State of the Market Report for PJM

Volume 1: Introduction

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2010 State of the Market Report for PJM*.

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

2 OATT Attachment M § II(f).

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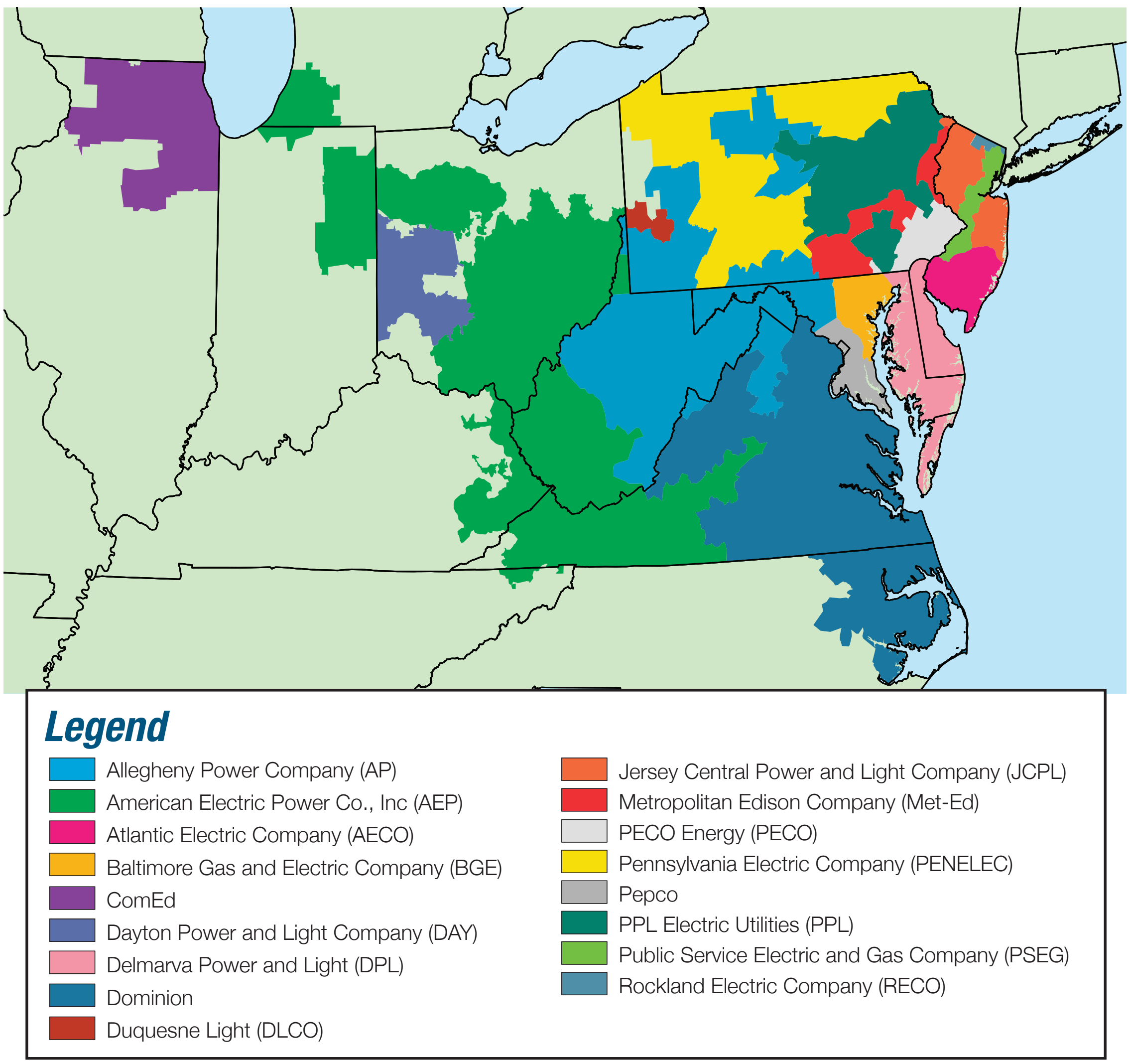
VOLUME 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2010, had installed generating capacity of 166,512 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 54 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)[1]. In 2010, PJM had total billings of $34.77 billion. As part of that 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 17 control zones



1 See the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

PJM Market Background

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, 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 in mid-1999. 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.[2, 3]

2 See also the *2010 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2010 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. 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, see the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2010, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

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. Unit markup is an important measure of participant behavior. Unit markup measures the relationship between the offer of a unit and the marginal cost of a unit. The higher the unit markup, the less competitive the offer.

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. Markup and net revenue are the most relevant measures of market performance. Markup measures the relationship between the marginal costs of marginal units and the marginal offers of marginal units and therefore the market clearing prices in the market. The higher the performance markup, the less competitive the market. Net revenue measures the revenues available from markets in excess of marginal costs which are available to cover all other unit costs.

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, do 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.

The MMU concludes the following for 2010:

Table 1-1 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI indicate that by the Federal Energy Regulatory Commission (FERC) standards, the PJM Energy Market during 2010 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1185 with a minimum of 942 and a maximum of 1599 in 2010.

- 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 TPS test, used to test local market structure, indicates the existence of market power in a number of 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 local market power, PJM's application of the TPS 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. In 2010, the markup component of the PJM real-time, load-weighted, average LMP was $0.31 per MWh, or 0.6 percent.

- 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.

Table 1-2 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: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For all auctions held, the PJM region failed theTPS test, which is conducted at the time of the auction.

- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which it was completed. For almost every auction held, all LDAs failed the TPS test, which is conducted at the time of the auction.

- 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 and the submitted sell offer exceeded the defined offer cap.

- 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 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, a definition of DR which permits an inferior product to substitute for capacity and inadequate rules to address buyer side market power.

Table 1-3 The Regulation Market results were not competitive[4]

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

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's TPS test in 73 percent of the hours.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the TPS test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours,

4 As Table 1-3 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.

- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 1-4 The Synchronized Reserve Markets results were competitive

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

- The market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand.
- Participant behavior was evaluated as competitive because the market rules require cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration by offer capping those suppliers.

Table 1-5 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 market structure was evaluated as competitive because the market failed the TPS test in only a very limited number of hours.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about five 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 TPS test should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-6 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The 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 in 2010 and there is no limit on FTR demand in any FTR auction.

- Performance was evaluated as competitive because it reflected the interaction between participant behavior and FTR supply limited by PJM's analysis of system feasibility.

- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Role of MMU in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Monitoring of PJM Market Rules, PJM Tariff and Market Design," in the section setting forth the MMU's function and responsibilities:

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the PJM Market Rules, PJM Tariff and design of the PJM Markets. The Market Monitoring Unit shall evaluate and monitor existing and proposed PJM Market Rules, PJM Tariff provisions, and the design of the PJM Markets. However, if the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit shall not effectuate its proposed market design since that is the responsibility of the Office of the Interconnection. The Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such markets, as well as changes to the PJM Market Rules and PJM Tariff. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues. The Market Monitoring Unit may also recommend changes to the PJM Market Rules and PJM Tariff provisions to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[5]

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: "In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[6]

5 OATT Attachment M § IV.D.
6 OATT Attachment M § VI.A.

Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[7] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2010 State of the Market Report for PJM*, the MMU makes the following summary recommendations. The MMU's detailed recommendations are in the relevant sections of the report.

Energy Market

- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. (Volume 2, Page 133)

- The MMU recommends that there be substantial improvement in measurement and verification methods be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The MMU makes a number of detailed recommendations regarding ways to improve the measurement and verification process for demand response activity. PJM is currently engaged in a pilot study to evaluate measurement and verification methods. (Volume 2, Page 140 and Page 141)

- The MMU recommends resolution of the double counting issue in the Emergency Load Response Program. The double counting issue can be directly resolved by not permitting the overcompliance which results from the interaction between PLC management and the PJM DR Program. A simple way to achieve this result would be to revise Attachment A to PJM Manual 18 (Load Forecasting and Analysis) to cap the baseline for measuring compliance under GLD at the customers' PLC. The MMU recommends action on this issue prior to the 2011/2012 delivery year. (Volume 2, Page 143)

- The MMU recommends that the limits on operational parameters apply to both price and cost-based schedules in order to prevent the exercise of market power. (Volume 2, Page 275)

- The MMU recommends incorporating startup and notification times as additional parameters subject to limits in order to ensure the reliability of the grid, as well as to deter market manipulation by offering artificially lengthy startup and notification time parameters to withhold generation from the market. (Volume 2, Page 275)

- The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of regulated wholesale energy prices. (Volume 2, Page 224)

7 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

Interchange Transactions

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent. The MMU recommends changing the not willing to pay congestion product to eliminate uncollected congestions charges, eliminating internal source and sink bus designations for external energy transactions, eliminating or modifying the dispatchable transactions and up to congestion transactions products to reduce or eliminate gaming opportunities associated with the products. (Volume 2, Pages 334, 343 and 347)

- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Volume 2, Page 327)

- The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles. (Volume 2, Pages 301, 313, 320 and 327)

Capacity Markets

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity. (Volume 2, Pages 357-359 and Page 362)

- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules. (Volume 2, Pages 357-358 and Page 408)

- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened. (Volume 2, Page 360 and Page 361)

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized. (Volume 2, Page 398)

Ancillary Services

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. (Volume 2, Page 420 and Page 430)

- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This is consistent with PJM's recommendation on this topic in the scarcity pricing matter. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Volume 2, Page 420 and Page 462)

- The MMU recommends that the DASR Market rules be modified to incorporate the application of the TPS test in order to address potential market power issues. (Volume 2, Page 420 and Page 465)

- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. (Volume 2, Page 420 and Page 469)

Congestion

- The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants. (Volume 2, Page 474)

- The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables. These issues are currently being considered in the PJM stakeholder process. (Volume 2, Page 536)

- The MMU recommends continued efforts to incorporate transmission investments into competitive markets. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, 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. (Volume 2, Page 472)

Financial Transmission Rights and Auction Revenue Rights

- The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. (Volume 2, Page 550)

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. (Volume 2, Page 539)

- The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding. (Volume 2, Page 539)

Highlights and New Analysis

The following presents highlights and new analysis from each of the sections of the *2010 State of the Market Report for PJM*:

Section 2, Energy Market, Part 1

- Average offered supply increased by 554 MW, less than one percent, from 153,520 MW in 2009 to 154,074 MW in 2010. (Volume 2, Page 27 and Page 31)

- The PJM system peak load for the summer 2010 was 136,465 MW, which was 9,667 MW, or 7.6 percent, higher than the summer 2009 peak load. (Volume 2, Page 27 and Page 35)

- On average, PJM real-time load increased in 2010 by 4.7 percent from 2009, rising from 76,035 MW to 79,611 MW. PJM day-ahead load increased in 2010 by 2.6 percent from 2009, rising from 88,707 MW to 90,985 MW. The increase in load is consistent with changes in the Temperature-Humidity Index (THI). (Volume 2, Page 28 and Page 31)

- PJM Real-Time Energy Market prices increased in 2010 compared to 2009. The load-weighted average LMP was 23.8 percent higher in 2010 than in 2009, $48.35 per MWh versus $39.05 per MWh. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh.[8] In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010. (Volume 2, Page 31 and Page 77)

- PJM Day-Ahead Energy Market prices increased in 2010 compared to 2009. The load-weighted LMP was 22.7 percent higher in 2010 than in 2009, $47.65 per MWh versus $38.82 per MWh. (Volume 2, Page 82)

- Analysis of real-time LMP showed that 39.4 percent of the annual, load-weighted LMP was the result of coal costs; 37.5 percent was the result of gas costs and 3.1 percent was the result of the cost of emission allowances. Markup was 0.6 percent of LMP, consistent with a competitive market outcome. (Volume 2, Page 78)

- Levels of offer capping for local market power remained low. In 2010, 1.2 percent of unit hours and 0.4 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.1 percent of MW were offer capped in the Day-Ahead Energy Market. (Volume 2, Page 27 and Page 41)

- The TPS test is applied whenever incremental relief is needed to solve a transmission constraint, but not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started to solve the constraint, are eligible to be offer capped. Only a small portion of the TPS tests resulted in offer capping. For example, of all the tests applied

8 The MMU's fuel cost adjusted LMP analysis reflects both fuel and emission cost differences over the periods in question. It could also be characterized as input cost adjusted LMP analysis.

to the regional 500 kV constraints, no more than seven percent of the tests for any constraint resulted in offer capping. (Volume 2, Page 43 and Page 45)

- The overcollected portion of transmission losses increased in 2010 to $836.6 million or 51.2 percent of the total losses compared to $639.7 million or 50.4 percent of total losses in 2009. (Volume 2, Page 92)

- The total MWh of load reduction under the Economic Program increased by 15,600 MWh, from 57,157 MWh in 2009 to 72,757 MWh in 2010, a 21 percent increase. Total payments under the Economic Program increased by $1.5 million, from $1.4 million in 2009 to $2.9 million in 2010, a 111 percent increase. (Volume 2, Page 122)

- The total MW registered in the Load Management Program increased by 1,758.1 MW, from 7,294.3 MW in 2009 to 9,052.4 MW in 2010, a 24 percent increase. Total payments under the Load Management Program increased by $209 Million or 69 percent, from $303 Million in 2009 to $512 million in 2010. (Volume 2, Page 128)

- Analysis of Load Management emergency event performance for the 2010 summer period shows a bimodal distribution of event days by performance level, with high frequencies of both high and low performing registrations. For any given event, approximately 31 percent of participants showed little or no reduction and 47 percent of participants did not meet half of their committed MW. The large disparity in performance and the proportion of underperforming assets are indicative of over compliance offsetting under performing resources, and consistent with the presence of the double counting issue. (Volume 2, Page 134)

- One way to evaluate the likelihood that a customer has managed their PLC is to compare the PLC to the observed load reduction in real time. For customers that did not manage PLC in prior years, the PLC should reflect unrestricted usage during system peak conditions. It is unlikely that these customers would be able to show a reduction in real time greater than their PLC unless their PLC represented a managed consumption level. GLD participants accounting for 41 percent of total GLD reductions show reductions in real time which are greater than or equal to 100 percent of their PLC. It is reasonable to conclude that such GLD customers did manage their PLCs in the prior year. The results show the extent to which customers with managed PLCs are participating under the GLD option of the Load Management Program, and are consistent with the presence of the double counting problem. (Volume 2, Page 135)

- For the 2010/2011 delivery year, approximately 79 percent of registered sites representing 73 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. The ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. (Volume 2, Page 113)

Section 3, Energy Market, Part 2

- Net revenues increased for all zones from 2009 to 2010 as a result of higher energy revenues, and, in most zones, higher capacity revenues. (Volume 2, Page 163)

- Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the Pepco and BGE zones for a new entrant CT and less than full annual fixed cost recovery in the other zones. Net revenues in 2010 were greater than or equal to full annual fixed cost recovery in the AECO, BGE, DPL, and Pepco zones for a new entrant CC and less than full annual fixed cost recovery in the other zones. There were no control zones with sufficient net revenue to cover the levelized fixed costs of a new entrant CP in 2010. (Volume 2, Pages 176, 180 and 184)

- Analysis of actual 2010 net revenues shows that capacity market revenues were required to provide supplemental revenue to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Such units included CTs, CCs and coal units. (Volume 2, Page 190 and Page 197)

- Analysis of actual 2010 net revenues shows that revenues from energy, ancillary and capacity markets were sufficient to cover avoidable costs for all CC technologies and nearly all CT technologies. (Volume 2, Page 199)

- Analysis of actual 2010 net revenues shows that a number of sub-critical and supercritical coal units did not recover avoidable costs even after capacity revenues were considered. The total installed capacity associated with coal units that did not cover their avoidable costs in 2010 was 6,769 MW, of which, 6,021 MW were located in the MAAC region. These units are considered at risk of retirement. Units accounting for 2,763 MW are recovering less than 65 percent of avoidable costs and units accounting for 4,862 MW are recovering less than 75 percent of avoidable costs. (Volume 2, Page 198 and Page 199)

- Units lacking controls for either NO_x emissions, SO_2 emissions, or both were identified as units at risk of significant capital expenditure on environmental control technologies in response to regulatory mandates. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue. (Volume 2, Page 200)

- Analysis of actual, unit specific net revenues and avoidable costs for coal plants lacking environmental controls in 2010 found that between 14,345 MW and 19,068 MW of installed capacity, depending on the nature of the requirements, would require an increase in energy or capacity revenue in order to recover avoidable costs including the project investment costs and remain in operation if faced with mandatory investment in environmental controls. (Volume 2, Page 151)

- There were no scarcity pricing events in 2010 under PJM's current Emergency Action based Scarcity Pricing Rules. (Volume 2, Page 230)

- Analysis of net resource levels found there were no reserve shortages in 2010. There were a number of relatively high load days in July, August and September of 2010. (Volume 2, Page 231)

- Operating reserve charges increased 74.6 percent in 2010 compared to 2009. Higher loads, locationally volatile natural gas prices, and increases in outages were the primary causes. Eastern reliability credits increased 9,584.1 percent in 2010 compared to 2009, mainly as a result of units required to operate for a specific transmission outage, and an increase in weather-related alerts. (Volume 2, Page 234)

- Balancing transaction operating reserve credits paid in December 2010 represent 82.9 percent of all balancing transaction operating reserve credits since 2000. (Volume 2, Page 273)

