synchronized reserve also clears.

32 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 64 (January 6, 2014), p. 77.

Figure 10-19 Daily average Non-Synchronized Reserve Market clearing price and MW purchased: 2013



Day-Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[33]

The DASR 30-minute reserve requirements are determined by the reliability region.[34] In the ReliabilityFirst (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[35] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.[36] The DASR requirement is a sum of the load forecast error and the forced outage rate. The load forecast error increased from 1.97 percent in 2012 to 2.13 percent in 2013 and the forced outage rate decreased from 4.93 percent to 4.66 percent. Added together, the 2013 DASR requirement is 6.91 percent. The DASR MW purchased averaged 6,805 MW per hour for 2013, a slight decrease from 6,841 MW per hour in 2012.

In 2013, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test in 2012.

All generation resources are required to offer DASR.[37] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. No demand resources offered in the DASR market in 2013.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[38] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. However, there is a positive opportunity cost in addition to this direct marginal cost, which is not part of the offer price but is calculated by PJM. As of December 31, 2013, 12 percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

Market Performance

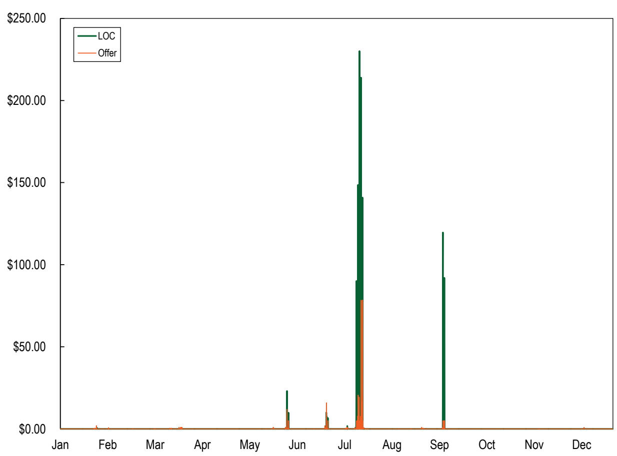
For 82 percent of hours in 2013, DASR cleared at a price of $0.00 (Figure 10-20). For 2013, the weighted DASR price was $0.70. The highest price was $230.10 on July 17, 2013. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of the offer price. When the DASR clearing price is greater than $0.00, 84 percent of the time the price consists solely of the offer price. The offer and LOC components of price are in Figure 10-20.

33 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
34 See PJM. "Manual 13, Emergency Requirements," Revision 55 (January 1, 2014), p. 11.
35 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 29 (November 1, 2013), pp. 19-20.
36 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
37 See PJM "Manual 11 " Revision 64, (January 6, 2014) p. 138 at Day-ahead Scheduling Reserves Market Rules.
38 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 63 (January 6, 2014), p. 143.

Table 10-28 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: 2012 and 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2013	Oct	6,077	$0.00	$0.05	$0.00	4,497,258	$2,363
2013	Nov	6,479	$0.00	$0.10	$0.00	4,665,156	$5,123
2013	Dec	7,033	$0.00	$0.80	$0.01	5,232,625	$25,192
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	4,454,997	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	4,584,792	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	5,179,876	$5,975

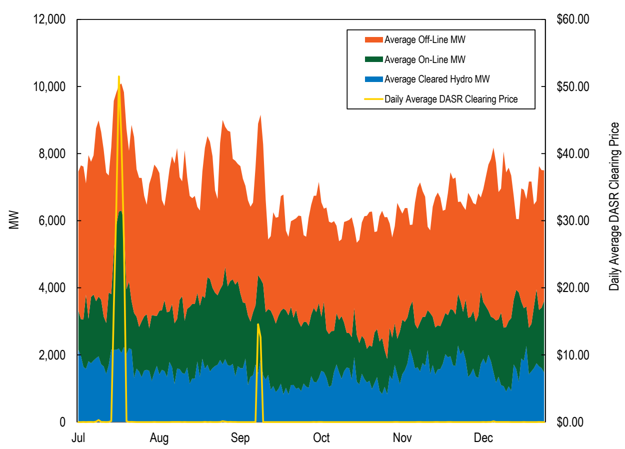
Figure 10-20 Hourly components of DASR clearing price: 2013



The secondary reserve requirement (DASR) is usually satisfied at no cost and with no need to redispatch energy resources. The amount of reserve available from hydro and off-line resources is relatively static. But when energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-20 shows the impact on price when online resources must be redispatched to satisfy the DASR requirement.

Figure 10-21 illustrates the sensitivity of DASR prices to high energy dispatch and the resource types (on-line, off-line, and hydro) used for secondary reserve. DASR prices remain very low even at high energy dispatch levels. DASR prices are high only at extreme peaks.

Figure 10-21 Daily average DASR prices and MW by classification: July – December, 2013



The 68-minute spinning event of September 10, 2013, was declared as a result of low ACE. Different classes of reserve exist for different classes of imbalance. A

68-minute inability to bring ACE into balance with no sudden generator outage is the type of imbalance that 30-minute secondary reserve was created to recover from. On September 10, 2013, the 30-minute reserve requirement was 8,893 MW. That requirement was cleared day-ahead for every hour of the day. In nine hours, the price was above $0.

In real time, an average of 7,393 MW of secondary reserve was actually available in each hour and resources were paid $2,685,038 for secondary reserve throughout the day. It is not clear why secondary reserve was either unavailable to the dispatchers or was never called. PJM dispatch called on tier 1, tier 2, and non-synchronized reserve and was unable to restore balance for 68 minutes. Tier 1 response was substantially less than the estimated available tier 1 MW. It is not clear why the secondary reserve, already paid for, was not called.

The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. The PJM and MMU proposal for system restoration was approved at the February 28, 2013, Markets and Reliability Committee (MRC).

The proposed changes include allowing PJM more flexibility in procuring black start resources by allowing cross zonal coordination between transmission zones, clarifying the responsibility for black start resources selection, revising the timing requirement for black start from 90 minutes to three hours, and implementing a process to revise black start plans on a five year basis in order to ensure system restoration needs are met. This proposal is a substantial improvement to current system restoration strategy, which does not give PJM adequate flexibility in procuring black start resources. This proposal also clarifies that PJM is the entity responsible for selecting the appropriate black start resources for each transmission zone based on system restoration requirements.

Black start payments are non-transparent payments made to units on the behalf of load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent the publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

Total black start charges is the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Total black start charges are allocated monthly to PJM customers proportionally to their zone and non-zone peak transmission use and point to point transmission reservations.

In 2013, total black start charges were $107.5 million with $20.9 million in revenue requirement charges.

Table 10-29 shows total revenue requirement charges from 2008 through 2013. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-29 Black start revenue requirement charges: 2008 through 2013

Period	Revenue Requirement Charges
2008	$13,146,539
2009	$12,329,456
2010	$9,984,687
2011	$20,091,680
2012	$18,577,185
2013	$20,939,804

Black start zonal charges in 2013 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $126,644) to $9.71 per MW-day in the AEP Zone (total charges were $82,588,453). For each zone, Table 10-30 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.05 per MW of reserve capacity.

Table 10-30 Black start zonal charges for network transmission use: 2013

Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$581,124	$41,138	$622,262	1,025,285	$0.61
AEP	$649,333	$81,939,120	$82,588,453	8,507,639	$9.71
APS	$267,202	$3,063	$270,264	3,111,370	$0.09
ATSI	$124,525	$2,119	$126,644	4,932,938	$0.03
BGE	$6,095,115	$10,301	$6,105,416	2,555,730	$2.39
ComEd	$4,097,259	$56,996	$4,154,255	8,614,329	$0.48
DAY	$241,080	$5,252	$246,332	1,280,092	$0.19
DEOK	$667,936	$8,662	$676,599	1,988,923	$0.34
Dominion	$508,734	$21,152	$529,886	4,138,535	$0.13
DPL	$558,101	$31,314	$589,415	1,501,647	$0.39
DLCO	$58,154	$7,928	$66,082	1,114,747	$0.06
EKPC	$214,758	$8,380	$223,138	509,919	$0.44
JCPL	$554,197	$14,945	$569,142	2,270,081	$0.25
Met-Ed	$789,692	$55,639	$845,330	1,108,286	$0.76
PECO	$1,405,096	$28,121	$1,433,217	3,120,385	$0.46
PENELEC	$510,881	$6,835	$517,716	1,061,420	$0.49
Pepco	$300,675	$24,095	$324,770	2,453,056	$0.13
PPL	$184,305	$0	$184,305	2,694,248	$0.07
PSEG	$2,094,342	$32,992	$2,127,334	3,821,477	$0.56
RECO	$0	$0	$0	0	NA
(Imp/Exp/Wheels)	$1,037,296	$4,295,829	$5,333,124	2,905,037	$1.84
Total	$20,939,804	$86,593,879	$107,533,683	58,715,141	$1.83

Table 10-31 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 10-31 NERC CIP Costs: 2013

Capital Cost Requested	Cost Recovered in 2013	Number of Units	MW
$1,736,971	$630,521	33	678

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[39] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

Total reactive service charges are the sum of reactive service revenue requirement charges and reactive service operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service revenue requirement charges are allocated monthly to PJM customers in the zone or zones where the reactive service was provided proportionally to their zone and non-zone peak transmission use and point to point transmission reservations. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. These operating

39 OATT Schedule 2.

reserve charges are allocated daily to the zone or zones where the reactive service was provided.

In 2013, total reactive service charges were $616.6 million compared to $368.3 million in 2012.[40] Total charges in 2013 ranged from $340.0 thousand in the RECO Zone to $76.8 million in the ATSI Zone. For each zone in 2013, Table 10-32 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-32 Reactive zonal charges for network transmission use: 2013

Zone	2012 Operating Reserve Charges	2012 Revenue Requirement Charges	2012 Total Charges	2013 Operating Reserve Charges	2013 Revenue Requirement Charges	2013 Total Charges
AECO	$1,610,237	$5,118,435	$6,728,673	$4,673,542	$5,132,697	$9,806,239
AEP	$3,377,039	$39,965,891	$43,342,930	$36,194,483	$40,300,353	$76,494,836
APS	$1,081,129	$21,881,530	$22,962,659	$10,688,148	$21,942,502	$32,630,649
ATSI	$15,913,491	$14,521,977	$30,435,468	$61,085,799	$15,741,841	$76,827,641
BGE	$6,287,524	$7,749,618	$14,037,141	$16,976,343	$7,771,212	$24,747,555
ComEd	$1,993,906	$24,878,682	$26,872,588	$22,192,595	$24,568,280	$46,760,875
DAY	$375,657	$8,413,711	$8,789,368	$3,759,513	$8,437,155	$12,196,668
DEOK	$522,480	$5,742,932	$6,265,412	$5,964,175	$5,758,935	$11,723,110
Dominion	$297,882	$29,842,049	$30,139,931	$3,267,018	$29,925,202	$33,192,220
DPL	$3,186,612	$9,665,346	$12,851,958	$22,979,048	$10,051,706	$33,030,754
DLCO	$18,049,249	NA	$18,049,249	$50,938,709	NA	$50,938,709
EKPC	NA	NA	$0	$2,387,655	$1,069,929	$3,457,584
JCPL	$4,945,378	$6,240,146	$11,185,523	$13,049,937	$6,257,533	$19,307,471
Met-Ed	$1,685,968	$7,458,870	$9,144,838	$3,709,406	$7,479,654	$11,189,060
PECO	$4,722,240	$17,334,300	$22,056,540	$10,155,174	$17,622,191	$27,777,365
PENELEC	$9,040,276	$4,637,417	$13,677,693	$36,562,731	$4,650,339	$41,213,069
Pepco	$5,030,624	$5,550,579	$10,581,202	$7,080,243	$5,257,464	$12,337,707
PPL	$6,962,007	$17,303,867	$24,265,874	$9,753,227	$18,872,215	$28,625,443
PSEG	$10,050,718	$27,190,537	$37,241,255	$17,688,214	$27,266,302	$44,954,516
RECO	$157,882	NA	$157,882	$339,964	NA	$339,964
(Imp/Exp/Wheels)	NA	$19,469,555	$19,469,555	NA	$19,055,365	$19,055,365
Total	$95,290,298	$272,965,442	$368,255,740	$339,445,925	$277,160,875	$616,606,800

40 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Congestion and Marginal Losses

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).[1]

SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.[2] SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus, or LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Total system-wide transmission losses for 2013 were 17,389 GWh, a 2.5 percent increase compared to 2012. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[3] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $147.9 million or 28.0 percent, from $529.0 million in 2012 to $676.9 million in 2013.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $231.4 million or 29.7 percent, from $779.9 million in 2012 to $1,011.3 million in 2013.
- **Balancing Congestion.** Balancing congestion costs decreased by $83.5 million or 33.3 percent from -$250.9 million in 2012 to -$334.4 million in 2013.[5]
- **Monthly Congestion.** Monthly total congestion costs in 2013 ranged from $27.8 million in April to $110.1 million in July.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the West interface, the ATSI Interface, the Bridgewater - Middlesex line, and the Bedington - Black Oak Interface.
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2013. Day-ahead congestion frequency increased by 44.0 percent from 249,572 congestion event hours in 2012 to 359,432 congestion event hours in 2013. Day-ahead, congestion-event hours increased on all types of congestion facilities.

1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January 2012 and as part of PJM for the second hour of January through December 2012. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June through June 2013.

2 For more information about LMP see the *Technical Reference for PJM Markets*, "Calculating Locational Marginal Price." <http://www.monitoringanalytics.com/reports/ Technical_References/references.shtml>.

3 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

4 The total congestion and marginal losses were calculated as of January 28, 2014, and are subject to change, based on continued PJM billing updates.

5 The balancing congestion cost is greater than the balancing congestion calculated by PJM by $0.26 million as a result of security constrained economic dispatch (SCED) software flat files format changes and the fact that SCED was down for many intervals for emergency fixes on August 8, 2013.

Real-time congestion frequency decreased by 7.6 percent from 20,921 congestion event hours in 2012 to 19,321 congestion event hours in 2013. Real-time, congestion-event hours increased on the interfaces, while congestion-event hours on the transformers, the flowgates and the transmission lines decreased.

Facilities were constrained in the Day-Ahead Energy Market more frequently than in the Real-Time Energy Market. In 2013, for only 2.0 percent of Day-Ahead Energy Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In 2013, for 38.1 percent of Real-Time Energy Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Energy Market.

The AP South Interface was the largest contributor to congestion costs in 2013. With $169.1 million in total congestion costs, it accounted for 25.0 percent of the total PJM congestion costs in 2013. The top five constraints in terms of congestion costs together contributed $223.7 million, or 33.0 percent, of the total PJM congestion costs in 2013. The top five constraints were the AP South Interface, the West Interface, the ATSI Interface, the Bridgewater – Middlesex line, and the Bedington - Black Oak Interface.

- **Zonal Congestion.** ComEd was the most congested zone in 2013. ComEd had -$477.3 million in total load costs, -$650.0 million in total generation credits and -$17.5 million in explicit congestion, resulting in $155.2 million in net congestion costs. The Nelson – Cordova line, the Byron - Cherry Valle flowgate, the Braidwood transformer, the Oak Grove – Galesburg flowgate and the Crete – St Johns Tap flowgate contributed $56.4 million, or 36.4 percent of the total ComEd Control Zone congestion costs.

  The AEP Control Zone was the second most congested zone in PJM in 2013, with $106.0 million. The AP South Interface contributed $23.5 million or 22.1 percent of the total AEP Control Zone congestion cost in 2013. The AP Control Zone was the third most congested zone in PJM in 2013, with a cost of $92.8 million.

- **Ownership.** In 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2013, financial companies received $102.8 million in net congestion credits, an increase of $19.8 million or 23.9 percent compared to 2012. In 2013, physical companies paid $779.7 million in net congestion charges, an increase of $167.7 million or 27.4 percent compared to 2012.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in 2013 increased by $53.6 million or 5.5 percent from 2012, from $981.7 million to $1,035.3 million. Day-ahead net marginal loss costs in 2013 increased by $133.9 million or 13.3 percent from 2012, from $1,003.8 million to $1,137.7 million. Balancing net marginal loss costs decreased in 2013 by $80.3 million or 363.4 percent from 2012, from -$22.1 million to -$102.4 million.
- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in 2013 ranged from $66.2 million in April to $142.1 million in July.
- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[6] The marginal loss credits decreased in 2013 by $55.8 million or 14.4 percent from 2012, from $386.7 million to $330.9 million.

6 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), pp 63-64. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Energy Cost

- **Total Energy Costs.** Total energy costs in 2013 decreased by $108.5 million or 18.3 percent from 2012, from -$593.0 million to -$701.5 million. Day-ahead net energy costs in 2013 decreased by $224.3 million or 36.8 percent from 2012, from -$609.9 million to -$834.2 million. Balancing net energy costs in 2013 increased by $132.4 million or 1,710.3 percent from 2012, from $7.7 million to $140.1 million.
- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in 2013 ranged from -$90.8 million in July to -$44.3 million in October.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion in 2013. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Increases in the LMP and fuel costs led to higher marginal loss costs in 2013 compared to 2012. Total marginal loss costs increased in 2013 by $53.6 million or 5.5 percent from 2012, from $981.7 million to $1,035.3 million.

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus will affect the components of LMP. With a distributed load reference bus, the energy component is a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8]

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/ Technical_References/references.shtml>.

8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for 2009 to 2013. The load-weighted average real-time LMP increased $3.43 or 9.7 percent from $35.23 in 2012 to $38.66 in 2013. The load-weighted average congestion component decreased $0.03 or 79.8 percent from $0.04 in 2012 to $0.01 in 2013. The load-weighted average loss component increased $0.01 or 38.2 percent from $0.01 in 2012 to $0.02 in 2013. The load-weighted average energy component increased $3.46 or 9.8 percent from $35.18 in 2012 to $38.64 in 2013. Given that these results are based on system average LMP including offsetting congestion components, a congestion component near zero is expected.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2009 through 2013[9]

Year	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2009 through 2013. The load-weighted average day-ahead LMP increased $4.37 or 12.7 percent from $34.55 in 2012 to $38.93 in 2013. The load-weighted average congestion component increased $0.03 or 26.1 percent from $0.11 in 2012 to $0.13 in 2013. The load-weighted average loss component increased $0.02 or 116.3 percent from -$0.01 in 2012 to $0.00 in 2013. The load-weighted average energy component increased $4.33 or 12.6 percent from $34.46 in 2012 to $38.79 in 2013.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2009 through 2013

Year	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00

9 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 11-3 for 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 11-4 for 2012 and 2013.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2012 and 2013

	2012				2013			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.55	$35.86	$0.23	$1.46	$41.11	$39.14	$0.27	$1.70
AEP	$33.15	$34.73	($0.75)	($0.83)	$35.56	$38.25	($1.78)	($0.92)
AP	$34.86	$34.91	$0.04	($0.09)	$37.70	$38.39	($0.57)	($0.11)
ATSI	$34.42	$34.99	($0.78)	$0.21	$42.12	$38.43	$3.27	$0.42
BGE	$40.03	$35.44	$2.99	$1.59	$43.52	$38.97	$2.79	$1.76
ComEd	$31.76	$35.39	($2.05)	($1.58)	$33.28	$38.65	($3.48)	($1.90)
DAY	$34.25	$35.14	($0.95)	$0.05	$36.15	$38.61	($2.35)	($0.11)
DEOK	$32.67	$35.16	($0.87)	($1.62)	$34.35	$38.57	($2.31)	($1.91)
DLCO	$33.53	$35.05	($0.47)	($1.05)	$35.70	$38.51	($1.61)	($1.20)
Dominion	$37.28	$35.45	$1.48	$0.35	$40.63	$38.84	$1.46	$0.33
DPL	$39.53	$35.53	$2.31	$1.68	$42.18	$38.96	$1.29	$1.93
EKPC	NA	NA	NA	NA	$33.96	$38.72	($2.73)	($2.02)
JCPL	$37.34	$35.92	$0.09	$1.33	$42.98	$39.54	$1.63	$1.81
Met-Ed	$36.30	$35.11	$0.67	$0.53	$39.72	$38.63	$0.34	$0.75
PECO	$36.78	$35.27	$0.61	$0.89	$39.70	$38.77	($0.11)	$1.03
PENELEC	$35.10	$34.66	($0.12)	$0.56	$38.71	$38.18	($0.10)	$0.63
Pepco	$39.08	$35.47	$2.68	$0.93	$42.78	$38.98	$2.62	$1.18
PPL	$35.44	$34.92	$0.00	$0.52	$39.26	$38.44	$0.18	$0.64
PSEG	$37.48	$35.38	$0.71	$1.39	$43.97	$38.93	$3.37	$1.67
RECO	$37.80	$36.09	$0.42	$1.29	$45.81	$39.65	$4.53	$1.63
PJM	$35.23	$35.18	$0.04	$0.01	$38.66	$38.64	$0.01	$0.02

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2012 and 2013

	2012				2013			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$37.36	$35.08	$0.66	$1.62	$41.48	$39.23	$0.61	$1.64
AEP	$32.71	$34.19	($0.51)	($0.97)	$36.44	$38.58	($1.26)	($0.88)
AP	$34.29	$34.26	$0.09	($0.06)	$38.23	$38.62	($0.21)	($0.18)
ATSI	$33.55	$34.32	($0.69)	($0.08)	$38.13	$38.69	($0.85)	$0.29
BGE	$39.55	$34.85	$2.76	$1.93	$44.32	$39.17	$3.46	$1.69
ComEd	$30.72	$34.60	($1.98)	($1.90)	$34.12	$38.86	($3.04)	($1.70)
DAY	$33.76	$34.58	($0.65)	($0.16)	$37.13	$38.89	($1.58)	($0.18)
DEOK	$32.18	$34.45	($0.49)	($1.79)	$35.46	$38.70	($1.54)	($1.69)
DLCO	$33.05	$34.42	($0.30)	($1.07)	$36.35	$38.75	($1.17)	($1.22)
Dominion	$36.56	$34.76	$1.31	$0.48	$41.34	$39.15	$2.03	$0.16
DPL	$38.91	$34.94	$1.86	$2.11	$42.55	$39.10	$1.56	$1.89
EKPC	NA	NA	NA	NA	$35.65	$39.37	($1.68)	($2.04)
JCPL	$37.03	$35.10	$0.47	$1.47	$42.86	$39.48	$1.66	$1.73
Met-Ed	$35.44	$34.29	$0.50	$0.65	$40.04	$38.62	$0.83	$0.59
PECO	$36.40	$34.62	$0.72	$1.06	$40.14	$38.87	$0.32	$0.94
PENELEC	$34.69	$33.95	$0.12	$0.62	$39.29	$38.14	$0.38	$0.77
Pepco	$38.26	$34.58	$2.39	$1.29	$43.16	$38.70	$3.33	$1.14
PPL	$34.82	$34.22	$0.12	$0.48	$39.67	$38.55	$0.65	$0.46
PSEG	$37.25	$34.81	$0.79	$1.65	$44.65	$39.17	$3.78	$1.70
RECO	$36.91	$35.20	$0.34	$1.36	$45.55	$39.37	$4.55	$1.62
PJM	$34.55	$34.46	$0.11	($0.01)	$38.93	$38.79	$0.13	$0.00

Component Costs

Table 11-5 shows the total energy, loss and congestion component costs and the total PJM billing for 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 11-5 Total PJM costs by component (Dollars (Millions)): 2009 through 2013[10, 11]

	Component Costs (Millions)					
Year	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($629)	$1,268	$719	$1,358	$26,550	5.1%
2010	($798)	$1,635	$1,423	$2,260	$34,771	6.5%
2011	($794)	$1,380	$999	$1,585	$35,887	4.4%
2012	($593)	$982	$529	$918	$29,181	3.1%
2013	($702)	$1,035	$677	$1,011	$33,862	3.0%

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[12] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the Balancing Energy Market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[13]

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product

10 The energy costs, loss costs and congestion costs include net inadvertent charges.

11 Total PJM billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

12 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term congestion costs as used here.

13 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

of the deviations between the real-time and day-ahead transacted MWs and the differences between the real-time CLMP at the transactions' sources and sinks.

- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. The net congestion bill is the source of payments to FTR holders. When load pays more for congestion in an area than generation receives, the positive difference is the source of payments to FTR holders as it is a measure of the value of transmission in bringing lower cost generation into the area.

Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[16] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South Interface means lower prices in western control zones and higher prices in eastern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment).

14 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

16 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

Total congestion costs in PJM in 2013 were $676.9 million, which was comprised of load congestion payments of $287.1 million, generation credits of -$461.3 million and explicit congestion of -$71.5 million (Table 11-6.)

Total Congestion

Table 11-6 shows total congestion by year from 2008 through 2013.

Table 11-6 Total PJM congestion (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,051.8	NA	$34,306	6.0%
2009	$719.0	(65.0%)	$26,550	2.7%
2010	$1,423.3	98.0%	$34,771	4.1%
2011	$999.0	(29.8%)	$35,887	2.8%
2012	$529.0	(47.0%)	$29,181	1.8%
2013	$676.9	28.0%	$33,862	2.0%

Total congestion costs in Table 11-7 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[17, 18]

Table 11-7 shows the congestion costs by category for 2013. The 2013 PJM total congestion costs were comprised of $287.1 million in load congestion payments, -$461.3 million in generation congestion credits, and -$71.5 million in explicit congestion costs.

Table 11-7 Total PJM congestion costs by accounting category (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$1,034.4	($1,053.9)	($36.5)	$0.0	$2,051.8
2009	$253.3	($515.1)	($49.4)	$0.0	$719.0
2010	$338.9	($1,167.0)	($82.6)	($0.0)	$1,423.3
2011	$454.0	($668.1)	($123.1)	$0.0	$999.0
2012	$115.1	($467.4)	($53.5)	$0.0	$529.0
2013	$287.1	($461.3)	($71.5)	$0.0	$676.9

Table 11-8 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 to 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9

17 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed April 17, 2013).

18 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Monthly Congestion

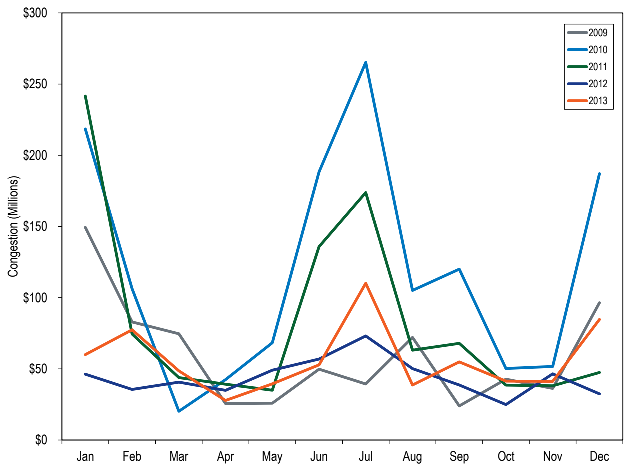
Table 11-9 shows that monthly total congestion costs ranged from $27.8 million to $110.1 million in 2013. Table 11-9 shows that monthly congestion costs in 2013 were higher than in 2012.

Table 11-9 Monthly PJM congestion costs by market (Dollars (Millions)): 2012 to 2013

	Congestion Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.3	($20.0)	$0.0	$46.3	$136.8	($76.8)	$0.0	$60.0
Feb	$54.8	($19.2)	$0.0	$35.5	$125.1	($47.7)	$0.0	$77.4
Mar	$59.8	($19.1)	$0.0	$40.7	$69.9	($21.4)	($0.0)	$48.5
Apr	$72.0	($37.1)	$0.0	$34.9	$37.7	($9.9)	$0.0	$27.8
May	$67.2	($18.2)	($0.0)	$49.1	$75.3	($35.8)	($0.0)	$39.5
Jun	$69.6	($12.7)	($0.0)	$56.8	$82.2	($29.4)	($0.0)	$52.8
Jul	$91.0	($17.9)	$0.0	$73.1	$131.3	($21.3)	$0.0	$110.1
Aug	$60.8	($10.6)	$0.0	$50.2	$46.0	($7.3)	$0.0	$38.6
Sep	$61.8	($23.1)	($0.0)	$38.7	$97.0	($42.1)	$0.0	$54.9
Oct	$54.4	($29.6)	$0.0	$24.9	$54.6	($13.3)	($0.0)	$41.4
Nov	$66.4	($19.9)	$0.0	$46.5	$59.3	($18.1)	($0.0)	$41.2
Dec	$55.8	($23.4)	$0.0	$32.4	$95.9	($11.2)	$0.0	$84.7
Total	$779.9	($250.9)	$0.0	$529.0	$1,011.3	($334.4)	$0.0	$676.9

Figure 11-1 shows PJM monthly total congestion cost for 2009 through 2013.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 to 2013



Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In 2013, there were 359,432 day-ahead, congestion-event hours compared to 249,572 day-ahead, congestion-event hours in 2012. In 2013, there were 19,321 real-time, congestion-event hours compared to 20,921 real-time, congestion-event hours in 2012.

