FirstEnergy

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PO Box 16001
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July 1, 2013

Ms. Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor, 1 North
Harrisburg, PA 17105-3265

Re: *Joint Application of West Penn Power Company doing business as Allegheny Power, Trans-Allegheny Interstate Line Company and FirstEnergy Corp. for a Certificate of Public Convenience Under Section 1102(A)(3) of the Public Utility Code Approving a Change of Control of West Penn Power Company and Trans-Allegheny Interstate Line Company*; Docket Nos. A-2010-2176520 and A-2010-2176732

Dear Ms. Chiavetta:

In accordance with paragraph 54 of the Joint Petition for Settlement approved in the above-referenced proceeding, enclosed please find the 2013 report on market prices and price trends in the PJM Interconnection LLC markets during 2012, prepared by The Brattle Group.

While the Companies assume the information presented in the enclosed report is accurate, they have not verified it and do not adopt these findings as their own. All of the facts, opinions, and arguments presented are those of The Brattle Group.

Enclosed is an extra copy of this transmittal letter and a stamped, self-addressed envelope in order that you may indicate receipt of this letter.

Sincerely,

Richard A. D'Angelo
Manager
Rates and Regulatory Affairs, PA

cc: Johnnie Simms, Bureau of Investigation and Enforcement
Tanya J. McCloskey, Office of Consumer Advocate
Steven Gray, Office of Small Business Advocate

The Brattle Group

Annual Report on Wholesale Market Prices and Trends in the Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company Service Areas

July 1, 2013

Attila Hajos
Philip Q Hanser
Charles Russell

Prepared for

Met-Ed®
Penelec®
Penn Power®
West Penn Power®

FirstEnergy Companies

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Contents

EXECUTIVE SUMMARY

This report was prepared by *The Brattle Group* on behalf of Metropolitan Edison Company ("MET-ED"), Pennsylvania Electric Company ("PENELEC"), Pennsylvania Power Company ("PENN POWER"), and West Penn Power Company ("WEST PENN"), collectively "the Companies," pursuant to the settlement agreement approved by the Pennsylvania Public Utility Commission ("PA PUC") in the proceeding at Docket Nos. A-2010-2176520 and A-2010-2176732. The Companies are part of the PJM Interconnection L.L.C. ("PJM") competitive wholesale market. They operate in four Pennsylvania zones of PJM: Metropolitan Edison Company ("MET-ED ZONE"), Pennsylvania Electric Company ("PENELEC ZONE"), Allegheny Power System ("APS ZONE") for West Penn, and the Penn Power portion of the American Transmission Systems load zone ("ATSI ZONE"). This report summarizes PJM market outcomes and trends, with a specific focus on the portion of the footprint where the Companies operate. Outcomes and trends in other parts of the PJM market are reported only to the extent they affect the areas served by the Companies.

Market trends in the four zones served by the Companies largely reflected overall PJM market trends in 2012. Total wholesale costs, which include the costs of energy, ancillary services, capacity, transmission, and other charges, fell in all four zones. Wholesale costs in the Met-Ed, Penelec, APS, and Penn Power zones fell by 14%, 10%, 28%, and 24%, respectively. The primary drivers of decreases in wholesale costs were lower capacity and energy prices, although some smaller components changed more in relative terms. In 2012, energy and capacity costs, on average, represented 85% of the total wholesale costs of power in PJM, with even larger shares in the Companies' zones.

In 2012, the Met-Ed Zone remained the zone with the highest average energy price, primarily due to transmission congestion. In the day-ahead market, average zonal peak-hour locational marginal prices ("LMPs") decreased by 24% from 2011 to 2012, while off-peak LMPs decreased by 22%. Average real-time, peak-hour LMPs decreased by 22%, and off-peak LMPs decreased by 23%. The Met-Ed Zone continues to show the largest positive transmission congestion cost component for both peak- and off-peak hours. Total net transmission congestion costs, consisting of transmission congestion costs to loads, transmission congestion credits to generators, and transmission congestion charges for point-to-point transactions, decreased in PJM, including within the Companies' four zones.

PJM's Reliability Pricing Model ("RPM") is a forward capacity market that interacts with and works in tandem with the PJM energy market to provide price and revenue signals to attract new and retain existing capacity. Capacity is procured three years in advance of each delivery year, which runs from June through May of the following year. Consequently, capacity prices for the calendar year 2012 were determined in capacity auctions for two delivery years: 2011/12 and 2012/13. RPM is a locational capacity market that can result in differential capacity prices between zones, depending on transmission constraints. For the unconstrained part of the Regional Transmission Organization ("RTO"), the Base Residual Auctions ("BRA") held for the 2011/12 and 2012/13 delivery years cleared at capacity prices of $110/MW-day and $16.46/MW-day, respectively. In the 2011/12 delivery year, all of the Companies' zones remained in the unconstrained part of the RTO, while in the 2012/13 delivery year the Mid-Atlantic Area Council ("MAAC") Locational Deliverability Area ("LDA"), containing the Penelec and Met-Ed zones, cleared at a capacity price of $133.37/MW-day. Since the ATSI Zone was integrated into PJM in 2011 and did not participate in the PJM forward capacity auctions for the 2011/12 and 2012/13 delivery years, two transitional ATSI Zone Fixed Resource Requirement ("FRR") integration auctions were held in March 2010. These two auctions cleared at $108.89/MW-day and $20.46/MW-day, respectively.

Four capacity auctions were held in 2012, including the BRA for the 2015/16 delivery year, and three incremental auctions for prior delivery years. The BRA for 2015/16 cleared at an RTO price of $136/MW-day, a MAAC price of $167.46/MW-day, and an ATSI Zone price of $357/MW-day.[1] Compared to the 2014/15 BRA, capacity prices in all three LDAs were higher. The largest capacity price increase occurred in the ATSI Zone which cleared at $125.99/MW-day as part of the unconstrained RTO in the previous 2014/15 BRA. Capacity prices in MAAC and the rest of the RTO increased by $30.96/MW-day and $10.01/MW-day, respectively. PJM attributed these moderate capacity price increases in MAAC and the unconstrained part of the RTO to a number of factors that had largely offsetting impacts. In contrast, the ATSI Zone experienced a large concentration of generator retirements which, coupled with limited transfer capabilities to allow capacity imports, as well as, relatively short lead-time for entry by new capacity, led to high locational capacity prices.

PJM operates competitive markets for four ancillary services: regulation, synchronized reserves, non-synchronized reserves, and day-ahead scheduling reserves. Effective October 1, 2012, PJM implemented performance-based regulation to comply with FERC Order No. 755.[2] The main objective of the order is to ensure that flexible resources are properly compensated for providing regulation service. Traditionally, regulation has been priced based solely on capability (measured in terms of MW per minute), which disadvantaged flexible resources that were more often dispatched for regulation than other less flexible resources. Under the new pay-for-performance construct, regulation offers consist of two parts, including a regulation capability cost component and a regulation performance cost component. In addition, PJM introduced two distinct types of frequency response: (1) RegA (traditional and slower oscillation signal) and (2) RegD (faster oscillation signal). The implementation of performance-based regulation allowed PJM to lower the regulation requirement. Previously, requirements were calculated as 1% of forecasted daily peak load for on-peak hours, and 1% of forecasted minimum daily load for off-peak hours. Following October 1, 2012, PJM lowered the regulation requirement to 0.78%, which was further lowered to 0.7% by the end of 2012. Although regulation requirements fell after October 1, 2012, regulation prices rose. PJM's Independent Market Monitor noted that by December 2012, the total cost of regulation had dropped because while prices remained high, the total amount of regulation cleared dropped. The market monitor also concluded that the effectiveness of the new regulation market design has yet to be determined.

In 2012, the PJM reserve markets significantly changed. Following the implementation of the new shortage pricing mechanism, PJM's primary reserve requirement may also be satisfied by non-synchronized reserves, subject to the condition that non-synchronized reserves may not exceed 50% of the total primary reserve requirement. Therefore, a separate non-synchronized reserve market was established. The geography of the synchronized reserve market also changed effective October 1. Previously, the PJM synchronized reserve market contained two reserve zones and one subzone: the Reliability*First* Corporation ("RFC") Synchronized Reserve Zone and its subzone, the Mid-Atlantic Subzone, and the Southern Synchronized Reserve Zone. Effective October 1, 2012, the RFC Synchronized Reserve Zone and the Southern Synchronized

1 These are resource clearing prices for annual resources.

2 FERC (2011c).

Reserve Zone were merged into a single RTO Zone. In addition, due to the electrical similarities of the former Mid-Atlantic Subzone and the Southern Synchronized Reserve Zone, both were merged into a new subzone, the Mid-Atlantic Dominion Subzone. Contribution of demand resources to the supply of synchronized reserves remained significant in 2012. Historically, there has been a cap on demand resources participation at 25% of the synchronized reserve requirement. On December 6, 2012, PJM raised this cap to 33% of the synchronized reserve requirement.

According to the assessment of PJM's Independent Market Monitor, the PJM wholesale market continued to operate in a competitive manner during 2012. All but the regulation market yielded competitive outcomes. The regulation market was determined not to be competitive during the period from January through September because the application of PJM's current opportunity cost methodology resulted in market prices that deviated from the competitive price, which reflects the actual marginal cost of the marginal resource. In addition, the market designs of the PJM capacity and Day-Ahead Scheduling Reserve ("DASR") markets were deemed mixed.

