State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

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

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

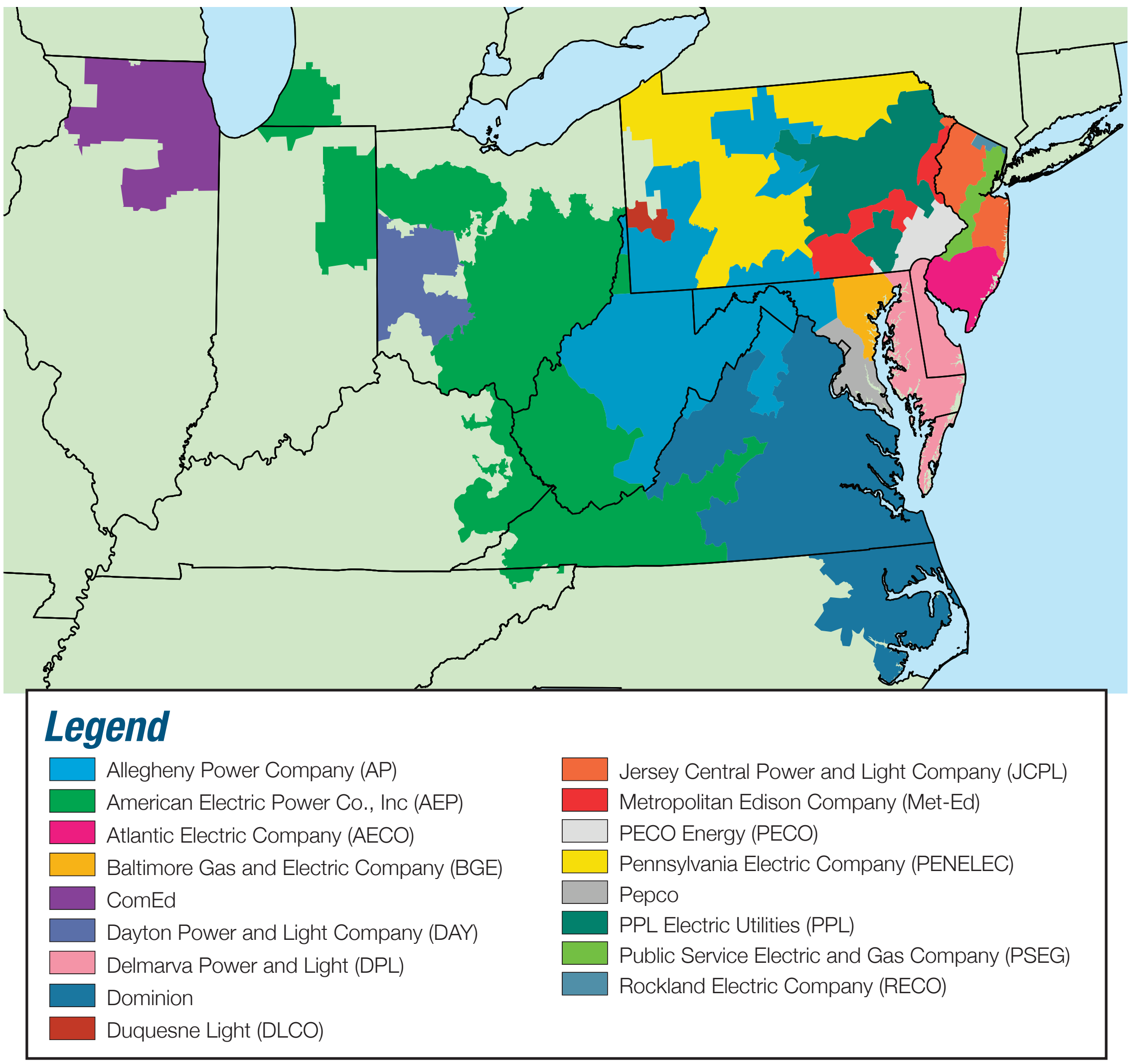
1 OATT Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC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

2 OATT Attachment M § II(f).

SECTION 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 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 (Herfindahl-Hirschman Index) indicate that by the 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 three pivotal supplier 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 three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets. 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 the Three Pivotal Supplier Test (TPS), 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 Three Pivotal Supplier Test (TPS), 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 three pivotal supplier (TPS) test in 73 percent of the hours.

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

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation

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.

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.

- 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 three pivotal supplier 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 three pivotal supplier 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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (Pages 357-359 and Page 362)

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

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

- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized. (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. (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. (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. (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. (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. (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. (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. (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. (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. (Page 539)

- The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding. (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. (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. (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). (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (Page 151)

- There were no scarcity pricing events in 2010 under PJM's current Emergency Action based Scarcity Pricing Rules. (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. (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. (Page 234)

- Balancing transaction operating reserve credits paid in December 2010 represent 82.9 percent of all balancing transaction operating reserve credits since 2000. (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. (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. (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. (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. (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.(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. (Page 301)

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

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

- The Midwest ISO and PJM filed a settlement agreement resolving all complaints regarding the management of the Joint Operating Agreement. (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. (Page 311)

- The Commission conditionally accepted a Congestion Management Protocol between PJM and Progress Energy Carolinas. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (Page 425 and Page 462)

- Since 2001, the cost of ancillary services per MW of load has been relatively low and stable. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (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. (Page 561)

- No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period. (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. (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] (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 Reliability Pricing Model (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]

15 OATT Schedule 12.
16 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6
17 OATT Schedule 1A.
18 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
19 OATT Schedule 6A.
20 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
21 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
22 OA Schedule 1 § 3.6.
23 OA Schedule 1 § 5.3b.

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

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%

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