During 2013, for only 2.0 percent of day-ahead energy market facility constrained hours were the same facilities also constrained in the Real-Time Energy Market. During 2013, for 38.1 percent of real-time energy market facility constrained hours, the same facilities were also constrained in the Day-Ahead Energy Market.

The AP South Interface was the largest contributor to congestion costs in 2013. With $169.1 million in total congestion costs, it accounted for 33.2 percent of the total PJM congestion costs in 2013. The top five constraints in terms of congestion costs together contributed $223.7 million, or 44.0 percent, of the total PJM congestion costs in 2013. The top five constraints were the AP South Interface, the West Interface, the ATSI Interface, and the Bridgewater – Middlesex line, and the Bedington - Black Oak flowgate.

Congestion by Facility Type and Voltage

In 2013, compared to 2012, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours decreased on all types of facilities except internal PJM interfaces.

Day-ahead congestion costs decreased on the flowgates in 2013 compared to 2012 and increased on PJM interfaces, transmission lines and transformers in 2013 compared to the 2012. Balancing congestion costs increased on flowgates, transmission lines and interfaces and decreased on transformers in 2013 compared to 2012.

Table 11-10 provides congestion-event hour subtotals and congestion cost subtotals comparing 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19, 20] For comparison, this information is presented in Table 11-11 for 2012.[21]

Table 11-12 and Table 11-13 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-12. In 2013, there were 359,432 congestion event hours in the Day-Ahead Energy Market. Among those day-ahead congestion event hours, only 7,240 (2.0 percent) were also constrained in the Real-Time Energy Market. In 2012, among the 249,572 day-ahead congestion event hours, only 8,118 (3.3 percent) were binding in the Real-Time Energy Market.[22]

Table 11-10 Congestion summary (By facility type): 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing				Event Hours		
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($52.2)	($187.5)	$20.0	$155.3	$0.9	$12.3	($40.1)	($51.4)	$103.9	34,549	5,707
Interface	$180.7	($95.3)	$15.7	$291.6	$23.6	$36.6	($36.1)	($49.1)	$242.5	15,625	1,745
Line	$87.9	($262.2)	$62.2	$412.3	($21.4)	$68.9	($107.0)	($197.2)	$215.1	198,392	10,025
Other	$9.8	($0.8)	$6.6	$17.1	($0.3)	$0.2	($3.8)	($4.3)	$12.8	10,821	161
Transformer	$29.0	($63.5)	$25.5	$118.0	$2.4	$11.1	($23.2)	($31.8)	$86.2	100,045	1,683
Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.5)	$16.4	NA	NA
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$676.9	359,432	19,321

Table 11-11 Congestion summary (By facility type): 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing				Event Hours		
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($60.2)	($189.7)	$39.2	$168.7	($5.8)	$10.1	($81.4)	($97.3)	$71.4	28,330	7,755
Interface	$70.8	($68.8)	$2.9	$142.5	$14.6	$21.6	($3.6)	($10.6)	$131.9	7,005	737
Line	$78.1	($193.9)	$63.3	$335.3	($9.1)	$31.8	($82.9)	($123.8)	$211.5	146,041	10,174
Other	$9.6	($4.3)	$2.1	$15.9	($0.6)	$0.0	($0.9)	($1.6)	$14.4	7,977	431
Transformer	$31.2	($54.6)	$22.6	$108.3	$4.4	$3.8	($15.5)	($14.9)	$93.5	60,219	1,824
Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	NA	NA
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0	249,572	20,921

19 Unclassified are congestion costs related to non-transmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Non-transmission facility constraints include Day-Ahead Market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

20 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

21 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

22 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Among the hours for which a facility is constrained in the Real-Time Energy Market, the number of hours during which the facility is also constrained in the Day-Ahead Energy Market are presented in Table 11-13. In 2013, there were 19,321 congestion event hours in the Real-Time Energy Market. Among these real-time congestion event hours, 7,360 (38.1 percent) were also constrained in the Day-Ahead Energy Market. In 2012, among the 20,921 real-time congestion event hours, only 8,031 (38.4 percent) were also in the Day-Ahead Energy Market.

Table 11-12 Congestion event hours (Day-Ahead against Real-Time): 2012 to 2013

	Congestion Event Hours					
	2012			2013		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	28,330	3,239	11.4%	34,549	2,177	6.3%
Interface	7,005	369	5.3%	15,625	1,228	7.9%
Line	146,041	3,516	2.4%	198,392	3,093	1.6%
Other	7,977	265	3.3%	10,821	168	1.6%
Transformer	60,219	729	1.2%	100,045	574	0.6%
Total	249,572	8,118	3.3%	359,432	7,240	2.0%

Table 11-13 Congestion event hours (Real-Time against Day-Ahead): 2012 to 2013

	Congestion Event Hours					
	2012			2013		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	7,755	3,320	42.8%	5,707	2,314	40.5%
Interface	737	395	53.6%	1,745	1,329	76.2%
Line	10,174	3,402	33.4%	10,025	3,044	30.4%
Other	431	229	53.1%	161	106	65.8%
Transformer	1,824	685	37.6%	1,683	567	33.7%
Total	20,921	8,031	38.4%	19,321	7,360	38.1%

Table 11-14 shows congestion costs by facility voltage class for 2013. In comparison to 2012 (shown in Table 11-15), congestion costs decreased for facilities rated at 138 kV, and 115 kV 2013.

Table 11-14 Congestion summary (By facility voltage): 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$4.6	($17.0)	$8.5	$30.1	($0.2)	$0.5	$0.7	$0.1	$30.2	10,457	22
500	$177.8	($106.3)	$19.1	$303.1	$29.0	$39.7	($49.3)	($60.0)	$243.1	20,509	2,144
345	($41.7)	($163.7)	$18.5	$140.5	$0.0	$14.8	($49.9)	($64.7)	$75.7	59,043	3,933
230	$83.6	($147.6)	$39.7	$270.8	($2.9)	$52.1	($53.4)	($108.4)	$162.4	58,887	3,629
161	($9.9)	($20.5)	($0.8)	$9.8	($1.3)	$0.7	($3.7)	($5.6)	$4.2	3,552	1,075
138	($15.2)	($160.4)	$40.1	$185.3	($7.3)	$16.6	($48.8)	($72.7)	$112.6	158,834	6,398
123	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
115	$24.3	$0.9	$3.9	$27.3	($5.2)	($0.3)	($5.3)	($10.2)	$17.1	21,349	1,348
69	$26.2	$3.0	$0.1	$23.3	($7.0)	$4.8	($0.4)	($12.2)	$11.0	18,842	743
34	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	7,401	29
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.5)	$16.4	9,999	9,999
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$676.9	369,431	29,320

Table 11-15 Congestion summary (By facility voltage): 2012

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.2)	($3.4)	$3.2	$6.5	$0.2	($0.1)	($0.1)	$0.1	$6.6	3,412	89
500	$75.3	($79.3)	$5.2	$159.9	$19.7	$25.8	($8.4)	($14.6)	$145.3	12,025	1,129
345	($41.6)	($135.0)	$23.7	$117.1	$1.6	$7.8	($35.7)	($41.9)	$75.2	34,038	3,628
230	$67.2	($72.4)	$19.8	$159.3	$4.8	$11.0	($38.7)	($44.9)	$114.5	35,443	4,052
161	($14.3)	($23.3)	$3.8	$12.7	($1.5)	$1.9	($10.2)	($13.6)	($0.9)	3,622	1,407
138	($9.1)	($202.2)	$69.7	$262.9	($9.0)	$15.5	($89.6)	($114.1)	$148.8	130,402	8,660
115	$24.1	($1.5)	$3.6	$29.2	($0.5)	$2.1	($1.4)	($4.0)	$25.2	18,614	901
69	$28.0	$5.9	$1.1	$23.1	($11.8)	$3.3	($0.1)	($15.3)	$7.9	10,531	1,053
34	$0.0	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.1	1,470	2
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	NA	NA
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$529.0	249,572	20,921

Constraint Duration

Table 11-16 lists the constraints in 2012 and 2013 that were most frequently in effect and Table 11-17 shows the constraints which experienced the largest change in congestion-event hours from 2012 to 2013.

Table 11-16 Top 25 constraints with frequent occurrence: 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	18,619	8,676	(9,943)	0	0	0	213%	99%	(114%)	0%	0%	0%
2	Braidwood	Transformer	0	8,252	8,252	0	0	0	0%	94%	94%	0%	0%	0%
3	AP South	Interface	2,586	6,330	3,744	351	1,138	787	30%	72%	43%	4%	13%	9%
4	Gould Street - Westport	Line	1,470	7,401	5,931	2	21	19	17%	84%	67%	0%	0%	0%
5	Sunbury	Transformer	0	6,866	6,866	0	0	0	0%	78%	78%	0%	0%	0%
6	Tanners Creek	Transformer	1,911	6,846	4,935	0	0	0	22%	78%	56%	0%	0%	0%
7	Nelson - Cordova	Line	2,643	5,764	3,121	288	244	(44)	30%	66%	35%	3%	3%	(1%)
8	Howard - Shelby	Line	2,460	5,489	3,029	0	0	0	28%	62%	34%	0%	0%	0%
9	Clinch River	Transformer	0	5,168	5,168	0	0	0	0%	59%	59%	0%	0%	0%
10	Readington - Roseland	Line	1,083	4,177	3,094	95	817	722	12%	48%	35%	1%	9%	8%
11	West Moulton-City Of St. Marys	Line	1,099	4,176	3,077	0	0	0	13%	48%	35%	0%	0%	0%
12	Oak Grove - Galesburg	Flowgate	3,622	3,177	(445)	1,359	888	(471)	41%	36%	(5%)	16%	10%	(5%)
13	Mardela - Vienna	Line	206	3,747	3,541	126	213	87	2%	43%	40%	1%	2%	1%
14	Rockport Works	Transformer	595	3,921	3,326	0	0	0	7%	45%	38%	0%	0%	0%
15	Haurd - Steward	Line	1,708	3,588	1,880	1	0	(1)	19%	41%	21%	0%	0%	(0%)
16	Hunlock Creek - A.G.A. Gas	Line	256	3,578	3,322	0	0	0	3%	41%	38%	0%	0%	0%
17	Michigan City - Laporte	Flowgate	873	3,382	2,509	40	0	(40)	10%	39%	29%	0%	0%	(0%)
18	Rocky Mount - Battleboro	Line	105	2,945	2,840	0	430	430	1%	34%	32%	0%	5%	5%
19	Bridgewater - Middlesex	Line	847	3,046	2,199	31	257	226	10%	35%	25%	0%	3%	3%
20	South Cadiz	Transformer	1,578	3,283	1,705	0	0	0	18%	37%	19%	0%	0%	0%
21	Eldred - Sunbury	Line	0	3,035	3,035	0	0	0	0%	35%	35%	0%	0%	0%
22	Zion	Line	325	3,018	2,693	0	0	0	4%	34%	31%	0%	0%	0%
23	Huntingdon - Huntingdon1	Line	3,421	3,011	(410)	0	0	0	39%	34%	(5%)	0%	0%	0%
24	Breed - Wheatland	Flowgate	2,821	2,344	(477)	428	658	230	32%	27%	(6%)	5%	7%	3%
25	Danville - East Danville	Line	2,234	2,982	748	14	13	(1)	26%	34%	8%	0%	0%	(0%)

Table 11-17 Top 25 constraints with largest year-to-year change in occurrence: 2012 and 2013

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	18,619	8,676	(9,943)	0	0	0	213%	99%	(114%)	0%	0%	0%
2	Braidwood	Transformer	0	8,252	8,252	0	0	0	0%	94%	94%	0%	0%	0%
3	Sunbury	Transformer	0	6,866	6,866	0	0	0	0%	78%	78%	0%	0%	0%
4	Gould Street - Westport	Line	1,470	7,401	5,931	2	21	19	17%	84%	67%	0%	0%	0%
5	Clinch River	Transformer	0	5,168	5,168	0	0	0	0%	59%	59%	0%	0%	0%
6	Tanners Creek	Transformer	1,911	6,846	4,935	0	0	0	22%	78%	56%	0%	0%	0%
7	AP South	Interface	2,586	6,330	3,744	351	1,138	787	30%	72%	43%	4%	13%	9%
8	Readington - Roseland	Line	1,083	4,177	3,094	95	817	722	12%	48%	35%	1%	9%	8%
9	Mardela - Vienna	Line	206	3,747	3,541	126	213	87	2%	43%	40%	1%	2%	1%
10	Graceton - Raphael Road	Line	2,664	0	(2,664)	723	0	(723)	30%	0%	(30%)	8%	0%	(8%)
11	Rockport Works	Transformer	595	3,921	3,326	0	0	0	7%	45%	38%	0%	0%	0%
12	Hunlock Creek - A.G.A. Gas	Line	256	3,578	3,322	0	0	0	3%	41%	38%	0%	0%	0%
13	Rocky Mount - Battleboro	Line	105	2,945	2,840	0	430	430	1%	34%	32%	0%	5%	5%
14	Nelson - Cordova	Line	2,643	5,764	3,121	288	244	(44)	30%	66%	35%	3%	3%	(1%)
15	West Moulton-City Of St. Marys	Line	1,099	4,176	3,077	0	0	0	13%	48%	35%	0%	0%	0%
16	Eldred - Sunbury	Line	0	3,035	3,035	0	0	0	0%	35%	35%	0%	0%	0%
17	Howard - Shelby	Line	2,460	5,489	3,029	0	0	0	28%	62%	34%	0%	0%	0%
18	Bayway - Federal Square	Line	3,034	155	(2,879)	48	0	(48)	35%	2%	(33%)	1%	0%	(1%)
19	Zion	Line	325	3,018	2,693	0	0	0	4%	34%	31%	0%	0%	0%
20	Electric Junction - Frontenac	Line	0	2,540	2,540	0	0	0	0%	29%	29%	0%	0%	0%
21	Bagley - Graceton	Line	0	2,087	2,087	0	440	440	0%	24%	24%	0%	5%	5%
22	Bellefonte - Grangston	Line	2,603	127	(2,476)	0	0	0	30%	1%	(28%)	0%	0%	0%
23	Michigan City - Laporte	Flowgate	873	3,382	2,509	40	0	(40)	10%	39%	29%	0%	0%	(0%)
24	Bridgewater - Middlesex	Line	847	3,046	2,199	31	257	226	10%	35%	25%	0%	3%	3%
25	Big Sandy - Grangston	Line	3,066	651	(2,415)	0	0	0	35%	7%	(28%)	0%	0%	0%

Constraint Costs

Table 11-18 and Table 11-19 present the top constraints affecting congestion costs by facility for the periods 2013 and 2012.

Table 11-18 Top 25 constraints affecting PJM congestion costs (By facility): 2013

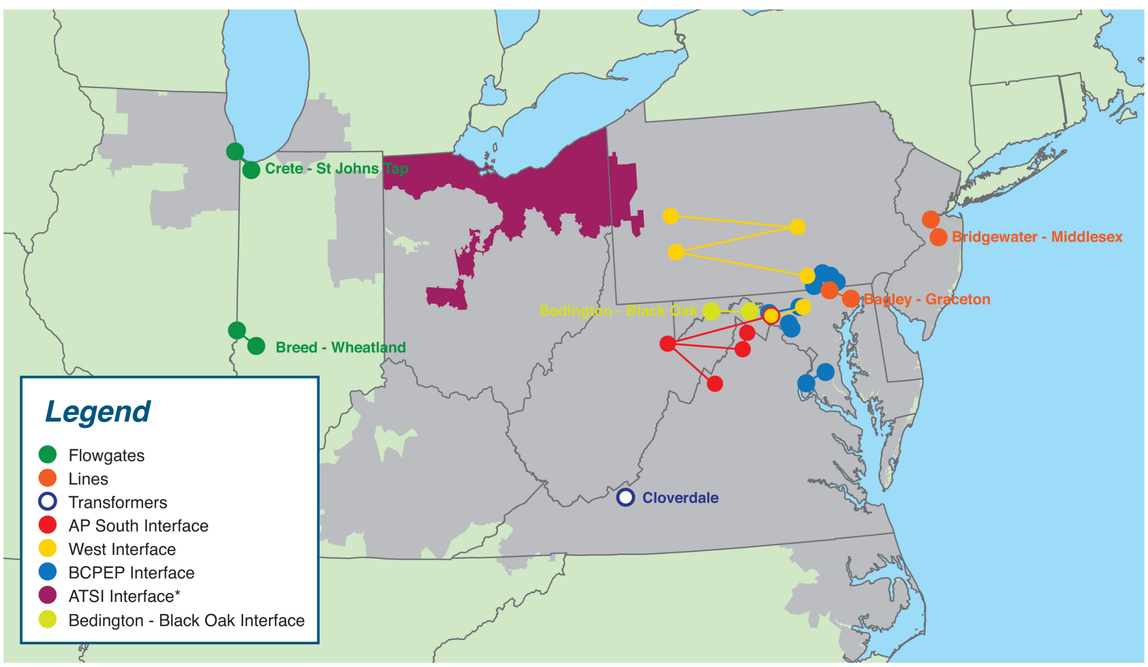
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013
1	AP South	Interface	500	$139.8	($32.8)	$13.2	$185.8	$8.2	$15.5	($9.3)	($16.7)	$169.1	25.0%
2	West	Interface	500	$4.7	($27.9)	($0.6)	$32.0	$3.0	$3.3	($1.1)	($1.4)	$30.7	4.5%
3	Bridgewater - Middlesex	Line	PSEG	$0.4	($26.9)	$2.7	$30.0	$2.2	$4.9	($2.2)	($5.0)	$25.0	3.7%
4	ATSI	Interface	ATSI	$0.0	$0.0	$0.0	$0.0	$10.2	$9.0	($24.7)	($23.5)	($23.5)	(3.5%)
5	Bedington - Black Oak	Interface	500	$16.4	($8.1)	$0.6	$25.0	$0.1	$2.2	($0.4)	($2.6)	$22.4	3.3%
6	Breed - Wheatland	Flowgate	MISO	($5.5)	($27.6)	$0.9	$22.9	$0.3	($0.4)	($3.9)	($3.1)	$19.8	2.9%
7	BCPEP	Interface	Pepco	$15.8	($3.2)	$1.8	$20.9	$0.2	$1.9	$0.6	($1.2)	$19.7	2.9%
8	Bagley - Graceton	Line	BGE	$15.8	($2.1)	$2.3	$20.1	$0.4	($0.9)	($2.1)	($0.8)	$19.3	2.9%
9	Cloverdale	Transformer	AEP	$8.3	($3.9)	$4.9	$17.1	$0.0	$0.0	$0.0	$0.0	$17.1	2.5%
10	Unclassified	Unclassified	Unclassified	$26.0	$16.8	$7.6	$16.9	$0.7	$2.3	$1.1	($0.5)	$16.4	2.4%
11	Crete - St Johns Tap	Flowgate	MISO	($3.2)	($13.7)	$4.6	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	2.2%
12	Monticello - East Winamac	Flowgate	MISO	($2.5)	($27.8)	$4.2	$29.5	$0.3	$5.4	($11.4)	($16.6)	$12.9	1.9%
13	Laporte - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.7)	$1.3	($4.9)	($12.9)	($12.9)	(1.9%)
14	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.1)	$5.2	($6.9)	($12.2)	($12.2)	(1.8%)
15	Braidwood	Transformer	ComEd	($0.2)	($9.9)	$1.7	$11.4	$0.0	$0.0	$0.0	$0.0	$11.4	1.7%
16	5004/5005 Interface	Interface	500	$0.9	($12.4)	($0.5)	$12.8	$1.6	$4.5	$0.5	($2.3)	$10.5	1.6%
17	Byron - Cherry Valley	Flowgate	MISO	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	1.5%
18	Benton Harbor - Palisades	Flowgate	MISO	($1.8)	($12.1)	$2.2	$12.5	($0.1)	$0.8	($2.0)	($2.8)	$9.7	1.4%
19	Conastone - Graceton	Line	BGE	$5.6	($2.1)	$1.7	$9.4	($0.0)	($0.1)	($0.2)	($0.2)	$9.2	1.4%
20	South Canton	Transformer	AEP	($3.5)	($11.4)	$1.2	$9.1	($0.2)	$0.5	$0.8	$0.1	$9.1	1.3%
21	AEP - DOM	Interface	500	$4.9	($4.1)	$1.8	$10.8	$0.1	$0.4	($1.5)	($1.8)	$9.0	1.3%
22	Wescosville	Transformer	PPL	$3.2	($7.3)	$1.3	$11.7	$1.1	$1.7	($2.1)	($2.8)	$9.0	1.3%
23	Nelson - Cordova	Line	ComEd	($19.7)	($38.2)	$1.4	$19.9	($1.1)	$0.6	($9.4)	($11.1)	$8.8	1.3%
24	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	1.3%
25	Byron - Cherry Valley	Line	ComEd	$0.0	($0.2)	$0.1	$0.3	($1.2)	$2.5	($5.0)	($8.7)	($8.4)	(1.2%)

Table 11-19 Top 25 constraints affecting PJM congestion costs (By facility): 2012

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012
1	AP South	Interface	500	$48.3	($20.0)	$2.2	$70.5	$8.3	$7.6	($2.7)	($2.1)	$68.5	12.9%
2	Graceton - Raphael Road	Line	BGE	$26.5	($7.7)	($1.1)	$33.1	$1.0	($1.2)	($0.3)	$1.9	$35.0	6.6%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	5.7%
4	West	Interface	500	$2.5	($24.7)	($0.5)	$26.7	$1.6	$4.0	$0.1	($2.3)	$24.4	4.6%
5	Bedington - Black Oak	Interface	500	$13.6	($6.0)	$0.4	$20.0	$1.0	$1.1	($0.7)	($0.8)	$19.1	3.6%
6	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.8	($8.5)	($8.3)	$15.2	2.9%
7	Belvidere - Woodstock	Line	ComEd	($0.9)	($8.5)	$0.2	$7.7	($2.4)	$3.3	($16.3)	($22.0)	($14.3)	(2.7%)
8	Monticello - East Winamac	Flowgate	MISO	($0.2)	($19.6)	$11.5	$31.0	$0.4	$1.9	($15.5)	($17.0)	$14.0	2.6%
9	Nelson - Cordova	Line	ComEd	($19.3)	($34.3)	$6.9	$21.9	($0.9)	$1.7	($7.9)	($10.5)	$11.3	2.1%
10	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.3	$0.6	$0.9	$0.2	($0.1)	$10.2	1.9%
11	AEP - DOM	Interface	500	$8.3	($3.9)	$0.7	$12.9	$1.0	$4.2	($0.4)	($3.6)	$9.3	1.8%
12	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	1.7%
13	Rantoul - Rantoul Jct	Flowgate	MISO	($7.3)	($13.0)	$4.3	$10.0	($0.2)	($0.1)	($1.7)	($1.9)	$8.2	1.5%
14	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.9	$0.1	$0.0	($0.0)	$0.0	$7.9	1.5%
15	Crete - St Johns Tap	Flowgate	MISO	($5.6)	($19.2)	$0.1	$13.8	$0.3	$0.9	($5.7)	($6.3)	$7.5	1.4%
16	Pleasant Valley - Belvidere	Line	ComEd	($2.3)	($8.5)	$1.6	$7.8	$0.1	$0.1	($0.8)	($0.7)	$7.1	1.3%
17	Prairie State - W Mt. Vernon	Flowgate	MISO	($4.8)	($10.7)	$1.9	$7.7	($0.0)	($0.0)	($0.7)	($0.7)	$7.0	1.3%
18	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.2)	$7.0	($0.2)	$0.1	$0.2	($0.0)	$7.0	1.3%
19	Sporn	Transformer	AEP	($0.1)	($0.6)	$6.0	$6.5	$0.0	$0.0	$0.0	$0.0	$6.5	1.2%
20	Harwood - Susquehanna	Line	PPL	$0.7	($5.4)	$0.3	$6.4	$0.1	$0.1	$0.1	$0.1	$6.5	1.2%
21	Unclassified	Unclassified	Unclassified	$6.2	($1.2)	$1.7	$9.1	($0.5)	$1.2	($1.2)	($2.8)	$6.3	1.2%
22	Leonia - New Milford	Line	PSEG	$1.5	$1.8	$2.7	$2.4	($0.4)	$0.4	($7.2)	($7.9)	($5.6)	(1.0%)
23	Breed - Wheatland	Flowgate	MISO	($2.8)	($17.9)	$0.5	$15.6	$0.4	$0.3	($10.1)	($10.1)	$5.5	1.0%
24	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1.0%
25	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.0%

Figure 11-2 shows the locations of the top 10 constraints affecting PJM congestion costs in 2013.

Figure 11-2 Location of the top 10 constraints affecting PJM congestion costs: 2013[23]



* ATSI is comprised of all tie lines into the ATSI transmission zone.

23 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

Congestion-Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[24] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[25] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2013, PJM had 159 flowgates eligible for M2M (Market to Market) coordination and MISO had 265 flowgates eligible for M2M coordination.

Table 11-20 and Table 11-21 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2013 and 2012, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in 2013, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Beaver Channel - Albany flowgate made the most significant contribution to negative congestion.

Table 11-20 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2013

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($5.5)	($27.6)	$0.9	$22.9	$0.3	($0.4)	($3.9)	($3.1)	$19.8	2,344	658
2	Crete - St Johns Tap	($3.2)	($13.7)	$4.6	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	1,943	0
3	Monticello - East Winamac	($2.5)	($27.8)	$4.2	$29.5	$0.3	$5.4	($11.4)	($16.6)	$12.9	2,041	554
4	Byron - Cherry Valley	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	72	0
5	Benton Harbor - Palisades	($1.8)	($12.1)	$2.2	$12.5	($0.1)	$0.8	($2.0)	($2.8)	$9.7	2,495	114
6	Michigan City - Laporte	($7.8)	($13.8)	$2.2	$8.2	$0.0	$0.0	$0.0	$0.0	$8.2	3,382	0
7	Oak Grove - Galesburg	($8.5)	($16.7)	($0.4)	$7.9	($0.5)	$0.6	($0.5)	($1.6)	$6.3	3,177	888
8	Cumberland - Bush	($1.2)	($8.6)	$1.2	$8.6	$0.7	$1.7	($3.3)	($4.3)	$4.3	2,465	213
9	Edwards - Kewanee	($3.3)	($5.5)	$2.1	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	2,672	12
10	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.1	($3.2)	($4.1)	($4.1)	0	106
11	Rocky - Battlebo	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
12	Rantoul - Rantoul Jct	($4.0)	($6.3)	$1.4	$3.8	$0.0	$0.0	$0.0	$0.0	$3.8	1,722	0
13	Prairie State - W Mt. Vernon	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1,021	836
14	Miami Fort	($0.9)	($3.7)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,098	0
15	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
16	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.7	($0.9)	($2.1)	($2.1)	0	222
17	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
18	Hegew	($0.3)	($1.9)	$0.3	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	225	0
19	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	82	161
20	Pleasant Prairie - Zion	($0.5)	($1.7)	$0.8	$1.9	($0.0)	($0.0)	($0.5)	($0.5)	$1.4	1,010	76

24 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

25 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 11-21 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2012

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	1,073	0
2	Monticello - East Winamac	($0.2)	($19.6)	$11.5	$31.0	$0.4	$1.9	($15.5)	($17.0)	$14.0	2,734	578
3	Rantoul - Rantoul Jct	($7.3)	($13.0)	$4.3	$10.0	($0.2)	($0.1)	($1.7)	($1.9)	$8.2	2,036	315
4	Crete - St Johns Tap	($5.6)	($19.2)	$0.1	$13.8	$0.3	$0.9	($5.7)	($6.3)	$7.5	2,377	277
5	Prairie State - W Mt. Vernon	($4.8)	($10.7)	$1.9	$7.7	($0.0)	($0.0)	($0.7)	($0.7)	$7.0	1,483	1,015
6	Breed - Wheatland	($2.8)	($17.9)	$0.5	$15.6	$0.4	$0.3	($10.1)	($10.1)	$5.5	2,821	428
7	Rising	($3.1)	($3.2)	$2.3	$2.4	($1.2)	$0.8	($5.4)	($7.4)	($5.0)	408	363
8	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	$0.1	$0.4	($4.0)	($4.3)	($4.3)	0	331
9	Benton Harbor - Palisades	($0.6)	($5.5)	($0.8)	$4.1	$0.1	$0.3	($0.2)	($0.4)	$3.8	840	71
10	Miami Fort - Hebron	($1.8)	($5.7)	($0.2)	$3.7	($0.1)	($0.0)	$0.1	$0.0	$3.7	1,053	76
11	Palisades - Roosevelt	($0.9)	($5.6)	($0.6)	$4.1	$0.1	$0.3	($0.2)	($0.4)	$3.7	855	209
12	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($11.1)	($11.8)	($1.3)	2,053	316
13	Brokaw	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($1.1)	($1.2)	($1.2)	0	81
14	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.2	($0.2)	($1.1)	($1.1)	0	36
15	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.2	$0.0	($0.1)	($0.3)	($0.2)	$1.0	314	68
16	Michigan City - Maple	($1.0)	($0.7)	$0.5	$0.2	($0.4)	($0.1)	($0.8)	($1.1)	($0.9)	73	51
17	Beaver Channel - Albany	($6.0)	($17.0)	($0.1)	$11.0	($4.8)	($0.4)	($5.7)	($10.2)	$0.8	1,256	460
18	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.8)	($0.8)	0	20
19	Dune Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	61
20	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	74

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[26]

Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[27]

Table 11-22 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2013, and which had the greatest congestion cost impact on PJM.