- The concentration of operating reserve credits remains high, but decreased in 2010 compared to 2009. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 33.2 percent of total operating reserve credits in 2010, compared to 37.1 percent in 2009. In 2010, the top generation owner received 24.9 percent of the total operating reserve credits paid, a decrease from 2009, when the top generation owner received 32.8 percent of the total operating reserve credits. (Volume 2, Page 262)

- In 2010, coal units provided 49.3 percent, nuclear units 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, waste 0.7 percent and wind 1.2 percent of total generation. Compared to calendar year 2009, generation from coal units increased 3.5 percent, and generation from nuclear units increased 2.1 percent. Generation from natural gas units increased 28.4 percent, and from oil units 106.8 percent. (Volume 2, Page 204)

- At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2010. Wind projects account for approximately 38,301 MW of capacity or 50.1 percent of the capacity in the queues and combined-cycle projects account for 16,541 MW of capacity or 21.6 percent of the capacity in the queues. (Volume 2, Page 204)

- 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 2010, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 7.41 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Indiana, Kentucky, and Tennessee have enacted no renewable portfolio standards. (Volume 2, Page 223)

Section 4, Interchange Transactions

- Real-time net exports increased from -1,407 GWh in 2009 to -9,661 GWh in 2010, and Day-ahead net exports decreased from -9,032.5 GWh in 2009 to -6,470.0 GWh in 2010.(Volume 2, Page 287)

- In 2010, the direction of power flows at the borders between PJM and the Midwest ISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a majority of hours in 2010, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO. (Volume 2, Page 301)

- System loop flows increased from 2.2 percent for the calendar year 2009 to 5.2 percent for the calendar year 2010. (Volume 2, Page 318)

- PJM initiated fewer TLRs in 2010 (110 TLRs) than in 2009 (129 TLRs). (Volume 2, Page 328)

- The Midwest ISO and PJM filed a settlement agreement resolving all complaints regarding the management of the Joint Operating Agreement. (Volume 2, Page 312)

- The Commission supported an expedited timeline in the Broader Regional Market docket, and ordered interface pricing modifications and the development of a market-to-market congestion management protocol by the second quarter of 2011. (Volume 2, Page 311)

- The Commission conditionally accepted a Congestion Management Protocol between PJM and Progress Energy Carolinas. (Volume 2, Page 315)

- Changes to the marginal loss surplus allocation created opportunities for market participants to submit uneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus. Customers entering uneconomic bids profited by $9.6 million after the cost of transmission as a result of the change in the allocation methodology. (Volume 2, Page 342)

- The daily volume of up-to congestion bids increased from approximately 600 bids per day, prior to the September 17, 2010 modification to the up-to congestion product that eliminated the requirement to procure transmission, to approximately 950 bids per day. (Volume 2, Page 277)

- Total uncollected congestion charges for 2010 were $3.3 million, a 379 percent increase from the 2009 total uncollected congestion charges of $688,547. (Volume 2, Page 343)

- Balancing operating reserve credits, allocated to real-time dispatchable import transactions, were approximately $24 million in 2010, an increase from the 2009 total of approximately $91,000. (Volume 2, Page 347)

Section 5, Capacity Markets

- The RTO resource clearing price in the 2010/2011 RPM Base Residual Auction increased $72.25 per MW-day (70.8 percent) from the 2009/2010 RPM Base Residual Auction, and the RTO resource clearing price for the 2010/2011 RPM Third Incremental Auction increased $10.00 per MW-day (25.0 percent) from the 2009/2010 RPM Third Incremental Auction. (Volume 2, Page 386 and Page 387)

- RPM has resulted in new resources. New generation capacity resources (5,986.1 MW), reactivated generation capacity resources (849.7 MW), uprates to existing generation capacity resources (4,905.3 MW), and the net increase in capacity imports (4,126.1 MW) totaled 15,867.2 MW since the implementation of RPM. (Volume 2, Page 366 and Page 368)

- The results of the 2011/2012 and 2012/2013 ATSI Integration Auctions are reported. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW. (Volume 2, Page 365 and Page 367)

- Capacity in the RPM load management programs increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. (Volume 2, Pages 376-378)

- Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $100.26 per MW-day in 2013. (Volume 2, Page 386 and Page 388)

- Average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in 2009 to 7.2 percent in 2010. (Volume 2, Page 401)

- The PJM aggregate equivalent availability factor (EAF) decreased from 85.7 percent in 2009 to 84.8 percent in 2010. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent in 2009 to 2.9 percent in 2010, the equivalent planned outage factor (EPOF) increased from 6.7 percent in 2009 to 7.4 percent in 2010, and the equivalent forced outage factor (EFOF) increased from 4.8 percent in 2009 to 4.9 percent in 2010. (Volume 2, Page 400 and Page 401)

Section 6, Ancillary Services

- Regulation prices were 23.3 percent lower in 2010 than in 2009 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.4 percent higher in 2010 than in 2009. The total cost of regulation per MW was 77.4 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005. (Volume 2, Page 423 and Page 442)

- Total self-scheduled regulation MW in 2010 was 15.5 percent of all regulation, an increase from 10.9 percent in 2009. The supply of eligible regulation increased by two percent in 2010 relative to 2009 levels. (Volume 2, Page 421 and Page 436)

- Synchronized reserve prices were 36.1 percent higher in 2010 than in 2009, but lower than in any other year since 2005. Synchronized reserves total costs per MW were 47.5 percent higher in 2010 than in 2009. The total cost of synchronized reserves per MW was 36.6 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. (Volume 2, Page 425 and Page 462)

- Since 2001, the cost of ancillary services per MW of load has been relatively low and stable. (Volume 2, Page 420 and Page 427)

- Of the LSEs' obligation to provide regulation, 82.2 percent was purchased in the spot market, 15.4 percent was self scheduled, and 2.3 percent was purchased bilaterally. (Volume 2, Page 420 and Page 436)

- DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July. (Volume 2, Page 420 and Page 465)

- Black start zonal charges ranged from $0.03 per MW in DLCO zone to $0.55 per MW in PSEG zone. (Volume 2, Page 420 and Page 466)

Section 7, Congestion

- Congestion costs in 2010 increased by 99 percent over congestion costs in 2009. Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008. (Volume 2, Page 472)

- In 2010, Dominion was the most congested zone. Dominion accounted for nearly 20 percent of the total congestion cost. In 2009, ComEd was the most congested zone, accounting for nearly 30 percent of the total congestion cost. (Volume 2, Page 494)

- Summer high-demand months (May through August) accounted for 45 percent of the total congestion cost in 2010. By contrast, the same period accounted for 26 percent of the total congestion cost in 2009. (Volume 2, Page 480)

- Review of the generation and transmission interconnection process. The generation and transmission interconnection process is complex and time consuming as a result of the nature of the required analyses. (Volume 2, Page 528)

- Review of backbone facilities. PJM backbone projects are a subset of significant baseline upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. (Volume 2, Page 531)

Section 8, Financial Transmission Rights and Auction Revenue Rights

- FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010. (Volume 2, Page 575)

- The net revenue from the 2011 to 2014 Long Term FTR Auction increased 60 percent ($18.7 million) from the 2010 to 2013 Long Term FTR Auction. In contrast, the net revenue from the 2010 to 2011 Annual FTR Auction decreased 21 percent ($280 million) from the 2009 to 2010 Annual FTR Auction. (Volume 2, Page 542)

- The percent of ARRs self-scheduled as FTRs in the Annual FTR Auction decreased by 8 percent from the 2009 to 2010 planning period, to the 2010 to 2011 planning period. (Volume 2, Page 540)

- The total secondary bilateral FTR obligation market volume increased from 8,810 MW in the 2009 to 2010 planning period to 24,034 MW in the first seven months of the 2010 to 2011 planning period. (Volume 2, Page 559)

- The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than the buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction with the result that the total weighted-average cleared price for all 24 hour buy bid FTRs was negative (-$0.16). The weighted-average cleared price for all 24 hour buy bid FTRs in the 2010 to 2013 Long Term Auction was $0.53. (Volume 2, Page 561)

- No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period. (Volume 2, Page 589)

- FTRs were profitable overall and were profitable for both physical entities and financial entities in 2010. Total FTR profits in 2010 were $909.6 million for physical entities and $138.7 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities. (Volume 2, Page 542)

- On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court and at the FERC.[9] The FERC's investigation of whether manipulation of the FTR markets occurred continues.[10] (Volume 2, Page 540)

9 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.

10 See 127 FERC ¶ 61,007 at PP 2&5 (2009).

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, transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-7 provides the average price and total revenues paid, by component for calendar years 2009 and 2010.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges represent the three largest components of the total price per MWh of wholesale power, contributing 96.5 percent of the total price per MWh in 2010. The cost of energy was 72.5 percent of the total price per MWh in 2010, the cost of capacity was 18.1 percent and the cost of transmission service was 6.0 percent.

The total per MWh price of wholesale power for 2010, $66.72, was 19.5 percent higher than total per MWh price of wholesale power for 2009, $55.85. This increase in the total price per MWh is largely attributable to the 23.8 percent increase in the price of energy.

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 Load Weighted Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of RPM payments.
- The Transmission Service Charge component is the average price per MWh of network integration charges and firm and non firm point to point transmission service.[11]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[12]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[13]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[14]
- 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 (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.

11 OATT §§ 13.7, 14.5, 27A & 34.
12 OA Schedules 1 §§ 3.2.3 & 3.3.3.
13 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
14 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.

- 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 TrAILCo and PATH projects.[15]

- 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.[16]

- 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.[17]

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[18]

- The Black Start component is the average cost per MWh of black start service.[19]

- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[20]

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[21]

- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[22]

- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[23]

Table 1-7 Total price per MWh by category and total revenues by category: Calendar years 2009 and 2010

Category	Totals ($ Millions) 2009	Totals ($ Millions) 2010	Percent Change Totals	2009 $/MWh	2010 $/MWh	Percent Change $/MWh	2009 Proportion of $/MWh	2010 Proportion of $/MWh	Percent Change in Proportions
Energy	$26,008.22	$33,717.30	29.6%	$39.05	$48.35	23.8%	69.9%	72.5%	3.6%
Capacity	$7,338.36	$8,409.34	14.6%	$11.02	$12.06	9.4%	19.7%	18.1%	(8.4%)
Transmission Service Charges	$2,663.31	$2,786.58	4.6%	$4.00	$4.00	(0.1%)	7.2%	6.0%	(16.4%)
Operating Reserves (Uplift)	$321.83	$547.68	70.2%	$0.48	$0.79	62.5%	0.9%	1.2%	36.0%
Reactive	$242.32	$310.08	28.0%	$0.36	$0.44	22.2%	0.7%	0.7%	2.3%
PJM Administrative Fees	$203.49	$248.02	21.9%	$0.31	$0.36	16.4%	0.5%	0.5%	(2.6%)
Regulation	$228.18	$241.39	5.8%	$0.34	$0.35	1.0%	0.6%	0.5%	(15.4%)
Transmission Enhancement Cost Recovery	$63.21	$139.36	120.5%	$0.09	$0.20	110.6%	0.2%	0.3%	76.2%
Transmssion Owner (Schedule 1A)	$56.47	$61.38	8.7%	$0.08	$0.09	3.8%	0.2%	0.1%	(13.1%)
Synchronized Reserves	$34.27	$43.85	27.9%	$0.05	$0.06	22.2%	0.1%	0.1%	2.3%
NERC/RFC	$8.86	$13.81	56.0%	$0.01	$0.02	49.0%	0.0%	0.0%	24.7%
Black Start	$14.27	$11.45	(19.7%)	$0.02	$0.02	(23.3%)	0.0%	0.0%	(35.8%)
RTO Startup and Expansion	$9.12	$8.99	(1.4%)	$0.01	$0.01	(5.9%)	0.0%	0.0%	(21.2%)
Day Ahead Scheduling Reserve (DASR)	$2.32	$7.37	217.7%	$0.00	$0.01	203.5%	0.0%	0.0%	154.0%
Load Response	$1.35	$3.11	129.9%	$0.00	$0.00	119.6%	0.0%	0.0%	83.8%
Transmission Facility Charges	$1.39	$1.39	(0.4%)	$0.00	$0.00	(4.9%)	0.0%	0.0%	(20.4%)
Total	$37,196.97	$46,530.41	25.1%	$55.85	$66.72	19.5%	100.0%	100.0%	0.0%

Table 1-8 provides the average price by component for 2000 through 2010.

Table 1-8 shows that from 2007 through 2010, Energy, Capacity and Transmission Service Charges were the three largest components of the total price per MWh of wholesale power, contributing more than 96 percent of the total price per MWh on an annual basis in this period. Over the 2000 to 2010 period these three components respresented a minimum of 94.7 percent of the total price per MWh on an annual basis. Of these components, the cost of energy was consistently the largest, making up 69.9 to 91.1 percent of the total price per MWh for the 2000 through 2010 period. The cost of capacity varied between 0.04 percent and 19.73 percent over the same period due to the introduction of the RPM capacity market design in 2007. Transmission Service Charges contributed from 3.9 to 9.1 percent of the total price per MWh on an annual basis for the 2000 through 2010 period.

Table 1-8 Total price per MWh by category: Calendar Years 2000 through 2010[24]

Category	Totals ($/MWh) 2000	Totals ($/MWh) 2001	Totals ($/MWh) 2002	Totals ($/MWh) 2003	Totals ($/MWh) 2004	Totals ($/MWh) 2005	Totals ($/MWh) 2006	Totals ($/MWh) 2007	Totals ($/MWh) 2008	Totals ($/MWh) 2009	Totals ($/MWh) 2010
Energy	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35
Capacity	$0.20	$0.32	$0.12	$0.08	$0.09	$0.03	$0.03	$3.97	$8.33	$11.02	$12.06
Transmission Service Charges	$2.17	$3.46	$3.37	$3.56	$3.26	$2.68	$3.15	$3.41	$3.65	$4.00	$4.00
Operating Reserves (Uplift)	$0.57	$1.07	$0.69	$0.86	$0.93	$0.97	$0.45	$0.63	$0.61	$0.48	$0.79
Reactive	$0.15	$0.22	$0.20	$0.24	$0.25	$0.26	$0.29	$0.31	$0.32	$0.36	$0.44
PJM Administrative Fees	$0.15	$0.36	$0.43	$0.54	$0.50	$0.38	$0.40	$0.38	$0.24	$0.31	$0.36
Regulation	$0.30	$0.50	$0.42	$0.50	$0.50	$0.79	$0.53	$0.63	$0.70	$0.34	$0.35
Transmission Enhancement Cost Recovery										$0.09	$0.20
Transmssion Owner (Schedule 1A)	$0.05	$0.08	$0.07	$0.07	$0.11	$0.09	$0.09	$0.09	$0.09	$0.08	$0.09
Synchronized Reserves			$0.11	$0.19	$0.16	$0.15	$0.10	$0.11	$0.09	$0.05	$0.06
NERC/RFC								$0.01	$0.01	$0.01	$0.02
Black Start			$0.00	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion			$0.04	$0.05	$0.10	$0.37	$0.15	$0.01	$0.01	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)									$0.00	$0.00	$0.01
Load Response		$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.07	$0.03	$0.00	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$34.32	$42.66	$37.05	$47.36	$50.25	$69.20	$58.58	$71.30	$85.24	$55.85	$66.72

24 Results reflect the fact that data were not available for January through May of 2000 and January of 2002.

Table 1-9 Percentage of total price per MWh by category: Calendar years 2000 through 2010[25]

Category	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Energy	89.52%	85.91%	85.29%	87.07%	88.24%	91.70%	91.07%	86.48%	83.45%	69.92%	72.46%
Capacity	0.59%	0.75%	0.33%	0.18%	0.18%	0.04%	0.05%	5.57%	9.77%	19.73%	18.07%
Transmission Service Charges	6.33%	8.11%	9.11%	7.51%	6.48%	3.88%	5.38%	4.78%	4.28%	7.16%	5.99%
Operating Reserves (Uplift)	1.66%	2.51%	1.86%	1.81%	1.85%	1.40%	0.77%	0.88%	0.72%	0.87%	1.18%
Reactive	0.44%	0.52%	0.54%	0.51%	0.50%	0.38%	0.50%	0.43%	0.38%	0.65%	0.67%
PJM Administrative Fees	0.43%	0.84%	1.15%	1.14%	0.99%	0.55%	0.68%	0.54%	0.29%	0.55%	0.53%
Regulation	0.89%	1.16%	1.13%	1.06%	1.00%	1.14%	0.90%	0.88%	0.82%	0.61%	0.52%
Transmission Enhancement Cost Recovery										0.17%	0.30%
Transmssion Owner (Schedule 1A)	0.14%	0.19%	0.18%	0.14%	0.21%	0.13%	0.15%	0.12%	0.10%	0.15%	0.13%
Synchronized Reserves			0.29%	0.40%	0.31%	0.22%	0.17%	0.15%	0.10%	0.09%	0.09%
NERC/RFC								0.01%	0.01%	0.02%	0.03%
Black Start			0.00%	0.03%	0.03%	0.03%	0.04%	0.03%	0.03%	0.04%	0.02%
RTO Startup and Expansion			0.10%	0.10%	0.21%	0.53%	0.25%	0.02%	0.02%	0.02%	0.02%
Day Ahead Scheduling Reserve (DASR)									0.00%	0.01%	0.02%
Load Response		-0.00%	0.00%	0.01%	0.00%	0.00%	0.05%	0.09%	0.03%	0.00%	0.01%
Transmission Facility Charges	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

25 Results reflect the fact that data were not available for January through May of 2000 and January of 2002.

ENERGY MARKET, PART 1

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for 2010, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[26] The MMU concludes that the PJM Energy Market results were competitive in 2010.