I. INTRODUCTION

I.A. PURPOSE

This is the second annual report prepared by *The Brattle Group* on behalf of the Companies to comply with the Companies' commitment under the settlement agreement approved by the PA PUC in the proceeding at Docket Nos. A-2010-2176520 and A-2010-2176732. The report summarizes market outcomes and trends in the Pennsylvania portion of the PJM market where the Companies operate. Market outcomes and trends in other parts of the PJM market are not reported unless they affect the areas served by the Companies. This report was prepared using publicly available data and information. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone.

I.B. THE PJM MARKET

PJM operates a wholesale market for energy, capacity, and ancillary services that covers all or parts of thirteen states and the District of Columbia. The PJM footprint expanded to 19 load zones in 2012,[3] seven of which are fully or partially located within Pennsylvania. The Companies operate in four Pennsylvania zones of PJM: the Met-Ed Zone, the Penelec Zone, the APS Zone, and the Penn Power portion of the ATSI Zone.[4] Met-Ed and Penelec zones were part of the PJM market when it was designated an RTO by the FERC in 2001. The APS and ATSI Zones were integrated into PJM in 2002 and 2011, respectively. This report summarizes market prices and trends for the calendar year 2011 in the Met-Ed Zone, Penelec Zone, APS Zone, and Penn Power's portion of the ATSI Zone. The locations for each of the nineteen load zones within the PJM footprint are shown in Figure 1.

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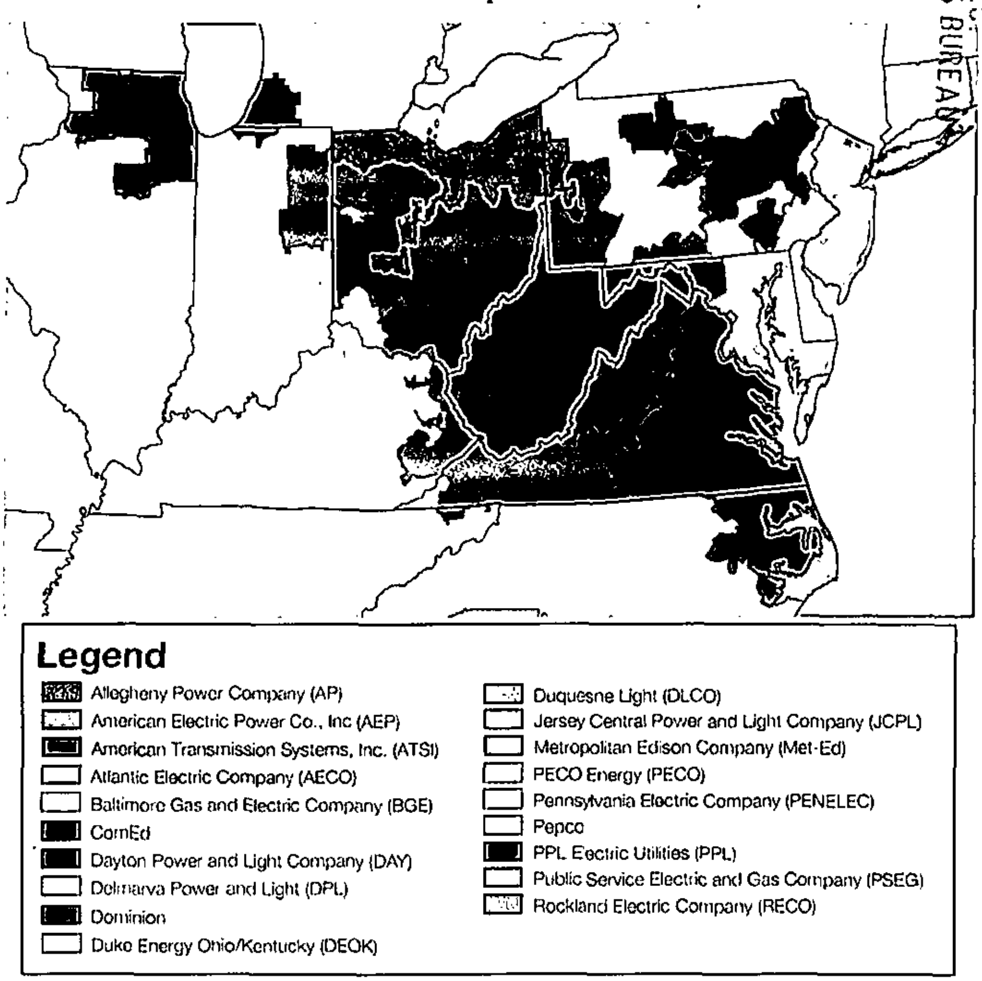
[3] Effective January 1, 2012, PJM integrated the Duke Energy Ohio and Kentucky ("DEOK") load zone into its footprint.

[4] By PJM's convention, load zones bear the name of a large utility service provider working within their boundaries; however, the nomenclature applies to the geographic area within the PJM footprint, not to any single company.

Figure 1[5]
PJM's Footprint in 2012



II. WHOLESALE POWER COSTS

II.A. WHOLESALE POWER COSTS IN PJM

The wholesale cost of power purchased in the PJM market consists of a number of components, including: (1) energy; (2) capacity; (3) transmission service charges; (4) operating reserves (uplift); (5) reactive power; (6) PJM administrative fees; (7) regulation; (8) transmission enhancement cost recovery charges; (9) synchronized reserves; (10) transmission owner (Schedule 1A) charges; (11) DASR; (12) black start; (13) North American Electric Reliability Corporation/Reliability*First* Corporation ("NERC/RFC") charges; (14) RTO Startup and Expansion; (15) load response; (16) transmission facility charges; and (17) non-synchronized reserves. Non-synchronized reserves represent a new component that was introduced in 2012. As discussed further in Section IV.C, due to the pricing and nature of this new reserve product, non-synchronized reserves represent a minor component of the total wholesale cost of electricity.

[5] Source: Monitoring Analytics (2013), Appendix A, Figure A-1.

Table 1 summarizes the magnitude of each component of the wholesale cost for PJM and the Companies' zones in 2012.

Table 1
Wholesale Costs of Electricity in 2012[6,7,8]
($/MWh)

	PJM	Penelec	Met-Ed	APS	Penn Power
Energy	$35.23	$35.10	$36.30	$34.86	$[illegible].02
Marginal Congestion Cost	*$0.04*	*-$0.12*	*$0.67*	*$0.04*	*-$[illegible].87*
Marginal Transmission Losses	*$0.01*	*$0.56*	*$0.53*	*-$0.09*	*-$[illegible].21*
Capacity	$6.05	$13.62	$13.62	$3.69	$3.69
Transmission Service Charges	$4.78	$2.52	$2.52	$2.70	$2.81
Operating Reserves (Uplift)	$0.79	$0.98	$0.98	$1.02	$1.02
Reactive	$0.43	$0.28	$0.52	$0.50	$0.23
PJM Administrative Fees	$0.42	$0.42	$0.42	$0.42	$0.42
Regulation	$0.26	$0.26	$0.26	$0.26	$0.26
Transmission Enhancement Cost Recovery	$0.34	$0.07	$0.09	$0.09	$0.08
Synchronized Reserves	$0.04	$0.08	$0.08	$0.08	$0.00
Transmssion Owner (Schedule 1A)	$0.08	$0.08	$0.08		$0.03
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	$0.05	$0.05	$0.05
Black Start	$0.03	$0.03	$0.03	$0.00	$0.00
NERC/RFC	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.01				
Load Response	$0.01	$0.03	$0.01	$0.02	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00
Non-Synchronized Reserves	$0.00	$0.01	$0.01	$0.01	$0.01
Total	$48.54	$53.54	$54.99	$43.71	$41.63

The price of wholesale power is the average price per MWh that buyers of electricity pay in the PJM marketplace. Some charges, such as the PJM Administrative Fees, regulation, DASR and NERC/RFC charges do not vary by zone. Other components, however, are either based on locational prices or allocated zonally. This is especially true for energy prices as the PJM energy market is based on a system of LMPs, whereas the price of energy reflects the marginal cost of delivering that energy to a given location within the PJM system.

[6] Note that Table 1 reports average cost per megawatt hour of energy; however, actual charges may be allocated differently. For example, capacity costs are allocated not on the basis of energy (MWh) consumed, but based on each customer's contribution to the PJM coincident peak load (so-called Peak Load Contribution) during the five highest summer load hours.

[7] For the Met-Ed, Penelec, and APS zones, the average synchronized reserve cost for the Mid-Atlantic Dominion Subzone is shown; however, portions of these two zones are located outside that synchronized reserve subzone, and consequently, consumers located in those areas incur a lower synchronized reserve cost.

[8] Source: Monitoring Analytics (2013) and *Brattle* analysis.

Energy and capacity costs make up the vast majority of the total wholesale cost. On average, the largest two components make up over 85% of the total wholesale cost. Energy costs represent the largest single component for all load zones at an average of 73% of the total wholesale price in PJM, with even larger shares in the Companies' zones.[9] As shown in Table 1, energy costs vary by load zone, reflecting the regional variation in LMPs. The Penelec price is close to the PJM average. As reflected in the marginal transmission congestion cost component of the energy price, energy costs are higher than the PJM average in the Met-Ed Zone, and lower than the PJM average in the APS and Penn Power area, reflecting the fact that the Met-Ed Zone is located in a more congested area of PJM, while APS and Penn Power lie in a less congested area. Further discussion of energy costs can be found in Section II.B. Similar to energy prices, capacity prices may vary by location, although price separation is less common in comparison to the energy market. Unlike 2011, capacity auctions held for the calendar year 2012 experienced price separation among Locational Deliverability Areas that contain the Companies' zones. As such, zonal average capacity costs differ from the PJM average. In contrast, capacity auctions held for 2011 had seen no such price separation, and zonal average capacity costs did not differ greatly from the PJM average. Transmission service charges are not market-based charges, but instead are payments to transmission owners for providing network integration, and both firm and non-firm point-to-point transmission service. Figure 2 shows the breakdown of wholesale costs, by component, for each load zone.