Table 11-22 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central East	Flowgate	NYISO	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	167
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.2)	($0.2)	0	31

26 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

27 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-23 and Table 11-24 show the 500 kV constraints impacting congestion costs in PJM for 2013 and 2012. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 11-23 Regional constraints summary (By facility): 2013

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$139.8	($32.8)	$13.2	$185.8	$8.2	$15.5	($9.3)	($16.7)	$169.1	6,330	1,138
2	West	Interface	500	$4.7	($27.9)	($0.6)	$32.0	$3.0	$3.3	($1.1)	($1.4)	$30.7	1,845	95
3	Bedington - Black Oak	Interface	500	$16.4	($8.1)	$0.6	$25.0	$0.1	$2.2	($0.4)	($2.6)	$22.4	2,148	164
4	5004/5005 Interface	Interface	500	$0.9	($12.4)	($0.5)	$12.8	$1.6	$4.5	$0.5	($2.3)	$10.5	562	196
5	AEP - DOM	Interface	500	$4.9	($4.1)	$1.8	$10.8	$0.1	$0.4	($1.5)	($1.8)	$9.0	2,746	38
6	Conemaugh - Hunterstown	Line	500	$0.4	($2.6)	$0.3	$3.4	$0.5	$0.7	($0.7)	($0.9)	$2.5	153	68
7	East	Interface	500	($0.9)	($3.3)	($0.1)	$2.2	$0.0	$0.0	$0.0	($0.0)	$2.2	504	13
8	Central	Interface	500	($0.9)	($3.5)	($0.5)	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	195	0
9	Juniata	Transformer	500	$0.2	($0.6)	$0.3	$1.1	$0.4	$0.1	($0.4)	($0.1)	$1.0	376	7
10	Nagel - Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
11	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	6

Table 11-24 Regional constraints summary (By facility): 2012

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$48.3	($20.0)	$2.2	$70.5	$8.3	$7.6	($2.7)	($2.1)	$68.5	2,586	351
2	West	Interface	500	$2.5	($24.7)	($0.5)	$26.7	$1.6	$4.0	$0.1	($2.3)	$24.4	841	130
3	Bedington - Black Oak	Interface	500	$13.6	($6.0)	$0.4	$20.0	$1.0	$1.1	($0.7)	($0.8)	$19.1	780	54
4	AEP - DOM	Interface	500	$8.3	($3.9)	$0.7	$12.9	$1.0	$4.2	($0.4)	($3.6)	$9.3	2,095	61
5	East	Interface	500	($2.6)	($8.1)	($0.6)	$4.8	$0.1	$0.5	($0.1)	($0.5)	$4.4	209	5
6	5004/5005 Interface	Interface	500	$0.2	($4.1)	$0.5	$4.8	$2.5	$3.5	$0.3	($0.6)	$4.2	191	128
7	Conemaugh - Hunterstown	Line	500	$0.4	($1.3)	$0.1	$1.7	$0.1	$2.0	($1.9)	($3.9)	($2.1)	38	117
8	Juniata	Transformer	500	$0.4	($0.6)	$0.3	$1.3	$0.2	$0.0	($0.2)	($0.1)	$1.2	299	38
9	Central	Interface	500	($0.9)	($1.6)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	214	2
10	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
11	Nagel	Line	500	$0.3	($0.0)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	128	0
12	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1	12	19

Table 11-25 Congestion cost by type of participant: 2013

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$50.2	$45.7	$84.6	$89.1	($34.1)	$1.5	($156.4)	($192.0)	$0.0	($102.8)
Physical	$230.9	($638.2)	$53.0	$922.1	$40.0	$129.8	($52.6)	($142.4)	$0.0	$779.7
Total	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9

Table 11-26 Congestion cost by type of participant: 2012

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	($1.6)	$8.6	$92.0	$81.8	($24.9)	($1.2)	($141.1)	($164.8)	$0.0	($83.0)
Physical	$137.1	($521.0)	$39.9	$698.1	$27.9	$69.7	($44.3)	($86.0)	$0.0	$612.0
Total	$135.5	($512.5)	$131.9	$779.9	$3.0	$68.5	($185.4)	($250.9)	$0.0	$529.0

In 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2013, financial companies received $102.8 million, an increase of $19.8 million or 23.9 percent compared to 2012. In 2013, physical companies paid $779.7 million in congestion charges, an increase of $167.7 million or 27.4 percent compared to 2012.

Marginal Losses

On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[28] The primary benefit of a marginal loss calculation is that it more accurately reflects the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. There is a separate marginal loss price for every location on the power grid. This marginal loss component of LMP (MLMP) is a component of LMP.

Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[29] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to load on a load ratio share basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load

28 OATT. Attachment K-Appendix (Market Operations) §3.4.
29 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments, that is paid back in full to load and exports on a load ratio basis. Payment to load is appropriate as load is the source of the surplus.

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system.

Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the Balancing Energy Market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

- **Day-Ahead Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus loss MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MWs and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[30]

The total marginal loss cost in PJM for 2013 was $1,035.3 million, which was comprised of load loss

30 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

payments of -$4.1 million, generation loss credits of -$1,083.3 million, explicit loss costs of -$43.9 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in 2013 ranged from $66.2 million in April to $142.1 million in July. Marginal loss credits decreased in 2013 by $55.8 million or 14.4 percent from 2012, from $386.7 million to $330.9 million.

Total Marginal Loss Costs

Table 11-27 shows the total marginal loss component costs for 2009 through 2013. Given that these results are based on system average marginal losses including offsetting marginal loss components, low total marginal loss component costs are expected.

Table 11-27 Total PJM costs by loss component (Dollars (Millions)): 2009 through 2013[31]

Year	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$1,268	NA	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,862	3.1%

Total marginal loss costs for 2009 through 2013 are shown in Table 11-28 and Table 11-29. Table 11-28 shows PJM total marginal loss costs by accounting category for 2009 through 2013. Table 11-29 shows PJM total marginal loss costs by accounting category by market for 2009 through 2013.

Table 11-28 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2009 through 2013

	Marginal Loss Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($77.8)	($1,313.6)	$32.0	($0.0)	$1,267.7
2010	($118.9)	($1,703.6)	$50.4	($0.0)	$1,635.0
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3

Table 11-29 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2009 through 2013

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.9	($2.0)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$27.4	$12.5	($45.4)	($30.6)	($0.0)	$1,635.0
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.7	$33.0	$29.1	($106.3)	($102.4)	($0.0)	$1,035.3

31 The loss costs include net inadvertent charges.

Monthly Marginal Loss Costs

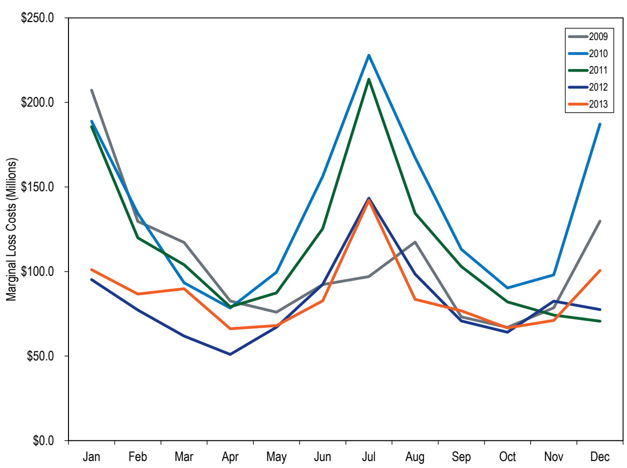
Table 11-30 shows a monthly summary of marginal loss costs by market type for 2012 and 2013.

Table 11-30 Monthly marginal loss costs by market (Dollars (Millions)): 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$100.6	($5.4)	$0.0	$95.2	$105.8	($4.7)	$0.0	$101.1
Feb	$80.4	($3.1)	$0.0	$77.2	$93.2	($6.5)	($0.0)	$86.7
Mar	$67.1	($5.2)	$0.0	$61.9	$97.2	($7.4)	($0.0)	$89.8
Apr	$55.4	($4.4)	$0.0	$51.0	$77.7	($11.5)	($0.0)	$66.2
May	$69.6	($2.5)	($0.0)	$67.1	$80.5	($12.4)	($0.0)	$68.1
Jun	$93.3	($0.8)	$0.0	$92.5	$91.7	($9.0)	($0.0)	$82.7
Jul	$141.8	$1.6	$0.0	$143.4	$149.2	($7.1)	($0.0)	$142.1
Aug	$96.1	$2.4	$0.0	$98.5	$91.3	($7.8)	($0.0)	$83.6
Sep	$71.7	($0.9)	($0.0)	$70.8	$85.0	($8.2)	($0.0)	$76.8
Oct	$65.9	($1.8)	$0.0	$64.2	$76.1	($9.5)	($0.0)	$66.7
Nov	$83.0	($0.6)	$0.0	$82.5	$79.3	($8.3)	($0.0)	$71.1
Dec	$78.8	($1.3)	($0.0)	$77.5	$110.7	($10.1)	($0.0)	$100.6
Total	$1,003.8	($22.1)	$0.0	$981.7	$1,137.7	($102.4)	($0.0)	$1,035.3

Figure 11-3 shows PJM monthly marginal loss costs for January 2009 through December 2013.

Figure 11-3 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through December of 2013



Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (generation energy credits less load energy payments) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 11-31 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for 2009 through 2013. The total marginal loss credits decreased $55.7 million in 2013 from 2012.

Table 11-31 Marginal loss credits (Dollars (Millions)): 2009 through 2013[32]

	Loss Credit Accounting (Millions)			
Year	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($628.8)	$1,267.7	$0.8	$639.7
2010	($797.9)	$1,635.0	($0.5)	$836.6
2011	($793.8)	$1,379.5	$0.9	$586.7
2012	($593.0)	$981.7	($2.0)	$386.7
2013	($701.5)	$1,035.3	($2.9)	$330.9

32 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the Balancing Energy Market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.

- **Day-Ahead Load Energy Payments.** Day-ahead, load energy payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. (Decrement bids and energy sales are equivalent to demand.) Day-ahead, load energy payments are calculated using MW and the load bus energy component of LMP (energy LMP), the decrement bid energy LMP or the energy LMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Energy Credits.** Day-ahead, generation energy credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. (Increment offers and energy purchases are equivalent to generation.) Day-ahead, generation energy credits are calculated using MW and the generator bus energy LMP, the increment offer energy LMP or the energy LMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Energy Payments.** Balancing, load energy payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load energy payments are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Balancing Generation Energy Credits.** Balancing, generation energy credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation energy credits are calculated using MW deviations and the real-time energy LMP for each bus where a deviation exists.
- **Explicit Energy Costs.** Explicit energy costs are the net energy costs associated with point-to-point energy transactions. These costs equal the product of the transacted MW and energy LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit energy costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time energy LMP at the transactions' sources and sinks. The explicit energy costs will sum to zero because the LMP (SMP) at the transactions' sources and sinks will be the same for each transaction.
- **Inadvertent Energy Charges.** Inadvertent energy charges are the net energy charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent energy charges are common costs, not directly attributable to specific participants, which are distributed on a load ratio basis.[33]

The total energy cost for 2013 was -$701.5 million, which was comprised of load energy payments of $42,773.8 million, generation energy credits of $43,467.8 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$7.5 million. The monthly energy costs for 2013 ranged from -$90.8 million in July to -$44.3 million in October.

33 OA. Schedule 1 (PJM Interchange Energy Market) §3.7.

Total Energy Costs

Table 11-32 shows total energy component costs and total PJM billing, for 2009 through 2013. The total energy component costs appear low compared to total PJM billing because these totals are actually net energy costs.

Table 11-32 Total PJM costs by energy component (Dollars (Millions)): 2009 through 2013[34]

Year	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($629)	NA	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($702)	18.3%	$33,862	(2.1%)

Energy costs for 2009 through 2013 are shown in Table 11-33 and Table 11-34. Table 11-33 shows PJM energy costs by accounting category for 2009 through 2013 and Table 11-34 shows PJM energy costs by market category for 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-32.

Table 11-33 Total PJM energy costs by accounting category (Dollars (Millions)): 2009 through 2013

	Energy Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,773.8	$43,467.8	$0.0	($7.5)	($701.5)

Table 11-34 Total PJM energy costs by market category (Dollars (Millions)): 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,794.6	$43,628.8	$0.0	($834.2)	($20.9)	($161.0)	$0.0	$140.1	($7.5)	($701.5)

34 The energy costs include net inadvertent charges.

Monthly Energy Costs

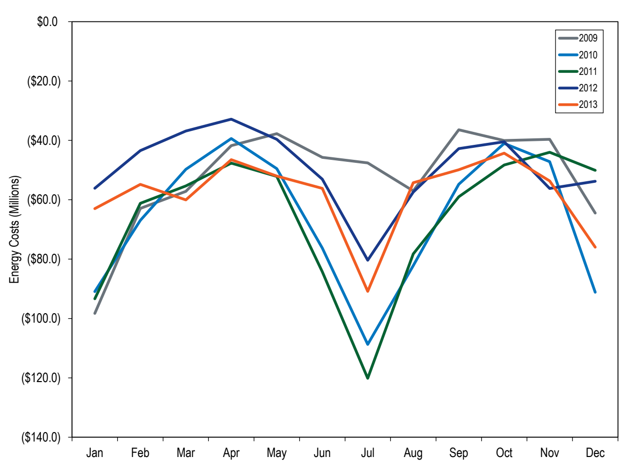
Table 11-35 shows a monthly summary of energy costs by market type for 2012 and 2013.

Table 11-35 Monthly energy costs by market type (Dollars (Millions)): 2012 and 2013

	Energy Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($48.5)	($10.1)	$2.5	($56.1)	($69.2)	$5.8	$0.5	($63.0)
Feb	($36.0)	($9.9)	$2.4	($43.5)	($60.6)	$5.9	($0.1)	($54.8)
Mar	($30.1)	($8.6)	$1.9	($36.8)	($63.9)	$4.2	($0.3)	($60.0)
Apr	($30.7)	($2.8)	$0.7	($32.8)	($46.8)	$0.9	($0.6)	($46.5)
May	($39.4)	$0.0	($0.3)	($39.7)	($48.3)	($3.4)	($0.3)	($52.0)
Jun	($57.1)	$4.0	$0.0	($53.1)	($63.4)	$7.8	($0.6)	($56.2)
Jul	($84.0)	$3.0	$0.6	($80.4)	($111.1)	$21.4	($1.1)	($90.8)
Aug	($60.3)	$2.6	$0.3	($57.4)	($71.0)	$17.4	($0.7)	($54.3)
Sep	($43.6)	$1.1	($0.2)	($42.8)	($67.3)	$18.3	($0.9)	($49.9)
Oct	($42.2)	$1.6	$0.2	($40.5)	($64.0)	$20.5	($0.8)	($44.3)
Nov	($65.2)	$7.8	$1.1	($56.2)	($71.7)	$19.2	($1.1)	($53.7)
Dec	($72.7)	$19.0	($0.1)	($53.8)	($96.9)	$22.2	($1.3)	($76.0)
Total	($609.9)	$7.7	$9.1	($593.0)	($834.2)	$140.1	($7.5)	($701.5)

Figure 11-4 shows PJM monthly energy costs of January 2009 through December 2013.

Figure 11-4 PJM monthly energy costs (Dollars (Millions)): January 2009 through December 2013



Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,775 MW at the end of 2013. Of the capacity in queues, 6,557 MW, or 9.7 percent, are uprates and the rest are new generators. Wind projects account for 18,063 MW of nameplate capacity or 26.8 percent of the capacity in the queues. Combined-cycle projects account for 39,420 MW of capacity or 58.5 percent of the capacity in the queues.

- **Generation Retirements.** As shown in Table 12-7, 24,932 MW is or is planned to be retired between 2011 and 2019, with all but 2,016.5 MW retired by June 1, 2015. The AEP Zone accounts for 4,124 MW, or 19.7 percent, of all MW planned for retirement from 2014 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be retired have withdrawn their retirement notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI Zone.

- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and the Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[1] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit or that requests interconnection of a merchant transmission facility must follow the process defined in the PJM tariff to obtain interconnection service.[2] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn and an accumulated backlog in completing studies.

- Changes to the planning process went into effect on May 12, 2012 including a return to six-month queue cycles and the creation of an alternate queue for small projects. Concurrent with these changes was a drop in new projects, starting in 2012 and a corresponding drop in withdrawn projects starting in 2013.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, and Susquehanna-Roseland.

1 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones. SWMAAC consists of the BGE and Pepco control zones. See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

2 OATT Parts IV & VI.

Regional Transmission Expansion Plan (RTEP)

- The PJM Board of Managers authorized $1.2 billion on October 3, 2013, and $5.9 billion on December 11, 2013, in transmission upgrades and improvements that were identified as part of PJM's regional planning process.

Economic Planning Process

A goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. Transmission investments have not been fully incorporated into competitive markets. The PJM economic planning process could enhance competition in PJM in at least three ways.

- **Competition to Build.** On its own initiative and in compliance with Order No. 1000, PJM introduced limited opportunities for non-incumbent transmission owners to compete with incumbent transmission owners to identify and sponsor the development of projects in the PJM region for economic reasons.[3] The rules accord no right of first refusal to incumbents.[4]
- **Competition to Finance.** Competition to provide financing could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. The MMU recommended this approach in PJM's proceeding on compliance with Order No. 1000 and continues to recommend that PJM implement this approach.[5]
- **Competition to Meet Load.** The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics and through the ability to offer transmission projects in RPM auctions.[6, 7]

Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[8]
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This could result in a conflict of interest when transmission owners have generation interests.
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.

3 *See* FERC Docket No. ER13-198; 145 FERC ¶ 61,214.
4 *See* 145 FERC ¶ 61,214 at PP 221–234.
5 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) at 4–7; 145 FERC ¶ 61,214 at P 268, 281.
6 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand response trends), order on reh'g, 123 FERC ¶ 61,051 (2008).
7 *See, e.g.,* OATT Attachment DD § 5.6.4 (Qualifying Transmission Upgrades).
8 *See* "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013)

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing. The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,775 MW in 2013. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1).[9] Overall, 1,127 MW of nameplate capacity were added in PJM in 2013.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2013[10]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011	5,008
2012	2,669
2013	1,127

PJM Generation Queues

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all entered projects for a given queue when that queue closes. The duration of the queue period has varied over time in an attempt to improve the efficiency of the queue process. Queues A and B were each open for a year. Queues C-T were open for six months. Starting in February 2008, for Queues U-Y1, the window was reduced to three months. In May 2012, the queue window was set back to six months, starting with Queue Y2. Queue Z2 is currently open.

All projects that have been entered in a queue will have an assigned status. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue

9 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or adjusted for deratings.

10 The capacity described in Table 12-1 refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction. In addition, wind capacity has been adjusted to reflect derating.

and listed separately. A project cannot be suspended until it has reached the status of under construction. A project suspended for more than three years is subject to termination of the Interconnection Service Agreement and corresponding cancellation costs.

Table 12-2 shows MW in queues by expected completion date and changes in the queues from January 1, 2013 to December 31, 2013, for ongoing projects, i.e. projects with the status active, under construction or suspended. Projects that are already in service are not included here. The total MW in queues for these projects decreased by 12,178 MW or 15.3 percent from 79,476 MW at the beginning of 2013 to 67,299 MW at the end of 2013. The change is a result of 11,669 MW in new projects entering the queue, 21,432 MW in existing projects being withdrawn, and 1,737 MW going into service. The remaining difference is the result of projects adjusting their expected.

Table 12-2 Queue comparison by expected completion year (MW): January 1, 2013 vs. December 31, 2013[11]

	As of 1/1/2013	As of 12/31/2013	Year-to-Year Change (MW)	Year-to-Year Change
≤ 2013	22,929	11,672	(11,257)	(49.1%)
2014	8,509	7,360	(1,149)	(13.5%)
2015	22,742	12,674	(10,069)	(44.3%)
2016	11,977	13,953	1,976	16.5%
2017	10,018	16,003	5,985	59.7%
2018	3,301	3,697	396	12.0%
2019	0	0	0	NA
2020	0	346	346	NA
2024	0	1,594	1,594	NA
Total	79,476	67,299	(12,178)	(15.3%)

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed from the beginning of 2013 to the end of 2013. For example, 14,883 MW entered the queue in 2013, 3,204 MW of which were withdrawn before the end of the year. Of the total 62,511 MW marked as active at the beginning of the year, 19,039 MW were withdrawn, 1,367 MW were suspended, and 4,491 MW started construction. The "In Service" column shows that 1,747 MW went into service in 2013, in addition to the 33,786 MW of capacity that already had the status "in service" at the beginning of the year.

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the regional transmission expansion plan (RTEP) process and the total amount of capacity that had been included in each queue. All items in queues A-L are either in service or have been withdrawn. As of December 31, 2013, there are 67,299 MW of capacity in queues that are not yet in service of which 6.4 percent is suspended and 20.9 percent is under construction. The remaining 72.7 percent, or 48,953 MW, have not yet begun construction.

Table 12-5 shows that for successful projects, there is an average time of 2,895 days, or 7.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 609 days between entering a queue and withdrawing. It takes an average of 3.1 years to begin construction, with the worst case taking 12.7 years.

Table 12-3 Change in project status (MW): January 1, 2013 vs. December 31, 2013

		Status at 12/31/2013				
Status at 1/1/2013	Total at 1/1/2013	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2013)		11,643	0	26	10	3,204
Active	62,511	37,310	1,367	4,491	304	19,039
Suspended	3,283	0	2,274	288	150	571
Under Construction	13,005	0	648	9,252	1,283	1,823
In Service	33,789	0	0	0	33,786	3
Withdrawn	234,621	0	0	0	0	234,621
Total at 12/31/2013		48,953	4,288	14,057	35,532	259,261

11 Wind capacity in Table 12-2 and Table 12-3 has not been adjusted to reflect derating.

Table 12-4 Capacity in PJM queues (MW): At December 31, 2013[12]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	0	0	17,934	19,050
H Expired 31-Jan-02	0	703	0	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	0	846	886
K Expired 31-Jul-03	0	218	0	0	2,425	2,643
L Expired 31-Jan-04	0	257	0	0	4,034	4,290
M Expired 31-Jul-04	0	505	150	0	3,706	4,360
N Expired 31-Jan-05	0	2,399	88	0	8,040	10,527
O Expired 31-Jul-05	10	1,688	225	217	5,451	7,592
P Expired 31-Jan-06	43	3,065	253	210	5,068	8,638
Q Expired 31-Jul-06	105	2,498	2,244	0	9,687	14,534
R Expired 31-Jan-07	1,226	1,386	728	440	18,974	22,755
S Expired 31-Jul-07	875	3,281	577	420	11,989	17,142
T Expired 31-Jan-08	3,671	1,319	631	868	21,068	27,556
U Expired 31-Jan-09	1,951	824	400	690	29,492	33,357
V Expired 31-Jan-10	3,148	266	2,696	172	10,720	17,001
W Expired 31-Jan-11	4,860	498	2,091	780	15,992	24,222
X Expired 31-Jan-12	11,638	282	3,656	29	14,762	30,366
Y Expired 30-Apr-13	12,584	109	318	462	12,636	26,109
Z through 31-Dec-13	8,842	0	0	0	217	9,060
Total	48,953	35,532	14,057	4,288	259,261	362,092

Table 12-5 Average project queue times (Days) at December 31, 2013

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,168	696	67	4,636
In-Service	2,895	1,377	262	6,124
Suspended	2,074	850	941	3,846
Under Construction	1,611	735	320	6,380
Withdrawn	609	623	0	4,249

12 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 12-6 shows the projects under construction, suspended, or active as of December 31, 2013, by unit type, control zone and LDA.[13] The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.[14] As of December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to 79,476 MW at January 1, 2013. Of the 24,640 MW withdrawn from the queues in 2013, 14,262 MW were natural gas projects, 5,871 MW were wind projects, and 2,966 MW were coal projects.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 12-6) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. The western part of the PJM footprint is also likely to see a shift to more natural gas-fired capacity due to changes in environmental regulations and natural gas costs, but likely will maintain a larger amount of coal steam capacity than eastern zones. The replacement of older steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-6 Queue capacity by control zone and LDA (MW) at December 31, 2013[15]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	AECO	1,684	71	8	0	0	377	0	0	1,069	3,208
	DPL	1,223	23	0	0	0	348	20	20	279	1,913
	JCPL	1,456	0	0	20	0	795	0	0	0	2,271
	PECO	861	17	6	0	330	0	0	2	0	1,215
	PSEG	3,374	326	9	0	0	163	0	1	0	3,873
	EMAAC Total	8,598	436	22	20	330	1,683	20	23	1,348	12,480
SWMAAC	BGE	678	256	29	0	0	22	132	0	0	1,117
	Pepco	3,078	0	0	0	0	0	0	0	0	3,078
	SWMAAC Total	3,756	256	29	0	0	22	132	0	0	4,195
WMAAC	Met-Ed	800	6	0	0	50	3	0	0	0	859
	PENELEC	919	121	39	40	0	32	0	10	755	1,916
	PPL	5,052	0	7	3	0	29	0	40	664	5,795
	WMAAC Total	6,771	127	46	43	50	64	0	50	1,419	8,569
Non-MAAC	AE	452	10	0	0	0	0	0	0	0	462
	AEP	6,399	40	20	7	102	96	302	98	8,241	15,305
	APS	2,009	1,418	63	59	0	2	49	0	428	4,029
	ATSI	2,425	1,484	0	0	0	15	135	0	867	4,926
	ComEd	1,170	216	32	23	120	19	0	81	4,047	5,707
	DAY	0	0	2	112	0	23	12	12	300	461
	DEOK	540	0	0	0	0	0	50	16	0	606
	DLCO	245	0	0	0	0	0	0	0	0	245
	Dominion	6,920	62	11	0	1,594	45	103	32	1,262	10,029
	EKPC	0	0	0	0	0	0	0	0	150	150
	Essential Power	135	0	0	0	0	0	0	0	0	135
	Non-MAAC Total	20,296	3,230	128	201	1,816	200	650	239	15,295	42,055
Total		39,420	4,049	225	264	2,196	1,969	802	311	18,063	67,299

13 Unit types designated as reciprocating engines are classified here as diesel.

14 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 18,063 MW of wind resources and 1,969 MW of solar resources, the 67,299 MW currently active in the queue would be reduced to 54,387 MW.

15 This data includes only projects with a status of active, under-construction, or suspended.

Planned Retirements

As shown in Table 12-7, 24,932.5 MW is planned to be retired between 2011 and 2019, with all but 2,016.5 MW retired by June, 2015. The AEP Zone accounts for 5,224 MW, or 21.0 percent, of all MW planned for deactivation from 2014 through 2019. Since January 1, 2013, 1,437 MW scheduled to be deactivated have withdrawn their deactivation notices and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI Zone. A map of retirements between 2011 and 2019 is shown in Figure 12-1 and a detailed list of pending deactivations is shown in Table 12-8.