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.[27] 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.[28]

Market Structure

- **Supply.** During the summer months of 2010, the PJM Energy Market received an hourly average of 154,074 MWh in supply offers including hydroelectric generation.[29] The summer months of 2010 average daily offered supply was 554 MWh higher than the summer months of 2009 average daily offered supply of 153,520 MWh.

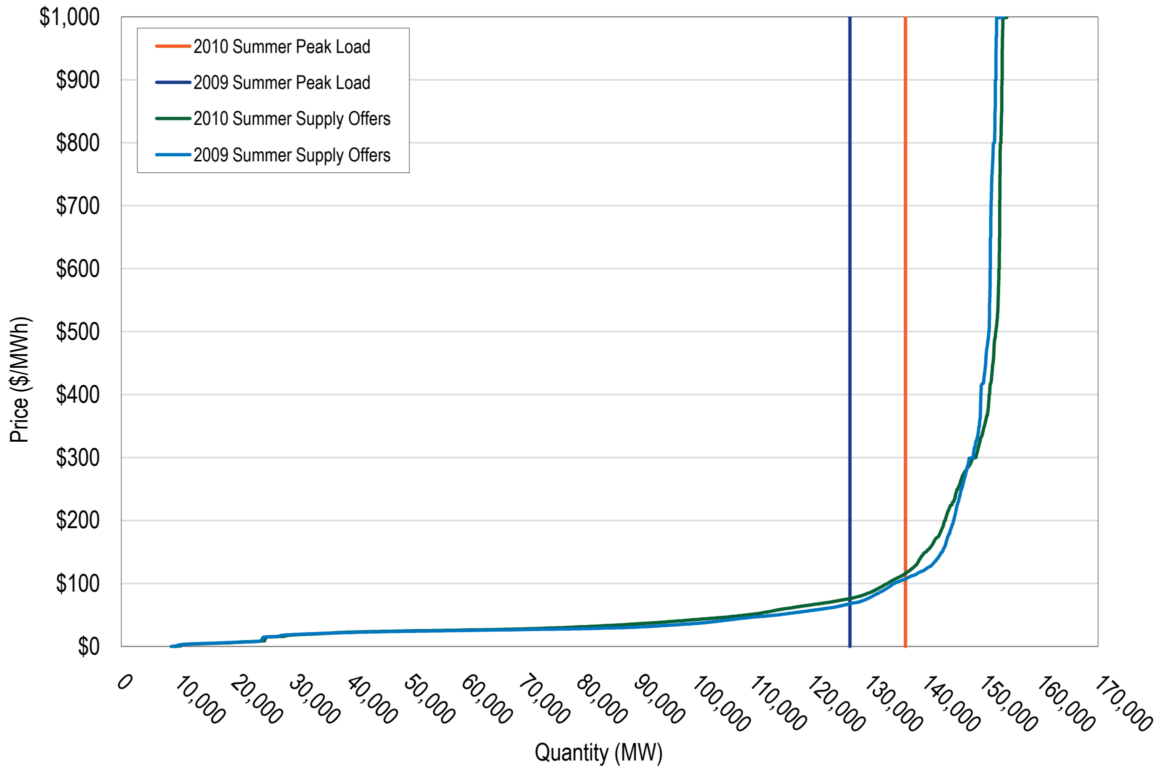
26 Analysis of 2010 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2010 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

27 OATT Attachment M

28 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.

29 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

Figure 1-2 Average PJM aggregate supply curves: Summers 2009 and 2010



- **Demand.** The PJM system peak load for the summer months 2010 was 136,465 MW in the hour ended 1700 EPT on July 6, 2010, while the PJM peak load for the summer months 2009 was 126,798 MW in the hour ended 1700 EPT on August 10, 2009.[30] The summer 2010 peak load was 9,667 MW, or 7.6 percent, higher than the summer 2009 peak load.

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Local Market Structure and Offer Capping.** A noncompetitive local market structure is the trigger for offer capping. PJM continued to apply a flexible, targeted, real-time approach to offer capping (the TPS test) as the trigger for offer capping in 2010. PJM offer caps units only 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

30 For the purpose of the *2010 State of the Market Report for PJM*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2010 State of the Market Report for PJM*, Appendix G, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

Energy Market offer-capped unit hours increased from 0.1 percent in 2009 to 0.2 percent in 2010. In the Real-Time Energy Market offer-capped unit hours increased from 0.4 percent in 2009 to 1.2 percent in 2010.

- **Local Market Structure.** In 2010, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, DPL, Met-Ed, PENELEC, PPL and PSEG 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.[31]

Table 1-10 Annual offer-capping statistics: Calendar years 2006 to 2010

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP in 2010 was $0.31 per MWh, or 0.6 percent. Coal steam (CP) units contributed -$0.99 to the total markup component of LMP. Combustion turbine (CT) units that use natural gas as their primary fuel source contributed $0.34 to the total markup component of LMP. Combined cycle (CC) units that use gas as their primary fuel source contributed $0.77 to the total markup component of LMP. The markup was $1.63 per MWh during peak hours and -$1.11 per MWh during off-peak hours.

31 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.60 per MWh, or -1.3 percent. Coal steam units contributed -$0.68 to the total markup component of LMP. Natural gas steam units contributed $0.05 to the total markup component of LMP. The markup was $0.03 per MWh during peak hours and -$1.27 per MWh during off-peak hours.

The overall 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.

- **Load.** On average, PJM real-time load increased in 2010 by 4.7 percent from 2009, rising from 76,035 MW to 79,611 MW. PJM day-ahead load increased in 2010 by 2.6 percent from 2009, rising from 88,707 MW to 90,985 MW.

- **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 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 2010 compared to 2009. The system simple average LMP was 20.9 percent higher in 2010 than in 2009, $44.83 per MWh versus $37.08 per MWh. The load-weighted LMP was 23.8 percent higher in 2010 than in 2009, $48.35 per MWh versus $39.05 per MWh. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP[32] was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh. In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010.

  PJM Day-Ahead Energy Market prices increased in 2010 compared to 2009. The system simple average LMP was 20.5 percent higher in 2010 than in the 2009, $44.57 per MWh versus $37.00 per MWh. The load-weighted LMP was 22.7 percent higher in 2010 than in 2009, $47.65 per MWh versus $38.82 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2010, 4.9 percent of real-time load was supplied by bilateral contracts, 19.3 percent by spot market purchases and 75.8 percent by self-supply. Compared with 2009, reliance on bilateral contracts decreased by 0.0 percentage points; reliance on spot supply increased by 4.4 percentage points; and reliance on self-supply decreased by 4.4 percentage points in 2010.

32 The MMU's fuel cost adjusted LMP analysis reflects both fuel and emission cost differences over the periods in question. It could also be characterized as input cost adjusted LMP analysis.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

  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.

  There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

  Demand-Side Response Activity. In 2010, in the Economic Program, participation was more concentrated among a smaller number of participants compared to 2009. Settled MWh and credits were higher in 2010 compared to 2009, which is partially attributable to higher price levels. However, there were generally fewer settlements submitted, fewer registered customers, and fewer active customers compared to the same period in 2009. Participation levels through calendar year 2009 and through the first three months of 2010 were generally lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification, but have showed strong growth through the summer period as price levels and load levels have increased. On the peak load day for the period 2010 (July 6, 2010), there were 1,725.7 MW registered in the Economic Load Response ProgrIn 2010, in the Emergency Program, specifically the Load Management (LM) Program, participation increased compared to 2009.[33] Participants in the LM Program are committed resources that receive RPM capacity credits and participation continues to increase through RPM delivery years. For the 2010/2011 delivery year, there were 9,052.4 MW registered in the LM Program, compared to 7,294.3 MW registered in the 2009/2010 delivery year.

  That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers.

  The proportion of customers meeting RPM commitments is substantially lower for these events, less than 50 percent, which implies significant over compliance from a subset of larger customers. Further, the MMU has raised concerns with PJM and stakeholders on the measurement and verification protocols in place to quantify load reductions for the 2010/2011 delivery year and these methods will be under review in calendar year 2011.

33 The Capacity Only and Full options of the Emergency Program are integrated into RPM through the Load Management Program. The Energy Only option is a voluntary program that does not interact with RPM, however, there are currently no participants registered in this option.

Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to participants in PJM demand side programs. In 2010, Economic Program revenues increased by $1.5 Million or 111 percent, from $1.4 million to $2.9 million. In 2010, Load Management (LM) Program revenues increased by $209 million or 69 percent, from $303 million to $512 million. Synchronized Reserve credits increased by $1.3 million, from approximately $4.0 million to $5.3 million from 2009 to 2010. In 2009, since there were no Load Management Events, no emergency energy revenues were eligible. However, in 2010, there were six Load Management Events resulting in $13.8 million in emergency energy revenues.

Energy Market, Part 1 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2010, including aggregate supply and demand, concentration ratios, TPS test results, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate hourly supply offered increased by about 554 MWh when comparing the summer of 2010 to the summer of 2009, while aggregate peak load increased by 9,667 MW, modifying the general supply demand balance from the summer of 2009 with a corresponding impact on Energy Market prices. Average load in 2010 also increased from 2009, rising from 76,035 MW to 79,611 MW. Market concentration levels remained moderate and average markup was slightly positive. 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.

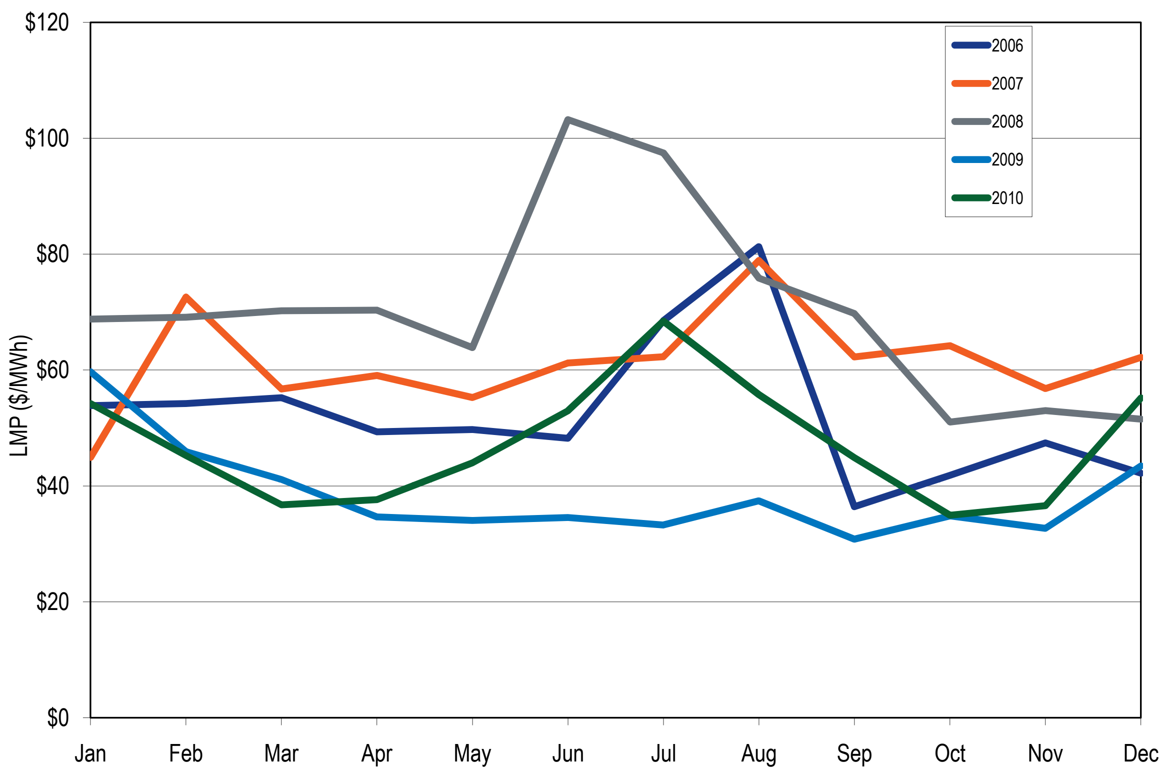
Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The TPS 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. 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 TPS 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 TPS 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 TPS 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.[34]

Energy Market results for 2010 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher demand and higher fuel costs. PJM Real-Time, load-weighted, average LMP for 2010 was $48.35, or 23.8 percent higher than the load-weighted, average LMP for 2009, which was $39.05. The 2010 real-time, fuel cost adjusted, load-weighted, average LMP was 19.6 percent higher than the 2009 load-weighted, average LMP, $46.70 per MWh versus $39.05 per MWh. In other words, if fuel costs in 2010 were the same as they had been in 2009, the 2010 load-weighted LMP would have been 3.4 percent lower, $46.70 per MWh, than the actual $48.35 per MWh, and 19.6 percent higher than the 2009 load-weighted average LMP. Higher loads and fuel costs contributed to upward pressure on LMP in 2010.

The overall market 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 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 2010.

Figure 1-3 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2006 to 2010



34 See the *2010 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2010. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Net Revenue

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

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

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

  In 2010, while total net revenues were not adequate to cover annual fixed costs for a new entrant coal plant (CP) in any zone, total net revenues were adequate to cover annual fixed costs for a new entrant CT in Pepco zone and in BGE zone, and total net revenues were adequate for a new entrant CC in the AECO, BGE, DPL and Pepco zones. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs than for other technologies, reflecting a relatively favorable spread between LMP and the cost of natural gas compared to the spread between LMP and the cost of delivered coal.

  In 2010, total net revenues were higher than in 2009. The increases in total net revenues by technology type were the result of increases in energy revenues, from an increase in energy prices which exceeded increases in fuel costs, and in most cases, increases in capacity revenues, from capacity prices determined in prior RPM auctions. In general, energy revenues are a larger proportion of total net revenues for CPs and CCs while capacity revenues are a larger proportion of total net revenues for CTs.

For the new entrant CT, all zones had higher total net revenue in 2010 compared to 2009. For the new entrant CT, all zones had higher energy net revenue, and all zones but two, BGE and Pepco, had higher available capacity revenues.[35] The 2010/2011 Base Residual Auction (BRA) cleared with much less price separation by location than prior BRAs and at a higher price for the RTO Locational Deliverability Area (LDA) than previous BRAs. As a result, zones that previously cleared in constrained LDAs saw only slight increases or, in the case of SWMAAC, decreases, in capacity revenue available for calendar year 2010, while zones that previously cleared in the unconstrained RTO LDA saw significant increases in capacity revenue. The BGE and Pepco zones, which previously cleared in the SWMAAC LDA for the 2009/2010 delivery year, had a lower clearing price associated with the unconstrained RTO LDA for the 2010/2011 BRA. The decreases in available capacity revenue in BGE and Pepco were more than offset by increases in energy net revenue. The six zones which had previously cleared in the EMAAC LDA (AECO, DPL, JCPL, PECO, PSEG and RECO) that were part of the MAAC+APS LDA for the 2009/2010 BRA had slightly higher capacity revenues available. Of these six zones, DPL showed the highest increase in capacity prices as DPL South separated and cleared at a slightly higher price than the RTO LDA in the 2010/2011 BRA. The five zones that had cleared in the unconstrained RTO LDA (AEP, ComEd, DAY, DLCO and Dominion) for the 2009/2010 BRA had significantly higher capacity revenues available as a result of higher capacity prices for the 2010/2011 BRA. The four zones that cleared in the MAAC+APS LDA and that had cleared with the unconstrained RTO LDA in the 2008/2009 BRA (AP, Met-Ed, PENELEC, and PPL) had significantly higher capacity revenues available associated with the constrained MAAC+APS LDA in the 2009/2010 BRA, but slightly lower capacity revenues associated with the 2010/2011BRA.

For the new entrant CC, all zones had higher total net revenue in 2010 compared to 2009. For the new entrant CC, all zones showed an increase in energy net revenue. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

For the new entrant coal plant (CP), all zones had higher total net revenue in 2010 compared to 2009. For the CP, all zones showed an increase in energy net revenues. For the two SWMAAC zones, higher energy net revenue more than offset decreases in capacity revenues.