[9] The energy component is the real time load weighted average PJM LMP, which is made up of two transmission costs (marginal transmission costs and transmission congestion) and one generation cost (marginal energy costs).

Figure 2
Wholesale Costs of Electricity in 2012[10]
(% of Total, by Component)

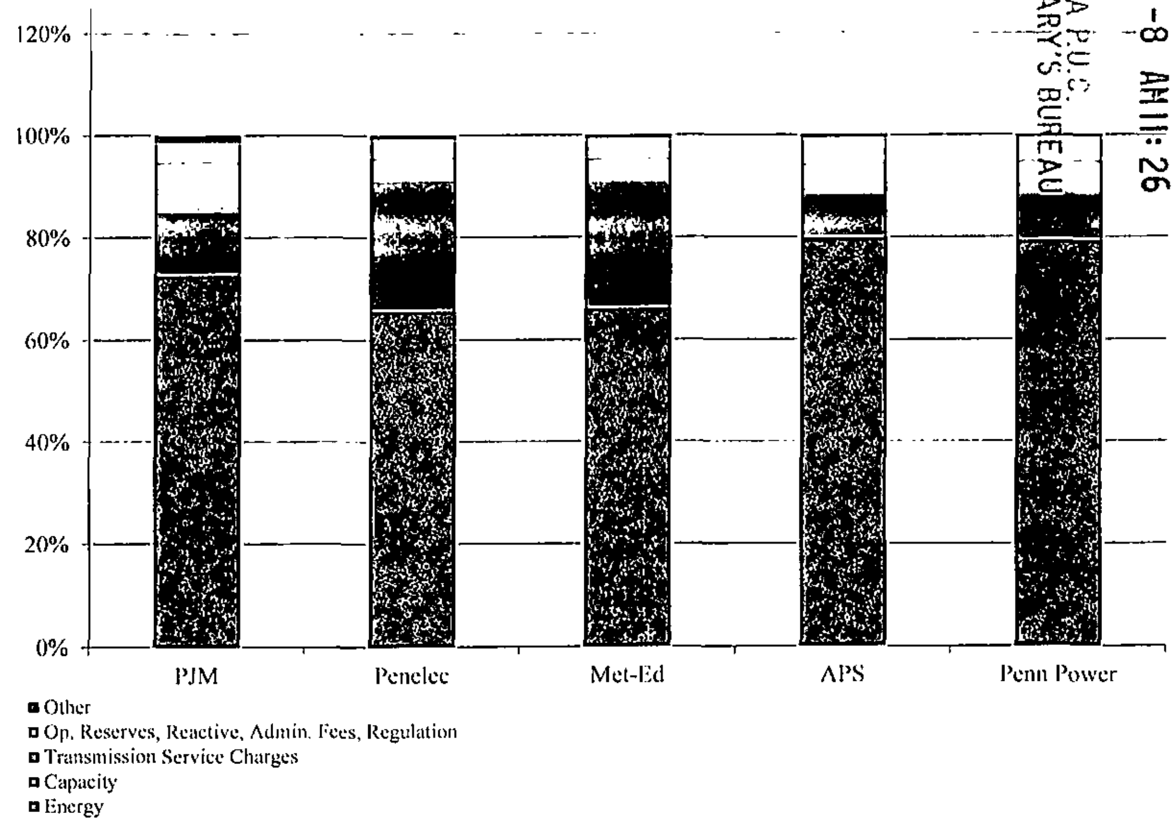


Table 2 shows the total wholesale cost of electricity by component for the calendar years 2010 and 2011. Between 2011 and 2012, the total cost of wholesale power fell by approximately 22%. Larger reductions in wholesale costs were registered in the APS and Penn Power zones, at 28% and 26%, respectively. In the Penelec Zone, wholesale costs fell by less than the PJM average. The reduction in wholesale costs was primarily driven by a decline in energy and capacity prices. Several factors influenced the decrease in energy prices, including changes in demand and supply, as well as the continuing decline of natural gas prices. Capacity costs in the APS and Penn Power zones decreased the most when compared to average capacity costs in 2011. Further discussion on capacity prices can be found in Section II.C.

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[10] As show above in Table 1, marginal transmission congestion costs and marginal transmission losses are a component of total cost of energy (LMP). In congested areas, such as Met-Ed, transmission congestion costs are approximately 2% of the LMP. In less congested areas, such as Penn Power, there is a transmission congestion *credit* of approximately 3%. Similarly, marginal transmission losses can range from a *cost* of about 2% of the LMP to a *credit* of approximately 1% of the LMP.

Table 2
Wholesale Costs of Electricity in 2010 and 2011[11]
($/MWh)

	2010				2011				
	PJM	Penelec	Met-Ed	APS	PJM	Penelec	Met-Ed	APS	Penn Power
Energy	$48.35	$45.17	$53.47	$47.63	$45.94	$45.12	$49.51	$45.49	$42.92
Congestion	*$0.08*	*-$1.73*	*$4.22*	*$0.01*	*$0.05*	*-$0.25*	*$2.87*	*$0.05*	*-$2.56*
Loss	*$0.04*	*-$0.28*	*$1.05*	*-$0.26*	*$0.02*	*$0.38*	*$0.82*	*-$0.13*	*-$0.51*
Capacity	$12.15	$14.04	$14.04	$9.54	$9.72	$9.68	$9.68	$9.68	$7.21
Transmission Service Charges	$4.00	$2.42	$2.42	$2.62	$4.42	$2.46	$2.46	$2.65	$2.36
Operating Reserves (Uplift)	$0.79	$1.15	$1.15	$1.24	$0.79	$1.06	$1.06	$1.06	$1.06
Reactive	$0.44	$0.19	$0.51	$0.45	$0.42	$0.19	$0.51	$0.46	$0.39
PJM Administrative Fees	$0.36	$0.36	$0.36	$0.36	$0.37	$0.37	$0.37	$0.37	$0.37
Regulation	$0.35	$0.35	$0.35	$0.35	$0.32	$0.32	$0.32	$0.32	$0.32
Transmission Enhancement Cost Recovery	*$0.21*	*$0.03*	*$0.04*	*$0.05*	*$0.29*	*$0.06*	*$0.07*	*$0.07*	*N/A*
Synchronized Reserves	$0.06	$0.12	$0.12	$0.12	$0.09	$0.19	$0.19	$0.19	$0.00
Transmssion Owner (Schedule 1A)	$0.09	$0.08	$0.08	N/A	$0.09	$0.08	$0.08	N/A	$0.03
Day Ahead Scheduling Reserve (DASR)	$0.01	$0.01	$0.01	$0.01	$0.05	$0.05	$0.05	$0.05	$0.05
Black Start	$0.02	$0.02	$0.03	$0.00	$0.02	$0.02	$0.03	$0.00	$0.00
NERC/RFC	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.01	N/A	N/A	N/A	$0.01	N/A	N/A	N/A	N/A
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$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
Non-Synchronized Reserves	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	$66.86	$63.97	$72.61	$62.40	$62.55	$59.61	$64.35	$60.36	$54.72

Between 2010 and 2012, the total price of wholesale power fell by an average of 27% for PJM as a whole. Similar to the trend between 2011 and 2012, Met-Ed, APS, and Penn Power saw larger decreases in wholesale costs than PJM, with a significant decrease in capacity and energy prices. Smaller components of total wholesale costs saw an increase from 2010 to 2012. For example, the average cost of Day-Ahead Scheduling Reserves increased fivefold, although as a percentage of total wholesale cost, they have very little impact. Table 3 shows the percentage change in wholesale cost components from 2010 to 2012 and from 2011 to 2012.

[11] Source: Monitoring Analytics (2011), Monitoring Analytics (2012), Monitoring Analytics (2013), and *Brattle* analysis.

