State of the Market Report for PJM

Volume 1: Introduction

Monitoring Analytics, LLC

Independent Market Monitor for PJM

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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

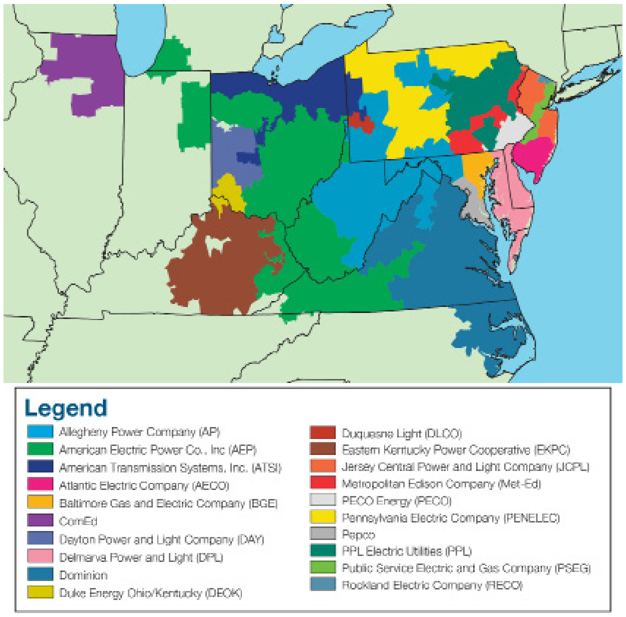
** Regulatory requirement remained 2,063MW throughout the year. Amount shown is daily average.

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 this quarterly report.

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 since the prior quarterly report

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.