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

  It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of

35 This section discusses available capacity revenues to new and existing units based on the clearing prices in Base Residual Auctions (BRA). It is not intended to reflect actual revenues associated with RPM.

investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

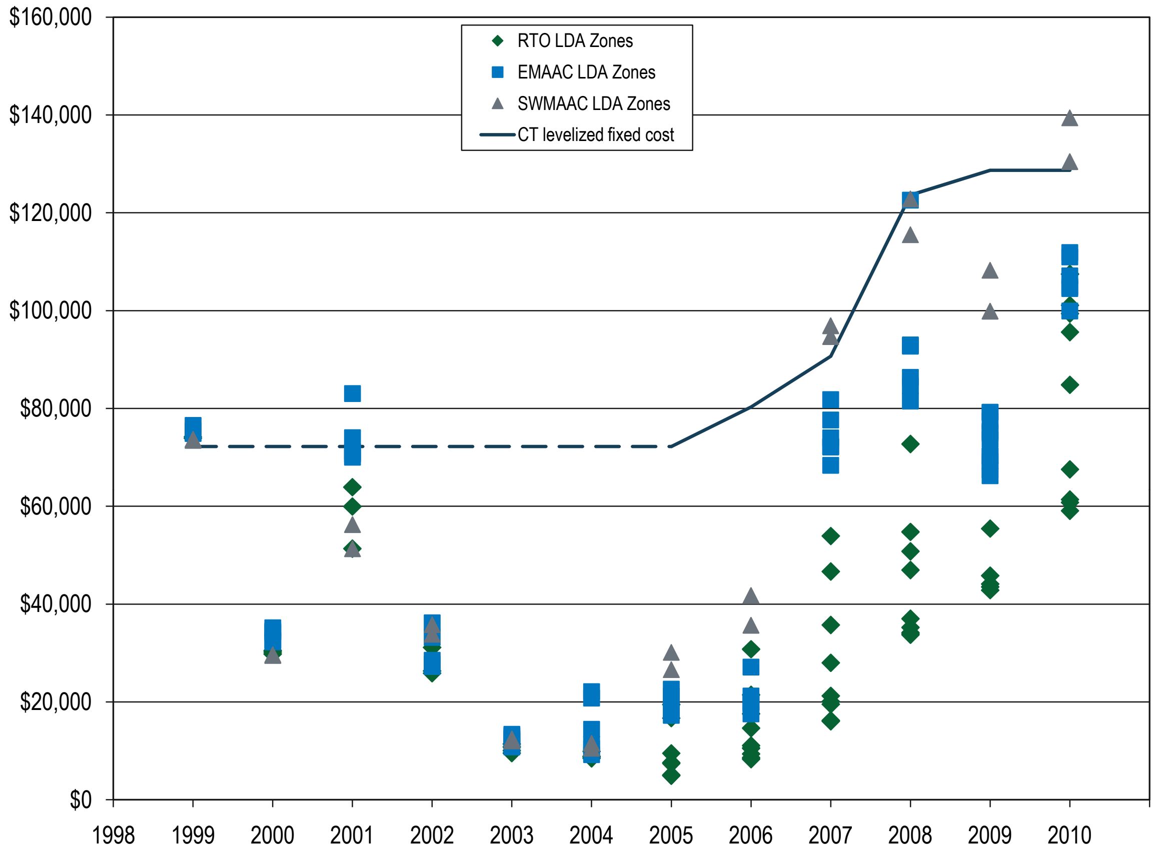
- For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and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

- The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2010 was 6,769 MW. Generally, coal units that did not recover avoidable costs in 2010 tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs. These units may be considered for deactivation.

- Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units under recovering avoidable costs excluding capital recovery as they may stay in service for the duration of the project life.

- Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. There are pending regulations that would require significant capital expenditures in environmental controls for existing coal units in PJM and a significant portion of these units would require additional revenues if faced with project investment for environmental controls. The MMU analyzed two scenarios based on actual energy and capacity revenues and avoidable costs in 2010 for units that may require project investments in environmental controls. In the first scenario, units accounting for 14,345 MW of installed capacity would require additional revenue for recovery of project investments. In the second scenario, which assumes more stringent unit specific NOx control requirements, units accounting for 19,068 MW of installed capacity would require additional revenue for recovery of project investments. For existing units, project investments associated with environmental controls are avoidable in nature and units facing these investments may be retired if it is not expected that the units will recover investments through a combination of energy or capacity revenue.

Figure 1-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2010 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2010



Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2010, PJM installed capacity resources fell slightly from 167,853.8 MW on January 1 to 166,512.1 MW on December 31, a decrease of 1,341.7 MW or 0.8 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2010, 40.8 percent was coal; 29.1 percent was natural gas; 18.3 percent was nuclear; 6.1 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was solid waste, and 0.4 percent was wind.

- **Generation Fuel Mix.** In 2010, coal provided 49.3 percent, nuclear 34.6 percent, gas 11.7 percent, oil 0.4 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 1.2 percent of total generation.

- **Planned Generation.** 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 EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in 2010.** PJM did not declare a scarcity event in 2010.

- **Scarcity and High Load Analyses.** The MMU analysis of net resource levels in the June through September period showed no evidence of reserve shortage events in the period. There were, however, a number of relatively high load days in July, August and September of 2010.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole payments, operating reserve credits 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. From the perspective of those participants paying the operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

  Operating Reserve Charges in 2010. The level of operating reserve credits and corresponding charges increased in 2010 by 74.6 percent compared to 2009, to $569 million in 2010 from $325 million in 2009. Reliability credits increased 268.0 percent, or $82 million, in 2010 compared to 2The overall increase in operating reserve charges in 2010 is comprised of a 4.5 percent decrease in day-ahead operating reserve charges, a 71.1 percent decrease in synchronous condensing charges and a 109.1 percent increase in balancing operating reserve charges. The increase in balancing charges can be attributed primarily to higher levels of demand in 2010 along with sustained periods of higher natural gas prices during winter months. December 2010, which includes 8.5 percent of the days in the year, accounted for 16.9 percent, or $96,032,958 of the annual operating reserve charges.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

One purpose of the rule changes was to allocate a larger portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, defined as real-time load and exports. This rule change had a significant impact in 2010. The new operating reserve rules resulted in an increase of $112,691,690 in charges assigned to real-time load and exports for 2010.

The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $26 million less in operating reserve charges in 2010 than they would have paid under the old rules.

As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $18 million, or 6.0 percent, higher for 2010 than they would have been under the old rules.

Table 1-11 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2010

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341	NA	0.535	NA
2001	$290,867,269	34.0%	8.7%	0.275	(19.5%)	1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.164	(40.4%)	0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.226	38.2%	1.197	52.0%
2004	$414,891,790	43.3%	4.8%	0.230	1.7%	1.236	3.3%
2005	$682,781,889	64.6%	3.0%	0.076	(66.9%)	2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.078	2.6%	1.331	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.057	(27.0%)	2.331	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.084	48.0%	2.113	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.120	42.3%	1.1100*	(47.5%)
2010	$569,062,688	74.6%	1.6%	0.113	(5.7%)	2.3103*	108.1%

Energy Market, Part 2 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.

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. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

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

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

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

In 2010, energy market revenues were generally higher for new entrant combustion turbines and combined cycles, both using natural gas, as energy market prices increased more than the average delivered price of natural gas in most zones. Energy market net revenues for new entrant coal plants were substantially higher in all zones as energy market prices increased more than the average delivered price of low sulfur coal.

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. All zones had more high demand days in 2010 than in 2009 and all zones showed a higher frequency of hours of real-time LMP greater than $200. The average on peak LMP for PJM increased 21 percent for 2010 compared to 2009. The PJM average real-time LMP was greater than $200 for twenty-six hours in 2010, compared to two hours in 2009. As a result, the average increase in energy net revenue for a new entrant CT was 274 percent, and the increases in energy net revenue for BGE and Pepco zones were 355 and 368 percent.

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

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when load following and peaking gas-fired units set price. In 2010, particularly in the third quarter, CCs and CTs ran more often, which resulted in an increase in the net revenue received by coal plants.

INTERCHANGE TRANSACTIONS

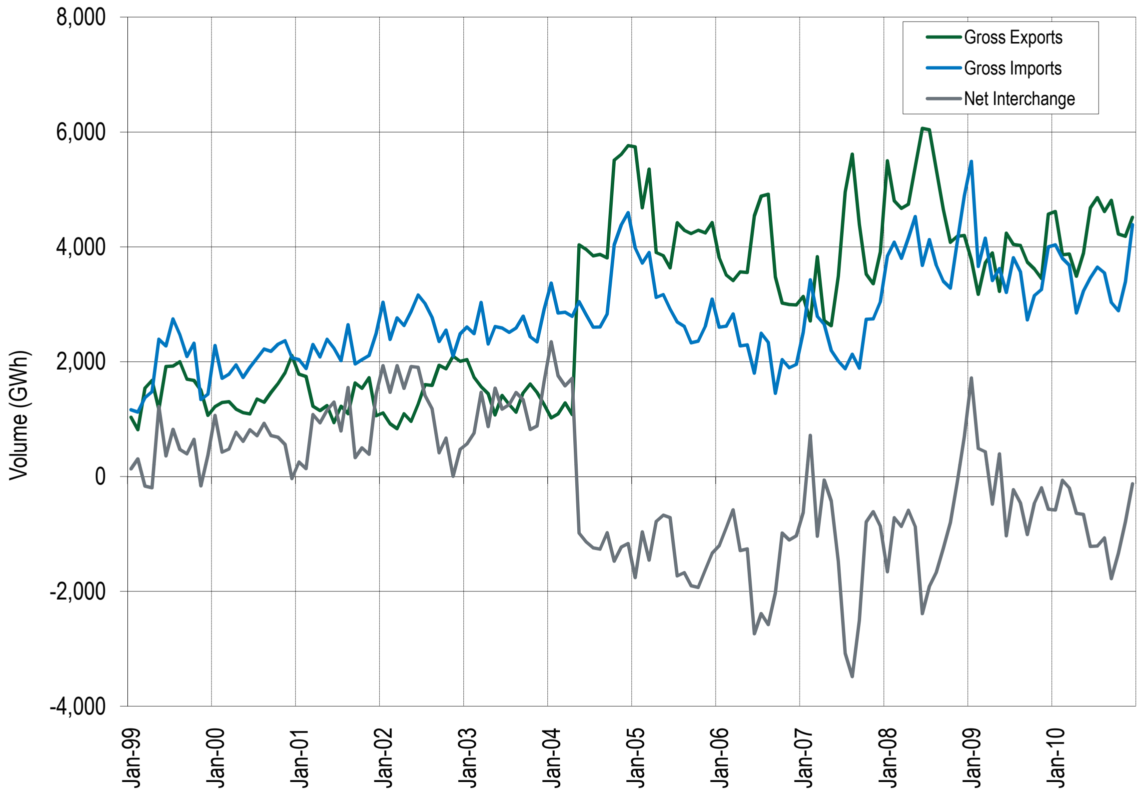
PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -805 GWh.[36] Gross monthly import volumes averaged 3,496 GWh while gross monthly exports averaged 4,301 GWh.

36 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

Figure 1-5 PJM scheduled import and export transaction volume history: 1999 through December 2010



- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2010, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months except August, November and December. In the Day-Ahead Energy Market, monthly net interchange averaged -539 GWh. Gross monthly import volumes averaged 7,342 GWh while gross monthly exports averaged 7,881 GWh.

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** In 2010, gross imports in the Day-Ahead Energy Market were 210 percent of the Real-Time Energy Market's gross imports (111 percent for the calendar year 2009), gross exports in the Day-Ahead Energy Market were 183 percent of the Real-Time Energy Market's gross exports (127 percent for the calendar year 2009) and net interchange in the Day-Ahead Energy Market was 67 percent of net interchange in the Real-Time Energy Market (-9,661GWh in the Real-Time Energy Market and -6,470 GWh in the Day-Ahead Energy Market).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market in 2010, there were net exports at 16 of PJM's 21 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 70 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 30 percent, PJM/Neptune (NEPT) with 20 percent and PJM/MidAmerican Energy Company (MEC) with 20 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Energy Market. Four PJM interfaces had net imports, with two importing interfaces accounting for 90 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 78 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 12 percent.[37]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, there were net exports at 12 of PJM's 21 interfaces. The top four net exporting interfaces accounted for 92 percent of the total net exports: PJM/NYIS with 33 percent, PJM/western Alliant Energy Corporation (ALTW) with 25 percent, PJM/MidAmerican Energy Company (MEC) with 18 percent and PJM/NEPT with 16 percent. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND). Combined, these interfaces made up 50 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net imports in the Day-Ahead Energy Market, with two interfaces accounting for 78 percent of the total net imports: PJM/OVEC with 47 percent and PJM/Michigan Electric Coordinated System (MECS) with 31 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** In 2010, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the PJM/MISO border was $33.33 while the Midwest ISO LMP at the border was $33.90, a difference of $0.57, while the average hourly flow in 2010 was -918 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 42 percent of hours of 2010. While the average hourly LMP difference at the PJM/MISO border was only $0.57, the average of the absolute value of the hourly difference was $11.64. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $51.5 million at the PJM/MISO Interface.

- **PJM and New York ISO Interface Prices.** In 2010, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2010, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was not consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the PJM/NYISO border was $47.64 while the NYISO LMP at the border was $44.69, a difference of $2.95, while the average hourly flow was -722 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is not consistent with the fact that the average PJM price was higher than the average NYISO price.) The direction of flows was consistent with price differentials in only 49 percent of the hours. While the average hourly LMP difference at the PJM/NYISO border was only $2.95, the average of the absolute value of the hourly difference was $14.74. For the hours when the direction of flows was not consistent with price differentials, the economic

37 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/western portion of Carolina Power & Light Company (CPLW)).

inefficiency, calculated as the interface price difference multiplied by the MWh of flow, was $52.7 million at the PJM/NYIS Interface.

- **Neptune Underwater Transmission Line to Long Island, New York.** In 2010, the average price difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Neptune Interface was $51.40 while the NYISO LMP at the Neptune Bus was $58.08, a difference of $6.67, while the average hourly flow in 2010 was -544 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours. While the average hourly LMP difference at the PJM/Neptune border was only $6.67, the average of the absolute value of the hourly difference was $23.30. For the hours when the direction of flows was not consistent with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was approximately $43.4 million at the PJM/NEPT Interface.

- **Linden Variable Frequency Transformer (VFT) Facility.** In 2010, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2010, the PJM average hourly LMP at the Linden Interface was $50.10 while the NYISO LMP at the Linden Bus was $51.58, a difference of $1.48, while the average hourly flow was -139 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 61 percent of the hours. While the average hourly LMP difference at the PJM/Linden border was only $1.48, the average of the absolute value of the hourly difference was $18.13. During all hours where flows did not align with price differentials, the economic inefficiency, calculated as the interface price difference multiplied by the MW of flow, was approximately $8.8 million at the PJM/LIND Interface.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**[38] On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

  The PJM/NYISO JOA does not include provisions for market based congestion management or other market to market activity, and, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued in 2010.

- **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued in 2010. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion

38 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) (Accessed March 7, 2011) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf> (2,285 KB).

on these flowgates and to assign the costs of congestion management appropriately. The MMU believes that this approach should be the minimum industry standard. This conceptual achievement, however, has not been matched by adequate attention to the details of its administration, which have resulted in multiple FERC filings by the Midwest ISO and PJM.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[39] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2010.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[40] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2010. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[41] The MMU responded to the filing on February 23, 2010.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[42] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** In 2010, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.[43] This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces.

39 See "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

40 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) (Accessed March 7, 2011) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx> (642 KB).

41 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

42 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed October 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

43 111 FERC ¶ 61,228 (2005).

Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

In 2010, net scheduled interchange was -6,778 GWh and net actual interchange was -6,425 GWh for a difference of 353 GWh or 5.2 percent (2.2 percent for the calendar year 2009).

Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2009, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-15,106 GWh in 2010 and -14,441 GWh for the calendar year 2009). The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,015 GWh in 2010 and 3,840 GWh for the calendar year 2009). The net difference between scheduled flows and actual flows at the PJM/MECS Interface was exports while the net difference at the PJM/TVA Interface was imports.

- **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces was significant in 2010. PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) are in the west. The largest differences in the west were at the TVA Interface. The net scheduled power flow at the TVA Interface was -703 GWh and the actual flow was 3,312 GWh, a difference of 4,015 GWh. PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK are in the east. The largest differences in the east were at the CPLE Interface. The net scheduled power flow at the CPLE Interface was -421 GWh and the actual flow was 8,350 GWh, a difference of 8,771 GWh.

- **PJM Transmission Loading Relief Procedures (TLRs).** In 2010, PJM issued 110 TLRs of level 3a or higher. Of the 110 TLRs issued, 65 events were TLR level 3a, and the remaining 45 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 110 TLRs in 2010, compared to 129 in 2009, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with the Midwest ISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would require the need for higher level TLRs.

- **Up-To Congestion.** In the period following the March 1, 2008, modifications to the up-to congestion bids (March 1, 2008, through December 31, 2010), the monthly average of up-to congestion bids increased from 3,027.1 GWh (for the period from January 1, 2006 through April

30, 2008) to 6,192.9 GWh. In June and July, there was a significant increase in the total up-to congestion bids. This increase in activity for up-to congestion transactions was the result of the allocation methodology for the marginal loss surplus.

- **Marginal Loss Surplus Allocation.** In an order on complaint, the Commission required PJM to correct an inconsistency in the tariff language defining the method for allocating the marginal loss surplus based on contributions to the fixed costs of the transmission system.[44] PJM's tariff modification resulted in an allocation of the marginal loss surplus based on usage of the system rather than based on the dollar contribution to the fixed costs of the transmission system. The inconsistency between the allocation principle defined by FERC and the actual allocation created an incentive for market participants to enter noneconomic transactions for the sole purpose of receiving an allocation of the marginal loss surplus.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

  The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service; and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. PJM stakeholders approved the changes recommended by the MMU. These modifications are currently being evaluated by PJM to determine if tariff or operating agreement changes are necessary prior to implementation.

- **Elimination of Sources and Sinks.** The MMU has recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch.

- **Spot Import.** In 2009, PJM and the MMU jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively withheld the service from other market participants who wished to utilize it. To address the

44 See 131 FERC ¶ 61,024 (2010) (order denying rehearing and accepting compliance filing); 126 FERC ¶ 61,164 (2009) (Order on request for clarification).

issue, PJM implemented new timing requirements that retracted spot import reservations if they were associated with a NERC Tag within 30 minutes of making the reservation. Although this resulted in an increase in scheduling, some participants were still able to schedule but not use spot import service to flow energy. As a result, the MMU and PJM recommended that PJM revert to unlimited ATC for non-firm willing to pay congestion service. The PJM Stakeholders agreed with the recommendation, and requested that PJM determine what would be needed to implement the change.