Table 3
Percent Change in Wholesale Cost Components[12]

	% Change (2012 vs. 2010)				% Change (2012 vs. 2011)				
	PJM	Penelec	Met-Ed	APS	PJM	Penelec	Met-Ed	APS	Penn Power
Energy	-27.1%	-22.3%	-32.1%	-26.8%	-23.3%	-22.2%	-26.7%	-23.4%	-23.1%
Congestion	-52.0%	-93.3%	-84.2%	292.7%	-26.8%	-53.0%	-76.7%	-34.7%	-66.1%
Loss	-61.1%	-301.0%	-49.6%	-63.6%	-40.3%	45.7%	-35.9%	-28.1%	-58.0%
Capacity	-50.2%	-3.0%	-3.0%	-61.4%	-37.8%	40.7%	40.7%	-61.9%	-48.9%
Transmission Service Charges	19.5%	4.2%	4.2%	3.0%	8.1%	2.5%	2.5%	1.8%	19.1%
Operating Reserves (Uplift)	0.0%	-14.9%	-14.9%	-17.4%	0.0%	-7.3%	-7.3%	-3.1%	-3.1%
Reactive	-2.3%	48.2%	2.3%	10.4%	2.4%	46.8%	1.9%	9.1%	-41.5%
PJM Administrative Fees	16.7%	16.7%	16.7%	16.7%	13.5%	13.5%	13.5%	13.5%	13.5%
Regulation	-25.7%	-25.7%	-25.7%	-25.7%	-18.8%	-18.8%	-18.8%	-18.8%	-18.8%
Transmission Enhancement Cost Recovery	61.9%	124.7%	97.4%	79.4%	17.2%	34.9%	23.8%	20.0%	-
Synchronized Reserves	-33.3%	-35.0%	-35.0%	-35.0%	-55.6%	-59.9%	-59.9%	-59.9%	92.1%
Transmission Owner (Schedule 1A)	-11.1%	0.0%	0.0%	-	-11.1%	0.0%	0.0%	-	6.2%
Day Ahead Scheduling Reserve (DASR)	400.0%	400.0%	400.0%	400.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Black Start	50.0%	29.2%	12.3%	45.3%	50.0%	50.7%	4.8%	40.5%	46.5%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion	0.0%	-	-	-	0.0%	-	-	-	-
Load Response	170.6%	54883.9%	1097.7%	739.9%	332.0%	14713.5%	1097.7%	5926.5%	194.1%
Transmission Facility Charges	-	-	-	-	-	-	-	-	-
Non-Synchronized Reserves	-	-	-	-	-	-	-	-	-
Total	-27.4%	-16.3%	-24.3%	-29.9%	-22.4%	-10.2%	-14.5%	-27.6%	-23.9%

II.B. WHOLESALE ENERGY PRICES

The LMP at any pricing node within the PJM system is comprised of three cost components: marginal energy, marginal transmission loss, and marginal transmission congestion. The marginal energy component is the incremental cost of energy without considering the cost of transmission losses and transmission congestion. The marginal transmission loss component captures the marginal cost of transmission system losses specific to a given location, while the marginal transmission congestion component captures the impact that load or generation has on transmission constraints. Table 4 and Table 5 summarize the zonal day-ahead and real-time simple average LMPs and their components for the calendar years 2010 through 2012. The difference between average real-time and day-ahead LMPs is small, typically under $1.00 per MWh. As in the case of overall wholesale cost of power, we observe similar trends in the LMPs over time with energy prices falling between 2010 and 2012. Penn Power is the only outlier in this case, experiencing an 11% increase in day-ahead prices from 2010 to 2011. With the exception of Penn Power, between 2010 and 2011 the Companies' zones experienced a 3% to 6% decrease in day-ahead prices, and 0.3% to 7% decrease in real-time prices. Between 2011 and 2012, they saw an average decrease of 18% to 26% in both day-ahead and real-time energy prices. In 2012, Met-Ed remained the zone with the highest average energy price, primarily due to transmission congestion.

12 Source: Monitoring Analytics (2011), Monitoring Analytics (2012), Monitoring Analytics (2013), and *Brattle* analysis.

Table 4
Zonal Day-Ahead, Simple Average LMP Components
Calendar Years 2010 - 2012[13,14]
($/MWh)

	2010				2011				2012			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$44.42	$44.61	$0.06	-$0.25	$42.96	$42.72	$0.29	-$0.05	$32.82	$32.72	$0.14	-$0.04
Penn Power	$35.16	$33.28	$1.14	$0.75	$38.95	$41.59	-$1.46	-$1.18	$31.83	$32.72	-$0.56	-$0.34
Met-Ed	$48.98	$44.61	$3.13	$1.24	$45.82	$42.72	$2.37	$0.72	$33.68	$32.72	$0.37	$0.59
Penelec	$43.94	$44.61	-$0.68	$0.01	$42.79	$42.72	-$0.17	$0.24	$33.41	$32.72	$0.10	$0.59

Table 5
Zonal Real-Time, Simple Average LMP Components
Calendar Years 2010 - 2012[15]
($/MWh)

	2010				2011				2012			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$44.62	$44.72	$0.12	-$0.22	$42.91	$42.77	$0.23	-$0.09	$33.08	$33.06	$0.09	-$0.07
Penn Power	$34.12	$32.31	$1.14	$0.68	$38.66	$41.19	-$1.88	-$0.66	$31.69	$33.06	-$0.81	-$0.56
Met-Ed	$49.14	$44.72	$3.47	$0.95	$45.82	$42.77	$2.34	$0.72	$33.96	$33.06	$0.44	$0.46
Penelec	$43.07	$44.72	-$1.42	-$0.24	$42.95	$42.77	-$0.19	$0.37	$33.50	$33.06	-$0.10	$0.54

Table 6 and Table 7 summarize the zonal day-ahead and real-time, load-weighted average LMPs by component for the calendar years 2010 through 2012. As prices tend to be higher in high-load hours, the load-weighted LMPs are typically higher than the simple average LMPs. This is demonstrated across years as well as across load zones.

[13] 2010 and 2011 values, p. 393, Table G-5 Zonal Day-ahead, Monitoring Analytics (2012). 2012 values, p. 423, Monitoring Analytics (2013).

[14] LMPs for the Penn Power portion of ATSI Zone are simple annual averages from *Ventyx: Energy and Velocity*.

[15] 2010 and 2011 values, p. 392, Table G-2 Zonal Real-Time, Monitoring Analytics (2012). 2012 values, p. 423, Monitoring Analytics (2013).

Table 6
Zonal Day-Ahead, Load-Weighted Average LMP Components
Calendar Years 2010 - 2012[16,17]
($/MWh)

	2010				2011				2012			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$47.08	$47.42	-$0.05	-$0.28	$47.66	$47.96	-$0.16	-$0.15	$34.29	$34.26	$0.09	-$0.06
Penn Power	$37.36	$35.51	$1.09	$0.76	$46.14	$50.87	-$3.07	-$1.66	$33.55	$34.32	-$0.69	-$0.08
Met-Ed	$52.78	$47.72	$3.70	$1.35	$52.37	$48.08	$3.28	$1.01	$35.44	$34.29	$0.50	$0.65
Penelec	$45.52	$46.41	-$0.88	$0.00	$47.41	$47.72	-$0.56	$0.24	$34.69	$33.95	$0.12	$0.62

Table 7
Zonal Real-Time, Load-Weighted Average LMP Components
Calendar Years 2010 - 2012[18,19]
($/MWh)

	2010				2011				2012			
Zone	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss	LMP	Energy	Congestion	Loss
APS	$47.08	$47.42	-$0.05	-$0.28	$48.57	$48.99	-$0.22	-$0.20	$34.86	$34.91	$0.04	-$0.09
Penn Power	$36.11	$34.33	$1.10	$0.69	$46.88	$51.24	-$3.85	-$0.51	$34.42	$34.99	-$0.78	$0.21
Met-Ed	$53.47	$48.20	$4.22	$1.05	$53.64	$49.22	$3.42	$1.00	$36.30	$35.11	$0.67	$0.53
Penelec	$45.17	$47.19	-$1.73	-$0.28	$48.18	$48.27	-$0.46	$0.37	$35.10	$34.66	-$0.12	$0.56

Table 8 contains the zonal peak and off-peak simple average LMPs for the day-ahead and real-time energy markets in 2012. In the day-ahead market, average zonal peak-hour LMPs decreased by 24% from 2011 to 2012, while off-peak LMPs decreased by 22%. Average real-time, peak-hour LMPs decreased by 22%, and off-peak LMPs decreased by 23%. Of the Companies' zones, the Met-Ed Zone continues to show the largest positive transmission congestion cost component for both peak- and off-peak hours.

16 2010 and 2011 values, p. 268, Table 10-4 Zonal and PJM day-ahead, Monitoring Analytics (2012). 2012 values, p. 299, Monitoring Analytics (2013).

17 2010 ATSI values are load-weighted averages from the FirstEnergy zone in MISO.

18 2010 and 2011 values, p. 268, Table 10-3 Zonal and PJM real-time, Monitoring Analytics (2012). 2012 values, p. 299, Monitoring Analytics (2013).

19 Note that load-weighted average LMPs listed in Table 7 differ from average energy costs reported in Tables 1 and 2. The differences are due to the different methodology used by PJM's market monitor to calculate load-weighted averages and differences in estimated and meter corrected hourly loads used to weight the hourly prices.