Table 12-7 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,196.5
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	50.0
Planned Retirements 2014	1,870.0
Planned Retirements 2015	9,975.0
Planned Retirements Post-2015	2,016.5
Total	24,932.5

Figure 12-1 Map of PJM unit retirements: 2011 through 2019

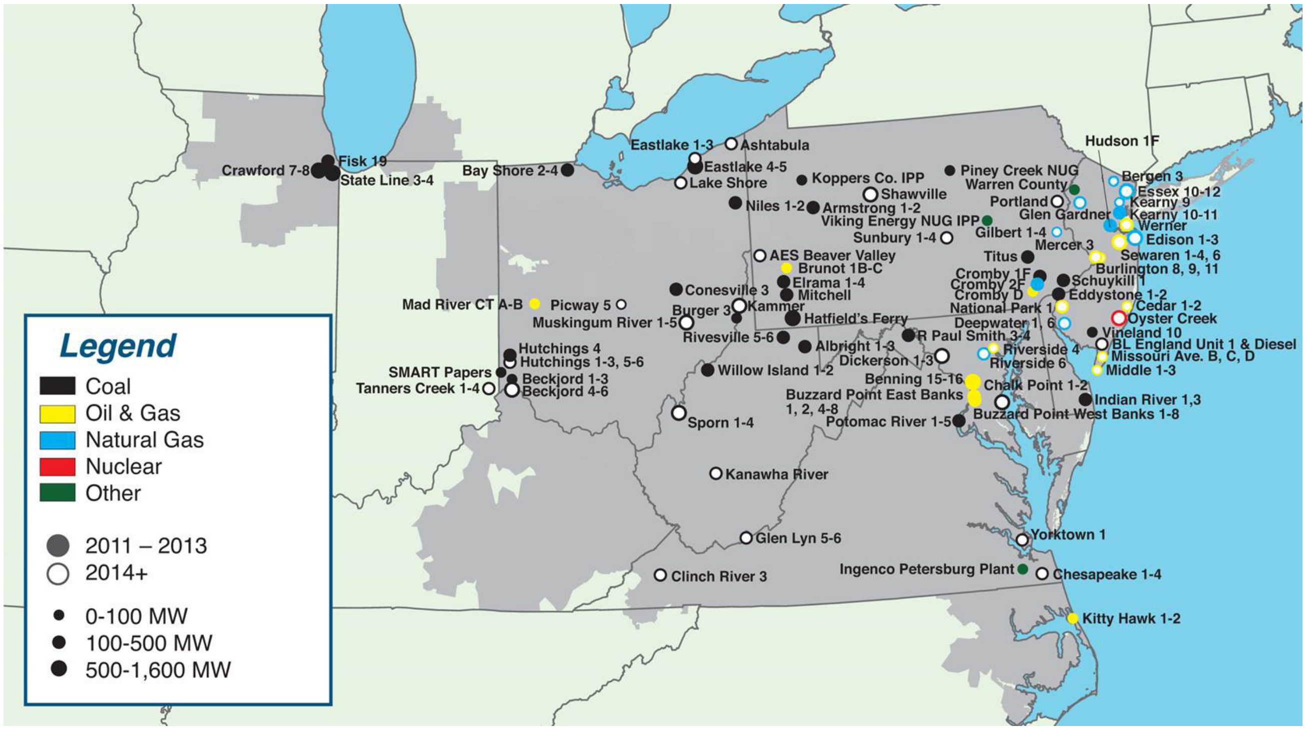


Table 12-8 Planned deactivations of PJM units, as of December 31, 2013

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
BL England 1	AECO	113.0	Coal	Steam	01-May-14
Deepwater 1, 6	AECO	158.0	Natural gas	Steam	01-Jun-14
Burlington 9	PSEG	184.0	Kerosene	Combustion Turbine	01-Jun-14
Portland	Met-Ed	401.0	Coal	Steam	01-Jun-14
Riverside 6	BGE	115.0	Natural gas	Combustion Turbine	31-Dec-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	01-Apr-15
Walter C Beckjord 4-6	DEOK	802.0	Coal	Steam	16-Apr-15
Shawville 1-7	PENELEC	603.0	Coal	Steam	01-May-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	31-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	01-Jun-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Eastlake 1-3	ATSI	327.0	Coal	Steam	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Lake Shore	ATSI	190.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Sunbury 1-4	PPL	347.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Riverside 6	BGE	74.0	Natural gas	Combustion Turbine	01-Jun-16
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-17
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		13,861.5			

Table 12-9 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 76.7 percent, of all MW retiring during this period are coal steam units. These units have an average age of 56.9 years, and an average size of 168.7 MW. This indicates that on average, retirements have consisted of smaller sub-critical coal steam units, and those without adequate environmental controls to remain viable beyond 2015.

Table 12-9 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	113	168.7	56.9	19,062.6	76.7%
Diesel	5	13.4	42.8	66.9	0.3%
Heavy Oil	2	120.0	60.0	240.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.3%
LFG	1	10.8	7.0	10.8	0.0%
Light Oil	15	76.6	43.8	1,148.7	4.6%
Natural Gas	49	57.9	46.8	2,838.5	11.4%
Nuclear	1	614.5	50.0	614.5	2.5%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	209	119.0	51.4	24,865.2	100.0%

Actual Generation Deactivations in 2013

Table 12-10 shows unit deactivations for 2013.[16] A total of 2,862.6 MW was retired in 2013, plus an additional 50 MW in early January, 2014.

Table 12-10 Unit deactivations between January 1, 2013 and January 15, 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	01-Jan-13
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	01-Jan-13
Marina Energy	Warren County Landfill	10.8	Landfill Gas	JCPL	07	09-Jan-13
First Energy	Piney Creek NUG	31.0	Waste Coal	PENELEC	20	12-Apr-13
Ingenco Wholesale Power, LLC	Ingenco Petersburg	2.9	Landfill Gas	Dominion	22	31-May-13
The AES Corporation	Hutchings 4	61.9	Coal	DAY	62	01-Jun-13
NRG Energy	Titus 1	81.0	Coal	Met-Ed	60	01-Sep-13
NRG Energy	Titus 2	81.0	Coal	Met-Ed	24	01-Sep-13
NRG Energy	Titus 3	81.0	Coal	Met-Ed	60	01-Sep-13
NextEra Energy	Koppers Co. IPP	08.0	Wood waste	PPL	59	30-Sep-13
Duke Energy	Walter C Beckjord 2	94.0	Coal	DEOK	44	01-Oct-13
Duke Energy	Walter C Beckjord 3	128.0	Coal	DEOK	43	01-Oct-13
First Energy	Hatfield's Ferry 1	530.0	Coal	APS	42	09-Oct-13
First Energy	Hatfield's Ferry 2	530.0	Coal	APS	65	09-Oct-13
First Energy	Hatfield's Ferry 3	530.0	Coal	APS	50	09-Oct-13
First Energy	Mitchell 2	82.0	Coal	APS	08	09-Oct-13
First Energy	Mitchell 3	277.0	Coal	APS	21	09-Oct-13
Delmarva Power	Indian River 3	165.0	Coal	DPL	44	31-Dec-13
First Energy	Mad River CTs A	25.0	Diesel	ATSI	41	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	41	09-Jan-14
Total		2,912.6				

16 *See* "*PJM Generator Deactivations,*" PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (Accessed January 15, 2014).

Generation Mix

Currently, PJM has an installed capacity of 195,775 MW (Table 12-11) including non-derated solar and wind resources, as well as energy-only units.

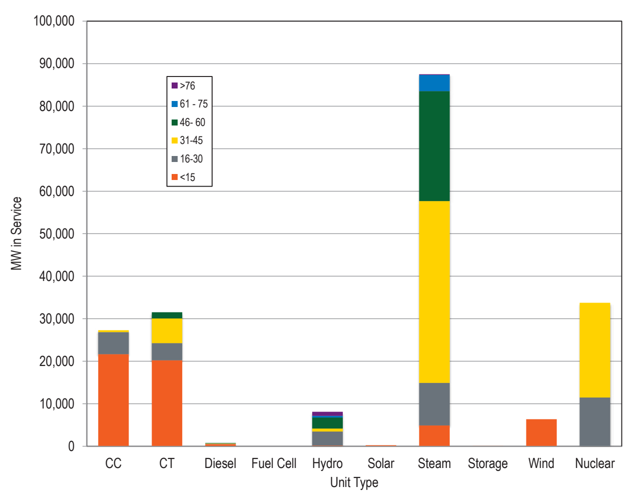
Table 12-11 Existing PJM capacity: At December 31, 2013[17] (By zone and unit type (MW))

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	706	23	0	0	0	40	1,087	0	8	2,026
AEP	4,900	3,682	63	0	1,072	2,071	0	21,145	0	1,753	34,686
APS	1,129	1,215	48	0	86	0	36	5,409	27	999	8,949
ATSI	685	1,667	73	0	0	2,134	0	6,540	0	0	11,099
BGE	0	835	18	0	0	1,716	0	2,996	0	0	5,565
ComEd	2,270	7,244	100	0	0	10,474	0	5,417	5	2,454	27,964
DAY	0	1,369	48	0	0	0	1	3,180	40	0	4,637
DEOK	0	842	0	0	0	0	0	3,932	0	0	4,774
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,875	154	0	3,589	3,581	3	8,403	0	0	23,634
DPL	1,125	1,820	96	30	0	0	4	1,635	0	0	4,711
EKPC	0	774	0	0	70	0	0	1,882	0	0	2,726
EXT	664	111	0	0	0	13	0	5,484	0	0	6,271
JCPL	1,693	1,233	16	0	400	615	45	10	0	0	4,011
Met-Ed	2,051	407	41	0	19	805	0	601	0	0	3,924
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	408	46	0	513	0	0	6,794	0	931	8,690
Pepco	230	1,092	10	0	0	0	0	3,649	0	0	4,981
PPL	1,808	616	49	0	707	2,520	15	5,529	20	220	11,483
PSEG	3,091	2,838	12	0	5	3,493	107	2,050	2	0	11,598
Total	27,292	31,584	799	30	8,109	33,745	253	87,504	95	6,364	195,775

Figure 12-2 shows the age of PJM generators by unit type. Units older than 30 years comprise 107,452 MW, or 54.8 percent, of the total capacity of 195,775 MW. Units older than 45 years comprise 35,359 MW, or 18.0 percent of the total capacity.

Table 12-12 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age in 2013 retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. The 79.3 percent of existing capacity in SWMAAC which is steam or nuclear would be reduced, by 2024, to 57.6 percent, and CC and CT generators would comprise 41.8 percent of total capability in SWMAAC.

Figure 12-2 PJM capacity (MW) by age (years): at December 31, 2013



17 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

In Non-MAAC zones, 81.3 percent of all generation 40 years or older, as of December 31, 2013, is steam, primarily coal.[18] If these older coal units retire and if all queued wind MW are built as planned, by 2020, wind farms would account for 12.1 percent of total ICAP MW in Non-MAAC zones.

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of December 31, 2013[19]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2024	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198	1.8%	9,282	27.7%	8,598	17,880	38.8%
	Combustion Turbine	3,764	34.0%	7,433	22.1%	436	7,870	17.1%
	Diesel	59	0.5%	150	0.4%	22	171	0.4%
	Fuel Cell	0	0.0%	30	0.1%	0	30	0.1%
	Hydroelectric	2,042	18.4%	2,047	6.1%	20	2,067	4.5%
	Nuclear	1,740	15.7%	8,654	25.8%	330	8,984	19.5%
	Solar	0	0.0%	198	0.6%	1,683	1,881	4.1%
	Steam	3,266	29.5%	5,761	17.2%	20	5,781	12.6%
	Storage	0	0.0%	3	0.0%	23	26	0.1%
	Wind	0	0.0%	8	0.0%	1,348	1,356	2.9%
	EMAAC Total	11,069	100.0%	33,566	100.0%	12,480	46,046	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.6%	3,756	3,986	15.7%
	Combustion Turbine	964	19.0%	1,927	13.4%	256	2,183	8.6%
	Diesel	0	0.0%	28	0.2%	29	57	0.2%
	Hydroelectric	0	0.0%	1,716	11.9%	0	1,716	6.8%
	Nuclear	0	0.0%	0	0.0%	22	22	0.1%
	Solar	4,099	81.0%	6,645	46.1%	132	6,777	26.7%
	Steam	0	0.0%	3,859	26.8%	6,771	10,630	41.9%
	SWMAAC Total	5,063	100.0%	14,404	100.0%	10,966	25,370	100.0%
WMAAC	Combined Cycle	714	7.2%	1,430	7.1%	127	1,557	7.1%
	Combustion Turbine	46	0.5%	136	0.7%	46	182	0.8%
	Diesel	887	9.0%	1,238	6.1%	43	1,281	5.8%
	Hydroelectric	0	0.0%	3,325	16.4%	50	3,375	15.3%
	Nuclear	0	0.0%	15	0.1%	64	79	0.4%
	Solar	8,974	90.6%	12,923	63.9%	0	12,923	58.6%
	Steam	0	0.0%	20	0.1%	50	70	0.3%
	Storage	0	0.0%	1,151	5.7%	1,419	2,570	11.7%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	WMAAC Total	9,907	100.0%	20,238	100.0%	1,798	22,037	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,922	10.9%	20,296	34,217	20.2%
	Combustion Turbine	1,301	3.0%	20,794	16.3%	3,230	24,023	14.2%
	Diesel	72	0.2%	485	0.4%	128	613	0.4%
	Hydroelectric	1,433	3.3%	4,824	3.8%	201	5,024	3.0%
	Nuclear	5,296	12.3%	20,049	15.7%	1,816	21,865	12.9%
	Solar	0	0.0%	40	0.0%	200	240	0.1%
	Steam	34,999	81.2%	62,175	48.7%	650	62,825	37.0%
	Storage	0	0.0%	72	0.1%	239	311	0.2%
	Wind	0	0.0%	5,206	4.1%	15,295	20,502	12.1%
	Non-MAAC Total	43,100	100.0%	127,566	100.0%	42,055	169,621	100.0%
All Areas	Total	69,139		195,775		67,299	263,074	

18 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion control zones

19 Percentages shown in Table 12-12 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Generation and Transmission Interconnection Planning Process

2012 Changes to the Open Access Transmission Tariff (OATT)

PJM established the Interconnection Process Senior Task Force (IPSTF) in February 2011 to address stakeholder concerns about the project queues and study turnaround delays. The IPSTF categorized the main causes for delays in its queue process into two types: "the sheer number of projects, including hundreds of small projects and a few very large projects in its queue; and the number of restudies that were required when projects drop out or reduced size."[20]

The following changes were proposed and accepted to address these concerns: Queue cycles went back to a six-month duration; sliding queues were established for certain projects that seek to modify the size of their Interconnection Requests; and an alternate queue for projects less than 20 MW was established. Other changes included reducing suspension rights if the suspension will negatively impact the timing or cost of a subsequent queue projects and clarifying the timeframe for notifying PJM if a project is transferring Capacity Interconnection Rights (CIRs) from a deactivating generator.[21]

These changes went into effect on May 1, 2012.[22] As of December 31, 2013, 34 queue projects, totaling 309.0 MW, have been assigned to the alternate queue. The impact of these changes is difficult to quantify. Table 12-13 shows an increase in new projects in 2010 and 2011, and an increase in withdrawals in 2011 and 2012. The subsequent and significant drop in queue activity in 2012 and 2013 would have likely eased the congestion and burden of completing the studies even without any changes to the tariff. Nonetheless, there is still a backlog in project study completion, as well as other issues, which warrant further analysis of the study process.

20 *See* letter from PJM to Secretary Kimberly Bose <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>. (Accessed December 4, 2013)

21 *Id.*

22 *See* PJM. Manual 14A. "Generation and Transmission Interconnection Process," <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.

Table 12-13 Projects added and withdrawn by year

Year	Projects Added	Projects Withdrawn
2005	110	53
2006	146	44
2007	219	36
2008	216	81
2009	174	106
2010	441	135
2011	356	249
2012	157	271
2013	153	176

Overview of the Planning Process

Table 12-14 shows an overview of PJM's study process. In addition to these steps, system impact and facilities studies are often redone, or retooled, when a project is withdrawn because withdrawals may affect the investments of the projects remaining in the queue.

PJM's Manual 14A states that it can take up to 739 days in addition to the (unspecified) time it takes to complete the facilities study to obtain an interconnection construction service agreement (ICSA). It further states that a feasibility study should take no longer than 334 days.[23]

Table 12-15, presents information on actual time in the stages of the queue. For the 372 active projects in the queue as of December 31, 2013, 52 had reached the milestone of feasibility study completion. On average, the time it took to complete the feasibility study was close to PJM's estimate of 334 days. However, completion time for 20 of the 52 projects at this milestone exceeded this estimate, with five of them in the queue over 500 days. PJM Manual 14A also states that a system impact study should take no longer than 514 days. Table 12-15 shows that for the 166 projects that are at this milestone, the system impact studies have taken an average of 1,280 days, with 25 of the 166 studies in the queue for over 2,000 days.

Analysis of projects in the active queues in stages of the study process show that 39.0 percent of the active projects in the queue are waiting for the results of the system impact study. At the same time, 42.7 percent of the projects withdrawn were done so after the system impact study was completed. Another 40.1 percent of the projects were withdrawn after the facility study was completed.

23 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," p.29, <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.

Table 12-14 PJM generation planning process[24]

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of Study (refundable deposit)	Varies	60
Develop Schedule of Work	Upon Acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Begin Construction (only for new generation)	Upon Acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

Table 12-15 PJM generation planning summary: at December 31, 2013

Milestone Completed	Number of Projects in Queue	Percent of Total Projects in Queue	Maximum Days in Queue	Average Days in Queue
Not Started	93	25.0%	432	110
Feasibility Study	52	14.0%	616	355
System Impact Study	166	44.6%	3,087	1,280
Facility Study	25	6.7%	2,352	1,291
ISA	1	0.3%	1,589	1,589
CSA	35	9.4%	3,227	1,767
Total	372			

Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the EHV (extra high voltage) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, and Susquehanna-Roseland.

The Mount Storm-Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability in its service areas. As of January 2014, construction is ahead of schedule.[25]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. The plans are for construction of the foundation in late 2013, construction in 2014 and completion in early 2015.

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland will be a new 500 kV transmission line connecting the Susquehanna – Lackawanna – Hopatcong – Roseland buses. The Susquehanna-Hopatcong portion of the project is currently expected to be in-service by June 2014, with the remainder of the project to be completed by June, 2015.

24 Other agreements may also be required, e.g. Interconnection Construction Service Agreement (ICSA), Upgrade Construction Service Agreement (UCSA). See "PJM Manual 14C: Generation and Transmission Interconnection Process," p.29, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

25 See "*Mt. Storm-Doubs 500kV Rebuild Project*," Dom.com <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (January 15, 2014).

Regional Transmission Expansion Plan (RTEP)

The PJM Board of Managers authorized $1.2 billion on October 3, 2013, and $5.9 billion on December 11, 2013, in baseline and network transmission upgrades and improvements that were identified as part of PJM's continued regional planning process. Table 12-16 shows the upgrades by transmission owner and upgrade type. This brings the total currently approved expenditures to $28.9 billion.

Table 12-16 Estimated approved upgrade costs by transmission owner and upgrade type (dollars (Millions)

Transmission Owner	Baseline	Network
AECO	$0.0	$39.8
AEP	$86.3	$1,481.5
APS	$60.4	$123.2
ATSI	$0.6	$136.7
BGE	$18.0	$0.4
ComEd	$30.3	$1,767.8
DAY	$0.0	$45.1
DEOK	$0.0	$4.2
DLCO	$0.0	$2.3
Dominion	$16.1	$10.6
DPL	$1.6	$51.0
Essential Power	$0.0	$0.9
EKPC	$4.9	$0.0
JCPL	$0.9	$0.8
Met-Ed	$0.0	$208.0
NRG Energy	$0.0	$0.0
PECO	$1.0	$0.0
PENELEC	$1.7	$34.2
Pepco	$6.8	$56.8
PPL	$68.6	$371.4
PSEG	$1,242.2	$12.2
Total	$1,539.3	$4,346.9

RTEP Proposal Windows

On July 22, 2013, PJM made a second filing in compliance with Order No. 1000 and in compliance with the order on its first compliance filing issued March 22, 2013.[26] PJM's Order No. 1000 compliance filing addressed a number of procedural issues identified by the Commission in the March 22 order. In the initial filing, PJM proposed to expand the regional planning process to provide greater opportunity for non-incumbent transmission developers to submit solution proposals.[27] PJM's filing established proposal windows for competitive solicitations, but limited the ability of competitors to make proposals within a defined time window.[28]

A test of whether PJM's new process can operate transparently and offer a meaningful opportunity for non-incumbents to compete involves Artificial Island, which includes the Salem and Hope Creek nuclear plants. On April 29, 2013, PJM submitted a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and to eliminate potential planning criteria violations in the Artificial Island Area. The RFP window closed on June 28, 2013. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSEG, and a range of proposals from other non-incumbents. The costs of solutions proposed ranged from approximately $54 million to $1.4 billion.[29] These proposals are currently being evaluated by PJM.

Economic Planning Process

A goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. Transmission investments have not been fully incorporated into competitive markets. The PJM economic planning process could enhance competition in PJM to build projects, to finance projects and to meet load without building new generation.

Competition to Build

On its own initiative and in compliance with Order No. 1000, PJM introduced limited opportunities for non-incumbent transmission owners to compete with incumbent transmission owners to identify and sponsor the development of projects in the PJM region for economic reasons.[30] The rules accord no right of first refusal to incumbents.[31] The efficacy of these rules may be limited by requirements that may favor incumbents, such as those based on ownership of existing infrastructure and rights of way and procedures that fail to provide adequate incentive to nonincumbents to

26 PJM Interconnection, L.L.C., Compliance Filing, Docket No. ER13-198-002 (July 22, 2013) (July 22nd PJM Filing"); 142 FERC ¶ 61,214. PJM transmission owners made a separate filing addressing cost allocation issues, also on March 22, 2013.

27 PJM Interconnection, L.L.C., Compliance Filing Docket No. ER13-198-000 (October 25, 2012). Originally filed under Docket No. RM 10-123-000, in compliance with FERCs Order No. 1000, Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities.

28 *Id.*; see also "*RTEP Proposal Windows*," PJM.com <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx>.

29 *See* "*PJM 2013 RTEP Proposal Window Tracking*," PJM.com <http://www.pjm.com/~/media/committees-groups/committees/teac/20130710/20130710-pjm-2013-rtep-proposal-window-tracking.ashx>.

30 *See* FERC Docket No. ER13-198; 145 FERC ¶ 61,214.

31 *See* 145 FERC ¶ 61,214 at PP 221–234.

identify locations on the system that could be enhanced with economic projects. The Commission has ordered and PJM has filed on compliance changes that would significantly narrow incumbents' advantages based on whether the project is an upgrade to an existing facility or requires access to an incumbent's right of way.[32] PJM also details a process that may afford protection to nonincumbents not available in the Primary Power matter.[33] An order on compliance is pending.

Competition to Finance

A feature of competitive transmission development that is as significant as ensuring competition to build is the potential to reduce the costs to customers of investment in transmission through competition to finance.

Under the current rules, non-incumbents and incumbents compete to develop projects for the same regulated rate of return, some including incentive adders.

An alternative approach would introduce competition to find the lowest cost source of capital. A competitive process would ensure that customers pay market rates of return.

Competition to provide financing could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. The MMU recommended this approach in PJM's proceeding on compliance with Order No. 1000 and continues to recommend that PJM implement this approach.[34]

Competition to Meet Load

Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics and through the ability to offer transmission projects in RPM auctions.[35, 36] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

32 *Id.* at PP 227, 229, 231.

33 *Id.* at PP 37–48; OA Schedule 6 § 1.5.7; see also 140 FERC ¶ 61,054 (2012).

34 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) at 4–7; 145 FERC ¶ 61,214 at P 268, 281.

35 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

36 *See*, e.g., OATT Attachment DD § 5.6.4 (Qualifying Transmission Upgrades). To date, no Qualifying Transmission Upgrade has cleared RPM.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and which creates the funds available to offset congestion costs in an LMP market.[2]

The *2013 State of the Market Report for PJM*, focuses on the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period, covering January 1, 2013, through December 31, 2013.

Table 13-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.

1 See 81 FERC ¶ 61,257, at 62,241 (1997).
2 See Id. at 62, 259–62,260 & n. 123.

- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and over sells FTRs. FTR funding levels are reduced as a result of these and other factors.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2014 to 2017 Long Term FTR Auction include the Monticello – East Winamac flowgate, approximately 120 miles north of Indianapolis, IN, and the Cumberland Ave - Bush flowgate, approximately 100 miles north of Indianapolis, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2013 to 2014 planning period include the Cumberland Ave – Bush flowgate, approximately 100 miles north of Indianapolis, IN and the Beaver Channel - Albany flowgate, approximately 100 miles north of Springfield, IL. The geographic location of these constraints is shown in Figure 13-1.
- **Market participants can also sell FTRs.** In the 2014 to 2017 Long Term FTR Auction, total participant FTR sell offers were 316,056 MW, up from 211,316 MW from the 2013 to 2016 Long Term FTR Auction. In the 2013 to 2014 Annual FTR Auction, total participant FTR sell offers were 417,118 MW, up from 356,299 MW in the 2012 to 2013 planning period. In the first seven months of the Monthly Balance of Planning Period FTR Auctions for the

2013 to 2014 planning period, total participant FTR sell offers were 3,862,503 MW, up from 3,589,824 MW for the same period during the 2012 to 2013 planning period.

- **Demand.** In the 2014 to 2017 Long Term FTR Auction, total FTR buy bids increased 10.8 percent from 2,772,621 MW to 3,072,909 MW. There were 3,274,373 MW of buy and self-scheduled bids in the 2013 to 2014 Annual FTR Auction, up from 2,561,835 MW in the previous planning period. The total FTR buy bids from the first seven months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 11.4 percent from 14,906,684 MW for the same time period of the prior planning period, to 16,604,063 MW.
- **Patterns of Ownership.** For the 2014 to 2017 Long Term FTR Auction, financial entities purchased 65.1 percent of prevailing flow FTRs and 79.7 percent of counter flow FTRs. For the 2013 to 2014 Annual FTR Auction, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 76.0 percent of prevailing flow and 85.8 percent of counter flow FTRs for January through December of 2013. Financial entities owned 59.0 percent of all prevailing and counter flow FTRs, including 50.6 percent of all prevailing flow FTRs and 75.3 percent of all counter flow FTRs during January through December 2013.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $531,678 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.
- **Credit Issues.** Ten participants defaulted during 2013 from 16 default events. The average of these defaults was $255,611 with 10 based on inadequate collateral and six based on nonpayment. The average collateral default was $93,749 and the average nonpayment default was $352,729. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** The 2014 to 2017 Long Term FTR Auction cleared 197,125 MW (6.4 percent of demand) of FTR buy bids, compared to 290,700 MW (10.5 percent) in the 2013 to 2015 Long Term FTR Auction. This is at least partially due to the newly implemented rule limiting Long Term FTR Auction capacity to 50 percent. The Long Term FTR Auction also cleared 21,501 MW (6.8 percent) of FTR sell offers, down from 56,692 MW (26.8 percent) in the 2013 to 2014 Long Term FTR Auction.

  In the Annual FTR Auction for the 2013 to 2014 planning period 420,489 MW (12.8 percent) of buy and self-schedule bids cleared. For the first seven months of the 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 2,283,411 MW (13.8 percent) of FTR buy bids and 742,731 MW (19.2 percent) of FTR sell offers.

- **Price.** In the 2014 to 2017 Long Term FTR Auction, 97.6 percent of FTRs were purchased for less than $1 per MW, up from 95.9 percent in the previous Long Term FTR Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction was -$0.18, down from $0.36 from the previous Long Term FTR Auction.

  For the 2013 to 2014 annual auction, 93.0 percent of FTRs were purchased for less than $1 per MW, up from 93.0 percent in the previous Annual FTR Auction. The weighted-average buy-bid FTR price for the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period.

  The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2013 to 2014 planning period was $0.06, down from $0.12 per MW in the 2012 to 2013 planning period.

- **Revenue.** The 2014 to 2017 Long Term FTR Auction generated $16.8 million of net revenue for all FTRs, down from $28.6 million in the 2013 to 2016 Long Term FTR Auction. The 2013 to 2014 Annual FTR Auction generated $558.4 million in net revenue, down $44.5 million from the 2012 to 2013 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $5.4 million in net revenue for all FTRs for the first seven months of the 2013 to 2014 planning period, down from $17.3

million for the same time period in the 2012 to 2013 planning period.

- **Revenue Adequacy.** FTRs were paid at 67.8 percent of the target allocation for the entire 2012 to 2013 planning period. FTRs were paid at 75.1 percent of the target allocation level for the first seven months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the first seven months of the 2013 to 2014 planning period and $614.0 million during the entire 2012 to 2013 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were Sunnymead and the Western Hub.

  Target allocations values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs.

- ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $170.2 million in profits for physical entities, of which $167.9 million was from self-scheduled FTRs, and $177.5 million for financial entities. As shown in Table 13-18, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013. FTR profits generally increased in the summer and winter months when congestion was higher.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the annual ARR allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the annual ARR allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the first seven months of the 2013 to 2014 planning period PJM allocated a total of 6,428.8 MW of residual ARRs with a total target allocation of $3,647,248.

- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 35,501 MW of ARRs associated with approximately $233,800 of revenue that were reassigned for the first seven months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first seven months of the 2013 to 2014 planning period, the ARR target allocations were $175.0 million while PJM collected $197.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $587.0 million while PJM collected $653.6 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first seven months of the

2013 to 2014 planning period and for the 2012 to 2013 planning period.

Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested. One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system as a hedge against congestion and pay for balancing congestion in order to increase the payout to holders of FTRs who are not loads.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period, the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013, the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM monthly is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real–time markets, including reactive interfaces, which directly results in differences in congestion between day - ahead and real-time markets; differences in day-ahead and real–time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day–ahead and real-time markets; the overallocation of ARRs which directly results in underfunding; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, PJM should reduce the number of FTRs sold.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths, subject to revenue availability. This value, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses.

Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation is a cap on what FTR holders can receive. Revenues above that level on individual FTR paths are used to fund FTRs on paths which received less than their target allocations. Available revenue to pay FTR holders is based on the amount of day-ahead and balancing congestion collected, along with Market to Market payments, excess ARR revenues available at the end of a month and any charges made to day-ahead operating reserves.