- **Real-Time Dispatchable Transactions.** Dispatchable transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes has eliminated the value that dispatchable transactions once provided market participants. Dispatchable transactions now only serve as a potential mechanism for receiving operating reserve credits.

  The MMU recommends that dispatchable transactions be eliminated as an option for market participants. Alternatively, the MMU recommends that the evaluation of dispatchable transactions be modified from the manual process implemented today, and be included in the Generation Control Application (GCA) tool and modeled in same way as a unit offer with a one hour minimum run time. This would eliminate the potential for a dispatchable transaction to be loaded and continue to flow in subsequent hours when the transaction is not economic, thus accruing balancing operating reserve credits, and would treat these transactions the same way that dispatchable units are treated. This would enhance the efficiency of PJM dispatch of system resources.

Interchange Transactions 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 hedging tools (FTRs and 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 analyzed the transactions between PJM and its neighboring balancing authorities for 2010, including evolving transaction patterns, economics and issues. In 2010, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 70 percent of the total real-time net exports and two interfaces accounted for 90 percent of the real-time net import volume. Four interfaces accounted for 92 percent of the total day-ahead net exports and two interfaces accounted for 78 percent of the day-ahead net import volume.

In 2010, the direction of power flows at the borders between PJM and the Midwest ISO and between PJM and the NYISO was not consistent with real-time energy market price differences for a majority of hours, 58 percent between PJM and the Midwest ISO and 51 percent between PJM and NYISO. The MMU recommends that PJM work with both Midwest ISO and NYISO to improve the ways in which interface prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability. The MMU concludes that the PJM Capacity Market results were competitive in 2010.

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region on June 1, 2007.[45] The RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

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.[46]

45 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
46 See 126 FERC ¶ 61,275 (2009) at P 86.

RPM prices are locational and may vary depending on transmission constraints.[47] 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 and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **Supply.** Total internal capacity increased 1,712.7 MW from 157,318.2 MW on June 1, 2009, to 159,030.9 MW on June 1, 2010.[48] This increase was the result of 406.9 MW of new generation, 165.0 MW that came out of retirement, 1,085.8 MW of net generation capacity modifications (cap mods), 43.7 MW of demand resource (DR) modifications (mods), and an increase of 11.3 MW due to lower equivalent demand forced outage rates (EFORds).

  In the 2011/2012, 2012/2013, and 2013/2014 auctions, new generation increased 3,969.4 MW; 486.9 MW came out of retirement and net generation cap mods were -2043.5 MW, for a total of 2,412.8 MW. DR and Energy Efficiency (EE) modifications totaled 11,360.5 MW through June 1, 2013. A decrease of 1,481.8 MW was due to higher EFORds. The classification of the Duquesne resources as external reduced total internal capacity by 3,006.6 MW, and the reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The integration of the ATSI zone resources added 13,175.2 MW to total internal capacity. The net effect from June 1, 2010, to June 1, 2013, was an increase in total internal capacity of 25,647.3 MW (16.1 percent) from 159,030.9 MW to 184,678.2 MW.

  In the 2010/2011 auction, 11 more generation resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new generation capacity resources consisted of seven new combustion turbine (CT) resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

  In the 2011/2012 auction, 21 more generation resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported

47 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.

48 Unless otherwise specified, all volumes are in terms of unforced capacity (UCAP).

(663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new generation capacity resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generation resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[49] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two CT resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT resources (521.5 MW) in the RTO. The new generation capacity resources consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

In the 2013/2014 auction, 37 more generation resources made offers than in the 2012/2013 auction. The increase in generation resources consisted of 63 ATSI resources that were not offered in the 2012/2013 BRA (11,325.4 MW), 31 new resources (1,038.2 MW), four resources that were previously entirely FRR committed (234.3 MW), and four additional resources imported (460.1 MW). The reduction in generation resources consisted of seven retired resources (824.0 MW), two deactivated resources (66.6 MW), 49 additional resources committed fully to FRR (307.7 MW), four less planned generation resources that were not offered (249.3 MW), two additional resources excused from offering (4.2 MW), and one less external resource that was not offered (45.7 MW). In addition, there were the following retirements of resources that were either exported or excused in the 2012/2013 BRA: three steam units (125.9 MW). The new generation capacity resources consisted of 11 solar resources (9.5 MW), 11 wind resources (245.7 MW), four combined cycle units (671.5 MW), three diesel resources (5.4 MW), one steam unit (23.8 MW), and one CT unit (82.3 MW). In addition, there were the following new generation resources that were not offered in to the auction because they were either exported or entirely committed to FRR for the 2013/2014 delivery year: four wind resources (66.2 MW).

49 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

Table 1-12 PJM capacity summary (MW): June 1, 2007 to June 1, 2013[50]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	3,199.6	5,976.5	6,518.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9
EE cleared						568.9	679.4
ILR	1,636.3	3,608.1	6,481.5	8,236.4	1,593.8		
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6
Short-Term Resource Procurement Target						3,343.3	3,749.7

- **Demand.** There was a 3,156.7 MW increase in the RPM reliability requirement from 153,480.1 MW on June 1, 2009 to 156,636.8 MW on June 1, 2010. On June 1, 2010, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 77.7 percent market share of load obligations under RPM, down from 79.6 percent on June 1, 2009.

- **Market Concentration.** For the 2010/2011, 2011/2012, 2012/2013, and 2013/2014 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2010/2011 BRA, 2010/2011 Third Incremental Auction, 2011/2012 BRA, 2011/2012 First Incremental Auction, 2011/2012 ATSI Integration Auction, 2012/2013 First Incremental Auction, 2012/2013 ATSI Integration Auction, and 2013/2014 BRA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the TPS market structure test.[51] In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation submitted by capacity market sellers that did not pass the test.[52, 53, 54]

- **Imports and Exports.** Net exchange decreased 707.2 MW from June 1, 2009 to June 1, 2010. Net exchange, which is imports less exports, decreased due to an increase in exports of 952.5 MW offset by an increase in imports of 245.3 MW.

50 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

51 Currently, there are 23 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).

52 OATT Attachment DD (Reliability Pricing Model) § 6.5.

53 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.

54 The definition of planned generation capacity resource and the rules regarding mitigation were redefined effective January 31, 2011. See 134 FERC ¶ 61,065 (2011).

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,783.3 MW from 6,899.7 MW on June 1, 2009 to 8,683.0 MW on June 1, 2010. Demand-side resources include demand resources and energy efficiency resources cleared in RPM auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 delivery year, ILR was eliminated. Starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year, the energy efficiency resource type is eligible to be offered in RPM auctions.[55]

- **RPM Net Excess.**[56] RPM net excess decreased 537.5 MW from 8,265.5 MW on June 1, 2009 to 7,728.0 MW on June 1, 2010.

Market Conduct

- **2010/2011 RPM Base Residual Auction.**[57] Of the 1,104 generation resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) avoidable cost rate (ACR) values.

- **2010/2011 Third Incremental Auction.**[58] Of the 303 generation resources which submitted offers, 193 resources elected the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM Base Residual Auction.**[59] Of the 1,125 generation resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) ACR values.

- **2011/2012 RPM First Incremental Auction.**[60] Of the 129 generation resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR values.

- **2011/2012 ATSI Integration Auction.**[61] Of the 141 generation resources which submitted offers, 52 resources elected the offer cap option of 1.1 times the BRA clearing price (36.9 percent). Unit-specific offer caps were calculated for four resources (2.8 percent). Offer caps of all kinds were calculated for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values.

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

56 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 through 2010/2011, certified ILR was used in the calculation. Forecast ILR less FRR DR is used in the calculation when ILR was not certified and prior to 2011/2012 because PJM forecast ILR including FRR DR for the first four Base Residual Auctions. PJM forecast ILR excluding FRR DR for 2011/2012, so FRR DR is not subtracted in the calculation for 2011/2012. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

57 For a more detailed analysis of the 2010/2011 RPM Base Residual Auction, see "Analysis of the 2010-2011 RPM Auction Revised" (July 3, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20102011-rpm-review-final-revised.pdf>.

58 For a more detailed analysis of the 2010/2011 RPM Third Incremental Auction, see "Analysis of the 2010/2011 RPM Third Incremental Auction" (December 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2010_2011_RPM_Third_Incremental_Auction_20101220.pdf>.

59 For a more detailed analysis of the 2011/2012 RPM Base Residual Auction, see "Analysis of the 2011/2012 RPM Auction Revised" (October 1, 2008) <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>.

60 For a more detailed analysis of the 2011/2012 RPM First Incremental Auction, see "Analysis of the 2011/2012 RPM First Incremental Auction" (January 6, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf>.

61 For a more detailed analysis of the 2011/2012 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" (January 14, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf>.

- **2012/2013 RPM Base Residual Auction.**[62] Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.

- **2012/2013 ATSI Integration Auction.**[63] Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). Offer caps of all kinds were calculated for 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.

- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). Offer caps of all kinds were calculated for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.

- **2013/2014 RPM Base Residual Auction.**[64] 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.

Market Performance

2010/2011 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 159,030.9 MW includes all generation resources and DR that qualified as a PJM capacity resource for the 2010/2011 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 137,360.7 MW. The 132,190.4 MW of cleared resources for the entire RTO represented a reserve margin of 16.5 percent, resulted in net excess of 7,728.0 MW over the reliability requirement of 132,698.8 MW (Installed Reserve Margin (IRM) of 15.5 percent), and resulted in a clearing price of $174.29 per MW-day.

  Total cleared resources in the RTO were 132,190.4 MW which resulted in a net excess of 7,728.0 MW, a decrease of 537.5 MW from the net excess of 8,265.5 MW in the 2009/2010 RPM BRA. Certified interruptible load for reliability (ILR) was 8,236.4 MW.

  Cleared capacity resources across the entire RTO will receive a total of $8.4 billion based on the unforced MW cleared and the prices in the 2010/2011 RPM BRA, an increase of approximately $960.4 million from the 2009/2010 BRA.

62 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>.

63 For a more detailed analysis of the 2012/2013 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" (January 14, 2011) <http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf>.

64 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, see "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" (September 20, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf>.

- **DPL South.** Total internal DPL South unforced capacity of 1,546.1 MW includes all generation resources and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. All imports offered into the auction are modeled in the RTO, so total DPL South RPM unforced capacity was 1,546.1 MW.[65] All of the 1,519.7 MW cleared in DPL South were cleared in the RTO before DPL South became constrained. Of the 26.4 MW of incremental supply, none cleared, because all 26.4 MW were priced above the demand curve. The DPL South resource clearing price of $186.12 per MW-day was determined by the intersection of the demand curve and a vertical section of the supply curve.

  Total resources in DPL South were 2,966.7 MW, which when combined with certified ILR of 97.2 MW resulted in a net excess of 14.5 MW (0.5 percent) greater than the reliability requirement of 3,049.4 MW.

2010/2011 RPM Third Incremental Auction

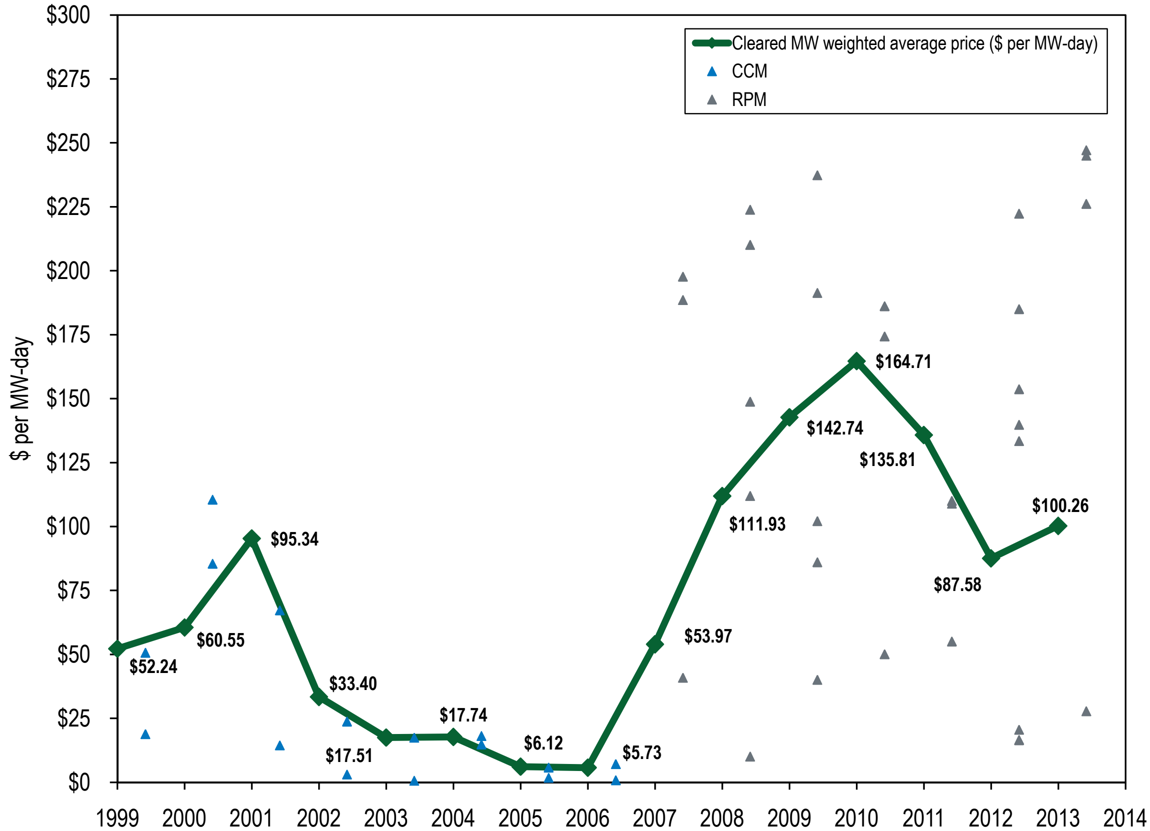
- **RTO.** There were 4,553.9 MW offered into the 2010/2011 Third Incremental Auction while buy bids totaled 5,221.0 MW. Cleared volumes in the RTO were 1,845.8 MW, resulting in an RTO clearing price of $50.00 per MW-day. The 2,708.1 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared capacity resources across the entire RTO will receive a total of $33.7 million based on the unforced MW cleared and the prices in the 2010/2011 RPM Third Incremental Auction.

- **DPL South.** Although DPL South was a constrained LDA in the 2010/2011 BRA, supply and demand curves resulted in a price less than the RTO clearing price. The result was that all of DPL South supply which cleared received the RTO clearing price. Supply offers in the incremental auction in DPL South (56.8 MW) exceeded DPL South demand bids (25.9 MW).

65 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 10 (June 1, 2010), p. 24.

Figure 1-6 History of capacity prices: Calendar year 1999 through 2013[66, 67]



Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.6 percent in 2009 to 7.2 percent in 2010. PJM Peak-Period Equivalent Forced Outage Rate Peak (EFORp) increased from 4.0 percent in 2009 to 5.2 percent in 2010.[68]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 85.7 percent in 2009 to 84.8 percent in 2010.

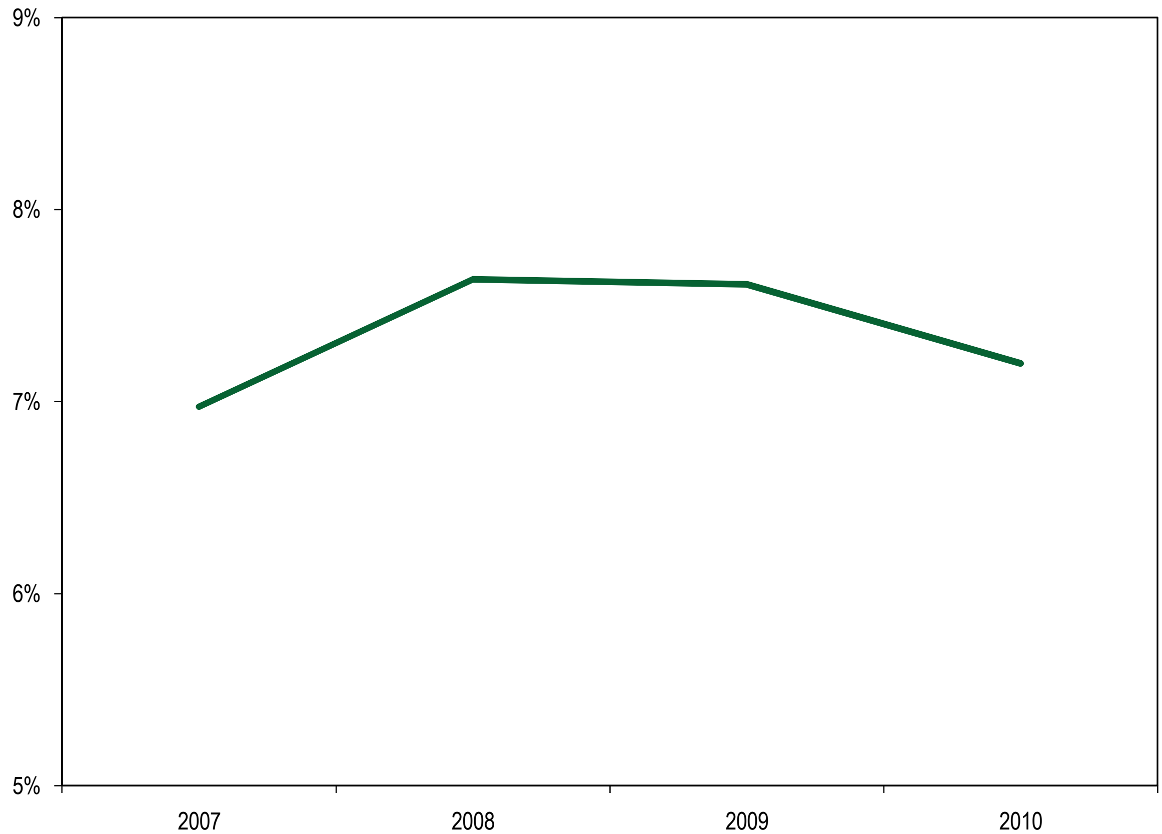
- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

66 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2013 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

67 The RPM weighted average prices were updated since the *2010 Quarterly State of the Market Report for PJM: January through September* to account for Make-Whole MW.