Table 8
Zonal On- and Off-Peak Average Day-Ahead and Real-Time LMPs in 2012
($/MWh)

2012 Day-Ahead Simple Average								
Zone	LMP		Energy		Congestion		Loss	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
APS	$38.20	$28.16	$38.31	$27.87	-$0.01	$0.28	-$0.10	$0.01
Penn Power	$36.99	$27.35	$38.31	$27.87	-$0.95	-$0.22	-$0.37	-$0.31
Met-Ed	$39.95	$28.24	$38.31	$27.87	$0.82	-$0.02	$0.82	$0.38
Penelec	$39.14	$28.45	$38.31	$27.87	$0.10	$0.10	$0.73	$0.47
PJM RTO	$38.46	$27.88	$38.31	$27.87	$0.16	$0.02	-$0.01	-$0.02

2012 Real-Time Simple Average								
Zone	LMP		Energy		Congestion		Loss	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
APS	$39.51	$27.51	$39.78	$27.24	-$0.13	$0.29	-$0.15	-$0.01
Penn Power	$37.72	$26.45	$39.78	$27.24	-$1.41	-$0.30	-$0.65	-$0.49
Met-Ed	$41.31	$27.59	$39.78	$27.24	$0.90	$0.03	$0.63	$0.32
Penelec	$40.27	$27.62	$39.78	$27.24	-$0.16	-$0.06	$0.65	$0.44
PJM RTO	$39.83	$27.29	$39.78	$27.24	$0.04	$0.04	$0.02	$0.01

As reflected in the transmission congestion component of LMPs, transmission congestion may arise in both the day-ahead and the real-time (balancing) market. Loads located on the constrained side of a transmission constraint pay a transmission congestion cost, while loads located on the unconstrained side of a constraint receive a transmission congestion credit. Similarly, the energy price paid to generators in the constrained area includes a transmission congestion credit, while generators located in the uncongested part of the market are assessed a transmission congestion cost in terms of lower energy payments. Transmission congestion costs and credits for loads and generators, as well as explicit transmission congestion costs associated with point-to-point energy transactions, may be summed up by zone to yield a net transmission congestion cost for the zone.[20] The net transmission congestion cost for a given zone may be both positive and negative. The sign of the net zonal transmission congestion cost does not necessarily reveal whether loads in the given zone tend to pay a transmission congestion cost or receive a transmission congestion credit, but rather is a reflection of the relative magnitude of transmission congestion costs and credits paid and received by all market participants located within the zone.

Net zonal transmission congestion costs and total net transmission congestion costs for PJM are summarized in Table 9. Overall, total net transmission congestion costs in PJM were $529 million in 2012, a decrease of 47% from 2011. Similarly, day-ahead congestion costs decreased

[20] Note that inadvertent interchange between PJM and its neighboring markets may generate additional transmission congestion costs that are not reflected in LMPs and are charged to market participants separately.

by over $400 million, falling 37% from 2011. Balancing market congestion costs fell by only 2% from 2011 to 2012. Transmission congestion costs have continued to significantly decrease since 2010, when net transmission congestion costs were $1,423 million.

Table 9
Zonal Transmission congestion Costs in 2011 and 2012[21]
(million $)

Total Congestion Costs in 2012

	Day-Ahead Market				Balancing Market				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
APS	$5.1	-$52.6	$8.7	$66.4	$3.7	$9.1	-$8.4	-$13.8	$52.5
ATSI	-$50.7	-$55.7	$1.4	$6.5	$2.7	$6.0	$0.4	-$3.0	$3.5
Met-Ed	$9.4	-$0.6	$1.5	$11.4	$0.0	$1.9	-$2.6	-$4.5	$7.0
Penelec	-$2.5	-$35.0	$2.4	$34.8	$0.9	$0.8	-$2.0	-$1.9	$32.9
PJM Total	$135.5	-$512.5	$131.9	$779.9	$3.0	$68.5	-$185.4	-$250.9	$529.0

Total Congestion Costs in 2011

	Day-Ahead Market				Balancing Market				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
APS	$6.9	-$143.7	-$2.6	$148.1	$5.7	$8.0	-$1.8	-$4.1	$143.9
ATSI	-$73.8	-$78.5	$1.6	$6.3	$2.1	$8.0	-$3.3	-$9.2	-$2.9
Met-Ed	$46.0	$48.1	$0.5	-$1.7	$1.7	$0.8	-$0.7	$0.2	-$1.5
Penelec	-$45.9	-$108.1	$0.7	$62.9	$4.2	$7.2	-$1.2	-$4.2	$58.7
PJM Total	$36.3	-$1,141.8	$66.9	$1,245.0	$75.9	$131.9	-$190.0	-$246.0	$999.0

Total Congestion Costs in 2010

	Day-Ahead Market				Balancing Market				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
APS	-$5.9	-$313.4	$0.8	$308.4	$11.7	$32.9	-$5.2	-$26.4	$282.0
ATSI	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Met-Ed	$62.9	$53.9	$1.3	$10.4	-$0.9	$0.1	-$1.6	-$2.5	$7.8
Penelec	-$124.0	-$221.9	$1.0	$98.9	$17.1	$8.6	-$0.7	$7.8	$106.7
PJM Total	$251.4	-$1,364.8	$96.9	$1,713.1	-$0.2	$110.1	-$179.3	-$289.6	$1,423.6

In 2012, all of the Companies' zones had a net zonal transmission congestion cost. Net zonal transmission congestion costs can be attributed to individual transmission facilities that constrain the most economic dispatch. The list of most congested transmission facilities for each zone, including associated transmission congestion costs, is summarized in Appendix A to this report. For each zone, the transmission constraints that have the largest transmission congestion cost impact are also among the top constraints for PJM as a whole. For example, the AP South interface, which has the highest transmission congestion impact in PJM, contributing 16.1% to

21 Source: Monitoring Analytics (2013), Table G-6 and Table G-7.

the total net PJM transmission congestion cost, approximately $68 million in costs,[22] is also the top constraint for the APS and ATSI Zones. The AP South interface is usually responsible for price separation between the eastern and western parts of PJM. Other major interfaces are also among the largest contributors to zonal transmission congestion. The top constraint in the Met-Ed Zone is the Hunterstown transformer, while the West Interface is the top constraint for the Penelec Zone. These constraints are typically among the top three constraints in PJM in terms of their impact on transmission congestion costs.

The new shortage pricing mechanisms, implemented by PJM, raise the combined energy and ancillary services markets offer cap to $2,700/MWh during periods of reserve shortages. As discussed in more detail in Section IV.B, reserve shortages will translate into higher energy prices through the use of reserve penalty factors. No reserve shortages occurred in 2012; therefore, shortage pricing was not triggered.

II.C. WHOLESALE CAPACITY PRICES

PJM operates the RPM capacity market that consists of three-year forward Base Residual Auctions and up to three incremental auctions[23] for each year. Capacity is procured for RPM delivery years, which run from June 1 through May 31 of the following calendar year. Consequently, for calendar year 2012, PJM procured capacity in two BRAs: one for delivery year 2011/12 held in May 2008, and one for delivery year 2012/13 held in May 2009. In addition, a 1st and a 3rd incremental auction was held for delivery year 2011/12 in June 2009 and during the months of February and March 2011, respectively. For the 2012/13 delivery year, 1st, 2nd, and 3rd incremental auctions were held in September 2010, July 2011, and during the months of February and March 2012, respectively.[24]

Average capacity costs reported in Table 1 are derived from the total procurement costs in all RPM capacity auctions. Capacity prices in these auctions are expressed in terms of dollars per MW per day ($/MW-day). Capacity prices may vary by LDAs, capacity zones that represent potentially congested parts of the PJM footprint. Each LDA is defined as a collection of zones and subzones. The composition and geography of LDAs modeled in RPM is illustrated in Figure 3. As shown, Met-Ed and Penelec zones are part of the MAAC LDA, while APS and Penn Power (part of the ATSI Zone) are part of the unconstrained RTO.[25]

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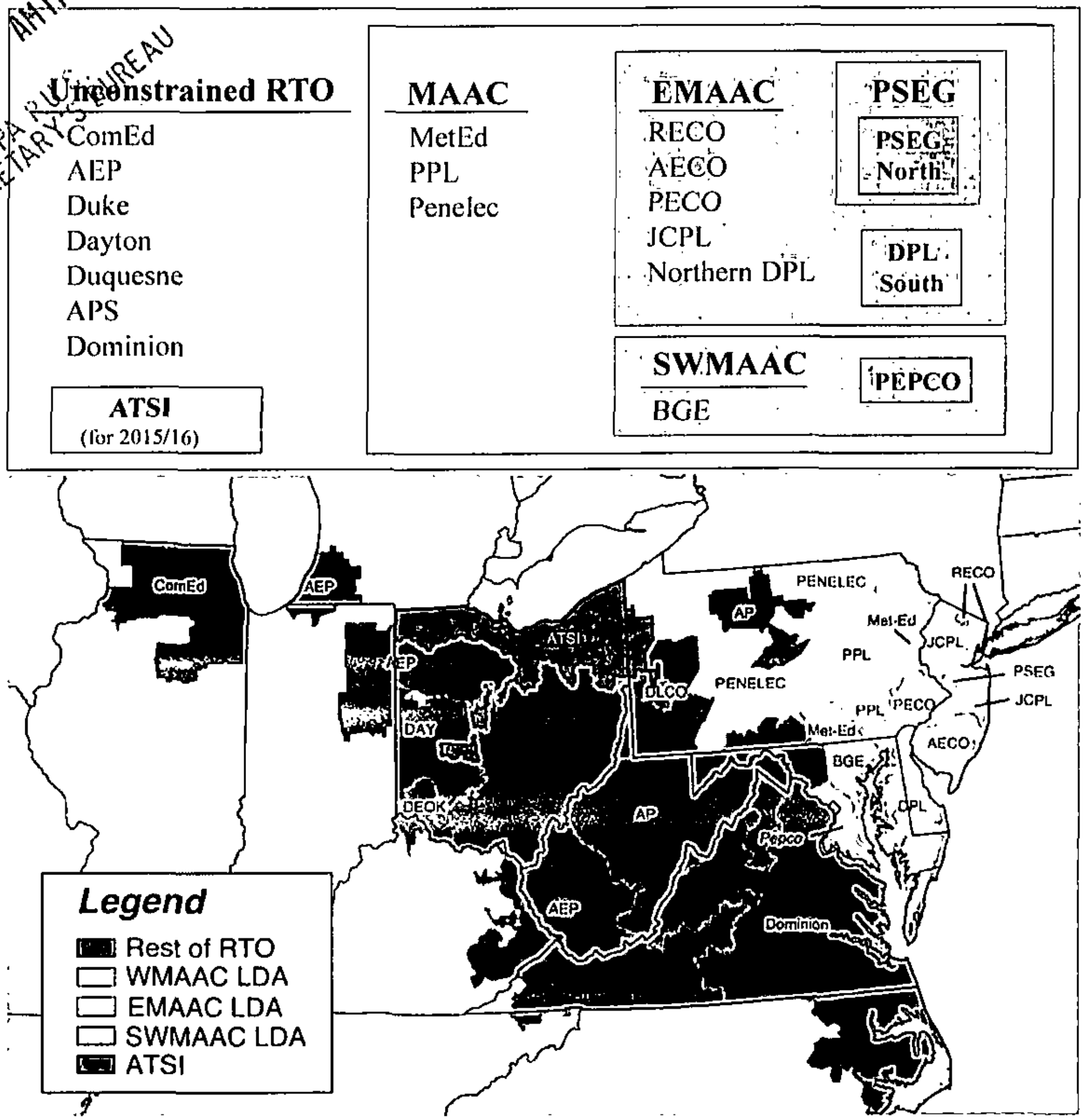
22 PJM 2012 SOM, Section 1.