FTR funding is not on a path specific basis or on a time specific basis. There are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. Revenues to fund FTRs come from both day-ahead congestion charges on the transmission system and balancing congestion charges. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self-scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates an Annual FTR Auction for all participants. In addition, PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, which allows participants to buy and sell residual transmission capability. PJM also runs a Long Term FTR Auction for the following three consecutive planning years. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

FTR buy bids and sell offers may be made as obligations or options and as any of the three classes. FTR self-scheduled bids are available only as obligations and 24-hour class, consistent with the associated ARRs, and only in the Annual FTR Auction.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[3] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction.

Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included in the model, while known outages of five days or more are included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[4]

But the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR.

Long Term FTR Auctions

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system

3 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 38.
4 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 55.

capability assuming that all ARRs allocated in the prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds.[5] The 2011 to 2014 and 2012 to 2015 Long Term FTR Auctions consisted of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one year or a single term of all three years. FTR products available in the Long Term Auction include 24-hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 1.** The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink.
- **Round 2.** The second round is conducted approximately three months after the first round and follows the same rules as Round 1.
- **Round 3.** The third round is conducted approximately six months after the first round and follows the same rules as Round 1.

Table 13-2 and Table 13-3 show the top 10 binding constraints for the 2014 to 2017 Long Term FTR Auction and the 2013 to 2014 Annual FTR Auction based on the marginal value of on peak hours. The severity ranking is based on the marginal value of the constraint in the simultaneous feasibility test.

Table 13-2 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2014 to 2017

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
Monticello - East Winamac	Flowgate	MISO	1	58	1
Cumberland Ave - Bush	Flowgate	MISO	10	1	2
West Lafayette - Cumberland	Flowgate	MISO	NA	2	16
Oak Grove - Galesburg	Flowgate	MISO	NA	11	3
Bartonsville - Stephenson	Line	AP	NA	NA	4
Mazon - Mazon	Line	ComEd	264	10	5
Cayuga	Line	Penelec	4	3	9
Commonwealth NG - Grassfields	Line	Dominion	5	NA	NA
New Carlisle - Map	Line	MISO	NA	4	NA
Gordonsville	Transformer	Dominion	6	143	NA

Annual FTR Auctions

After the Long Term FTR Auction, residual capability on the PJM transmission system is auctioned in the Annual FTR Auction. Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months are included in the determination of the simultaneous feasibility for the Annual FTR Auction. ARR holders who wish to self schedule must inform PJM prior to round one of this auction. Any self-scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24-hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Figure 13-1 shows the geographic location of the top ten binding constraints from the 2014 to 2017 Long Term FTR Auction, the 2013 to 2014 Annual FTR Auction and the 2013 to 2014 Annual ARR allocation. Many of the top binding constraints are flowgates and the binding constraints are primarily concentrated near the PJM-MISO border. All of the top Long Term FTR Auction constraints are also ARR constraints, denoted by a yellow border.

5 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

Figure 13-1 Geographic location of top five binding constraints for the Long Term FTR Auction, Annual FTR Auction and Annual ARR Allocation: Planning period 2014 to 2017 and 2013 to 2014

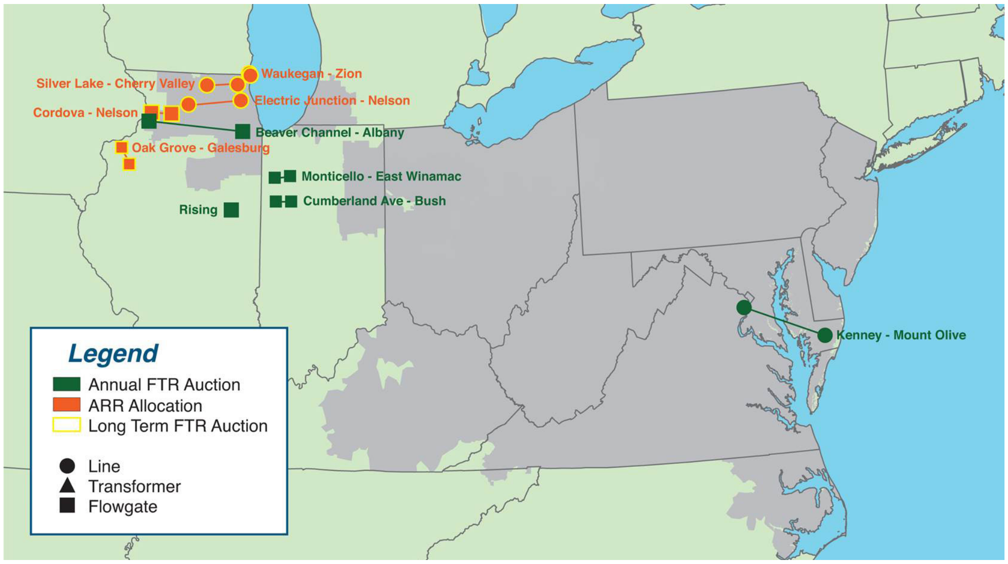


Table 13-3 shows the top 10 binding constraints for the 2013 to 2014 Annual FTR Auction based on the marginal value of on peak hours.

Table 13-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2013 to 2014

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Cumberland Ave - Bush	Flowgate	MISO	1	1	1	1
Beaver Channel - Albany	Flowgate	MISO	2	3	2	3
Monticello - East Winamac	Flowgate	MISO	3	2	3	2
Rising	Flowgate	MISO	NA	NA	NA	4
Kenney - Mount Olive	Line	DPL	7	NA	4	5
Roxbury - Shade Gap	Line	PENELEC	4	8	8	10
Prairie State - W. Mt. Vernon	Flowgate	MISO	5	5	10	NA
Glenarm - Windy Edge	Line	BGE	6	7	5	6
Kenney - Stockton	Line	DPL	NA	4	NA	NA
Pana North	Flowgate	MISO	8	6	6	NA

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Existing FTRs are modeled as fixed injections and withdrawals. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak and off peak products.[6]

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original

6 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 39.

FTR start time and the end time cannot be later than the original FTR end time.

Buy Bids

The total FTR buy bids in the 2013 to 2014 Annual FTR Auction were 3,274,373 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period were 19,685,688 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-4 presents the 2014 to 2017 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 65.1 percent of prevailing flow by bid FTRs and 79.7 percent of counter flow buy bid FTRs with the result that financial entities purchased 70.7 percent of all Long Term FTR Auction cleared buy bids for the 2014 to 2017 Long Term FTR Auction.

Table 13-4 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2014 to 2017

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	34.9%	20.3%	29.3%
	Financial	65.1%	79.7%	70.7%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	13.0%	13.0%	13.0%
	Financial	87.0%	87.0%	87.0%
	Total	100.0%	100.0%	100.0%

Table 13-5 presents the Annual FTR Auction cleared FTRs for the 2013 to 2014 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2013 to 2014 planning period, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs, with the result that financial entities purchased 61.5 percent of all Annual FTR Auction cleared buy bids for the 2013 to 2014 planning period.

Table 13-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2013 to 2014

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	9.2%	0.2%	7.0%
		No	36.1%	17.5%	31.5%
		Total	45.3%	17.8%	38.5%
	Financial	No	54.7%	82.2%	61.5%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		20.7%	19.0%	20.2%
	Financial		79.3%	81.0%	79.8%
	Total		100.0%	100.0%	100.0%

Table 13-6 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through December 2013 by trade type, organization type and FTR direction. Financial entities purchased 76.0 percent of prevailing flow and 85.8 percent of counter flow FTRs for the year, with the result that financial entities purchased 80.0 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through December 2013.

Table 13-6 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through December 2013

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	24.0%	14.2%	20.0%
	Financial	76.0%	85.8%	80.0%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	31.7%	28.6%	31.1%
	Financial	68.3%	71.4%	68.9%
	Total	100.0%	100.0%	100.0%

Table 13-7 presents the daily net position ownership for all FTRs for January through December 2013, by FTR direction.

Table 13-7 Daily FTR net position ownership by FTR direction: January through December 2013

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	49.4%	24.7%	41.0%
Financial	50.6%	75.3%	59.0%
Total	100.0%	100.0%	100.0%

Market Behavior

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real-time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 13-2 demonstrates the FTR forfeiture rule for INCs and DECs. The INC or DEC distribution factor (dfax) is compared to the largest impact withdrawal or injection dfax. If the absolute difference between the virtual bid and its counterpart is greater than or equal to 75 percent, the virtual bid is considered for forfeiture. This is the metric in the rule which defines the impact of the virtual bid on the constraint.

In the first part of the example in Figure 13-2, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfaxes is -0.75 (0.25 minus -0.5). The absolute value is 0.75. In the second part of the example in, the DEC has dfax of 0.5 and the maximum injection dfax on the constraint is -0.25. The difference between the two dfaxes is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-2 Illustration of INC/DEC FTR forfeiture rule

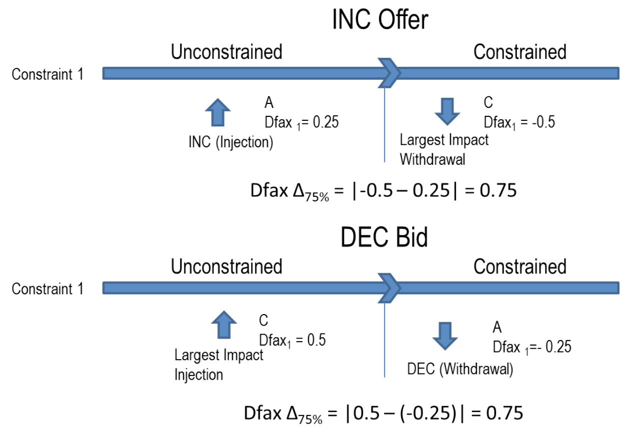


Figure 13-3 shows the FTR forfeitures values for both physical and financial participants for each month of June 2010 through December 2013. Currently, FTRs that alleviate a constraint are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2012 to 2013 planning period were $539,580 (0.09 percent of total FTR target allocations).

Figure 13-3 Monthly FTR forfeitures for physical and financial participants: June 2010 through December 2013

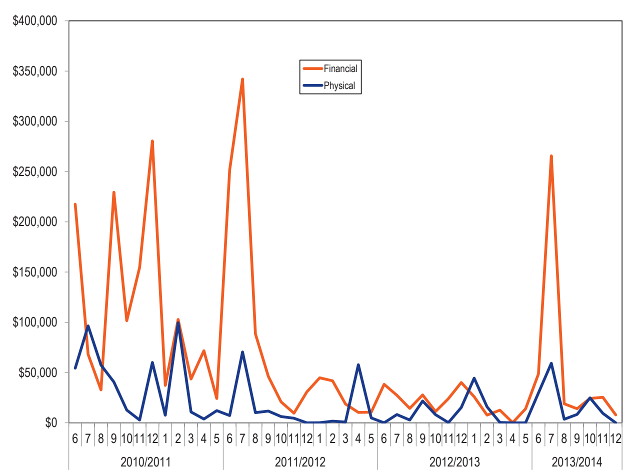
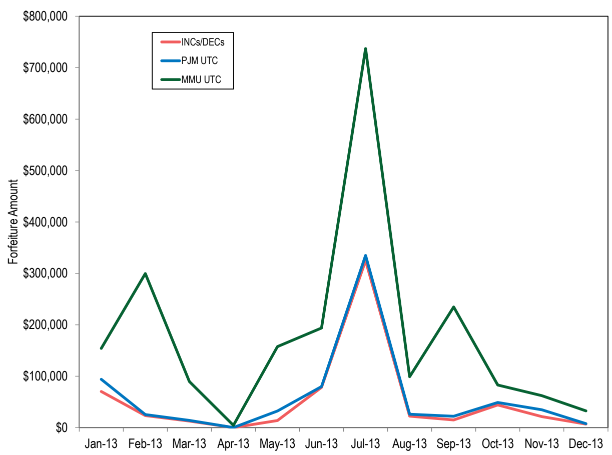


Figure 13-4 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through December 2013. The method proposed by PJM for calculating forfeitures associated with UTCs was implemented on September 1, 2013, and for each month thereafter. UTC forfeitures before September 2013 were not billed, but are included to illustrate the impact of the different methods of calculating forfeitures. The UTC curves include all forfeitures for the month associated with INCs, DECs and UTCs.

Figure 13-4 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through December 2013



Credit Issues

The credit issues reported here were not necessarily related to FTR positions.

Ten participants defaulted during 2013 from 16 default events. The average of these defaults was $255,611 with ten based on inadequate collateral and six based on nonpayment. The average collateral default was $93,749 and the average nonpayment default was $352,729. The majority of these defaults were promptly cured, with one partial cure.

Market Performance

Volume

Table 13-8 shows the 2014 to 2017 Long Term FTR Auction volume by trade type, FTR direction and period type.[7] The total volume was 3,072,909 MW for FTR buy bids and 316,056 MW for FTR sell offers in the 2014 to 2017 Long Term FTR Auction. This represents a 23.8 percent increase in buy bids and a 104.4 percent increase in FTR sell offers over the 2012 to 2015 Long Term FTR Auction.

The 2014 to 2017 Long Term FTR Auction cleared 197,125 MW (6.4 percent) of FTR buy bids, compared to 290,700 MW (10.5 percent) in the previous Long Term FTR Auction. The 2014 to 2017 Long Term FTR Auction also cleared 21,501MW (6.8 percent) of FTR sell offers, compared to 56,692 MW (26.8 percent) in the previous Long Term FTR Auction.

The volume of buy bids for the period covering all three years of the Long Term FTR Auction was 35,019 MW for both prevailing and counter flow FTRs, with a total of 3,197 MW clearing (9.1 percent). In the previous Long Term FTR Auction the buy bids for the three year FTR were 49,019 MW with 2,400 MW clearing, representing a 28.6 percent decrease in buy bids for the 2014 to 2017 planning periods.

In the 2014 to 2017 Long Term FTR Auction 76,703 MW (5.8 percent of demand; 38.9 percent of total FTR volume) of counter flow FTR buys bids and 120,421 MW (6.8 percent of demand; 61.1 percent of total FTR volume) of prevailing flow FTR buy bids cleared. In the 2014 to 2017 Long Term FTR Auction, there were 210,794 MW (2.4 percent) of counter flow sell offers and 105,262 MW (15.7 percent) of prevailing flow sell offers cleared.

7 Calculated values shown in Section 13, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 13-8 Long Term FTR Auction market volume: Planning period 2014 to 2017

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	98,411	526,986	27,349	5.2%	499,636	94.8%
		Year 2	85,834	385,003	22,845	5.9%	362,158	94.1%
		Year 3	79,639	367,513	23,312	6.3%	344,201	93.7%
		Year All	7,078	35,019	3,197	9.1%	31,822	90.9%
		Total	270,962	1,314,520	76,703	5.8%	1,237,817	94.2%
	Prevailing Flow	Year 1	104,304	668,739	44,052	6.6%	624,687	93.4%
		Year 2	89,178	545,049	38,446	7.1%	506,603	92.9%
		Year 3	82,292	509,847	36,862	7.2%	472,984	92.8%
		Year All	7,149	34,753	1,061	3.1%	33,693	96.9%
		Total	282,923	1,758,389	120,421	6.8%	1,637,967	93.2%
	Total		553,885	3,072,909	197,125	6.4%	2,875,785	93.6%
Sell offers	Counter Flow	Year 1	37,482	112,049	2,900	2.6%	109,149	97.4%
		Year 2	26,215	76,173	1,831	2.4%	74,342	97.6%
		Year 3	11,484	22,571	286	1.3%	22,285	98.7%
		Year All	NA	NA	NA	NA	NA	NA
		Total	75,181	210,794	5,017	2.4%	205,777	97.6%
	Prevailing Flow	Year 1	19,598	64,957	9,111	14.0%	55,846	86.0%
		Year 2	13,012	34,903	6,798	19.5%	28,105	80.5%
		Year 3	3,057	5,403	575	10.6%	4,828	89.4%
		Year All	NA	NA	NA	NA	NA	NA
		Total	35,667	105,262	16,484	15.7%	88,778	84.3%
	Total		110,848	316,056	21,501	6.8%	294,555	93.2%

Table 13-9 provides the Annual FTR Auction market volume for the 2013 to 2014 planning period. Total FTR buy bids were 3,274,373 MW, up 27.8 percent from 2,561,835 MW for the previous planning period. For the 2013 to 2014 planning period 391,148 MW (12.1 percent) of buy bids cleared, up 5.3 percent from 371,295 MW for the last planning period. There were 417,118 MW of sell offers with 37,821 MW (9.1 percent) clearing for the 2013 to 2014 planning period.

Table 13-9 Annual FTR Auction market volume: Planning period 2013 to 2014

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	76,647	365,441	103,814	28.4%	261,627	71.6%
		Prevailing Flow	234,724	1,650,737	225,006	13.6%	1,425,731	86.4%
		Total	311,371	2,016,178	328,820	16.3%	1,687,358	83.7%
	Options	Counter Flow	172	8,829	0	0.0%	8,829	100.0%
		Prevailing Flow	42,659	1,220,026	62,328	5.1%	1,157,698	94.9%
		Total	42,831	1,228,855	62,328	5.1%	1,166,527	94.9%
	Total	Counter Flow	76,819	374,269	103,814	27.7%	270,455	72.3%
		Prevailing Flow	277,383	2,870,763	287,334	10.0%	2,583,430	90.0%
		Total	354,202	3,245,033	391,148	12.1%	2,853,885	87.9%
Self-scheduled bids	Obligations	Counter Flow	129	231	231	100.0%	0	0.0%
		Prevailing Flow	2,847	29,110	29,110	100.0%	0	0.0%
		Total	2,976	29,341	29,341	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	76,776	365,672	104,045	28.5%	261,627	71.5%
		Prevailing Flow	237,571	1,679,847	254,116	15.1%	1,425,731	84.9%
		Total	314,347	2,045,518	358,161	17.5%	1,687,358	82.5%
	Options	Counter Flow	172	8,829	0	0.0%	8,829	100.0%
		Prevailing Flow	42,659	1,220,026	62,328	5.1%	1,157,698	94.9%
		Total	42,831	1,228,855	62,328	5.1%	1,166,527	94.9%
	Total	Counter Flow	76,948	374,500	104,045	27.8%	270,455	72.2%
		Prevailing Flow	280,230	2,899,873	316,444	10.9%	2,583,430	89.1%
		Total	357,178	3,274,373	420,489	12.8%	2,853,885	87.2%
Sell offers	Obligations	Counter Flow	36,423	144,023	11,356	7.9%	132,667	92.1%
		Prevailing Flow	54,723	262,545	25,761	9.8%	236,784	90.2%
		Total	91,146	406,568	37,117	9.1%	369,451	90.9%
	Options	Counter Flow	1	1	0	0.0%	1	100.0%
		Prevailing Flow	406	10,549	704	6.7%	9,845	93.3%
		Total	407	10,550	704	6.7%	9,846	93.3%
	Total	Counter Flow	36,424	144,024	11,356	7.9%	132,668	92.1%
		Prevailing Flow	55,129	273,095	26,465	9.7%	246,630	90.3%
		Total	91,553	417,118	37,821	9.1%	379,297	90.9%

Figure 13-5 shows the volume trend of the Annual FTR Auctions from planning period 2009 to 2010 through December 31, 2013. The payout ratio, represented by the green bars, for 2013 to 2014 is not yet final. The cleared MW over these planning periods has been increasing for off-peak and on-peak prevailing flow FTRs, and has remained relatively steady for all other FTR classes.

Figure 13-5 Annual FTR Auction volume: Planning period 2009 to 2010 to 2013 to 2014

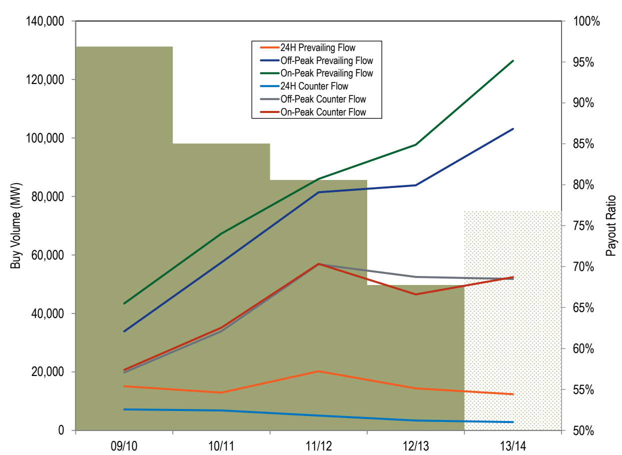


Table 13-10 shows the proportion of ARRs self scheduled as FTRs for the last five planning periods. The maximum possible level of self-scheduled FTRs includes all ARR, including RTEP ARRs. Eligible participants self-scheduled 29,341 MW (31.2 percent) of ARRs into FTRs for the 2013 to 2014 planning period, down from 41,716 MW (42.1 percent) in the previous planning period.

Table 13-10 Comparison of self-scheduled FTRs: Planning periods from 2009 to 2010 through 2013 to 2014

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%
2011/2012	46,017	103,735	44.4%
2012/2013	41,716	99,115	42.1%
2013/2014	29,341	94,061	31.2%

In an effort to reduce FTR underfunding caused by forced Stage 1A infeasibilities, PJM may use reduced capability limits instead of the increased Stage 1A capability limits in FTR auctions. These capability limits may be reduced if ARR funding is not impacted, all requested self-scheduled FTRs clear and net FTR Auction revenue is positive. If the normal capability limit cannot be reached due to infeasibilities then FTR Auction capability reductions are undertaken pro-rata based on the MWs of Stage 1A infeasibility. Reducing capability limits will reduce the number of oversold FTR facilities due to forced Stage 1A infeasibilities and reduce underfunding caused by these ARR infeasibilities. The downside to this strategy is that there will be less FTRs for sale in the FTR Auctions, therefore, less auction revenue will be collected to pay ARR holders.

Also in an effort to reduce FTR underfunding, PJM implemented a new rule stating that PJM may model normal capability limits on facilities which are infeasible due to modeled transmission outages in Monthly Balance of Planning Period FTR Auctions. The capability of these facilities may be reduced if ARR target allocations are fully funded and net auction revenues are greater than zero. The results of this action should be an increased feasibility of the FTR model and a reduced risk of FTR underfunding, but will lead to a reduction in FTR Auction revenue due to a lower capability.

Table 13-11 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2012 to 2013 planning period and the first seven months of the 2013 to 2014 planning period. There were 13,634,312 MW of FTR buy bid obligations and 2,969,751 MW of FTR sell offer obligations for all bidding periods in the first seven months of the 2013 to 2014 planning period. The monthly balance of planning period auctions cleared 2,186,617 MW (16.0 percent) of FTR buy bid obligations and 431,536 MW (11.9 percent) of FTR sell offer obligations.

There were 2,882,925 MW of FTR buy bid options and 979,578 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2013 to 2014 planning period. The monthly auctions cleared 96,794 (3.3 percent) of FTR buy bid options, and 311,195 MW (31.8 percent) of FTR sell offers.

Table 13-11 Monthly Balance of Planning Period FTR Auction market volume: January through December 2013

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-13	Obligations	Buy bids	150,397	963,036	166,622	17.3%	796,414	82.7%
		Sell offers	84,563	297,609	34,710	11.7%	262,899	88.3%
	Options	Buy bids	2,830	104,318	6,767	6.5%	97,551	93.5%
		Sell offers	10,204	73,624	17,322	23.5%	56,302	76.5%
Feb-13	Obligations	Buy bids	164,620	1,035,756	166,386	16.1%	869,369	83.9%
		Sell offers	76,210	261,631	36,402	13.9%	225,229	86.1%
	Options	Buy bids	2,518	94,039	4,749	5.0%	89,290	95.0%
		Sell offers	9,053	62,833	16,434	26.2%	46,399	73.8%
Mar-13	Obligations	Buy bids	168,718	1,092,986	188,849	17.3%	904,138	82.7%
		Sell offers	77,248	256,820	40,079	15.6%	216,741	84.4%
	Options	Buy bids	2,674	103,046	5,591	5.4%	97,455	94.6%
		Sell offers	10,054	84,993	21,581	25.4%	63,411	74.6%
Apr-13	Obligations	Buy bids	130,671	742,450	143,747	19.4%	598,703	80.6%
		Sell offers	55,739	206,725	33,203	16.1%	173,522	83.9%
	Options	Buy bids	1,852	47,911	4,069	8.5%	43,842	91.5%
		Sell offers	6,017	58,130	17,259	29.7%	40,870	70.3%
May-13	Obligations	Buy bids	99,964	562,240	119,522	21.3%	442,718	78.7%
		Sell offers	25,028	93,603	19,917	21.3%	73,686	78.7%
	Options	Buy bids	792	33,223	2,901	8.7%	30,322	91.3%
		Sell offers	2,634	24,643	15,506	62.9%	9,137	37.1%
Jun-13	Obligations	Buy bids	268,004	1,548,839	275,485	17.8%	1,273,354	82.2%
		Sell offers	150,754	474,950	59,536	12.5%	415,415	87.5%
	Options	Buy bids	4,155	313,972	14,825	4.7%	299,147	95.3%
		Sell offers	23,090	198,850	55,455	27.9%	143,395	72.1%
Jul-13	Obligations	Buy bids	296,234	2,006,362	281,879	14.0%	1,724,483	86.0%
		Sell offers	142,594	429,555	57,422	13.4%	372,133	86.6%
	Options	Buy bids	10,303	564,738	16,412	2.9%	548,326	97.1%
		Sell offers	20,146	140,558	51,541	36.7%	89,018	63.3%
Aug-13	Obligations	Buy bids	337,418	2,283,124	334,179	14.6%	1,948,945	85.4%
		Sell offers	133,353	385,475	61,167	15.9%	324,309	84.1%
	Options	Buy bids	8,850	443,384	12,719	2.9%	430,665	97.1%
		Sell offers	21,320	147,295	45,916	31.2%	101,379	68.8%
Sep-13	Obligations	Buy bids	316,757	2,128,460	354,081	16.6%	1,774,379	83.4%
		Sell offers	186,831	421,145	65,522	15.6%	355,623	84.4%
	Options	Buy bids	8,735	476,204	19,173	4.0%	457,032	96.0%
		Sell offers	20,991	137,118	47,328	34.5%	89,790	65.5%
Oct-13	Obligations	Buy bids	278,253	1,828,738	309,173	16.9%	1,519,565	83.1%
		Sell offers	149,754	410,505	64,132	15.6%	346,373	84.4%
	Options	Buy bids	9,107	404,346	13,732	3.4%	390,614	96.6%
		Sell offers	17,560	129,935	36,112	27.8%	93,822	72.2%
Nov-13	Obligations	Buy bids	280,197	1,882,603	315,898	16.8%	1,566,704	83.2%
		Sell offers	138,601	379,154	58,685	15.5%	320,469	84.5%
	Options	Buy bids	8,701	424,561	12,156	2.9%	412,404	97.1%
		Sell offers	15,495	104,508	32,240	30.8%	72,268	69.2%
Dec-13	Obligations	Buy bids	244,187	1,956,187	315,922	16.1%	1,640,265	83.9%
		Sell offers	133,204	382,140	65,072	17.0%	317,067	83.0%
	Options	Buy bids	9,184	342,546	7,776	2.3%	334,770	97.7%
		Sell offers	16,317	121,314	42,605	35.1%	78,710	64.9%
2012/2013*	Obligations	Buy bids	2,255,105	12,956,832	2,171,751	16.8%	10,785,081	83.2%
		Sell offers	1,080,775	3,922,225	468,426	11.9%	3,453,798	88.1%
	Options	Buy bids	103,926	6,728,856	74,889	1.1%	6,653,967	98.9%
		Sell offers	149,274	1,088,211	268,684	24.7%	819,527	75.3%
2013/2014**	Obligations	Buy bids	2,021,050	13,634,312	2,186,617	16.0%	11,447,695	84.0%
		Sell offers	1,035,091	2,882,925	431,536	15.0%	2,451,389	85.0%
	Options	Buy bids	59,035	2,969,751	96,794	3.3%	2,872,957	96.7%
		Sell offers	134,919	979,578	311,195	31.8%	668,382	68.2%

* Shows Twelve Months for 2012/2013; ** Shows seven months ended 31-Dec-13 for 2013/2014

Table 13-12 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for January through December 2013 is 257,717.7 MW. The average monthly cleared volume for January through December 2012 was 176,910.2 MW.