68 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 calendar year ending December 31, as downloaded from the PJM GADS database on January 21, 2011. Annual 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.

Figure 1-7 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2010



Capacity Market Conclusion

Capacity Market Design and Scarcity Revenues

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The Definition of Capacity

In order for capacity markets to work, it is essential that the product definition be correct.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the Day-Ahead Energy Market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; the obligation that the energy output from the resource be deliverable to load in PJM; and the obligation to test generation net capability.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the Day-Ahead Energy Market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the Day-Ahead Energy Market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the Day-Ahead Energy Market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

The obligation to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price. Demand resources that agree to interrupt only 10 times per year for a maximum of six hours per interruption should not be considered capacity resources. Generation resources that agree to provide an energy offer only under PJM emergency conditions should not be considered capacity resources. Generation resources that agree to provide energy only when the price is extremely high (and greater than the short run marginal cost of such units) should not be considered capacity resources. The only exception, and it is not really an exception, is that units which have a legitimate short term emergency condition, may appropriately offer the relevant portion of the unit as an emergency resource.

Capacity resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year. If the system reserve margin were comprised of demand resources that would only interrupt 10 times for a maximum of six hours or generation resources that would only perform during an emergency or generation that will only perform when the price is $999 per MWh, the probability of needing those resources would increase significantly and the number of hours during which those resources are needed would increase significantly. As a general matter, the probability of needing such resources increases with the level of such resources that are defined to be capacity and thus needed for reliability.

The actual dispatch of resources in the energy market should be a function of the marginal cost to produce energy for each resource and not based on the refusal of a resource to make a competitive offer. Net revenues from the energy market, the ancillary services markets and the capacity market are the market based compensation. Investment decisions result from this total compensation.

The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.

Capacity Prices and the Structure of Capacity Auctions

If capacity markets are to work to provide incentives for maintaining existing generation and building new generation, capacity market prices must reflect actual, local supply and demand conditions. For example, getting the price a little too low at the margin could result in undermining the incentives exactly where they need to be clear. If the prices are too low as a result of the market design, this would mean that the capacity market is a mechanism for transferring wealth rather than a functioning market providing market based incentives.

Capacity auctions must be mandatory for both load and generation, if they are to work. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In PJM, generation capacity resources have a must offer requirement, which means that all existing generation capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform or are committed to an FRR entity.

The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability. In addition, the limited definition of the DR product means that an inferior product is offered in the same auction as capacity and significantly affects the clearing prices. The DR product should be defined to require unlimited interruptions.

The three year forward auction was implemented in order to provide the potential for new resources to compete with existing resources and to provide an incentive for such new entry. The prior capacity credit structure did not provide for either. The three year forward structure creates both opportunity and risks. A new generation unit that offers into an auction for a delivery year three years in the future is taking the risk that the unit will not be completed, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. Demand resources also face both opportunities and risks in a three year forward auction. A demand resource that is offered into an auction for a delivery year three years in the future is taking the risk that the customer with the demand side resource will no longer exist, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. There is nothing unique about demand resources that requires a shorter lead time or that requires distorting the market design. The fact that some generation resources or demand resources can be developed in less than three years is not a reason to distort the market design. It would be possible to shorten the time frame of the auctions for all participants but at the cost of reducing competition from new generation projects.

The market design goal is to ensure that out of market payments do not permit offers at less than competitive prices, including zero, which suppress the market clearing prices. All generation should be offered in to the auctions at no less than and no more than competitive prices and receive capacity credit if cleared and not receive capacity credit if not cleared.

Locational Prices

Capacity prices must reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETL/CETO analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. For example, if a unit does not clear in an RPM auction and makes an economic decision to retire but is then informed by PJM that it is needed for reliability, this is evidence that the market is not working because the local market is not properly defined. PJM determinations that a unit is needed for reliability are based on a more detailed analysis than the CETL/CETO analysis. PJM should perform such a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions and units that face significant investment requirements due, for example, to environmental requirements. If such units are needed for reliability, this could result in the definition of additional LDAs to reflect the actual reliability requirements of the system. Accurate locational pricing also requires that generation owners make offers that reflect their legitimate investment requirements. For example, units that will be forced to retire by environmental regulators unless they make defined investments in new technology should reflect the costs of that investment in their capacity market offer. That is essential to the functioning of the forward looking capacity market.

Capacity Markets and Incentives

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, hourly market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing; it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the 500 hours defined as critical in RPM, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective, and of explicitly limiting the exercise of market power.

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the TPS test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service, including realistic interconnection costs. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. The energy market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Barriers to Entry

Competitive outcomes in the capacity market can be prevented by barriers to entry. There are a variety of possible barriers to entry into the capacity market that may affect the frequency and level of entry and thus market outcomes. Such potential barriers include control of sites based on historical utility and regulatory practices; environmental rules; the costs and uncertainty associated with the transmission interconnection process and control over the timing and details of the required studies; and the uncertainty created by the PJM transmission planning process.

These and other barriers to entry should be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. The uncertainty and resultant risks should be reflected in the cost of new entry used to establish the capacity market demand curve in RPM.

ANCILLARY SERVICE MARKETS

The FERC defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[69] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not

69 75 FERC ¶ 61,080 (1996).

defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[70] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[71] The purpose of this market is to satisfy 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 the market clearing price.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for 2010. The MMU concludes that the PJM Regulation Market results were not competitive in 2010, that the PJM Synchronized Reserve Markets results were competitive in 2010, and that the PJM Day-Ahead Scheduling Reserve Market results were competitive.

Regulation Market

The PJM Regulation Market in 2010 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented four changes to the Regulation Market: introducing the TPS test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC);

70 Regulation is used to help control the area control error (ACE). See the *2010 State of the Market Report for PJM,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2010.

71 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

and terminating the offset of regulation revenues against operating reserve credits. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[72] The MMU also reported on the impact of these changes in the 2009 State of the Market Report.[73] In September 2010, PJM fixed an error that had been identified by the MMU, which resulted in too small a number of switches to a different offer schedule for the opportunity cost calculation.[74] Despite this fix, several implementation issues remain in addition to the market design issues.

The MMU has continued to analyze the functioning of the Regulation Market. The MMU recognized flaws in its quantification of the impact of the Regulation Market changes in prior reports.[75] [76] The MMU determined that the MMU's prior quantification of the impact on the clearing price of the changed calculation of opportunity cost was not correct. A complete quantification of the impact is not required as a precondition to modifying the flawed market design. Differences from PJM estimates of the impact were the result of incorrect calculations by the MMU, which accounted for much of the difference, but were also the result of incorrect implementation of the rules by PJM, the failure by PJM to save some data required to check clearing prices, and a lack of transparency of the market clearing process. A continuing issue in carrying out analysis of the Regulation Market is that some data that are critical to the market clearing process are not saved, which makes it impossible to validate or check the final clearing price and its determinants. The MMU has requested that these data items be saved for future analysis. Absent these data items, it is not possible to determine the full dollar impact of the rules changes of December 2008 or confirm that the current market implementation is consistent with the current market rules. Equally important, absent these data items it is not possible to verify the Regulation Market prices to ensure consistency with economic fundamentals.

Market Structure

- **Supply.** In 2010, the supply of offered and eligible regulation in PJM was both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2010. The ratio of eligible regulation offered to regulation required averaged 2.95 for 2010, essentially unchanged from the 2009 ratio of 2.98.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements, resulting in a decrease in total demand for regulation. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. Previously the requirement had been fixed at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for 2010 increased to 893 MW, from 849 MW for 2009, as a result of increased forecast loads.

- **Market Concentration.** During 2010, the PJM Regulation Market had a load weighted, average HHI of 1464 which is classified as "moderately concentrated."[77] The minimum hourly HHI was

72 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).

73 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

74 See "Minutes" of the Market Implementation Committee. Agenda Item #9, pg. 5 <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx, 11/09/2010> November 9, 2010.

75 See the 2010 Quarterly State of the Market Report for PJM, January through June, pg. 155, fn 15.

76 See the 2010 Quarterly State of the Market Report for PJM, January through September, pg. 166, fn 18.

77 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

763 and the maximum hourly HHI was 3675. The largest hourly market share in any single hour was 53 percent, and 79 percent of all hours had a maximum market share greater than 20 percent.[78] In 2010, 73 percent of hours had one or more pivotal suppliers which failed PJM's TPS test. The MMU concludes from these results that the PJM Regulation Market in 2010 was characterized by structural market power in 73 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. As of December 1, 2008, owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers remain subject to the $100 per MWh offer cap.[79] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the TPS test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then re-solved.

  As part of the changes to the Regulation Market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50.[80] The impact of this change was to increase cost based offer prices compared to what they would have been with the $7.50 maximum margin.

  As part of the changes to the Regulation Market implemented on December 1, 2008, PJM was to calculate unit specific opportunity costs using the lesser of the available price based energy offer or the most expensive available cost based energy offer as the reference, rather than the offer on which the unit was operating in the energy market.[81] Depending on whether the units affected by the rule change are backed down or raised to regulate, the application of the rule change increased or decreased the unit's applicable opportunity costs relative to the correct definition of opportunity cost used prior to December 1, 2008. The impact of these changes to the calculation is that the hourly Regulation Market clearing price was either higher or lower than the outcome that would have occurred under the correct opportunity cost calculation used prior to December 1, 2008. However, PJM did not correctly implement this rule change until the third quarter of 2010.[82] The actual impact of the changed definition of opportunity cost was reduced as a result of the incorrect implementation of the rule.

78 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

79 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 39.

80 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

81 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 59: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation."

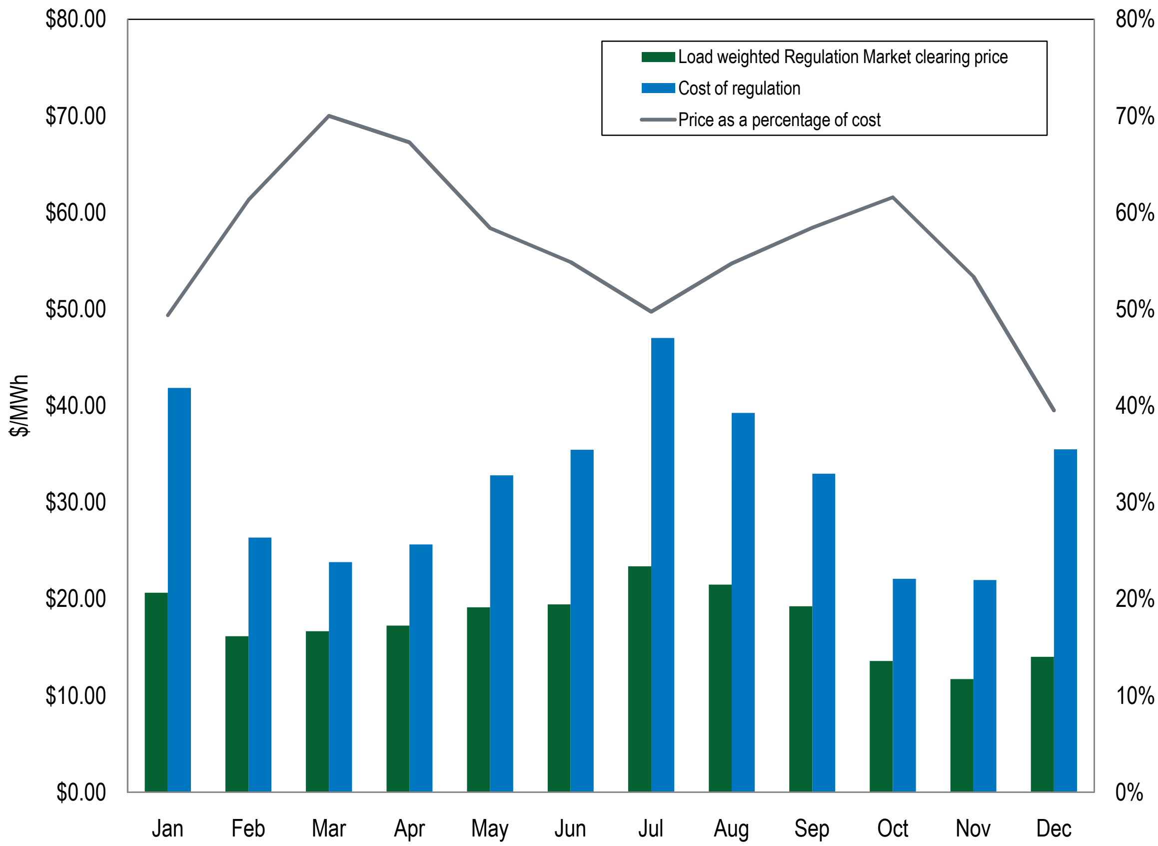
82 PJM staff reported the error at the November 9, 2010 meeting of the Market Implementation Committee and stated that the implementation was corrected on September 17, 2010.

Market Performance

- **Price.** For the PJM Regulation Market in 2010, the load weighted, average price per MW (the Regulation Market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $18.08 per MW. This was a decrease of $5.48, or 23 percent, from the average price for regulation during 2009. The total cost of regulation increased by $2.13 from $29.63 per MW, for all of 2009, to $32.07, or 7 percent. The difference between total regulation cost per MW and regulation price remains high. The Regulation Market clearing price was only 57 percent of the total regulation cost per MW.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market in 2010 were higher than they would have been in some hours and lower than they would have been in some hours as a result of the change to the definition of opportunity cost in the December 2008 Regulation Market changes. The modified definition of opportunity cost resulted in a switch of the offer schedule used for the calculation of opportunity cost and therefore resulted in an impact on the Regulation Market clearing price.

Figure 1-8 Monthly load weighted, average regulation cost and price: Calendar year 2010



Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made no changes to the Synchronized Reserve Market structure during 2010. In 2009, PJM made a structural change to address the problem of excessive after-market Tier 2 added by dispatchers when the market did not adequately provide for Tier 2 synchronized reserve in constrained, heavy-load, and/or off-peak hours. The structural change was to change the transfer interface which defines the Eastern sub-zone from Bedington-Blackoak to AP South. In addition, PJM made a non-structural change to address the same issue by changing the Tier 1 transfer capability of the AP South interface from 70 percent to 15 percent where it remained throughout 2010.[83] Synchronized reserves added out of market were five percent of all synchronized reserves during 2010, while they were 15 percent for the same time period in 2009. Opportunity cost payments accounted for 27 percent of total costs during 2010 compared to 32 percent for 2010.[84]

Market Structure

- **Supply.** In 2010, synchronized reserve offers were somewhat higher than in 2009. The offered and eligible excess supply ratio was 1.16 for the PJM Mid-Atlantic Synchronized Reserve Region.[85] For the RFC zone, the excess supply ratio was 2.68. The excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are low cost, and their participation in this market lowers overall Synchronized Reserve prices.

- **Demand.** PJM made several changes to the hourly required synchronized reserve requirement in 2010. On May 5, 2010, the synchronized reserve demand in the Mid-Atlantic Subzone was increased from 1,150 MW to 1,200 MW. This change was made to accommodate a dynamically changing largest contingency for the AP South constraint. In addition, double spinning was declared for May 24 and 25 of 1,800 MW because of a planned outage. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW. On September 21 and 22 the synchronized reserve requirement for the Mid-Atlantic Subzone was temporarily increased to 1,600 MW. Between November 15 and November 20 the synchronized reserve requirement for the Mid-Atlantic Subzone was increased to 1,630 MW. On October 12 and 13 the synchronized reserve requirement for the Mid-Atlantic Subzone was increased to 2,500 MW. For 2010, average synchronized reserve requirements were 1,246 MW for the Mid-Atlantic Subzone.

  For 2010, in the Mid-Atlantic Subzone, no Tier 2 synchronized reserve was needed in 33 percent of hours. The average required Tier 2 (including self scheduled) was 358 MW. The average required Tier 2 fell to 198 MW for the June through September period. For January

83 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, p. 40.
84 See "Motion to Intervene and Comments of the Independent Market Monitor for PJM."Docket No. ER10-713-000 (February 25, 2010)
85 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

through May and October through December the average was 438 MW. The decrease in the demand for Tier 2 was the result of an increase in Tier 1 during the summer months.