23 Following the BRA, up to three incremental auctions are held for each delivery year – 20 months, 10 months, and 4 months before each delivery year – that can be used by market participants to adjust their commitments and by PJM to procure additional capacity.

24 http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-auction-schedule.ashx

25 Potentially, any load zone could be defined as an LDA. In the 2015/16 BRA held in May 2012, PJM modeled ATSI Zone as a separate LDA.

Figure 3[26]
Locational Deliverability Areas in PJM



Capacity prices relevant to the Companies' zones from each RPM auction held for delivery during some part of the calendar year 2012 are summarized in Table 10. In RPM auctions held for the delivery year 2011/12, all of the Companies' zones remained in the unconstrained part of the RTO and, as a result, paid the same capacity price of $110/MW-day. Price separation occurred between MAAC and the rest of the RTO in the BRA held for the 2012/13 delivery year. While the capacity price in MAAC (including Met-Ed and Penelec) was $133.37/MW-day, the capacity price in the unconstrained part of the RTO (including APS) was only $16.46/MW-day. Since the ATSI Zone did not become part of PJM until 2011, it was not included in the BRAs held for the 2011/12 and 2012/13 delivery years. For these two delivery years, transitional ATSI Zone FRR integration auctions were held in March 2010, resulting in capacity prices of $108.89 and $20.46/MW-day, respectively.

[26] Source: Monitoring Analytics (2013), Figure 4-1

Historically, incremental auctions have cleared at prices below BRA clearing prices. This trend continued in the 2011/12 and 2012/13 delivery years. Cleared volumes in incremental auctions are much lower than in the BRAs, and therefore their impact on overall capacity costs is relatively small.

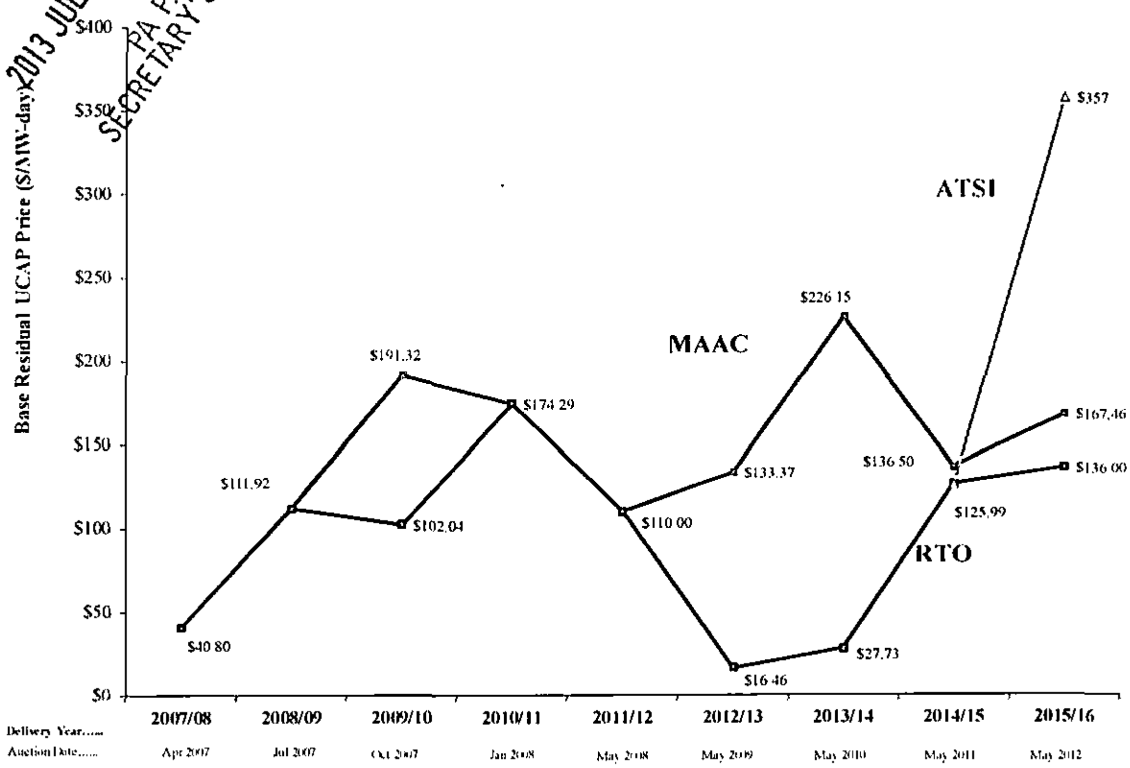
Table 10
Wholesale Capacity Prices in 2012
($/MW-day)

Delivery Year	LDA	Base Residual Auction	ATSI FRR Integration Auction	1st Incremental Auction	2nd Incremental Auction	3rd Incremental Auction
2011/12	RTO	$110.00	$108.89	$55.00	N/A	$5.00
2012/13	RTO	$16.46	$20.46	$16.46	$13.01	$2.51
	MAAC	$133.37	$20.46	$16.46	$13.01	$2.51

Figure 4 shows the BRA auction clearing prices for MAAC, ATSI, and the unconstrained part of PJM (rest of the RTO) from the first RPM delivery year 2007/08 through 2015/16. Although ATSI was included in the BRAs starting with the 2013/14 delivery year, 2015/16 was the first delivery year when ATSI was modeled as a separate LDA.[27] Capacity prices in MAAC (including Penelec and Met-Ed zones) remained around the long-term average during 2012, while capacity prices in the unconstrained part of PJM (including APS) significantly fell. By the 2015/16 delivery year, capacity prices in MAAC and the rest of the RTO start to converge, while the capacity price in ATSI rises to $357/MW-day. Note that Figure 4 shows BRA capacity prices for annual capacity resources only. Capacity prices applicable to extended summer and limited capacity resources may be lower and are discussed in more detail in Section III.B.

[27] An LDA is modeled in the BRA and has a separate capacity demand (VRR) curve if: (1) its CETO/CETL margin is less than 115%; (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; (3) the LDA is likely to have a locational price adder based on a PJM analysis using historic offer price levels; or (4) the LDA is EMAAC, SWMAAC, and MAAC.

Figure 4
Evolution of Base Residual Auction Clearing Prices in MAAC and Unconstrained RTO



II.D. OTHER WHOLESALE COSTS

PJM Transmission Service Charges are not market-based, but instead are based on annual transmission revenue requirements by a transmission owner, or transmission zone. This charge includes network integration services (serving network load) and both firm and non-firm point-to-point transmission services. These charges for the Companies' zones are consistently lower than the PJM average.

Apart from energy, capacity and the transmission service charges, the remaining charges typically make up between 5% and 6% of wholesale power cost. The operating reserve (uplift) component is the average price per MWh of operating reserve charges. It is broken into three components: day-ahead, synchronous condensing and balancing charges. The balancing portion is broken down further into generation and transactions, lost opportunity cost, canceled resources, and charges due to local transmission constraints. The generation and transactions category further separates into reliability charges, deviation charges, and lost opportunity costs and canceled resource charges. Of the hierarchy above, the only sub-categories that are zone-specific are the reliability charges and the deviation charges, which are broken down into the RTO, East and West (for both real-time load and real-time exports). The remaining charges are allocated on a RTO-wide basis.

Zone-specific ancillary services charges include charges for reactive power, synchronized reserves, and black start reserves. Reactive power and black start reserves are not market-based charges. PJM ensures the availability of black start reserves by charging transmission customers by load ratio share and compensating black start unit owners according to specific revenue requirements.[28] Similarly, PJM ensures the adequacy of reactive power by specific revenue requirements by load zone. Synchronized reserves, along with regulation, are cleared in the real-time market. The DASR market satisfies the supplemental reserve requirement, which allows generation resources to receive compensation based upon cleared supply at a market-clearing price. For a more detailed discussion of PJM ancillary services markets, see Section IV.

The remaining components in the cost of wholesale power do not change by zone, and are often too small to recognize the distinction between zones or add a significant amount to the total wholesale cost of power.