Table 13-12 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through December 2013

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	Bid	595,260	191,417	115,207				165,471	1,067,354
	Cleared	125,075	24,018	8,251				16,045	173,389
Feb-13	Bid	654,446	174,360	177,548				123,440	1,129,794
	Cleared	131,562	15,659	13,975				9,939	171,135
Mar-13	Bid	645,247	232,876	224,105				93,804	1,196,032
	Cleared	136,007	27,219	24,669				6,544	194,440
Apr-13	Bid	610,571	179,789						790,360
	Cleared	127,896	19,920						147,816
May-13	Bid	595,463							595,463
	Cleared	122,423							122,423
Jun-13	Bid	766,947	218,427	205,723	112,180	195,196	193,766	170,571	1,862,810
	Cleared	141,332	31,035	25,346	14,149	27,397	25,560	25,491	290,310
Jul-13	Bid	921,277	343,637	244,602		329,350	349,639	382,594	2,571,100
	Cleared	158,643	30,086	15,959		27,840	34,134	31,628	298,291
Aug-13	Bid	1,076,550	268,252	266,570		331,723	393,247	390,165	2,726,508
	Cleared	178,551	26,336	22,399		30,116	47,483	42,012	346,898
Sep-13	Bid	934,389	330,547	344,156		250,625	375,174	369,773	2,604,664
	Cleared	188,437	37,569	36,258		23,153	45,357	42,480	373,253
Oct-13	Bid	881,879	334,532	292,728			347,421	376,525	2,233,085
	Cleared	169,523	39,747	20,054			45,843	47,738	322,905
Nov-13	Bid	978,927	327,581	306,138			309,506	385,011	2,307,163
	Cleared	190,228	28,048	23,552			36,379	49,848	328,055
Dec-13	Bid	930,516	383,830	378,094			225,178	381,114	2,298,733
	Cleared	168,414	42,300	38,165			26,989	47,830	323,698

Figure 13-6 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2013, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with an accompanying rise in the share of Annual FTRs.

Figure 13-6 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2013

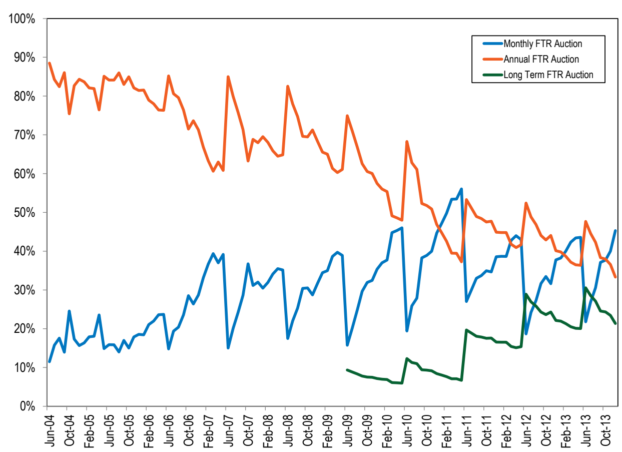


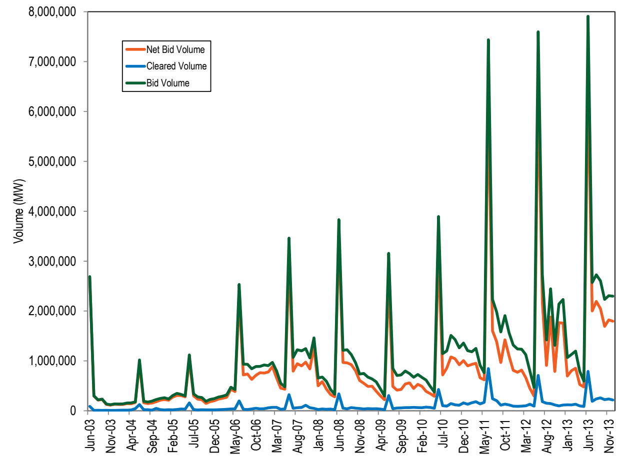
Table 13-13 provides the secondary bilateral FTR market volume for the entire 2012 to 2013 and 2013 to 2014 planning periods.

Table 13-13 Secondary bilateral FTR market volume: Planning periods 2012 to 2013 and 2013 to 2014[8]

Planning Period	Hedge Type	Class Type	Volume (MW)
2012/2013	Obligation	24-Hour	95
		On Peak	137
		Off Peak	60
		Total	292
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0
2013/2014	Obligation	24-Hour	110
		On Peak	41,590
		Off Peak	34,178
		Total	75,879
	Option	24-Hour	0
		On Peak	9,724
		Off Peak	914
		Total	10,638

Figure 13-7 shows the FTR bid, cleared and net bid volume from June 2003 through December 2013 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume is the volume of FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers, excluding sell offers. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

Figure 13-7 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2013



Price

Table 13-14 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2014 to 2017 Long Term FTR Auction. Only FTR obligation products are available in the Long Term FTR Auctions. In this auction, weighted-average buy bid FTR prices were $0.03 per MW, down $0.02 from 2013 to 2016 Long Term FTR Auction prices, while weighted-average sell offer FTR prices were $0.11 per MW, down $0.03 per MW from the previous Long Term FTR Auction.

8 The 2013 to 2014 planning period covers bilateral FTRs that are effective for any time between June 1, 2013 through December 31, 2013, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Table 13-14 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): Planning periods 2014 to 2017

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($0.68)	($0.22)	($0.36)	($0.29)
		Year 2	($0.68)	($0.19)	($0.27)	($0.25)
		Year 3	($0.54)	($0.17)	($0.25)	($0.21)
		Year All	NA	($0.04)	($0.08)	($0.05)
		Total	($0.65)	($0.17)	($0.28)	($0.23)
	Prevailing Flow	Year 1	$0.23	$0.19	$0.31	$0.24
		Year 2	$0.17	$0.15	$0.27	$0.20
		Year 3	$0.19	$0.14	$0.23	$0.18
		Year All	NA	$0.04	$0.08	$0.05
		Total	$0.19	$0.16	$0.27	$0.21
	Total		($0.18)	$0.02	$0.06	$0.03
Sell offers	Counter Flow	Year 1	($2.89)	($0.29)	($0.50)	($0.39)
		Year 2	NA	($0.33)	($0.60)	($0.45)
		Year 3	NA	($0.34)	($0.65)	($0.49)
		Year All	NA	NA	NA	NA
		Total	($2.89)	($0.31)	($0.54)	($0.42)
	Prevailing Flow	Year 1	$0.26	$0.23	$0.40	$0.31
		Year 2	$0.08	$0.13	$0.35	$0.22
		Year 3	NA	$0.18	$0.38	$0.23
		Year All	NA	NA	NA	NA
		Total	$0.12	$0.19	$0.38	$0.27
	Total		$0.03	$0.07	$0.16	$0.11

Figure 13-8 shows the cleared buy bid price frequency for the 2014 to 2017 Long Term FTR Auction and that 97.6 percent of Long Term FTRs were purchased for less than $1 per MW. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The majority of the cleared bids for the 2014 to 2017 Long Term FTR Auction fall into the $0 to $2 range.

Figure 13-8 Long Term FTR Auction clearing price per MW frequency: Planning periods 2014 to 2017

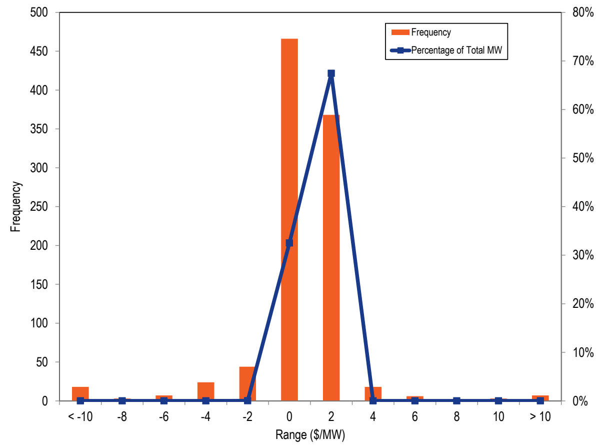


Table 13-15 shows the weighted-average cleared buy-bid prices by trade type, hedge type, FTR direction and class type for the Annual FTR Auction for the 2013 to 2014 planning period. The weighted-average buy-bid FTR price in the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period.

Table 13-15 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2013 to 2014

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.17)	($0.30)	($0.15)	($0.22)
		Prevailing Flow	$0.59	$0.51	$0.32	$0.43
		Total	$0.45	$0.27	$0.16	$0.23
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.19	$0.17	$0.10	$0.13
		Total	$1.19	$0.17	$0.10	$0.13
Self-scheduled bids	Obligations	Counter Flow	($0.24)	NA	NA	($0.24)
		Prevailing Flow	$0.73	NA	NA	$0.73
		Total	$0.72	NA	NA	$0.72
Buy and self-scheduled bids	Obligations	Counter Flow	($0.18)	($0.30)	($0.15)	($0.22)
		Prevailing Flow	$0.69	$0.51	$0.32	$0.49
		Total	$0.64	$0.27	$0.16	$0.30
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.19	$0.17	$0.10	$0.13
		Total	$1.19	$0.17	$0.10	$0.13
Sell offers	Obligations	Counter Flow	($1.95)	($0.57)	($0.35)	($0.54)
		Prevailing Flow	$0.35	$0.38	$0.21	$0.30
		Total	($0.18)	$0.14	$0.02	$0.05
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.07	$0.07	$0.07
		Total	$0.00	$0.07	$0.07	$0.07

Figure 13-9 shows the volume-weighted average buy bid price for the Annual FTR Auctions from the 2009 to 2010 planning period through December 31, 2013 of the 2013 to 2014 planning period. The payout ratio, represented by gray bars, for the 2013 to 2014 planning period is not yet final. Overall, the prices of 24 hour obligation FTRs are down, while Off-peak and On-peak FTR buy bid prices remain relatively unchanged.

Figure 13-9 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through December 31, 2013

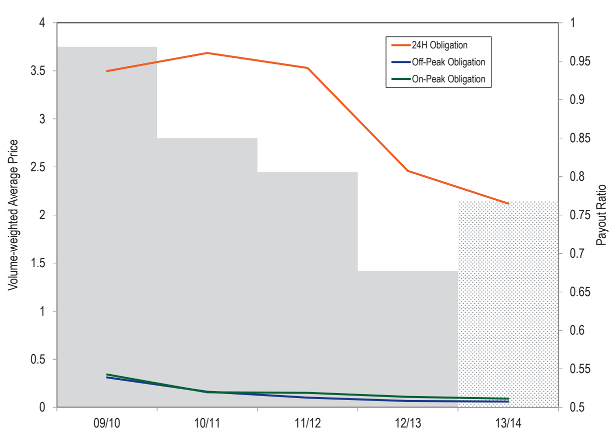


Figure 13-10 shows the weighted-average cleared buy-bid price frequency for the 2013 to 2014 Annual FTR Auction. 92.9 percent of Annual FTRs were purchased for less than $1 per MW.

Figure 13-10 Annual FTR Auction clearing price per MW: Planning period 2013 to 2014

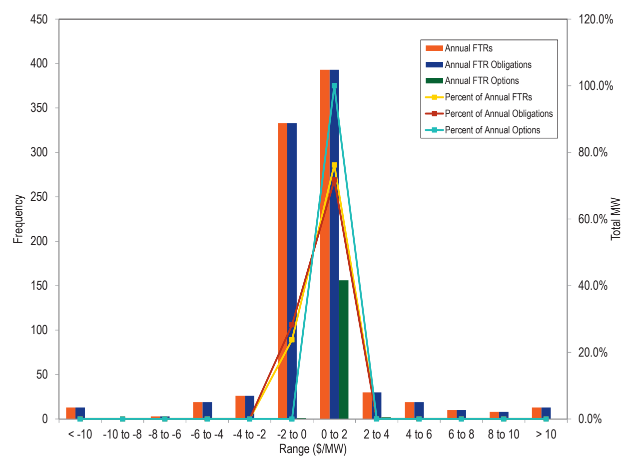


Table 13-16 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2013 through December 2013. For example, for the January 2013 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is

March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2013 Monthly Balance of Planning Period FTR Auction.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through December 2013 was $0.06 per MW, down from $0.12 per MW in the same time last year.

Table 13-16 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through December 2013

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	$0.11	$0.20	$0.05				$0.09	$0.11
Feb-13	$0.09	$0.12	$0.10				$0.13	$0.10
Mar-13	$0.10	$0.12	$0.10				$0.05	$0.10
Apr-13	$0.10	$0.16						$0.11
May-13	$0.09	$0.00						$0.09
Jun-13	$0.08	$0.21	$0.19	$0.15	$0.16	$0.14	$0.10	$0.06
Jul-13	$0.10	$0.17	($0.14)		$0.12	$0.07	$0.06	$0.08
Aug-13	$0.08	$0.17	$0.07		$0.07	$0.07	$0.06	$0.08
Sep-13	$0.06	$0.07	$0.04		$0.11	$0.09	$0.06	$0.07
Oct-13	$0.08	$0.09	($0.01)			$0.08	$0.07	$0.06
Nov-13	$0.06	$0.07	$0.12			$0.05	$0.07	$0.04
Dec-13	$0.07	$0.09	$0.04			$0.12	$0.08	$0.06

Profitability

Table 13-17 FTR profits by organization type and FTR direction: January through December 2013

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($43,931,263)	$167,898,667	$44,305,554	$1,907,612	$170,180,569
Financial	$50,622,405	NA	$126,872,101	NA	$177,494,506
Total	$6,691,142	$167,898,667	$171,177,655	$1,907,612	$347,675,076

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but the ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 13-17 lists FTR profits by organization type and FTR direction for the period from January through December, 2013. FTR profits are the sum of the daily FTR credits, including for self-scheduled FTRs, minus the daily FTR auction costs for each FTR held by an organization. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days, but self-scheduled FTRs have zero cost. FTRs were profitable overall, with $170.2 million in profits for physical entities, of which $169.8 million was from self-scheduled FTRs, and $177.5 million for financial entities.

Table 13-18 lists the monthly FTR profits in 2013 by organization type.

Table 13-18 Monthly FTR profits by organization type: January through December 2013

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$4,433,798	$24,630,019	$13,640,158	$42,703,975
Feb	$14,090,796	$20,676,306	$16,980,941	$51,748,044
Mar	($9,498,908)	$15,149,289	$4,849,731	$10,500,113
Apr	($12,666,550)	$6,571,358	$2,187,796	($3,907,396)
May	($3,242,261)	$14,590,963	$12,513,107	$23,861,810
Jun	$1,557,793	$12,289,397	$14,357,719	$28,204,910
Jul	$9,677,398	$20,442,580	$33,133,249	$63,253,226
Aug	(11,149,377.18)	$6,876,920	$3,987,989	($284,468)
Sep	$9,770,015	$14,681,142	$30,413,658	$54,864,815
Oct	($3,363,184)	$7,679,380	$8,438,729	$12,754,925
Nov	($3,783,325)	$10,090,289	$9,346,813	$15,653,777
Dec	$4,548,096	$16,128,634	$27,644,615	$48,321,345
Total	$374,291	$169,806,278	$177,494,506	$347,675,076

Revenue

Long Term FTR Auction Revenue

Table 13-19 shows the Long Term FTR Auction revenue data by trade type, FTR direction, period type and class type. The 2014 to 2017 Long Term FTR Auction netted $16.8 million in revenue, $11.8 million less than the previous Long Term FTR Auction. Buyers paid $27.2 million and sellers received $10.4 million, down $35.5 million and $23.7 million over the previous Long Term FTR Auction.

Table 13-19 Long Term FTR Auction Revenue: Planning periods 2014 to 2017

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($2,686,267)	($17,437,460)	($15,165,264)	($35,288,992)
		Year 2	($2,517,547)	($12,137,365)	($10,466,042)	($25,120,954)
		Year 3	($1,034,386)	($11,337,075)	($9,840,633)	($22,212,094)
		Year All	$0	($952,834)	($1,125,735)	($2,078,569)
		Total	($6,238,200)	($41,864,735)	($36,597,675)	($84,700,609)
	Prevailing Flow	Year 1	$475,987	$26,701,546	$19,917,305	$47,094,838
		Year 2	$779,165	$19,766,021	$13,859,144	$34,404,330
		Year 3	$1,112,584	$16,609,539	$11,914,315	$29,636,438
		Year All	$0	$364,497	$402,309	$766,806
		Total	$2,367,736	$63,441,603	$46,093,074	$111,902,412
	Total		($3,870,464)	$21,576,868	$9,495,400	$27,201,803
Sell offers	Counter Flow	Year 1	($126,480)	($2,763,327)	($2,103,648)	($4,993,454)
		Year 2	$0	($2,123,903)	($1,500,852)	($3,624,754)
		Year 3	0	($397,087)	($215,352)	($612,439)
		Year All	NA	NA	NA	NA
		Total	($126,480)	($5,284,316)	($3,819,851)	($9,230,647)
	Prevailing Flow	Year 1	$88,606	$7,106,180	$5,129,677	$12,324,463
		Year 2	$34,781	$4,520,648	$2,127,053	$6,682,482
		Year 3	48,560	$392,453	$212,369	$653,382
		Year All	NA	NA	NA	NA
		Total	$171,947	$12,019,281	$7,469,099	$19,660,327
	Total		$45,468	$6,734,965	$3,649,247	$10,429,680
Total			($3,915,932)	$14,841,903	$5,846,152	$16,772,123

For the 2014 to 2017 Long Term FTR Auction, the counter flow FTRs netted -$75.5 million in revenue, down $63.0 million, while prevailing flow FTRs netted $ 92.2 million in revenue, down $104.1 million from the previous Long Term FTR Auction.

Figure 13-11 summarizes total revenue associated with all FTRs, regardless of sink, to FTR sources that produced the largest positive and negative revenue from the 2014 to 2017 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $46.0 million of the total revenue of $29.8 million paid in the auction, they also comprised 7.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$22.6 million of revenue and constituted 2.9 percent of all FTRs bought in the auction.

Figure 13-11 Ten largest positive and negative revenue production FTR sources purchased in the Long Term FTR Auction: Planning periods 2014 to 2017

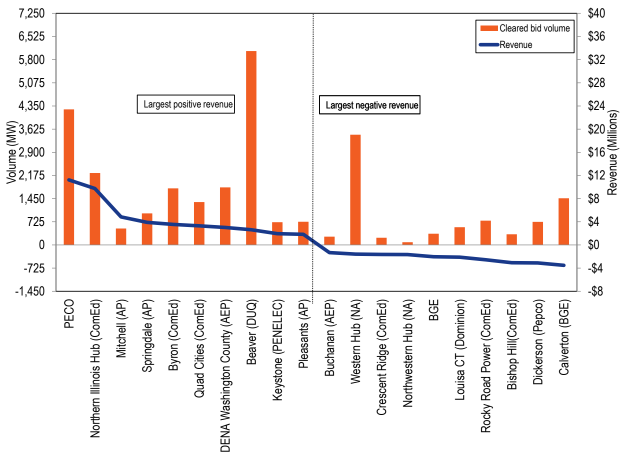


Figure 13-12 Ten largest positive and negative revenue producing sinks purchased in the Long Term FTR Auction: Planning periods 2014 to 2017[10]

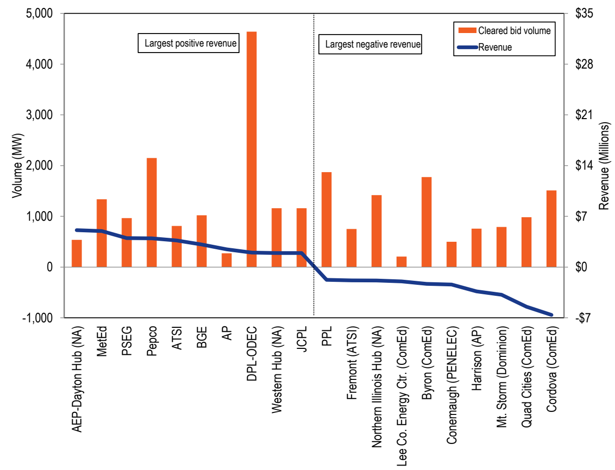


Figure 13-12 summarizes the total revenue associated with all FTRs, regardless of source, to FTR sources that produced the largest positive and negative revenue from the 2014 to 2017 Long Term FTR Auction.[9] The top 10 positive revenue production FTR sinks accounted for $33.1 million of the total revenue of $40.4 million paid in the auction, they also comprised 5.0 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$31.4 million of revenue and constituted 3.8 percent of all FTRs bought in the auction.

Annual FTR Auction Revenue

Table 13-20 shows the Annual FTR Auction revenue by trade type, hedge type, FTR direction and class type. The Annual FTR Auction for the 2013 to 2014 planning period generated $558.4 million, down 7.4 percent from $602.9 million in the 2012 to 2013 planning period, and down 45.8 percent from the 2011 to 2012 planning period. Counter flow FTR holders received $73.5 million from the auction and prevailing flow FTR holders paid $631.9 million.

9 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce the net auction revenue, therefore, the sum of the highest revenue production FTRs can exceed the net auction revenue.

10 For Figure 13-11 through Figure 13-16, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Table 13-20 Annual FTR Auction revenue: Planning period 2013 to 2014

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($3,584,655)	($61,297,999)	($34,970,300)	($99,852,954)
		Prevailing Flow	$57,603,843	$244,753,274	$143,657,697	$446,014,815
		Total	$54,019,189	$183,455,275	$108,687,397	$346,161,861
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$773,687	$20,414,078	$15,109,880	$36,297,645
		Total	$773,687	$20,414,078	$15,109,880	$36,297,645
	Total	Counter Flow	($3,584,655)	($61,297,999)	($34,970,300)	($99,852,954)
		Prevailing Flow	$58,377,530	$265,167,352	$158,767,577	$482,312,460
		Total	$54,792,875	$203,869,353	$123,797,277	$382,459,506
Self-scheduled bids	Obligations	Counter Flow	($484,421)	NA	NA	($484,421)
		Prevailing Flow	$185,666,567	NA	NA	$185,666,567
		Total	$185,182,146	NA	NA	$185,182,146
Buy and self-scheduled bids	Obligations	Counter Flow	($4,069,076)	($61,297,999)	($34,970,300)	($100,337,375)
		Prevailing Flow	$243,270,411	$244,753,274	$143,657,697	$631,681,382
		Total	$239,201,335	$183,455,275	$108,687,397	$531,344,007
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$773,687	$20,414,078	$15,109,880	$36,297,645
		Total	$773,687	$20,414,078	$15,109,880	$36,297,645
	Total	Counter Flow	($4,069,076)	($61,297,999)	($34,970,300)	($100,337,375)
		Prevailing Flow	$244,044,097	$265,167,352	$158,767,577	$667,979,027
		Total	$239,975,022	$203,869,353	$123,797,277	$567,641,652
Sell offers	Obligations	Counter Flow	($6,178,881)	($10,761,004)	($9,879,378)	($26,819,263)
		Prevailing Flow	$3,672,742	$21,045,102	$11,155,364	$35,873,207
		Total	($2,506,139)	$10,284,097	$1,275,986	$9,053,944
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$87,616	$133,050	$220,666
		Total	$0	$87,616	$133,050	$220,666
	Total	Counter Flow	($6,178,881)	($10,761,004)	($9,879,378)	($26,819,263)
		Prevailing Flow	$3,672,742	$21,132,718	$11,288,414	$36,093,874
		Total	($2,506,139)	$10,371,714	$1,409,036	$9,274,610
Total			$242,481,161	$193,497,639	$122,388,241	$558,367,042

Figure 13-13 summarizes the total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Annual FTR Auction for the 2013 to 2014 planning period. The top ten positive revenue sinks accounted for 65.0 percent of total revenue. The top ten negative revenue sinks accounted for 3.9 percent of total revenue.

Figure 13-13 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2013 to 2014

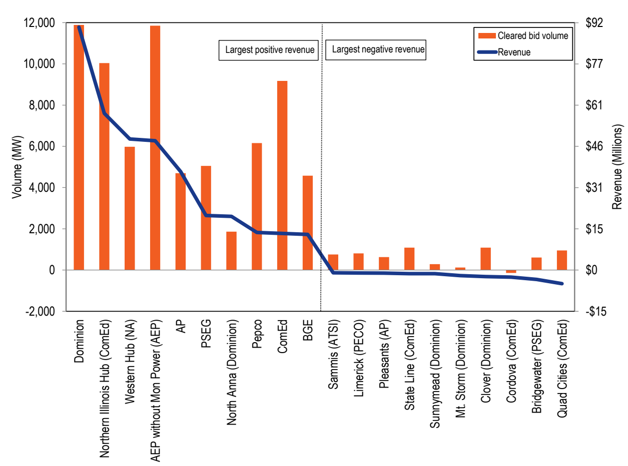
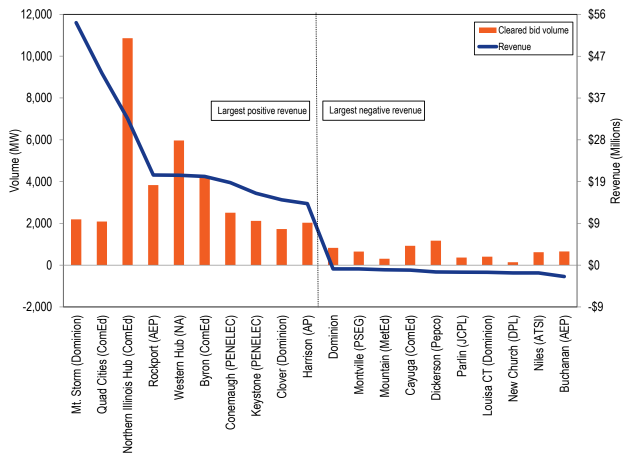


Figure 13-14 summarizes the total revenue associated with all FTRs, regardless of sink, to the FTR sinks that produced the largest positive and negative revenue in the Annual FTR Auction for the 2013 to 2014 planning period. The top 10 positive revenue sinks accounted for 45.2 percent of total revenue. The top 10 negative revenue sinks accounted for 2.6 percent of total revenue.

Figure 13-14 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2013 to 2014



Monthly Balance of Planning Period FTR Auction Revenue

Table 13-21 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through December 2013. The Monthly Balance of Planning Period FTR Auction netted $5.4 million in revenue, with buyers paying $116.0 million and sellers receiving $110.6 million for the first seven months of the 2013 to 2014 planning period. Net revenues were down 68.8 percent, with a net revenue of $17.3 million for the first seven months of the 2012 to 2013 planning period. For the entire 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions netted $23.8 million in revenue with buyers paying $127.7 million and sellers receiving $22.1 million. For the entire 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions netted $26.3 million in revenue with buyers paying $132.6 million and sellers receiving $106.4 million.

Table 13-21 Monthly Balance of Planning Period FTR Auction revenue: January through December 2013

Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
			Class Type			
Jan-13	Obligations	Buy bids	$42,552	$4,558,023	$3,371,362	$7,971,937
		Sell offers	$106,975	$2,609,123	$1,599,772	$4,315,870
	Options	Buy bids	$0	$237,321	$153,334	$390,655
		Sell offers	$0	$1,133,641	$1,206,317	$2,339,958
Feb-13	Obligations	Buy bids	$176,565	$3,587,647	$2,468,155	$6,232,366
		Sell offers	$401,600	$1,782,016	$1,097,066	$3,280,682
	Options	Buy bids	$5,100	$99,651	$128,731	$233,482
		Sell offers	$0	$861,109	$904,603	$1,765,712
Mar-13	Obligations	Buy bids	$189,939	$4,040,854	$3,035,268	$7,266,060
		Sell offers	$61,862	$2,221,264	$1,434,875	$3,718,001
	Options	Buy bids	$16,526	$229,272	$95,137	$340,935
		Sell offers	$0	$1,242,062	$1,381,010	$2,623,072
Apr-13	Obligations	Buy bids	($27,848)	$3,384,641	$2,231,023	$5,587,816
		Sell offers	$414,627	$1,703,707	$1,085,350	$3,203,684
	Options	Buy bids	$46,767	$236,939	$92,241	$375,947
		Sell offers	$0	$816,642	$702,628	$1,519,270
May-13	Obligations	Buy bids	$22,637	$2,501,391	$1,418,753	$3,942,781
		Sell offers	$210,649	$1,133,878	$524,793	$1,869,320
	Options	Buy bids	$0	$146,702	$55,903	$202,605
		Sell offers	$441	$739,219	$602,794	$1,342,454
Jun-13	Obligations	Buy bids	$258,896	$12,840,102	$8,210,854	$21,309,852
		Sell offers	$6,203,476	$4,763,316	$2,821,569	$13,788,360
	Options	Buy bids	$1,937	$527,792	$270,176	$799,905
		Sell offers	$0	$4,338,954	$2,862,300	$7,201,254
Jul-13	Obligations	Buy bids	$510,314	$9,102,951	$4,353,703	$13,966,968
		Sell offers	$93,068	$5,789,068	$4,745,346	$10,627,482
	Options	Buy bids	$4,131	$627,541	$557,307	$1,188,979
		Sell offers	$0	$3,737,741	$3,401,595	$7,139,335
Aug-13	Obligations	Buy bids	$865,368	$8,730,071	$6,036,457	$15,631,896
		Sell offers	$80,061	$5,495,491	$4,455,681	$10,031,232
	Options	Buy bids	$2,361	$533,585	$446,817	$982,762
		Sell offers	$0	$2,977,768	$2,590,004	$5,567,772
Sep-13	Obligations	Buy bids	$528,800	$8,147,903	$5,670,300	$14,347,003
		Sell offers	$219,616	$4,804,814	$3,795,424	$8,819,854
	Options	Buy bids	$633	$617,446	$628,494	$1,246,573
		Sell offers	$0	$3,184,129	$2,500,854	$5,684,983
Oct-13	Obligations	Buy bids	$1,686,257	$6,662,996	$5,029,439	$13,378,692
		Sell offers	$106,651	$4,788,674	$4,196,692	$9,092,018
	Options	Buy bids	$1,985	$450,964	$396,471	$849,419
		Sell offers	$0	$2,494,525	$1,831,822	$4,326,347
Nov-13	Obligations	Buy bids	$840,852	$6,572,261	$3,136,906	$10,550,020
		Sell offers	$157,148	$4,355,453	$2,684,978	$7,197,579
	Options	Buy bids	$0	$473,050	$413,497	$886,548
		Sell offers	$0	$1,988,825	$1,523,642	$3,512,467
Dec-13	Obligations	Buy bids	$615,410	$7,685,428	$4,886,446	$13,187,284
		Sell offers	$545,647	$3,994,464	$1,678,204	$6,218,314
	Options	Buy bids	$0	$572,909	$400,160	$973,069
		Sell offers	$0	$3,031,134	$2,631,315	$5,662,449
2012/2013*	Obligations	Buy bids	$67,116	$76,349,386	$43,832,157	$120,248,659
		Sell offers	$4,731,328	$40,127,400	$18,982,130	$63,840,858
	Options	Buy bids	$152,160	$4,512,768	$2,793,076	$7,458,004
		Sell offers	$313,760	$22,240,204	$17,444,010	$39,997,974
	Total		($4,825,812)	$18,494,550	$10,199,092	$23,867,830
2013/2014**	Obligations	Buy bids	$5,305,898	$59,741,712	$37,324,105	$102,371,715
		Sell offers	$7,405,666	$33,991,280	$24,377,894	$65,774,840
	Options	Buy bids	$161,270	$7,788,263	$5,635,822	$13,585,355
		Sell offers	$0	$24,937,206	$19,842,384	$44,779,590
	Total		($1,938,499)	$8,601,489	($1,260,352)	$5,402,639

* Shows Twelve Months; ** Shows seven months ended 31-Dec-2013 for 2013/2014

Figure 13-15 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period. The top 10 positive revenue producing FTR sources accounted for $42.5 million of the total revenue of $4.5 million paid in the auction, they also comprised 4.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$14.5 million of revenue and constituted 1.8 percent of all FTRs bought in the auction.