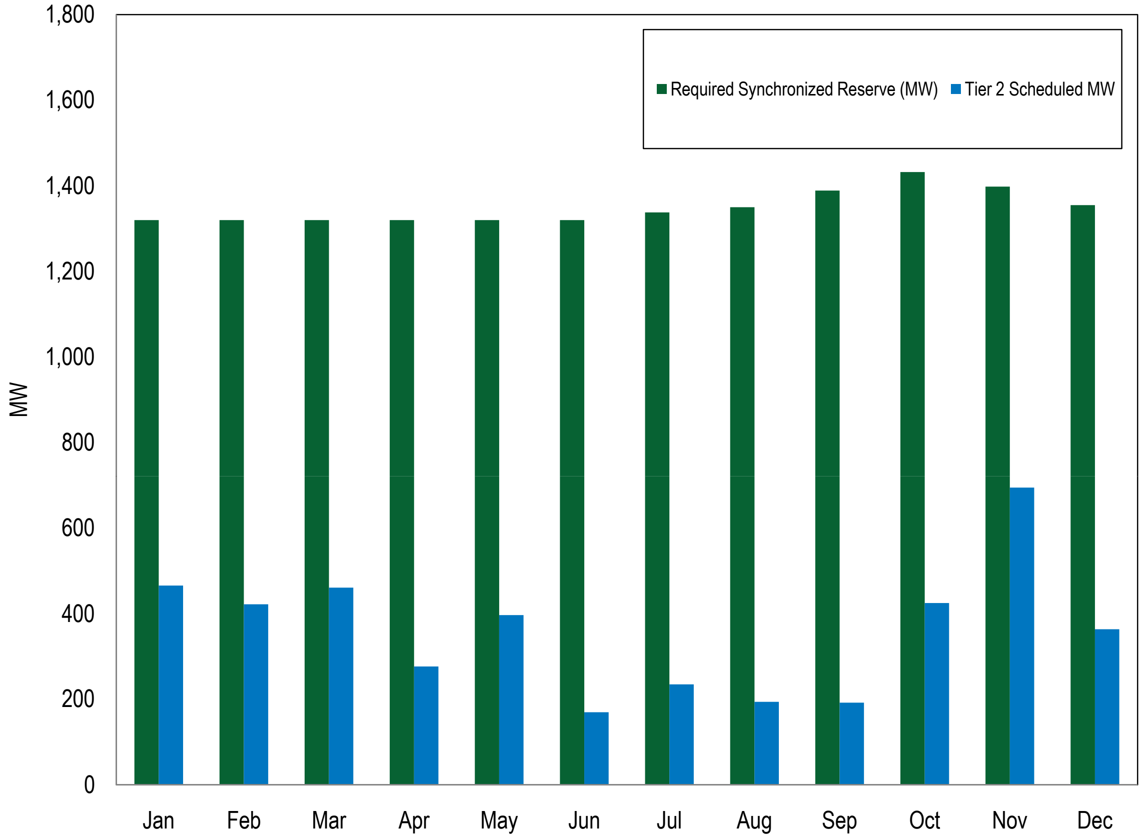
In the PJM Mid-Atlantic Synchronized Reserve Subzone, 67 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 358 MW. The demand was met by self scheduled synchronized reserves, which averaged 129 MW, and cleared Tier 2 synchronized reserves, which averaged 220 MW in 2010.

Synchronized reserves added out of market were five percent of all PJM Mid-Atlantic subzone synchronized reserves in 2010.

For the first six months of 2010, the synchronized reserve requirement was 1,320 MW for the RFC Synchronized Reserve Zone. On July 1, 2010, the requirement for the RFC Synchronized Reserve Zone was increased from 1,320 MW to 1,350 MW, to accommodate the largest single unit contingency. Additionally, there were 85 hours between September 20 and September 29 when the synchronized reserve requirement for the RFC Synchronized Reserve Zone was increased to 1,700 MW as a result of outages.

Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone for only 11 hours in 2010.

Figure 1-9 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2010



- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for 2010 was 3222, which is classified as "highly concentrated."[86] For purchased synchronized reserve (cleared plus added) the HHI was 3268. In 2010, 68 percent of hours had a maximum market share greater than 40 percent, compared to 36 percent of hours in 2009.

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2010, 62 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the full RFC Synchronized Reserve Market (which cleared only 27 hours in 2010) 100 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the Southern Synchronized Reserve Zone (which cleared only 11 hours in 2010) none of those hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the RTO zone and Mid-Atlantic subzone Synchronized Reserve Markets in 2010 were characterized by structural market power.

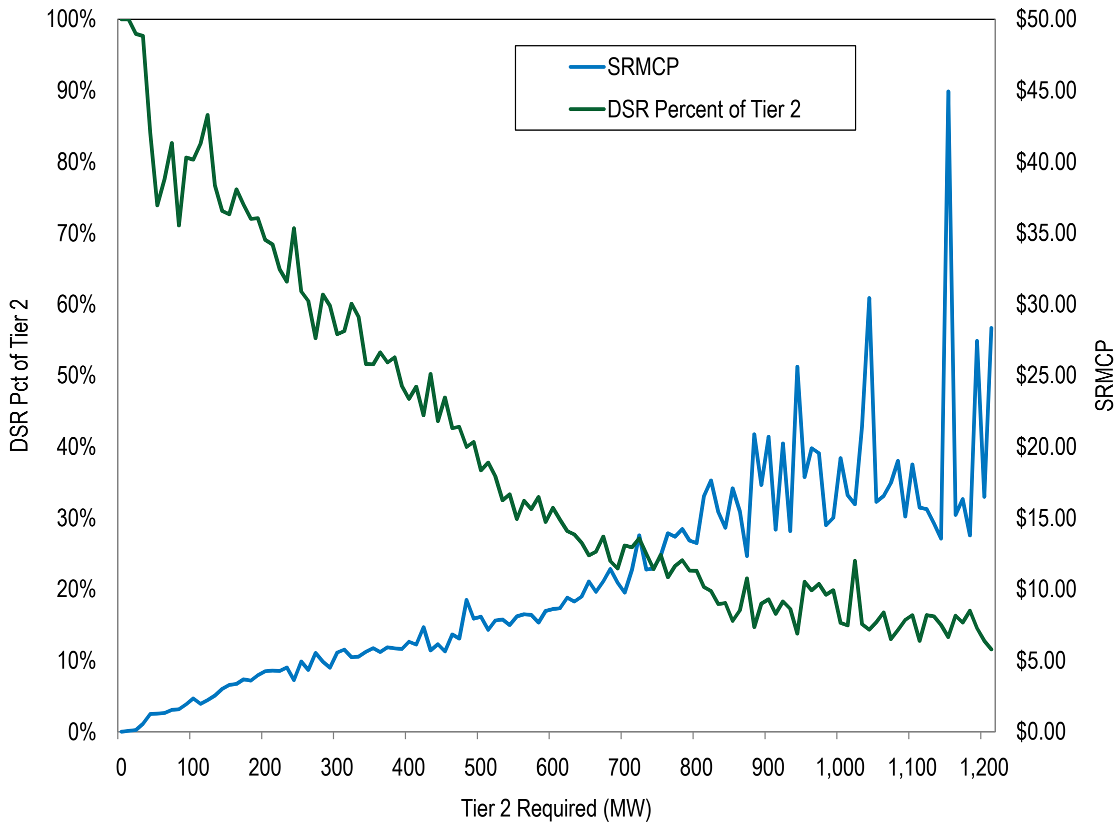
86 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using LMP forecasts, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

  Demand side resources remained significant participants in the Synchronized Reserve Market in 2010. In eight percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by demand side resources.

Figure 1-10 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2



Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $10.55 per MW in 2010, a $2.80 per MW increase from 2009. The market clearing price was only 63 percent of the total synchronized reserve cost per MW in 2010, lower than in 2009.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in 2010.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[87] The purpose of this market is to satisfy 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.[88] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** In 2010, the TPS test was failed in the DASR Market in 1.3 percent of hours, all of which were in the months of June, July, August, and September.

- **Demand.** In 2010, the required DASR was 6.88 percent of peak load forecast, up from 6.75 percent in 2009.[89] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 9 percent in 2010 over 2009.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, five percent of units offered at $50 or more and 45 units offered at more than $900, in a market with an average clearing price of $0.16 and a maximum clearing price of $39.99. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[90] Units that do not offer will have their offers set to $0/MW. Every unit type had significant offers at $10/MW or lower.

- **DSR.** Demand side resources do participate in the DASR Market, but remain insignificant.

87 See 117 FERC ¶ 61,331 (2006).
88 See PJM. "Manual 13: Emergency Operations," Revision 42, (January 21, 2011); pp 11-12.
89 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
90 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 45 (June 23, 2010), p. 122.

Market Performance

- **Price.** DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July.

Black Start Service

Black Start Service is necessary to help ensure the reliable restoration of the grid following a blackout. Black Start Service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[91]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for all costs associated with providing this service, as defined in the tariff. For 2009, charges were about $12.3 million. In 2010, total black start service charges were $10.0 million. There was substantial zonal variation.

As a consequence of new NERC standards related to Critical Infrastructure Protection and PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs necessary for compliance with the new NERC standards, black start costs likely will increase substantially.

The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market rather than a separate zone by zone basis. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Ancillary Services costs per MW of load: 2001 - 2010

Table 1-13 shows PJM ancillary services costs from 2001 through 2010 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Blackstart Services; Direct Assignment Facilities;

91 OATT Schedule 1 § 1.3BB.

and Reliability First Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 1-13 History of ancillary services costs per MW of Load: 2001 through 2010

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
2010	$1,428	99%	$34,771	4%
Total	$9,591		$185,358	5%

Ancillary Services Conclusion

While the MMU has identified a number of issues with the design and implementation of the Regulation Market, these issues can be resolved as a single package in a timely manner. The MMU recommends that such a resolution be pursued in 2011 with the goal of implementing the appropriate changes in 2011.

The design of the Regulation Market can be improved. The MMU recommends that, as part of a package of modifications to improve the Regulation Market design, the clearing price for regulation be determined based on the actual LMP. The regulation clearing price is generally too low because it is based on forecast LMP, which appears to systematically understate actual LMP. The proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.[92] The MMU recommends that when this modification is implemented, the margin be reduced to no higher than its current level. The result would be to make Regulation Market prices more transparent and more reflective of the actual cost of providing regulation and is expected to increase revenues to the providers of regulation, after accounting for all the recommended changes.

The MMU continues to conclude that the results of the Regulation Market are not competitive.[93] The MMU's conclusion is not the result of the behavior of market participants, which was competitive, in part as a result of the application of the TPS test, but is the result of the market design changes. The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, are inconsistent with basic

92 See, *e.g.*, PJM compliance filing in Docket No. ER09-1063-004 (June 18, 2010); Protest and Compliance Proposal of the Independent Market Monitor for PJM, Docket No. ER09-1063-004, (July 19, 2010).

93 The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

economic logic, and because of incorrect implementation of the market rules. For example, the changes to the calculation of the opportunity cost resulted in offers greater than competitive offers in some hours and therefore in prices greater than competitive prices in some hours, and resulted in offers less than competitive offers in some hours and therefore in prices less than competitive prices in some hours. The competitive price is the price that would have resulted from a combination of competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules.

The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits also be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic. The MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design.

The MMU also recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.

The structure of each 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. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) 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.

The MMU recommends that the DASR Market rules be modified to incorporate the application of the TPS test. The MMU concludes that the DASR Market results were competitive in 2010.

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.

Overall, the MMU concludes that the Regulation Market results were not competitive in 2010 as a result of the identified market design changes and their implementation. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in 2010. The MMU concludes that the DASR Market results were competitive in 2010.

CONGESTION

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[94] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. LMPs reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of ARRs and/or FTRs. While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[95]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets in 2010.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $709.1 million or 99 percent, from $719.0 million in 2009 to $1,428.1 million in 2010. Day-ahead congestion costs increased by $816.4 million or 91 percent, from $901.4 million in 2009 to $1,717.9 million in 2010. Balancing congestion costs decreased by $107.3 million or 59 percent, from -$182.4.0 million in 2009 to -$289.7 million in 2010. Despite the increase, total congestion in 2010 was lower than total congestion in every year from 2005, when PJM grew through a series of major integrations, through 2008. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in 2010, which is higher than the three percent share in 2009, but lower than the share of total billings from 2003 through 2008. Total PJM billings in 2010 were $34.771 billion.

94 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

95 See the *2009 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

Table 1-14 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2010

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($9.5)	($76.1)	$5.5	$72.0	($3.1)	$3.8	($53.2)	($60.1)	$11.9	6,830	3,242
Interface	$84.6	($631.0)	$2.7	$718.2	$22.4	$24.0	($4.1)	($5.7)	$712.5	9,823	2,619
Line	$178.4	($433.9)	$68.9	$681.2	($44.3)	$42.5	($101.3)	($188.1)	$493.1	72,457	14,291
Transformer	$128.3	($81.5)	$10.4	$220.1	($10.9)	$4.7	($20.2)	($35.8)	$184.4	11,618	3,307
Unclassified	$16.6	($0.3)	$9.3	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	NA	NA
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1	100,728	23,459

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2010, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2010 ranged from $20.4 million in March to $268.9 million in July.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price.** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface and other 500 kV constraints in the east. The AP South interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2010.[96] The AP South Interface was the largest contributor to congestion costs in 2010. With $421.6 million in total congestion costs, it accounted for 30 percent of the total PJM congestion costs in 2010. The top five constraints in terms of congestion costs together contributed $745.8 million, or 52 percent, of the total PJM congestion costs in 2010. The top five constraints were the AP South interface, the Bedington – Black Oak interface, the 5004/5005 interface, the Doubs transformer, and the AEP-DOM interface.

96 In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained.

Table 1-15 Congestion summary (By facility type): Calendar year 2010

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$40.9	$15.1	$0.3	$26.1	$0.5	($1.3)	($0.1)	$1.7	$27.7
AEP	($137.6)	($353.1)	$11.2	$226.7	($21.6)	$31.2	($18.9)	($71.7)	$155.0
AP	$14.8	($293.7)	$0.8	$309.3	$7.5	$28.8	($5.3)	($26.6)	$282.7
BGE	$198.2	$124.6	$9.3	$82.9	$15.2	($4.9)	($11.4)	$8.7	$91.6
ComEd	($483.2)	($795.1)	($5.5)	$306.4	($21.8)	$9.5	($11.9)	($43.2)	$263.2
DAY	($18.7)	($30.0)	$5.6	$16.9	$1.4	$1.8	($6.9)	($7.3)	$9.6
DLCO	($95.1)	($139.6)	($0.7)	$43.8	($11.9)	$1.1	$0.2	($12.9)	$30.9
DPL	$72.7	$23.5	$1.3	$50.5	$0.0	$1.7	($1.6)	($3.3)	$47.2
Dominion	$260.1	($33.3)	$15.9	$309.3	($5.6)	($0.6)	($18.8)	($23.9)	$285.5
External	($184.1)	($198.7)	$17.4	$32.0	$2.2	($20.0)	($69.1)	($46.9)	($14.9)
JCPL	$76.1	$26.5	$0.5	$50.2	$1.0	($0.5)	($0.7)	$0.8	$51.0
Met-Ed	$61.2	$52.0	$1.3	$10.5	($0.8)	$0.2	($1.5)	($2.6)	$8.0
PECO	$62.5	$72.1	$0.3	($9.3)	($2.9)	$2.3	($0.9)	($6.0)	($15.3)
PENELEC	($56.5)	($154.8)	$1.0	$99.2	$17.0	$8.4	($0.7)	$7.8	$107.0
PPL	$96.4	$110.4	$3.6	($10.4)	$12.4	$9.1	($0.5)	$2.7	($7.7)
PSEG	$129.5	$100.2	$28.3	$57.6	($9.6)	$20.2	($23.5)	($53.3)	$4.3
Pepco	$357.5	$250.9	$6.1	$112.8	($20.0)	($12.1)	($6.8)	($14.8)	$98.0
RECO	$3.5	$0.2	$0.1	$3.4	$1.0	($0.0)	($0.2)	$0.9	$4.3
Total	$398.3	($1,222.9)	$96.7	$1,717.9	($35.9)	$75.0	($178.8)	($289.7)	$1,428.1

- **Zonal Congestion.** In 2010, the Dominion Control Zone experienced the highest congestion costs of the control zones in PJM with $285.5 million.[97] The AP South interface, the Cloverdale – Lexington line, the Doubs transformer, the Bedington – Black Oak interface, and the Clover transformer contributed $183.4 million, or 64 percent of the total Dominion Control Zone congestion costs. The AP Control Zone had the second highest congestion cost in PJM in 2010. The $282.7 million in congestion costs in the AP Control Zone represented a 187 percent increase from the $95.3 million in congestion costs for the zone in 2009. The AP South interface contributed $110.3 million, or 39 percent of the total AP Control Zone congestion cost. Increases in day-ahead congestion frequency and congestion costs from the Bedington – Black Oak interface and the Doubs transformer also contributed to the increase in congestion cost in the AP Control Zone from 2009 to 2010. The Bedington – Black Oak interface contributed $32.5 million to the AP Control Zone congestion costs and the Doubs transformer contributed $27 million to the AP Control Zone congestion costs.

97 See the *Report to the North Carolina Utilities Commission: Congestion in the Dominion Service Territory in North Carolina: May 1, 2008 through April 30, 2010*(Accessed February 14, 2011), <http://www.monitoringanalytics.com/reports/Reports/SR2010/State_Congestion_Report_NC_DOM_20100715.pdf >.