III. RPM CAPACITY MARKET

III.A. INTRODUCTION

The RPM capacity market is designed to ensure that reliability and resource adequacy requirements are achieved at the lowest possible cost. The demand for capacity is based on an administratively determined, downward-sloping demand curve such that the market price of capacity rises as the PJM capacity reserve margin increases, and falls as the reserve margin decreases. The capacity demand curve is anchored at the net cost of new entry ("Net CONE") in such a manner that the capacity-clearing price equals Net CONE approximately at the target reserve level. Net CONE represents the amount of revenue in $/kW-year that a new entrant must earn in capacity payments, in addition to net energy and ancillary services revenues, in order to recover the investment cost levelized over the lifetime of the plant. Net CONE is calculated by subtracting energy and ancillary services revenues from gross investment cost ("Gross CONE"). As a result of this offset, the PJM capacity market interacts with the energy and ancillary services markets. Whenever net revenues earned in the energy and ancillary services markets rise, the Net CONE will decrease, resulting in a reduced demand for capacity.[29] At the same time, capacity suppliers earning higher margins in the energy and ancillary services markets will be able to lower their offer prices in the capacity auctions. The combined effect is that as the net revenues in the energy and ancillary services market rise, capacity prices will tend to fall.

The RPM capacity market interacts with and works in tandem with the PJM energy market to provide price and revenue signals to attract new and retain existing capacity. It signals the need for new capacity when new capacity is needed; once the target reserve level is reached, the demand curve and the corresponding capacity prices drop off steeply. Another key feature of the RPM market design is that it signals scarcity through locational prices. These prices signal not just the need for new capacity, but also the attractiveness of a particular location for that capacity.

28 Monitoring Analytics (2013), p. 291.

29 In the PJM capacity market, the Net Energy and Ancillary Services ("E&AS") revenue offset is based on the historical average of the three most recent calendar years. Gross CONE values are evaluated every three years. Unless CONE values are revised for a given delivery year, the prior-year CONE value, escalated using the most recently published twelve-month change in Total Other Plant Production Plant Index shown in the Handy Whitman Index ("HWI") of Public Utility Construction Costs, is used. PJM (2013a), Sections 3.3.1 and 3.3.2.

Lastly, the RPM capacity market allows a range of resource types to meet resource adequacy requirements. Given the forward nature of the market, not just existing but also planned resources are allowed to participate. In addition, resources that are available only on a seasonal basis, such as extended summer and limited capacity resources, are also allowed to participate. Furthermore, in addition to traditional generating capacity, demand resources, energy efficiency, and transmission upgrades may be also offered in the RPM capacity auctions.

These basic features of the RPM design remained in place during 2012. In addition, two significant changes were made to the capacity market design. The first change is related to the 2.5% short-term resource procurement target ("STRPT") that was first implemented for the 2012/13 delivery year.[30] STRPT represents the portion of the overall RTO capacity requirement that is held back from the BRA and procured in incremental auctions. The 2.5% "holdback" is the amount of capacity that is subtracted from the BRA capacity demand curve and procured in the incremental auctions, with 0.5% procured in the first incremental auction approximately two years prior to the delivery year, 0.5% in the second incremental auction about one year prior to the delivery year, and 1.5% in the third incremental auction, just prior to the delivery year. Starting with the 2014/15 BRA, PJM began subtracting STRPT not only from the VRR curve, but also from the minimum annual and minimum extended summer resource requirements. This approach meant that the resources procured in the incremental auctions were primarily for higher quality (*i.e.*, annual) capacity resources. In its second triennial review of the RPM capacity market,[31] *Brattle* recommended that PJM retain the 2.5% holdback, but eliminate any holdbacks that apply to specific resource categories. On December 1, 2011, PJM filed proposed tariff revisions to implement this recommendation with the FERC.[32] The FERC approved the PJM filing on January 30, 2012.[33] The changes increased the minimum annual and summer resources requirements in the 2015/16 BRA by 2.5% relative to the minimum requirements in place for the 2014/2015 BRA.

The second significant change to the RPM design affected the Minimum Offer Price Rule ("MOPR"). The 2015/2016 BRA, held in May 2012, was the second BRA conducted under the MOPR that was revised effective April 13, 2011,[34] and the first BRA conducted under the subsequent FERC orders that included a clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process. The purpose of the MOPR is to mitigate the impact of new out-of-market capacity (*e.g.*, capacity procured through long-term contracts by states) that would otherwise artificially depress the market price of capacity. The MOPR applies to sell offers of certain planned generation capacity, including planned upgrades of existing generators.[35] Unless a MOPR exception is requested by the supplier and approved by the market monitor, a sell offer submitted in any BRA or incremental auction that is less than 90% of the applicable Net CONE is set equal to 90% of the Net CONE. In its filing on May 12,

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30 STRPT was introduced primarily to accommodate demand-side resources that had never before had to make three-year forward commitments. Generation owners, almost all transmission owners, and the Independent Market Monitor have voiced their concerns over the 2.5% holdback and suggested that it should be eliminated. See *Brattle* (2011), pp. 143-147.

31 See *Brattle* (2011).

32 PJM (2011a).

33 FERC (2012a).

34 FERC (2011a).

35 See PJM (2013a), Section 5.3.5.

2011, PJM clarified the procedures and criteria by which planned capacity resources could seek an exception from the MOPR.[36] PJM's filing was approved by FERC on November 17, 2011.[37]

III.B. Results of PJM Capacity Auctions in 2012

Four RPM auctions were held during the 2012 calendar year: the BRA for the 2015/16 delivery year; the 1st incremental auction for the 2014/15 delivery year; the 2nd incremental auction for the 2013/14 delivery year; and the 3rd incremental auction for the 2012/13 delivery year.

As shown in Figure 4, the BRA for 2015/16 cleared at an RTO price of $136/MW-day, a MAAC price of $167.46/MW-day, and the ATSI Zone price of $357/MW-day.[38] Compared to the 2014/15 BRA, capacity prices in all three LDAs were higher. The largest capacity price increase occurred in the ATSI Zone, which in the previous 2014/15 BRA cleared at $125.99/MW-day as part of the unconstrained RTO. Capacity prices in MAAC and the rest of the RTO increased by $30.96/MW-day and $10.01/MW-day, respectively. PJM attributed the moderate increases to the MAAC and unconstrained RTO capacity prices to a number of factors that had largely offsetting impacts.[39] The load forecast, and thus the RTO reliability requirement, *decreased* to 177,184 MW, which was over 900 MW lower than in the 2014/15 BRA. Demand-side factors that, all else equal, had the tendency to *increase* the RPM capacity price include:

- *Increase* in the total demand for capacity in the BRA due to AEP Ohio and Duke Ohio choosing to directly participate in the RPM auctions, instead of electing for the FRR alternative, as they did previously.
- *Increase* in the minimum amount of annual and extended summer requirements procured in the BRA, as a result of the market design change discussed above.
- *Increase* in the Net CONE values by 7.6% (for the RTO) and by 5.3% to 6.5% (depending on the LDA) over the 2013/2014 values. This was caused by an update to the energy and ancillary services revenue offset and an increase in the gross CONE value of 4.9% (adjusted using the most recently published twelve-month change in Total Other Plant Production Plant Index shown in the Handy Whitman ("HWI") of Public Utility Construction Costs).[40]

Supply-side factors that, all else equal, had the tendency to *increase* the RPM capacity price include:

- *Decrease* in capacity supply due to upcoming environmental regulations, primarily the Mercury and Air Toxics Standard ("MATS"). Over 14,000 MW of generation retirements are expected, starting with the 2015/16 delivery year.

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36 PJM (2011b).

37 FERC (2011b).

38 These are resource clearing prices for annual resources.

39 PJM 2015/2016 RPM Base Residual Auction Results Report, May 2012, pp. 25-28.

- *Increase* in the cost of capacity supply due to increases in the default Avoidable Cost Rate ("ACR") values, as a result of the annual ACR update using the ten-year annual average rate of change in the Handy-Whitman Index of Public Utility costs.[41]
- *Increase* in the cost of capacity supply due to increases in the default ACR values for suppliers, which include the cost of investments necessary to comply with upcoming environmental regulations, such as the MATS and New Jersey's High Electricity Demand Day ("HEDD") rule.[42]

Supply-side factors that, all else equal, had the tendency to *decrease* the RPM capacity price include:

- *Increase* in the aggregate capacity supply by 10,872 MW as capacity resources located in the DEOK and AEP zones, previously committed under the FRR option, were included in the 2015/16 BRA.
- *Increase* in the total offered demand response and energy efficiency capacity by 5,000 MW between the 2014/15 BRA and the 2015/16 BRA.
- *Increase* in the total offered capacity from new resources, as well as uprates at existing facilities. The 2015/2016 BRA attracted over 8,200 MW of offers from new generation capacity in the form of new facilities and uprates at existing facilities.[43]

Unlike in the unconstrained part of the RTO and in the MAAC LDA, the above factors did not have an offsetting impact in the ATSI Zone. The ATSI LDA experienced a large concentration of generator retirements which, coupled with limited transfer capabilities to allow capacity imports as well as relatively short lead time for entry by new capacity, led to high locational capacity prices.