Figure 13-15 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through December 31, 2013

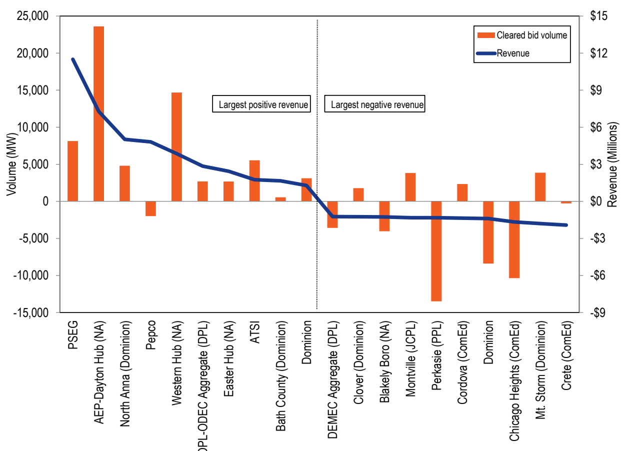
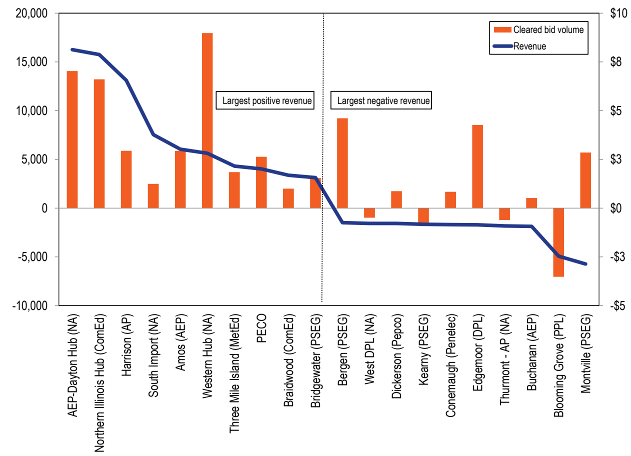


Figure 13-16 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period through December 31, 2013. The top 10 positive revenue producing FTR sources accounted for $39.6 million of the total revenue of $4.5 million paid in the auction, they also comprised 4.8 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$12.0 million of revenue and constituted 1.1 percent of all FTRs bought in the auction.

Figure 13-16 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014 through December 31, 2013



FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the first seven months of the 2013 to 2014 planning. Figure 13-17 shows the ten largest positive and negative FTR target allocations, summed by sink, for the first seven months of the 2013 to 2014 planning period. The top 10 sinks that produced financial benefit accounted for 19.1 percent of total positive target allocations during the 2013 to 2014 planning period with the Western Hub accounting for 3.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 7.6 percent of total negative target allocations with the AEP-Dayton Hub accounting for 1.1 percent of all negative target allocations.

Figure 13-17 Ten largest positive and negative FTR target allocations summed by sink: 2013 to 2014 planning period through December 31, 2013

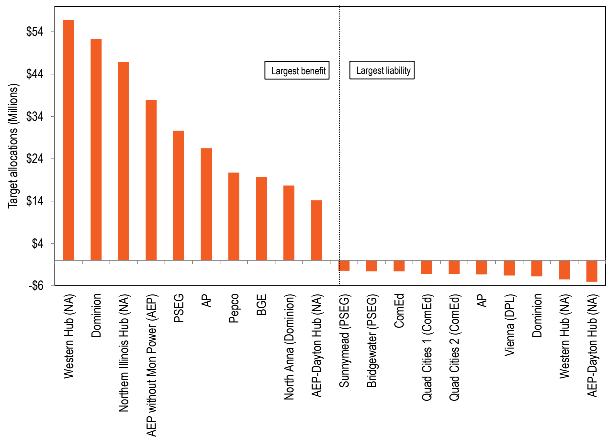
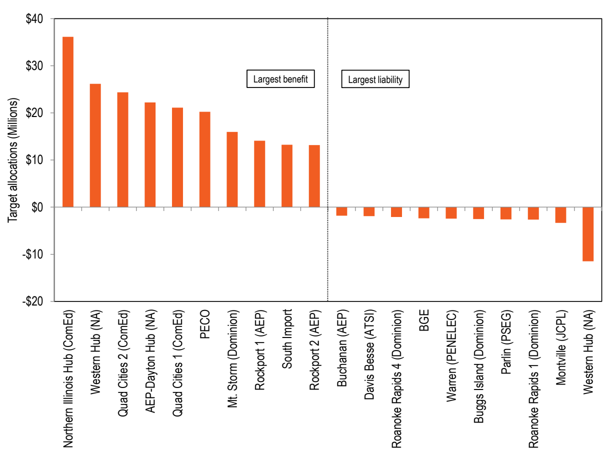


Figure 13-18 shows the ten largest positive and negative FTR target allocations, summed by source, for the first seven months of the 2013 to 2014 planning period. The top 10 sources with a positive target allocation accounted for 12.2 percent of total positive target allocations with the Northern Illinois Hub accounting for 2.1 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 7.4 percent of all negative target allocations, with the Western Hub accounting for 2.5 percent.

Figure 13-18 Ten largest positive and negative FTR target allocations summed by source: 2013 to 2014 planning period through December 31, 2013



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[11] That is the source of the congestion revenue to pay holders of ARRs and FTRs. In general, FTR revenue adequacy exists when the sum of congestion credits is equal to or greater than the sum of congestion across the positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues to the total target allocations across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. The adequacy of FTRs as an offset against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability or purchase of FTRs.

FTRs are paid each month from congestion revenues, both day-ahead and balancing, FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not

11 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets, and net negative congestion.[12] FTR revenues also include ARR excess, which is the difference between ARR target allocations and FTR auction revenues, and negative FTR target allocations, which is an income for the FTR market from FTRs with a negative target allocation. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-22 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates (M2M flowgates) in MISO and NYISO whose operating limits are respected by PJM.[13]

In 2013, the market to market operations resulted in NYISO, MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

For the 2012 to 2013 planning period, PJM paid MISO and NYISO a combined $40.3 million for the redispatch on the designated M2M flowgates, and for the first seven months of the 2013 to 2014 planning period PJM has paid MISO and NYISO a combined $2.3 million. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any previous PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

FTRs were paid at 75.1 percent of the target allocation level for the first seven months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $287.4 million of FTR revenues during the first seven months of the 2013 to 2014 planning period, and $335.7 million during the first seven months of the 2012 to 2013 planning period, a 14.4 percent decrease. For the first seven months of the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the Northern Illinois Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were the AEP-Dayton Hub and the Western Hub.

Table 13-22 presents the PJM FTR revenue detail for the 2012 to 2013 planning period and the first seven months of the 2013 to 2014 planning period.

12 Hourly congestion revenues may be negative.

13 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

Table 13-22 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

Accounting Element	2012/2013	2013/2014*
ARR information		
ARR target allocations	$587.0	$303.1
FTR auction revenue	$653.6	$341.3
ARR excess	$66.7	$36.0
FTR targets		
Positive target allocations	$992.9	$663.5
Negative target allocations	($86.1)	($44.3)
FTR target allocations	$906.8	$619.2
Adjustments:		
Adjustments to FTR target allocations	($1.0)	($0.5)
Total FTR targets	$905.8	$618.7
FTR revenues		
ARR excess	$66.7	$36.0
Competing uses	$0.1	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($90.6)	($36.0)
Hourly congestion revenue	$668.4	$461.8
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($41.1)	($6.6)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.0)	$0.0
Total FTR revenues	$601.9	$455.2
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$12.1	$9.2
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$614.0	$287.4
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$614.0	$287.4
Remaining deficiency	$292.3	$154.2

* Shows seven months ended 31-Dec-13

Unallocated Congestion Charges

When congestion revenue at the end of an hour is negative, target allocations in that hour are set to zero, and there is a congestion liability for that hour. At the end of the month, if excess ARR revenue and excess congestion from other hours and months are not adequate to offset the sum of these hourly differences, day-ahead operating reserves are charged the unallocated congestion charges so that the total congestion for the month is not less than zero. This charge is applied retroactively at the end of the month as additional day-ahead operating reserves charges and is never credited back to day-ahead operating reserves in the case of excess congestion. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation and there was not enough excess during the month to pay the difference. From 2010 through May 31, 2012, these charges were only made three times, for a total of $7.3 million. However, in the 2012 to 2013 planning period these charges were made in five months for a total of $12.1 million in just one planning period.

Table 13-23 shows the monthly unallocated congestion charges made to day-ahead operating reserves for the 2012 to 2013 planning period and the 2013 to 2014 planning period through December. Months with no unallocated congestion are excluded from the table.[14]

Table 13-23 Unallocated congestion charges: Planning period 2012 to 2013 to 2013 and 2014

Period	Charge
Oct-12	$794,752
Dec-12	$193,429
Jan-13	$5,233,445
Mar-13	$701,303
May-13	$5,210,739
Jun-13	$2,828,660
Sep-13	$6,411,602
2012/2013	$12,133,668
2013/2014	$9,240,262

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and are defined to be the revenue required to compensate FTR holders for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-24 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 13-24 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

14 See Section 4, "Energy Uplift" at "Energy Uplift Charges" for the impact of Unallocated Congestion Charges on Operating Reserve rates.

Table 13-24 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2012 to 2013 and 2013 to 2014

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-12	$58.5	$62.9	92.9%	$58.5	93.0%	($4.4)
Jul-12	$71.3	$80.0	88.9%	$71.3	88.9%	($8.8)
Aug-12	$54.1	$55.4	97.1%	$54.1	97.3%	($1.3)
Sep-12	$38.7	$82.5	46.7%	$38.7	46.8%	($43.8)
Oct-12	$24.3	$58.2	41.8%	$25.1	42.7%	($33.1)
Nov-12	$52.0	$59.6	87.2%	$52.0	87.3%	($7.5)
Dec-12	$36.3	$50.1	72.2%	$36.5	72.5%	($13.6)
Jan-13	$63.4	$120.3	53.4%	$68.6	56.5%	($51.7)
Feb-13	$77.2	$128.1	60.5%	$77.2	60.2%	($50.9)
Mar-13	$51.7	$70.7	73.2%	$52.4	74.2%	($18.2)
Apr-13	$32.7	$47.4	69.4%	$32.7	69.0%	($14.7)
May-13	$41.8	$90.7	46.1%	$47.0	51.9%	($43.7)
Summary for Planning Period 2012 to 2013						
Total	$601.9	$905.8		$614.0	67.8%	($291.8)
Jun-13	$61.3	$81.9	74.7%	$64.1	78.2%	($17.8)
Jul-13	$113.5	$128.3	88.3%	$113.5	88.5%	($14.7)
Aug-13	$43.1	$45.8	94.0%	$43.1	94.0%	($2.7)
Sep-13	$60.3	$116.0	52.0%	$66.7	57.5%	($49.3)
Oct-13	$47.4	$63.9	74.0%	$47.4	74.1%	($16.6)
Nov-13	$44.7	$66.9	66.9%	$44.7	66.9%	($22.1)
Dec-13	$85.0	$115.9	73.3%	$85.0	73.3%	($31.0)
Summary for Planning Period 2013 to 2014						
Total	$455.2	$618.7		$464.5	75.1%	($154.3)

Figure 13-19 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 2013. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 13-19 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratios for months in the 2013 to 2014 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 13-19 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2013

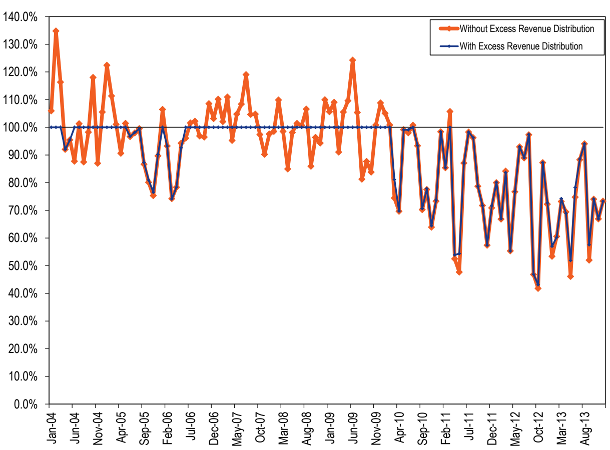


Table 13-25 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves.

Table 13-25 PJM reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	75.1%

*2013/2014 Through 31-Dec-13

FTR Uplift Charge

At the end of the planning period, an uplift charge is applied to FTR holders. This charge is to cover the net of the monthly deficiencies in the target allocations calculated for individual participants. An individual participant's uplift charge is a pro-rata charge, to cover this deficiency, based on their net target allocation with respect to the total net target allocation of all participants with net positive target allocations for the planning period. Participants pay an uplift charge that is a ratio of their share of net positive target allocations to the total net positive target allocations.

The uplift charge is only applied to, and calculated from, members with a net positive target allocation at the end of the planning period. Members with a net negative target allocation have their year-end target allocation set to zero for all uplift calculations. Since participants in the FTR market with net positive target allocations are paying the uplift charge to fully fund FTRs, their payout ratio cannot be 100 percent. The end of planning period payout ratio is calculated as the participant's target allocations minus the uplift charge applied to them divided by their target allocations. The calculations of uplift are structured so that, at the end of the planning period, every participant in the FTR market with a positive net target allocation receives payments based on the same payout ratio. At the end of the planning period and the end of a given month no payout ratio is actually applied to a participant's target allocations. The payout ratio is simply used as a reporting mechanism to demonstrate the amount of revenue available to pay target allocations and represent the percentage of target allocations a participant with a net positive portfolio has been paid for the planning period. However, this same calculation is not accurate when calculating a single month's payout ratio as currently reported, where the calculation of available revenue is not the same.

The total planning period target allocation deficiency is the sum of the monthly deficiencies throughout the planning period. The monthly deficiency is the difference in the net target allocation of all participants and the total revenue collected for that month. The total revenue paid to FTR holders is based on the hourly congestion revenue collected, which includes hourly M2M, wheel payments and unallocated congestion credits.

Table 13-26 provides a demonstration of how the FTR uplift charge is calculated. In this example it is important to note that the sum of the net positive target allocations is $32 and the total monthly deficiency is $10. The uplift charge is structured so that those with higher target allocations pay more of the deficit, which ultimately impacts their net payout. Also, in this example, and in the PJM settlement process, the monthly payout ratio varies for all participants, but the uplift charge is structured so that once the uplift charge is applied the end of planning period payout ratio is the same for all participants.

For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every participant experiences the same payout ratio. This means that some participants subsidize others and receive less payout from their FTRs after the uplift is applied, while others receive a subsidy and get a higher payout after the uplift is applied. In this example, participants 1 and 5 are paid less after the uplift charge is applied, while participants 3 and 4 are paid more.

Table 13-26 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	80.0%	68.8%
2	($4.00)	$0.00	$0.00	$0.00	($4.00)	100.0%	100.0%
3	$15.00	$10.00	$5.00	$4.69	$10.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00		

Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown in Table 13-27 reflect the PJM reported payout ratios for each month of the planning period. These reported payout ratios equal congestion revenue divided by the sum of the net positive and net negative target allocations for each hour of the month. This does not correctly measure the payout ratio actually received by positive target allocation FTR holders in the month, but provides an estimate of the ratio based on the approach to end of planning period calculations, including cross subsidies.

The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in a month. In fact, the actual monthly payout ratio includes the net negative target allocations as a source of funding for FTRs with net positive target allocations in an hour. Revenue from FTRs with net negative target allocations in an hour is included with congestion revenue when funding FTRs with net positive target allocations.[15] Also included in this revenue is any M2M charge or credit for the month and any excess ARR revenues for the month. The revenue and net target allocations are then summed over the month to calculate the monthly payout ratio. There is no payout ratio applied on a monthly basis, each participant receives a different share of the available revenue based on availability, it is simply used as a reporting mechanism. At the end of a given month, a participant's FTR payments are a proportion of the congestion credits collected, based on the participant's share of the total monthly target allocation. The payout ratio is only used and calculated at the end of the planning period after uplift is applied to each participant. The actual monthly payout ratio received by FTR holders equals congestion revenue plus the net negative target allocations divided by the net positive target allocations for each hour. The actual payout ratio received by the holders of positive target allocation FTRs, reported on a monthly basis, is greater than reported by PJM.

15 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), p. 50.

Table 13-27 shows the PJM reported and actual monthly payout ratio for the 2013 to 2014 planning period. In September 2013, the PJM reported payout ratio is 3.4 percentage points below the actual payout ratio. On a month to month basis, the payout ratio currently reported by PJM does not take into account all sources of revenue available to pay FTR holders. On a monthly basis, this provides a slightly overstated level of underfunding.

Table 13-27 PJM Reported and Actual Monthly Payout Ratios: Planning period 2013 to 2014

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jan-13	57.0%	59.9%
Feb-13	60.3%	62.5%
Mar-13	74.2%	75.5%
Apr-13	68.9%	70.8%
May-13	51.9%	54.2%
Jun-13	78.3%	79.5%
Jul-13	88.8%	89.3%
Aug-13	94.1%	94.7%
Sep-13	57.5%	61.0%
Oct-13	74.1%	76.2%
Nov-13	66.9%	69.1%
Dec-13	73.3%	74.8%

Netting Target Allocations within Portfolios

Currently, FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

In fact, if done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current system all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Elimination of portfolio netting should also be applied to the end of planning period FTR uplift calculation. With this approach, negative target allocations would not offset positive target allocations at the end of the planning period when allocating uplift. The FTR uplift charge would be based on participants' share of the total positive target allocations paid for the planning period.

Table 13-28 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net target allocation is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 13-28 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive Target Allocation	Negative Target Allocation	Percent Negative Target Allocation	Net Target Allocation	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	-	$115.00	$45.00	$45.00	-

Table 13-29 shows the total value for the 2012 to 2013 and first month of the 2013 to 2014 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

Table 13-29 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2012 to 2013 and 2013 to 2014

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jan-13	$129,096,732	($8,682,957)	$233,783,161	($113,347,680)	$68,617,681	57.0%	77.8%
Feb-13	$135,702,271	($7,613,234)	$259,657,461	($131,557,526)	$77,154,565	60.3%	80.4%
Mar-13	$74,421,312	($3,760,700)	$146,552,085	($75,878,638)	$52,428,118	74.2%	87.6%
Apr-13	$50,520,958	($3,090,289)	$108,760,047	($61,325,460)	$32,698,909	68.9%	86.5%
May-13	$95,352,565	($4,678,790)	$190,798,195	($100,110,478)	$47,015,169	51.9%	77.1%
Jun-13	$86,723,727	($4,836,912)	$164,066,220	($82,101,063)	$64,060,468	78.3%	89.1%
Jul-13	$134,302,957	($6,017,378)	$255,724,128	($127,113,708)	$113,548,567	88.8%	94.1%
Aug-13	$51,545,380	($5,741,003)	$104,601,365	($58,796,985)	$43,059,687	94.1%	97.4%
Sep-13	$126,168,822	($10,172,695)	$279,972,757	($163,977,565)	$66,719,631	57.5%	82.4%
Oct-13	$69,748,034	($5,779,197)	$158,354,017	($94,365,761)	$47,353,545	74.1%	89.5%
Nov-13	$71,460,441	($4,566,566)	$156,649,135	($89,755,253)	$44,748,426	66.9%	85.9%
Dec-13	$123,125,598	($7,182,127)	$256,139,289	($140,195,812)	$84,974,997	73.3%	87.9%
2012/2013 Total	$992,878,752	($86,061,137)	$1,897,830,880	($990,471,801)	$614,014,377	67.7%	84.5%
2013/2014 Total	$663,074,957	($44,295,877)	$1,375,506,911	($674,205,083)	$464,465,322	75.1%	82.8%

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.7 percent and the payout ratio for the seven months of the 2013 to 2014 planning period would have been 82.8 percent instead of 75.1 percent.

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. This increased payout ratio would apply only to negative target allocations associated with counter flow FTRs.

Table 13-30 Example implementation of counter flow adjustment method

	Prevailing A-B 10MW	Counter C-D 10MW
Auction Cost	$50.00	($30.00)
Target Allocation	$40.00	($20.00)
Payout	$30.00	($20.00)
Profit without underfunding	($10.00)	$10.00
Profit after underfunding	($20.00)	$10.00
Payout for Positive TA	$35.00	($20.00)
Profit for Positive TA	($15.00)	$10.00
Payout after CF Adjustment	$36.67	($21.67)
Profit after CF Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

Table 13-31 Counter flow FTR payout ratio adjustment impacts

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jan-13	$233,783,161	($113,347,680)	$120,435,482	$68,617,681	57.0%	$181,965,360	83.4%	$194,865,402
Feb-13	$259,657,461	($131,557,526)	$128,099,935	$77,154,565	60.2%	$208,712,090	85.4%	$221,784,584
Mar-13	$146,552,085	($75,878,638)	$70,673,447	$52,428,118	74.2%	$128,306,756	90.8%	$133,040,564
Apr-13	$108,760,047	($61,325,460)	$47,434,587	$32,698,909	68.9%	$94,024,369	90.2%	$98,077,747
May-13	$190,798,195	($100,110,478)	$90,687,717	$47,015,169	51.8%	$147,125,648	82.9%	$158,212,887
Jun-13	$164,066,220	($82,101,063)	$81,965,157	$64,060,468	78.2%	$146,161,531	91.9%	$150,770,760
Jul-13	$255,724,128	($127,113,708)	$128,610,420	$113,548,567	88.3%	$240,662,275	95.6%	$244,362,737
Aug-13	$104,601,365	($58,796,985)	$45,804,380	$43,059,687	94.0%	$101,856,672	98.1%	$102,592,928
Sep-13	$279,972,757	($163,977,565)	$115,995,192	$66,719,631	57.5%	$230,697,196	87.3%	$244,550,556
Oct-13	$158,354,017	($94,365,761)	$63,988,256	$47,353,545	74.0%	$141,719,306	92.5%	$146,446,632
Nov-13	$156,649,135	($89,755,253)	$66,893,882	$44,748,426	66.9%	$134,503,679	89.9%	$140,751,323
Dec-13	$256,139,289	($140,195,812)	$115,943,477	$84,974,997	73.3%	$225,170,809	91.3%	$233,817,126
Total 2012/2013	$1,897,830,880	($990,471,801)	$907,359,079	$614,537,096	67.7%	$1,605,008,896	88.6%	$1,681,443,058
Total 2013/2014	$1,375,506,911	($756,306,146)	$619,200,765	$464,465,322	75.0%	$1,220,771,467	91.8%	$1,263,292,062

* Reported payout ratios may vary due to rounding differences when netting

Table 13-30 provides an example of how the counter flow adjustment method would impact a two FTR system. In this example there is $15 of total congestion revenue available, corresponding to a reported payout ratio of 75 percent and a monthly actual payout ratio of 87.5 percent. In the example, the profit before and after underfunding can be seen in addition to the profit after underfunding with the counter flow adjustment made. As illustrated, a counter flow FTR's profit does not change when underfunding is applied, whereas a prevailing flow FTR's profit decreases. Applying the counter flow adjustment distributes the underfunding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-31 shows the monthly positive, negative and total target allocations.[16] Table 13-31 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $42.5 million (27.5 percent of underfunding) in revenue available to fund positive target allocations for the first seven months of the 2013 to 2014 planning period.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the first seven months of the 2012 to 2013 planning period from the reported 75.0 percent to 91.8 percent.

16 Reported payout ratio may differ between Table 13-29 and Table 13-31 due to rounding differences when netting target allocations and considering each FTR individually.

Figure 13-20 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 2013.

Figure 13-20 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through December 2013

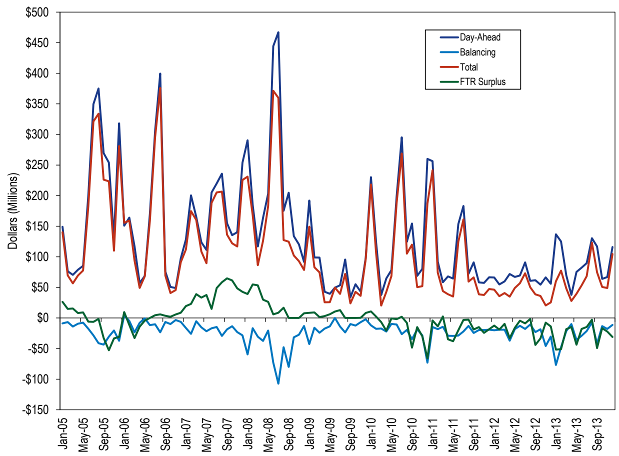
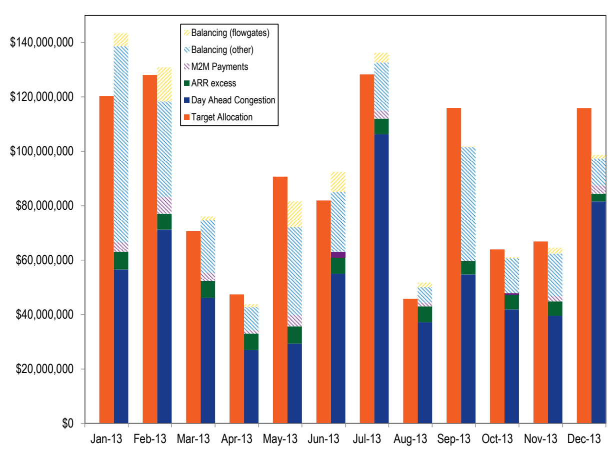


Figure 13-21 shows the relationship among balancing congestion, M2M payments and day-ahead congestion. In January 2013, balancing congestion not from flowgates contributed a large negative portion to FTR funding. In June and October, M2M payments were positive, providing revenue for FTR funding.

Figure 13-21 FTR target allocation compared to sources of positive and negative congestion revenue



Up-to-Congestion Impacts on FTR Funding

In order to study the impacts of UTCs on FTR funding, the Day-Ahead Market was rerun by PJM with and without UTC transactions for five days in May 2013.

Analysis of PJM's data from these reruns of the May 2, 4, 22, 23, 27 of 2013 day ahead market with and without UTC bids supports the hypothesis that UTC transactions contribute significantly to FTR underfunding.[17] The data indicate that removal of UTCs significantly improves FTR funding for each of the five days. FTR underfunding is a measure of the difference between total FTR target allocations and total congestion dollars available to fund FTRs. When FTR target allocations are greater than total congestion dollars, FTRs are considered underfunded, as FTR obligations are less than congestion dollars available. When FTR target allocations are less than congestion dollars available, FTRs are considered fully funded and there is a surplus of congestion dollars. Table 13-32 shows, for each study day, the actual FTR underfunding for the day, the FTR underfunding after the removal of UTC, the change in FTR underfunding caused by the removal of UTC from PJM's day ahead market model.