Table 1-16 Congestion cost summary (By control zone): Calendar year 2010

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$4,219,721	$25,540,714	($2,067,671)	$10,817,043	($12,884,714)	0.0%
AEP	$223,262,229	$157,919,018	$214,898,039	$166,283,208	$101,031,029	$65,252,179	>100%
AP	$365,048,488	$185,774,650	$324,136,428	$226,686,710	$132,996,453	$93,690,257	>100%
BGE	$52,131,739	$29,778,076	$34,611,142	$47,298,673	$40,787,754	$6,510,919	>100%
ComEd	$27,261,279	$61,701,901	$12,504,362	$76,458,818	$192,953,092	($116,494,274)	39.6%
DAY	$7,505,314	$1,208,852	($146,827)	$8,860,993	$7,993,310	$867,683	>100%
DLCO	$2,454,337	$10,773,597	($3,631,769)	$16,859,703	$25,084,077	($8,224,374)	67.2%
Dominion	$213,840,239	$156,718,198	$240,575,877	$129,982,560	$150,288,685	($20,306,125)	86.5%
DPL	$18,915,429	$13,281,446	$38,621,277	($6,424,402)	$28,398,375	($34,822,777)	0.0%
JCPL	$34,924,192	($890,074)	$44,362,866	($10,328,748)	$18,958,788	($29,287,536)	0.0%
Met-Ed	$27,312,021	$15,468,233	$35,876,903	$6,903,351	$4,609,666	$2,293,685	>100%
PECO	$49,863,646	$21,467,430	$56,377,913	$14,953,163	($22,617,637)	$37,570,800	>100%
PENELEC	$49,412,326	$61,808,839	$63,892,689	$47,328,476	$58,884,119	($11,555,643)	80.4%
Pepco	$23,702,306	$111,232,601	$102,336,490	$32,598,417	$66,040,760	($33,442,343)	49.4%
PJM	$9,979,482	($4,934,756)	($3,846,501)	$8,891,227	$8,551,453	$339,774	>100%
PPL	$55,143,860	$21,032,754	$65,711,467	$10,465,147	($8,203,127)	$18,668,274	>100%
PSEG	$94,609,270	$34,463,423	$119,797,997	$9,274,696	($1,140,092)	$10,414,788	>100%
RECO	($41,455)	($1,186,779)	($2,875,400)	$1,647,166	$1,562,712	$84,454	>100%
Total	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%

Generation and Transmission Interconnection Planning Process

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process. The process is complex and time consuming as a result of the nature of the required analyses. Nonetheless, this process potentially creates barriers to entry by creating uncertainty for potential entrants about the cost and time associated with interconnecting to the grid. The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

Key Backbone Facilities

PJM baseline projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of significant baseline upgrades. The backbone upgrades are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Carson – Suffolk; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac

– Appalachian Transmission Highline (PATH); Susquehanna – Roseland; and the Trans Allegheny Line (TrAIL). The total planned costs for all of these projects are $6,048.4 million.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism, typically under traditional regulation. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[98] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Restructuring Responsibility for Grid Development.** The FERC's recent decisions in the Primary Power and Central Transmission cases addressed significant issues about the ownership of transmission, the resultant incentives to build new transmission facilities and the potential for competitive forces to reduce the cost of transmission.[99] On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking (NOPR) including a proposal to "remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer."[100] These cases and the proposed rule have the potential to significantly change the incentives to build transmission for both incumbents and potential entrants and therefore to have potentially significant impacts on the wholesale power markets.

Congestion Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were four percent of total PJM billings in 2010. Total PJM billings in 2010 were $34,771 million. Total congestion costs increased by $709.1 million or 99 percent, from $719.0 million in 2009 to $1,428.1 million in 2010. Day-ahead congestion costs increased by $816.4 million or 91 percent, from $901.4 million in 2009 to $1,717.9 million in 2010. Balancing congestion costs decreased by $107.3 million or 59 percent, from -$182.4 million in 2009 to -$289.7 million in 2010. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly

98 *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).

99 131 FERC ¶ 61,015 (April 13, 2010); 131 FERC ¶ 61,243 (June 17, 2010).

100 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, FERC Docket No. RM10-23-000, 131 FERC ¶ 61,253.

higher in the Day-Ahead Market than in the Real-Time Market. Day-ahead congestion frequency increased from 2009 to 2010 by 22,198 congestion event hours or 28 percent. In 2010, there were 100,728 day-ahead, congestion-event hours compared to 78,530 day-ahead, congestion-event hours in 2009. Real-time congestion frequency increased from 2009 to 2010 by 8,012 congestion event hours. In 2010, there were 23,459 real-time, congestion-event hours compared to 15,447 real-time, congestion-event hours in 2009.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged 96.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period.[101] During the first seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7 percent of the congestion costs within PJM. FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period.[102] Revenue adequacy for a planning period is not final until the end of the period.

There are other ways to evaluate the effectiveness of ARRs and FTRs as a hedge. The value of ARRs and FTRs was 4.2 percent of total real-time energy charges to load for the calendar year 2010.[103]

One constraint accounted for 30 percent of total congestion costs in 2010 and the top five constraints accounted for 52 percent of total congestion costs. The AP South Interface was the largest contributor to congestion costs in 2010.

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[104] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint

101 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-33, "ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011."

102 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-21, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010"

103 See the *2010 State of the Market Report for PJM* Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-34, "ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2010"

104 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM in 2010 were $1,428.1 million, which was comprised of load congestion payments of $362.4 million, negative generation credits of $1,147.8 million and negative explicit congestion of $82.1 million.

FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[105] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2010 State of the Market Report for PJM* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010, and the 2010 to 2011 planning period which covers June 1, 2010, through May 31, 2011. The *2010 State of the Market Report for PJM* also analyzes the results of the 2011 to 2014 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2011 through May 31, 2012, June 1, 2012 through May 31, 2013 and June 1, 2013 through May 31, 2014.

105 87 FERC ¶ 61,054 (1999).

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The most recent Long Term FTR Auction was conducted during the 2010 to 2011 planning period and covers three consecutive planning periods between 2011 and 2014. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the 2011 to 2014 Long Term FTR Auction include the Millville – Old Chapel Line and the Lovettsville – Millville Line. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2010 to 2011 planning period include the Doubs Transformer and the Messick Road - Ridgeley line. Market participants can also sell FTRs. In the 2011 to 2014 Long Term FTR Auction, total FTR sell offers were 177,540 MW, up from 51,582 MW during the 2010 to 2013 Long Term FTR Auction. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR sell offers were 178,428. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2010) of the 2010 to 2011 planning period, there were 2,766,728 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2011 to 2014 Long Term FTR Auction, total FTR buy bids were 1,996,084 MW. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR buy bids were 1,708,556 MW, up from 1,436,335 MW during the 2009 to 2010 planning period. Total FTR self scheduled bids were 55,732 MW for the 2010 to 2011 planning period, a decrease from 68,589 MW for the 2009 to 2010 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2010) of the 2010 to 2011 planning period, total FTR buy bids were 8,973,645 MW.

- **FTR Credit Issues.** There were no participant defaults in 2010. The MMU continues to recommend the complete elimination of unsecured credit from PJM markets, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

- **Tower Companies Litigation and Investigation.** On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court and at the FERC.[106] This matter concerned in part

106 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.

allegations that the Tower Companies "manipulated PJM's Day-ahead energy and Financial Transmission Rights (FTR) markets."[107] The FERC also commenced its own independent investigation.[108] The Market Monitor had been scheduled to testify in the Court proceeding as a fact witness and as a non-retained or employed expert witness on the basis of the MMU's extensive non-public analysis. Under the terms of the settlement, the Tower Companies paid $18 million in return for PJM withdrawing its civil complaint and the remainder of its complaint at the FERC related to this matter. In September 2010, the PJM Members Committee adopted and then implemented the following resolution: "The PJM Members Committee resolves to request the chair of the Members Committee to send a letter to FERC Office of Enforcement to request expeditious conclusion of the investigation of Tower affiliates in the matter of alleged improper use of virtual trades and make public the results of that investigation consistent with FERC practices and prPatterns of Ownership. The ownership concentration of cleared FTR buy bids resulting from the 2010 to 2011 Annual FTR Auction was low to moderate for FTR obligations and moderate to high for FTR options. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (MMU) categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. During the 2010 to 2011 planning period, physical entities own 54 percent of prevailing flow Annual cleared buy bid FTRs while financial entities own 72 percent of counter flow Annual cleared buy bid FTRs. Overall, financial entities own 53 percent of all FTRs bought in the Annual Auction. Financial entities own 84 percent of FTRs bought and sold in the Long Term FTR Auction. Financial entities own 77 percent of prevailing flow and 88 percent of counter flow FTRs bought in the Monthly Balance of Planning Period Auctions. Overall, financial entities own 82 percent of all Monthly Balance of Planning Period cleared buy bid FTRs. Physical entities owned 49 percent of all FTRs in 2010. Financial entities owned 68 percent of all counter flow FTRs and 46 percent of all prevailing flow FTRs in 2010.

Market Performance

- **Volume.** The 2011 to 2014 Long Term FTR Auction cleared 238,681 MW (12.0 percent of demand) of FTR buy bids, up from 86,108 MW (8.1 percent) in the 2010 to 2013 Long Term FTR Auction. The 2011 to 2014 Long Term FTR Auction also cleared 12,501 MW (7.0 percent) of FTR sell offers, up from 5,147 MW (10.0 percent) in the 2010 to 2013 Long Term FTR Auction. For the 2010 to 2011 planning period, the Annual FTR Auction cleared 231,663 MW (13.6 percent) of FTR buy bids, up from 155,612 MW (10.8 percent) for the 2009 to 2010 planning period. The Annual FTR Auction also cleared 10,315 MW (5.8 percent) of FTR sell offers for the 2010 to 2011 planning period, up from 7,399 MW (5.2 percent) for the 2009 to 2010 planning period. For the first seven months of the 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,092,956 MW (12.2 percent) of FTR buy bids and 292,530 MW (10.6 percent) of FTR sell offers.

107 See 127 FERC ¶ 61,007 at P 1 (2009).
108 *Id.*

- **Price.** In the 2011 to 2014 Long Term FTR Auction, 93.3 percent of the Long Term FTRs were purchased for less than $1 per MWh and 96.7 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs in the 2011 to 2014 Long Term FTR Auction were -$0.16 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.06 per MWh for off peak FTRs. The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction which made the total weighted-average cleared price for 24 hour buy bid FTRs negative. Weighted-average prices paid for Long Term buy-bid FTRs in the 2010 to 2013 Long Term FTR Auction were $0.53 per MWh for 24-hour FTRs, $0.03 per MWh for on peak FTRs and $0.10 per MWh for off peak FTRs. For the 2010 to 2011 planning period, 87.4 percent of the Annual FTRs were purchased for less than $1 per MWh and 93.5 percent for less than $2 per MWh. For the 2010 to 2011 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.43 per MWh for 24-hour FTRs, $0.35 per MWh for on peak FTRs and $0.32 per MWh for off peak FTRs. Weighted-average prices paid for annual buy-bid FTR obligations for the 2009 to 2010 planning period were $0.66 per MWh for 24-hour FTRs and $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. The weighted-average prices paid for 2010 to 2011 planning period annual buy-bid FTR obligations and options were $0.35 per MWh and $0.26 per MWh, respectively, compared to $0.53 per MWh and $0.35 per MWh, respectively, in the 2009 to 2010 planning period.[109] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2010 to 2011 planning period was $0.17 per MWh, compared with $0.18 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2009 to 2010 planning period.

- **Revenue.** The 2011 to 2014 Long Term FTR Auction generated $49.8 million of net revenue for all FTRs, up from $31.1 million in the 2010 to 2013 Long Term FTR Auction. The Annual FTR Auction generated $1,049.8 million of net revenue for all FTRs during the 2010 to 2011 planning period, down from $1,329.8 million for the 2009 to 2010 planning period. The Monthly Balance of Planning Period FTR Auctions generated $16.7 million in net revenue for all FTRs during the first seven months of the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were 96.9 percent revenue adequate for the 2009 to 2010 planning period. FTRs were paid at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $981.4 million of FTR revenues during the first seven months of the 2010 to 2011 planning period and $878.4 million during the 2009 to 2010 planning period. For the first seven months of the 2010 to 2011 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations was the Western Hub.

- **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 and were profitable for both physical entities and financial entities

109 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2010 to 2011 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,112 hours) and off peak (4,648 hours).

in 2010. FTR profits tended to increase in the summer and winter months when congestion was higher and decrease in the shoulder months when congestion was lower.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2010 to 2011 planning period were the AP South Interface and the Electric Junction — Nelson line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 135,614 MW for the 2010 to 2011 planning period with 61,793 MW bid in Stage 1A, 27,850 MW bid in Stage 1B and 45,971 MW bid in Stage 2. This is down from 140,037 MW for the 2009 to 2010 planning period with 64,987 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 17,831 MW of ARRs associated with approximately $269,600 per MW-day of revenue that were reassigned in the first seven months of the 2010 to 2011 planning period. There were 19,061 MW of ARRs associated with approximately $362,400 per MW-day of revenue that were reassigned for the full 2009 to 2010 planning period.

Market Performance

- **Volume.** Of 135,614 MW in ARR requests for the 2010 to 2011 planning period, 101,843 MW (75.1 percent) were allocated. There were 61,793 MW allocated in Stage 1A, 27,850 MW allocated in Stage 1B and 12,200 MW allocated in Stage 2. Eligible market participants self scheduled 55,732 MW (54.6 percent) of these allocated ARRs as Annual FTRs. Of 140,037 MW in ARR requests for the 2009 to 2010 planning period, 109,413 MW (78.1 percent) were allocated. There were 64,913 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.6 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2010 to 2011 planning period, ARR holders will receive $1,028.8 million in ARR credits, with an average hourly ARR credit of $1.15 per MWh. During the 2010 to 2011 planning period, the ARR target allocations were $1,028.8 million while PJM collected $1,066.9 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 2010, making ARRs revenue adequate. During the 2009 to 2010 planning period, ARR holders received $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. For the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,349.3 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period since there were no constraints limiting the allocation in these two stages. Some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. For the 2009 to 2010 planning period, no ARRs were prorated in Stage 1A and Stage 1B of the annual ARR allocation.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The effectiveness of ARRs as a hedge can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The effectiveness of ARRs and FTRs as a hedge against congestion can be measured by comparing the revenue received by ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market. For the 2009 to 2010 planning period, all ARRs and FTRs hedged more than 96.2 percent of the congestion costs within PJM. During the first seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs and FTRs can also be measured by comparing the value of the ARRs and FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs and FTRs. The total value of ARRs plus FTRs was 4.2 percent of the total real time energy charges in calendar year 2010.

Table 1-17 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$4,219,721	$25,540,714	($2,067,671)	$10,817,043	($12,884,714)	0.0%
AEP	$223,262,229	$157,919,018	$214,898,039	$166,283,208	$101,031,029	$65,252,179	>100%
AP	$365,048,488	$185,774,650	$324,136,428	$226,686,710	$132,996,453	$93,690,257	>100%
BGE	$52,131,739	$29,778,076	$34,611,142	$47,298,673	$40,787,754	$6,510,919	>100%
ComEd	$27,261,279	$61,701,901	$12,504,362	$76,458,818	$192,953,092	($116,494,274)	39.6%
DAY	$7,505,314	$1,208,852	($146,827)	$8,860,993	$7,993,310	$867,683	>100%
DLCO	$2,454,337	$10,773,597	($3,631,769)	$16,859,703	$25,084,077	($8,224,374)	67.2%
Dominion	$213,840,239	$156,718,198	$240,575,877	$129,982,560	$150,288,685	($20,306,125)	86.5%
DPL	$18,915,429	$13,281,446	$38,621,277	($6,424,402)	$28,398,375	($34,822,777)	0.0%
JCPL	$34,924,192	($890,074)	$44,362,866	($10,328,748)	$18,958,788	($29,287,536)	0.0%
Met-Ed	$27,312,021	$15,468,233	$35,876,903	$6,903,351	$4,609,666	$2,293,685	>100%
PECO	$49,863,646	$21,467,430	$56,377,913	$14,953,163	($22,617,637)	$37,570,800	>100%
PENELEC	$49,412,326	$61,808,839	$63,892,689	$47,328,476	$58,884,119	($11,555,643)	80.4%
Pepco	$23,702,306	$111,232,601	$102,336,490	$32,598,417	$66,040,760	($33,442,343)	49.4%
PJM	$9,979,482	($4,934,756)	($3,846,501)	$8,891,227	$8,551,453	$339,774	>100%
PPL	$55,143,860	$21,032,754	$65,711,467	$10,465,147	($8,203,127)	$18,668,274	>100%
PSEG	$94,609,270	$34,463,423	$119,797,997	$9,274,696	($1,140,092)	$10,414,788	>100%
RECO	($41,455)	($1,186,779)	($2,875,400)	$1,647,166	$1,562,712	$84,454	>100%
Total	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%

FTR and ARR Conclusion

The annual ARR allocation and the FTR auctions provide market participants with the opportunity to hedge positions or to speculate. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2010 to 2011 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. Positively valued ARRs follow load when load switches between suppliers. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

ARRs were 100 percent revenue adequate for both the 2009 to 2010 and the 2010 to 2011 planning periods. FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. Revenue adequacy for a planning period is not final until the end of the period. The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased.

The total of ARR and FTR revenues hedged more than 96.2 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period and 78.7 percent of the congestion costs in PJM for the first seven months of the 2010 to 2011 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.