Analysis of PJM's data shows that for the five days studied, the removal of UTCs changed FTR funding relative to target allocations from a deficit of -$4.1 million to a net surplus of $537 thousand, a gain in funding relative to target allocations of $4.7 million. The magnitude of the effect depends on the day, but the results indicate that the removal of UTC takes PJM FTRs from a state of underfunding to a state of surplus in the five days studied.

Analysis of PJM's data from these reruns shows that removal of UTCs significantly decreases FTR target allocations on the five studied days. Target allocations are a function of FTR MW and the difference in the day ahead CLMP at the FTR source and sink bus. The removal of UTC bids significantly decreased day ahead congestion and CLMPs. This reduction in congestion and CLMPs reduced the target allocations of all FTRs. Table 13-32 shows, for each study day, the actual target allocations, the target allocations after the removal of UTC, and the change in target allocations caused by the

17 These conclusions are based on the five days selected by PJM and the system conditions on those days.

removal of UTC from PJM's day-ahead market model. PJM's data show that removing UTCs reduced the target allocations over the five study days by $8.5 million, or 52 percent.

Table 13-32 Changes in target allocations in PJM results by day: May 2, 4, 22, 23, 27 of 2013

Date	Actual Target Allocations	No UTC Target Allocations	Difference in Target Allocations	Change in Target Allocations
2-May-13	$1,361,464	$1,060,874	($300,590)	(22.1%)
4-May-13	$934,840	$137,589	($797,250)	(85.3%)
22-May-13	$7,002,555	$2,605,640	($4,396,915)	(62.8%)
23-May-13	$6,125,559	$3,779,988	($2,345,571)	(38.3%)
27-May-13	$817,088	$196,132	($620,956)	(76.0%)
Total	$16,241,505	$7,780,223	($8,461,282)	(52.1%)

The PJM data show that the inclusion of UTCs significantly increased total day ahead congestion compared to the case where there were no UTCs in the market, and significantly increased (made balancing charges more negative) the real time balancing congestion adjustment offset to day ahead total congestion compared to the case with no UTCs.

Table 13-33 Changes in FTR funding in PJM results by day: May 2, 4, 22, 23, 27 of 2013

	Actual Underfunding	No UTC Underfunding	Difference in Underfunding	Change in Underfunding
2-May-13	($456,443)	($424,086)	$32,358	(7.1%)
4-May-13	($305,854)	$124,345	$430,200	(140.7%)
22-May-13	($1,758,420)	$1,175,869	$2,934,289	(166.9%)
23-May-13	($1,874,367)	($631,962)	$1,242,406	(66.3%)
27-May-13	($38,119)	($24,031)	$14,089	(37.0%)
Total	($4,433,204)	$220,137	$4,653,341	(105.0%)

Up-to-Congestion Transaction FTR Forfeitures

Currently there is no FTR forfeiture rule implemented for up-to-congestion transactions (UTCs). A proposed tariff change that would apply the FTR forfeiture rule to UTCs is pending at FERC.[18] The FTR forfeiture rule should be applied to UTCs in the same way it is applied to INCs and DECs. The goal of the rule is to prevent the use of virtual bids (generally unprofitable virtual bids) to increase day-ahead congestion on an FTR path in order to increase the value of the FTRs. The proposed penalty should be the same as it is for the INC and DEC rule, the forfeiture of any profits from FTRs whose value is affected by a UTC with the same owner.

18 *See* FERC Docket No. ER13-1654.

However, the rule submitted by PJM, currently under review by FERC, would not be consistent with the application of the current forfeiture rule for INCs and DECs. Under PJM's proposed method the simple net dfax of the UTC transaction is the only consideration for forfeiture, representing the contract path of the UTC transaction. Under this method, the net dfax is the sink dfax of the UTC minus the source dfax of the UTC. The net dfax alone cannot be used as an indication of helping or hurting a constraint, rather, the direction of the constraint must also be considered. In addition, the PJM method only considers UTC transactions whose net dfax is positive. This logic not only passes transactions that should fail the forfeiture test, but fails transactions that should pass the forfeiture test.

PJM's logic also does not hold when one of the points of the UTC is far from the constraint. In this case, one side of the UTC would have a dfax of zero, indicating no connection to the constraint being considered. If a point of the UTC transaction has no connection to the constraint, there can be no power flow directly between the two UTC points, so the simple net dfax, which relies on the contract path of the UTC, cannot logically be used in this case to indicate whether a UTC is eligible for forfeiture. Under the MMU method this UTC would be treated as an INC or DEC and follow the same rules as the current INC/DEC FTR forfeiture rule.

Figure 13-22 shows an example of the two proposed FTR forfeiture rules for UTC transactions. In both cases, the net dfax of the UTC is taken. Under the PJM method the net dfax of the UTC is calculated by subtracting the dfax of the sink bus A (0.2) from the dfax of the source bus B (0.5) to get a net dfax of -0.3. If this net dfax value is greater than 0.75 the UTC is subject to forfeiture. Under the MMU method, the net dfax is calculated by subtracting the dfax of sink A (0.2) from the dfax of source bus B (0.5) to get a net dfax of 0.3. This net dfax is then compared to the withdrawal point with the largest impact on the constraint. The MMU method compares the net UTC dfax to a withdrawal because the UTC is a net injection. In this example, the net dfax is 0.3 and it is compared to the largest withdrawal dfax at C (-0.5). The absolute value of the difference is calculated from these two points to determine if the UTC fails the FTR forfeiture rule. In this case, the absolute value of the difference is the dfax of bus C (-0.5) minus the net UTC dfax (0.3) for a total impact of 0.8, which is over the

0.75 threshold for the FTR forfeiture rule. The result is that this UTC fails the FTR forfeiture rule. The MMU proposes to apply the same rules to UTC transactions as is applied to INCs and DECs, treat the UTC as equivalent to an INC or a DEC depending on its net impact. A UTC transaction is essentially a paired INC/DEC, it has a net impact on the flow across a constraint, as an INC or DEC does. While total system power balance is maintained by a UTC, local flows may change based on the UTC's net impact on a constraint. The MMU method captures this impact.

Figure 13-22 Illustration of UTC FTR forfeiture rule

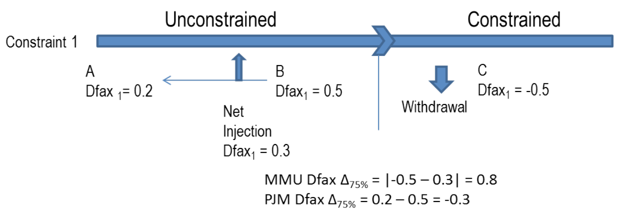
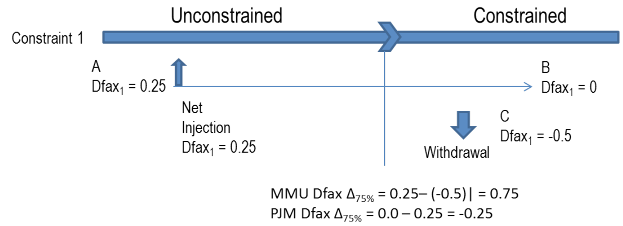


Figure 13-23 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to the constraint, as the other end of the UTC has no impact on the constraint. However, the PJM approach would not treat the UTC as an INC or DEC, despite the effective absence of the other end of the UTC. This is a flawed result.

As demonstrated in Figure 13-23, the UTC is no different than an INC on the constraint being considered. Using the PJM method this UTC would pass the FTR forfeiture rule. The net dfax would be calculated as the dfax of bus B (0) minus the dfax of bus A (0.25) for a net dfax of -0.25, with no comparison to any withdrawal bus. Since the dfax is negative, it would pass the PJM FTR forfeiture rule. Under the MMU's method, the net dfax is calculated as an injection with a dfax of 0.25, and then the absolute value of the difference is calculated between that injection and the dfax of the largest withdrawal on the constraint. In this example that is bus C, with a dfax of -0.5. The result is an absolute value of the dfax difference of 0.75, meaning that this UTC fails the FTR forfeiture test.

Figure 13-23 Illustration of UTC FTR Forfeiture rule with one point far from constraint



The MMU recommends that the FTR forfeiture rule be applied to UTCs in the same way it is applied to INCs and DECs.

Impact of ATSI Interface Constraint

The ATSI Interface was created by PJM effective July 17, 2013. It is not an interconnection reliability operating limit (IROL) transfer interface, which includes reactive transfer interfaces, nor does it reflect actual thermal transmission limits. The ATSI Interface, comprised of all the tie lines into the ATSI Control Zone,[19] was created by PJM in order to let emergency demand resources set real time prices in the ATSI Control Zone.

The creation of the ATSI Interface allows demand resources (DR) dispatched in the ATSI Control Zone to be marginal for providing energy during real-time emergency operations. The ATSI Interface is not defined or modeled in the Day-Ahead Energy Market and it cannot be defined in the Day-Ahead Energy Market because Emergency DR is not in the Day-Ahead Energy Market.

The ATSI interface constraint was binding in real time for four hours on July 18, for seven hours on September 10, and for eight hours on September 11, 2013. The ATSI interface constraint is not modeled in the Day-Ahead Energy Market and cannot set price in the Day-Ahead Energy Market.

The ATSI interface constraint resulted in $23.4 million in negative balancing congestion for those three days, reducing revenues available for FTR funding.

19 See PJM. "ATSI Interface" <http://www.pjm.com/~/media/etools/oasis/system-information/atsi-interface-definition-update.ashx>.

A similar interface constraint to address constraint pricing in the BC-Pepco region was enforced in the Real-Time Energy Market on December 24, 2013, and not modeled in the Day-Ahead Market until December 27, 2013. The result was negative balancing congestion of $1.1 million, reducing revenues available for FTR funding. Once the BCPEP Interface was enforced in the Day-Ahead Market, balancing congestion returned to normal levels.

Creation of new constraints in the middle of a planning period that are not modeled in the Day-Ahead Energy Market creates underfunding. Constraints that are included in the Real-Time Energy Market but are not modeled in the Day-Ahead energy Market cause negative balancing congestion when they are binding. The addition of such constraints in the middle of a planning period results in FTR underfunding because it means that the facility limits in the area are now lower than when modeled, which is equivalent to over selling FTRs on affected paths.

PJM has indicated that it plans to implement several new interface constraints to modify pricing in certain areas.[20] PJM plans to incorporate these interfaces in the Annual FTR Auction for the 2014-2015 planning year.

PJM should not have the authority to decide when energy prices should be high in an entire zone, yet that is what PJM did when it established the ATSI Interface.[21] The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding. Regardless of the reason for implementing closed loop interfaces, such implementation and the impacts on FTR funding do not constitute a reason to require load to subsidize FTR funding. FTRs are a market product, purchased by participants who choose to take the risks associated with the product.

Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[22] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.

ARRs are available only as obligations (not options) and only as the 24-hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs

20 See PJM. "PJM Price-Setting Changes,"<http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx> (December 20, 2013).

21 See the *2013 State of the Market Report for PJM*, Volume 2, Section 3: Scarcity.

22 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

are reallocated, as load shifts between LSEs within the transmission zone.

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[23] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2013 to 2014 planning period, all eligible market participants were allocated ARRs.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. The top ten binding transmission constraints for the 2013 to 2014 planning period are shown in Table 13-34.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[24] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis. Long Term ARR holders can self schedule their Long Term ARRs as FTRs for any planning period during the 10 planning period timeline.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.25
- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

23 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

24 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

25 See PJM. "Manual 6: Financial Transmission Rights" Revision 15 (October 10, 2013), p. 22.

- **Stage 2.** Stage 2 of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[26] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing will be introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[27]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[28] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 13-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[29]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating only of ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs.

Table 13-34 shows the top 10 principal binding transmission constraints that limited the 2013 to 2014 Annual ARR Allocation. For the 2013 to 2014 ARR Stage 1A allocation, PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[30]

Table 13-34 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2013 to 2014

Constraint	Type	Control Zone
Cordova - Nelson	Flowgate	MISO
Silver Lake - Cherry Valley	Line	ComEd
Electric Junction - Nelson	Line	ComEd
Oak Grove - Galesburg	Flowgate	MISO
Waukegan-Zion	Line	ComEd
Zion - Lakeview	Line	ComEd
Lakeview	Transformer	MISO
Zion	Transformer	ComEd
Braidwood - East Frankfort	Line	ComEd
Greystone - West Wharton	Line	JCPL

26 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 21.

27 See "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx> The introduction of residual zone pricing, while approved by PJM members, depends on a FERC order.

28 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 55-56.

29 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

30 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[31] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 35,501 MW of ARRs associated with approximately $233,800 of revenue that were reassigned for the first seven months of the 2013 to 2014 planning period.

Table 13-35 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2012 and December 2013.

Table 13-35 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2012, through December 31, 2013

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2012/2013 (12 months)	2013/2014 (7 months)*	2012/2013 (12 months)	2013/2014 (7 months)*
AECO	581	662	$3.0	$2.6
AEP	4,656	2,142	$58.9	$19.6
AP	3,518	1,492	$84.3	$31.5
ATSI	5,314	3,622	$8.3	$4.6
BGE	3,203	2,478	$37.3	$28.7
ComEd	11,824	6,079	$170.9	$63.0
DAY	589	881	$0.9	$1.6
DEOK	2,979	3,695	$1.6	$5.5
DLCO	2,708	4,137	$19.1	$9.3
DPL	1,989	1,415	$11.5	$12.8
Dominion	0	5	$0.0	$0.1
EKPC	NA	0	NA	$0.0
JCPL	1,373	884	$5.6	$3.9
Met-Ed	1,107	584	$8.6	$4.4
PECO	3,416	1,378	$22.8	$11.0
PENELEC	920	674	$8.3	$7.0
PPL	3,198	2,003	$20.7	$7.8
PSEG	2,313	1,385	$16.6	$13.8
Pepco	3,073	1,800	$21.4	$6.6
RECO	67	186	$0.0	$0.1
Total	52,825	35,501	$499.8	$233.8

* Through 31-Dec-2013

Incremental ARRs (IARRs) for RTEP Upgrades

Table 13-36 lists the incremental ARR allocation volume for the current and previous planning periods from the 2008 to 2009 planning period through the 2013 to 2014 planning period.

Table 13-36 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2013 to 2014

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	890.5	890.5	100%	0	0%
2009/2010	14	530.5	530.5	100%	0	0%
2010/2011	14	531.0	531.0	100%	0	0%
2011/2012	15	595.0	595.0	100%	0	0%
2012/2013	15	687.4	687.4	100%	0	0%
2013/2014	17	1,087.4	1,087.4	100%	0	0%

31 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 28.

Table 13-37 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs.

Table 13-37 IARRs allocated for 2013 to 2014 Annual ARR Allocation for RTEP upgrades[32]

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

Residual ARRs

Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs are available if additional transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any residual ARRs are available as ARRs in the annual ARR allocation. Stage 1 ARR holders have a priority right to ARRs. Residual ARRs are a separate product from incremental ARRs.

Effective August 1, 2012, as ordered by the FERC in Docket No. EL12-50-000, in addition to new transmission, residual ARRs are now available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. These residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation.

Table 13-38 shows the residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 13-38 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-13	6,773.0	1,547.2	22.8%	$488,251
Feb-13	1,567.4	1,493.7	95.3%	$229,856
Mar-13	5,351.2	1,522.7	28.5%	$286,193
Apr-13	5,452.1	1,608.9	29.5%	$325,662
May-13	6,054.7	1,647.4	27.2%	$282,425
Jun-13	10,864.1	1,272.7	11.7%	$667,291
Jul-13	10,936.9	1,323.7	12.1%	$714,675
Aug-13	9,357.2	767.2	8.2%	$236,885
Sep-13	1,855.0	402.9	21.7%	$85,884
Oct-13	1,555.3	411.5	26.5%	$27,639
Nov-13	1,393.5	564.1	40.5%	$116,103
Dec-13	2,343.6	1,686.7	72.0%	$186,383
Total	63,504.0	14,248.7	22.4%	$3,647,248

32 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following 10 pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03

Market Performance

Volume

Table 13-39 shows the volume of ARR allocations for each round of the 2012 to 2013 and 2013 to 2014 planning periods.

Table 13-39 Annual ARR Allocation volume: planning periods 2012 to 2013 and 2013 to 2014

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2012/2013	1A	0	16,069	67,302	67,300	100.0%	2	0.0%
	1B	1	11,487	30,013	18,432	61.4%	11,581	38.6%
	2	2	4,887	22,597	2,701	12.0%	19,896	88.0%
		3	3,682	22,496	3,334	14.8%	19,162	85.2%
		4	3,023	22,362	6,219	27.8%	16,143	72.2%
		Total	11,592	67,455	12,254	18.2%	55,201	81.8%
	Total		39,148	164,770	97,986	59.5%	66,784	40.5%
2013/2014	1A	0	18,022	67,861	67,861	100.0%	0	0.0%
	1B	1	14,227	32,679	15,782	48.3%	16,897	51.7%
	2	2	5,476	22,096	3,519	15.9%	18,577	84.1%
		3	4,128	22,480	3,200	14.2%	19,280	85.8%
		4	3,335	22,348	2,612	11.7%	19,736	88.3%
		Total	12,939	66,924	9,331	13.9%	57,593	86.1%
	Total		45,188	167,464	92,974	55.5%	74,490	44.5%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine transmission upgrades so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year of this test PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be included in the PJM RTEP process.

For the 2012 to 2013 planning period, Stage 1A of the Annual ARR Allocation was infeasible. According to Section 7.4.2 (i) of the PJM OATT the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and that these increased limits must then be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability.

The consequence of this increased capability in the models which does not reflect actual capability is an over allocation of both ARRs and FTRs for the entire planning period. In the case of ARRs this over allocation will lower the ARR funding level by selling more capability on the same transmission network. In the case of FTRs the over allocation will exacerbate the underfunding problem by selling more FTRs than are physically feasible with no increase in congestion collected.

Table 13-40 lists the constraints for which ARR requests were found to be infeasible for the 2012 to 2013 ARR Stage 1A Allocation and the MW increase in modeled facility ratings required to make them feasible. In addition, the reason for infeasibility is provided, whether it is an increase in network load, or due to transmission outages in the simultaneous feasibility test.

Table 13-40 Constraints with capacity increases due to Stage 1A infeasibility for the 2013 to 2014 ARR Allocation

Constraint	Contingency	Type	Zone	MW Increase	Reason
Silver Lake - Cherry Valley	Nelson - Electric Junction	Line	ComEd	251	Load
Cordova - Nelson	Nelson	Flowgate	MISO	215	Load
Electric Junction - Nelson	Nelson - Electric Junction	Line	ComEd	202	Load
Oak Grove - Galesburg	Nelson - Electric Junction	Flowgate	MISO	151	Load
Silver Lake - Cherry Valley	BASE	Line	ComEd	139	Load
Waukegan - Zion	BASE	Line	ComEd	129	Load
Zion	Cherry Valley - Silver Lake	Transformer	ComEd	121	Load
Zion - Lakeview	Cherry Valley - Silver Lake	Line	ComEd	121	Load
Lakeview	Cherry Valley - Silver Lake	Transformer	MISO	121	Load
Electric Junction - Nelson	BASE	Line	ComEd	113	Load
Waukegan - Zion	Cherry Valley - Silver Lake	Line	ComEd	106	Load
Roseland - Whippany	Roseland - Readington	Line	PSEG	103	Outages
Roseland - Whippany	BASE	Line	PSEG	93	Outages
Kenney - Mount Olive	New Church - Piney Grove	Line	DPL	70	Outages
Prairie State - W. Mt. Vernon	St Francis - Lutesville	Flowgate	MISO	60	Load
Kenney - Stockton	New Church - Piney Grove	Line	DPL	59	Outages
Mount Olive - Piney	New Church - Piney Grove	Line	DPL	54	Outages
Belvidere - Woodstock	Cherry Valley - Silver Lake	Line	ComEd	51	Load
Belvidere - Chrysler Corp.	Cherry Valley - Silver Lake	Line	ComEd	51	Load
Dixon - Stillman Valley	Nelson - Electric Junction	Line	ComEd	45	Load
Pleasant Valley - Belvidere 2	Cherry Valley - Silver Lake	Line	ComEd	41	Load
McGirr Road - Steward	Nelson - Electric Junction	Line	ComEd	37	Load
Athenia - Saddlebrook	BASE	Line	PSEG	24	Outages
Mazon - Mazon	Kickapoo Creek - Lasalle	Line	ComEd	16	Load
Pleasant Valley - Belvidere 1	Cherry Valley - Silver Lake	Line	ComEd	13	Load

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs.

The adequacy of ARRs as an offset to total congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs offset market participants' actual, total congestion into their zone. Customers that self schedule ARRs as FTRs provide the same offset to congestion as all other FTRs.

ARR holders received a projected $562.8 million in credits from the FTR auctions during the first seven months of the 2013 to 2014 planning period. During the first seven months of the 2012 to 2013 planning period, ARR holders received $620.2 million in ARR credits.

Table 13-41 lists projected ARR target allocations from the Annual ARR Allocation, and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period and the first seven months of the 2013 to 2014 planning periods.

Table 13-41 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

	2012/2013	2013/2014
Total FTR auction net revenue	$626.7	$562.8
Annual FTR Auction net revenue	$602.9	$558.4
Monthly Balance of Planning Period FTR Auction net revenue*	$23.9	$4.4
ARR target allocations	$570.5	$503.8
ARR credits	$570.5	$503.8
Surplus auction revenue	$56.2	$59.0
ARR payout ratio	100%	100%
FTR payout ratio*	67.8%	75.1%

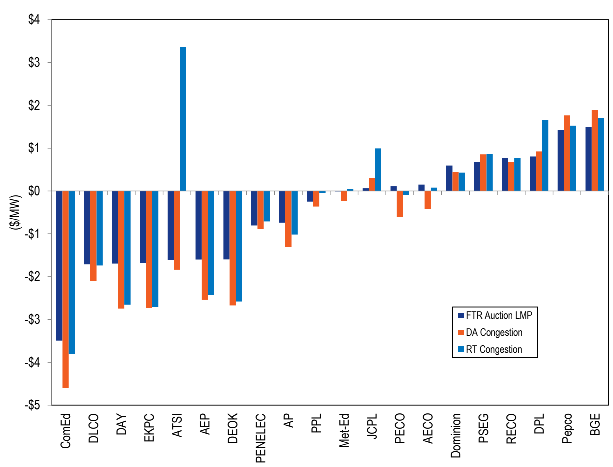
* Shows twelve months for 2012/2013 and seven months for 2013/2014.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 13-24 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the first seven months of the 2013 to 2014 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 13-24 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: 2013 to 2014 planning period through December 31, 2013



Effectiveness of ARRs as an Offset to Congestion

One measure of the effectiveness of ARRs as an offset to congestion is a comparison of the revenue received by the holders of ARRs and the congestion paid by the holders of ARRs in both the Day-Ahead Energy Market and the Balancing Energy Market. The revenue which serves as an offset for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments from the Day-Ahead Energy Market and the Balancing Energy Market. During the first seven months of the 2013 to 2014 planning period, the total revenues received by the holders of all ARRs and FTRs offset 100 percent of the total congestion costs within PJM.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the Balancing Energy Market is presented by control zone in Table 13-42. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[33] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the ARR credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self-scheduled FTR MW) and the cleared price for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and may be less than the target allocation. The FTR payout ratio was 75.1 percent of the target allocation for the first seven months of the 2013 to 2014 planning period. The target allocation is not a guarantee of payment nor does it reflect congestion incurred on a particular FTR path. The target allocation is used to set a cap on path specific FTR payouts.

ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total

33 For Table 13-42 through Table 13-44, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first seven months of the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

The Congestion column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the Balancing Energy Market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Table 13-42 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through December 31, 2013[34]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$4.1	$0.0	$4.1	$0.5	$3.6	>100%
AEP	$32.4	$28.9	$61.2	$3.7	$67.1	>100%
APS	$42.1	$12.9	$54.9	$0.1	$59.2	>100%
ATSI	$5.8	$0.1	$5.9	$0.5	$5.5	>100%
BGE	$29.3	$0.7	$30.0	$2.2	$28.0	>100%
ComEd	$74.6	$0.0	$74.6	$5.2	$69.4	>100%
DAY	$4.0	($0.0)	$4.0	($0.1)	$4.1	>100%
DEOK	$3.7	$0.6	$4.3	($0.1)	$4.6	>100%
DLCO	$1.9	$0.0	$1.9	($0.0)	$1.9	>100%
Dominion	$7.5	$33.9	$41.5	($0.1)	$52.8	>100%
DPL	$17.2	$1.8	$19.0	$1.4	$18.2	>100%
EKPC	$0.6	$0.1	$0.7	$0.1	$0.6	>100%
External	$2.3	$0.1	$2.3	$0.4	$1.9	>100%
JCPL	$6.6	$0.0	$6.6	$1.2	$5.4	>100%
Met-Ed	$6.8	$0.1	$6.9	$0.6	$6.4	>100%
PECO	$22.3	$0.0	$22.3	($0.4)	$22.7	>100%
PENELEC	$12.2	$0.0	$12.2	$0.6	$11.6	>100%
Pepco	$16.3	$1.8	$18.1	$2.7	$16.0	>100%
PPL	$10.0	$0.1	$10.1	$1.3	$8.8	>100%
PSEG	$36.6	$2.0	$38.5	$2.2	$37.0	>100%
RECO	$0.1	$0.0	$0.1	$0.1	$0.0	>100%
Total	$336.2	$88.7	$424.9	$22.1	$432.2	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-43 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the Balancing Energy Market for the first seven months of the 2013 to 2014 planning period. This compares the total offset provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the cleared price of the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions, and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 75.1 percent of the target allocation for the first seven months of the 2013 to 2014 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR offset is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the Balancing Energy Market in each control zone.[35] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

34 The "External" zone was labeled as "PJM" in previous State of the Market Reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM interfaces.

35 The total zonal congestion numbers were calculated as of January 27, 2014 and may change as a result of continued PJM billing updates.

Table 13-43 ARR and FTR congestion offset (in millions) by control zone: 2013 to 2014 planning period through December 31, 2013

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$4.1	$2.9	$4.9	$2.1	$4.2	($2.1)	49.5%
AEP	$83.5	$67.7	$103.3	$47.9	$76.4	($28.5)	62.7%
APS	$66.4	$23.7	$32.8	$57.2	$48.8	$8.4	>100%
ATSI	$5.9	$22.2	$0.9	$27.1	($18.7)	$45.8	>100%
BGE	$30.5	$26.1	$32.2	$24.4	$26.4	($2.0)	92.5%
ComEd	$84.1	$60.4	$56.7	$87.9	$106.5	($18.7)	82.5%
DAY	$4.0	$4.0	$3.9	$4.1	$2.5	$1.6	>100%
DEOK	$4.4	$4.1	$4.6	$3.9	($2.9)	$6.8	>100%
DLCO	$2.1	$1.2	$0.6	$2.7	$1.9	$0.8	>100%
Dominion	$94.9	$73.7	$134.5	$34.1	$49.0	($15.0)	69.5%
DPL	$19.3	$23.7	$15.1	$28.0	$18.0	$10.0	>100%
EKPC	$2.1	$0.4	$2.8	($0.3)	($1.9)	$1.6	0.0%
External	$2.8	$1.3	$1.9	$2.2	$3.4	($1.1)	66.0%
JCPL	$6.6	$19.8	$5.8	$20.5	$17.2	$3.3	>100%
Met-Ed	$6.9	$8.3	$7.8	$7.5	$2.6	$4.8	>100%
PECO	$22.4	$4.2	$18.5	$8.2	($9.7)	$17.9	>100%
PENELEC	$12.0	$27.1	$43.1	($4.0)	$19.7	($23.7)	0.0%
Pepco	$19.6	$47.8	$75.0	($7.6)	$44.9	($52.6)	0.0%
PPL	$10.1	$10.3	$0.3	$20.2	$4.3	$15.9	>100%
PSEG	$38.1	$39.4	$49.1	$28.3	$29.1	($0.8)	97.2%
RECO	$0.1	($0.4)	($1.0)	$0.7	$2.2	($1.5)	30.1%
Total	$519.9	$467.9	$592.9	$394.9	$423.9	($29.0)	93.2%

Table 13-44 shows the total offset due to ARRs and FTRs for the entire 2012 to 2013 and the first seven months of the 2013 to 2014 planning periods. ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 93.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first seven months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Table 13-44 ARR and FTR congestion hedging (in millions): Planning periods 2012 to 2013 and 2013 to 2014[36]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2012/2013	$577.2	$610.3	$654.1	$533.4	$575.9	($42.5)	92.6%
2013/2014*	$519.9	$467.9	$592.9	$394.9	$423.9	($29.0)	93.2%

* Shows seven months ended December 31, 2013

36 The FTR credits do not include after-the-fact adjustments. For the 2013 to 2014 planning period, the ARR credits were the total credits allocated to all ARR of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the planning period and the portion of Annual FTR Auction revenue distributed to the entire planning period.