The 2015/16 BRA was the second BRA that incorporated differentiated capacity products. In addition to annual capacity resources, suppliers may submit offers for Extended Summer Demand Resources ("EXTENDED SUMMER DR") and Limited Demand Resource ("LIMITED DR"). Unlike Limited DR, which PJM may activate only up to ten times per year and only for a duration of up to six hours per event, Annual and Extended Summer DR can be called upon more frequently and for longer durations.[44] As discussed in Section III.A, a minimum amount of annual and extended summer resources is established for each BRA. If these minimum constraints bind, the prices of annual, extended summer and limited DR resources may diverge. In the 2015/16 BRA, Extended Summer DR and annual resources (generation and Annual DR), cleared at the same price: $167.46/MW-day in MAAC, and $136/MW-day in the unconstrained RTO. Limited DR cleared at a lower price, $118.54/MW-day, in both LDAs.

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41 ACR values are used to calculate capacity market offer caps.

42 *Ibid.*

43 *Ibid.*

44 Annual DR must be able to respond to PJM calls in all seasons, while Extended Summer DR must be able to respond to an unlimited number of calls during the summer period. Extended Summer resources include all Annual resources and Extended Summer DR (i.e., all resources that must be available at least as often as Extended Summer DR). All generating capacity is considered to be Annual resource.

III.C. Cost of New Entry and Revenue Adequacy

Net revenue is the total wholesale market revenue earned from PJM energy, capacity, and ancillary services markets, including a return on investment, depreciation, and taxes, net of variable costs. Net revenue is the generator's net income that can be used to cover its fixed costs. As such, net revenue is an indicator of profitability. Investment in new generation will be incented only if net revenue is expected to cover the generator's fixed cost in the long term. For an existing generator, net revenue can be compared to the fixed costs that can be avoided by shutting down the plant; if net revenue is consistently less than avoidable fixed costs, the generator is considered to be at a risk of retirement.

Net revenues vary from year to year, depending on market outcomes, and also by generating technology. PJM's market monitor has traditionally performed annual assessments of revenue adequacy of hypothetical new entrant plants for three reference technologies: (1) gas-fired combustion turbines, (2) combined cycle gas plants, and (3) coal plants.[45] Starting with the 2012 State of the Market Report, the market monitor began reporting results of its net revenue analysis for other generation technologies, including new entrant integrated gasification combined cycle (IGCC) and nuclear plants, as well as new entrant wind and solar installations. Net revenues are calculated using a hypothetical dispatch against historical day-ahead and real-time energy prices for each calendar year.

Table 11 summarizes net revenues for the Companies' zones and for PJM as a whole for the calendar years 2010 through 2012. The adequacy of net revenues to incent investment in new generation can be assessed by comparing net revenue estimates to the levelized fixed costs of each plant type.[46] Net revenues as a percentage of these levelized fixed costs are shown in the rightmost three columns of Table 11. During the period from 2010 through 2012, only new combined cycle plants would have earned sufficient net revenue to cover their total fixed costs, and only in one year, 2011. During the same period, coal plants were the least revenue adequate, followed by combustion turbines, and combined cycle plants. In 2012, the revenue adequacy of all three types of plants declined significantly. New entrant coal plants would have recovered only 13% of their levelized fixed costs, and new entrant combustion turbines would not have earned enough revenues to recover even half of their levelized fixed cost.[47] The decrease in net revenues in 2012 was caused by the decline in energy and capacity market revenues in all of the Companies' zones. In 2012, the Penelec Zone had the highest level of net revenue adequacy for combined cycle and coal plants, while combustion turbines had the highest net revenue in the Met-Ed Zone.[48]

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45 Monitoring Analytics (2013), Section 6.

46 In 2012, PJM's market monitor assumed a twenty-year levelized fixed cost of $113/kW-year for combustion turbines; $155/kW-year for combined cycle plants; $480/kW-year for coal plants, $714/kW-year for IGCC plants, $801/kW-year for nuclear plants, $196/kW-year for wind installations, and $395/kW-year for solar installations. Monitoring Analytics (2013), Table 6-15.

47 The total net revenues covered only 5% of the levelized fixed costs of a new entrant IGCC plant, and 28% of the levelized fixed costs of a new entrant nuclear plant. Renewable technologies had a higher rate of revenue sufficiency, primarily due to production tax credits and renewable energy credits, which account for 40% of the net revenue of new wind installations and over 80% of the net revenue of new solar installations. The total net revenues covered 97% of the levelized fixed costs of a new entrant solar installation, and 65% of the levelized costs of new wind installations. Monitoring Analytics (2013), p. 189.

48 The market monitor did not report net revenue estimates for the ATSI Zone.

Table 11
Net Revenues Estimates for New Entrants

New Entrant Combustion Turbine						
	Net Revenue ($/MWh-year)			% of 20-year Levelized Fixed Costs		
Zone	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
APS	$97,085	$82,498	$40,503	74%	75%	36%
ATSI	NA	NA	NA	NA	NA	NA
Met-Ed	$103,999	$90,342	$67,837	79%	82%	60%
Penelec	$88,900	$81,631	$64,862	68%	74%	57%
PJM	**$92,287**	**$85,664**	**$54,246**	**70%**	**77%**	**48%**

New Entrant Combine Cycle						
	Net Revenue ($/MWh-year)			% of 20-year Levelized Fixed Costs		
Zone	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
APS	$155,492	$162,812	$121,495	89%	106%	78%
ATSI	NA	NA	NA	NA	NA	NA
Met-Ed	$162,125	$160,903	$140,977	93%	105%	91%
Penelec	$145,233	$158,298	$151,152	83%	103%	97%
PJM	**$148,113**	**$155,889**	**$130,290**	**85%**	**101%**	**84%**

New Entrant Coal Plant						
	Net Revenue ($/MWh-year)			% of 20-year Levelized Fixed Costs		
Zone	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
APS	$159,395	$144,140	$73,443	34%	30%	15%
ATSI	NA	NA	NA	NA	NA	NA
Met-Ed	$199,873	$106,902	$80,076	43%	23%	17%
Penelec	$183,038	$140,378	$94,165	39%	30%	20%
PJM	**$175,164**	**$118,488**	**$64,889**	**38%**	**25%**	**13%**

In addition to the net revenue analysis for hypothetical new entrants, the market monitor also performed an actual net revenue analysis of existing units by comparing the avoidable costs of each generator to the actual revenues they earned from PJM markets. Avoidable costs include both avoidable costs of operation as well as the annualized costs of investments required to maintain the plant as a capacity resource. The market monitor found that since 2009, PJM capacity market revenues have been sufficient for the majority of plants to cover any shortfalls between energy and ancillary services market revenues and avoidable costs, with the exception of coal and oil or gas steam units. Further, it found that in addition to those plants that have already started or requested deactivation, an additional 3,724 MW of coal units did not cover their avoidable costs even when capacity revenues are considered; and thus, these units are considered to be at risk for retirement.[49]

[49] Monitoring Analytics (2013), pp. 201-206.

The RPM capacity market plays a crucial role in ensuring long-term revenue adequacy. PJM estimates that since the launch of the current resource adequacy construct in 2007, the RPM capacity market has attracted or retained over 52,000 MW of capacity, as summarized in Table 12. This includes new generation, upgrades of exiting generators, generation reactivations, demand and energy efficiency resources, withdrawn or canceled retirements, and capacity imports.

Table 12[50]
Impact of RPM on Capacity Availability to Date

Change in Capacity Availability	Installed Capacity (MW)
New Generation	15,136
Generation Upgrades (excluding reactivations)	5,697
Generator reactivations	539
Demand Resources and Energy Efficiency	20,589
Withdrawn and Canceled Retirements	4,174
Net Imports	6,047
Total	**52,181**

IV. ANCILLARY SERVICE MARKETS

PJM currently procures four ancillary services products in organized markets: (1) regulation, (2) synchronized reserves, (3) non-synchronized reserves, and (4) DASR.[51] As discussed below, PJM's introduction of a new shortage pricing methodology on October 1, 2012, resulted in major changes to the structure and operation of their ancillary services markets. One of those changes was the introduction of a new market-based ancillary service, non-synchronized reserves, used to satisfy PJM's primary (contingency) reserve requirements.

Other ancillary services, procured on a non-market basis, were not affected by these changes, and they continue to be compensated on the basis of incentive rates or costs. These services include reactive power and black start reserves. The remainder of this section discusses each of these ancillary services in greater depth.

IV.A. Regulation

Regulation reserves are procured by PJM to be able to respond to minute-by-minute changes in load. PJM operates a single market for regulation and the market clearing price is the uniform price paid for regulation across the RTO footprint. On October 1, 2012, PJM implemented performance-based regulation to comply with FERC Order No.755.[52] The main objective of the order is to ensure that flexible resources are properly compensated for providing regulation service. Traditionally, regulation was priced based solely on capability (measured in terms of

50 PJM (2011c).

51 Energy imbalance service, defined in FERC Order No. 888, is provided through the PJM real-time energy market.

52 FERC (2011c).

MW per minute), which disadvantaged flexible resources that were more often dispatched for regulation than other less flexible resources.

Under the new pay-for-performance construct, regulation offers consist of two parts: a regulation capability cost component, and a regulation performance cost component. In addition, PJM introduced two distinct types of frequency response: (1) RegA (traditional and slower oscillation signal) and (2) RegD (faster oscillation signal). A study commissioned by PJM found that newer and faster response technologies could be used, in combination with traditional resources, to reduce the need for regulation. The study also showed that RegD response is a substitute, up to a point and at a diminishing rate, for RegA response. RegA and RegD resources are cleared in a single regulation market with a uniform price; and therefore, the offers of the two types of resources are converted into comparable units. This is accomplished by adjusting the capability offer component of each resource by the unit-specific benefits factor and historic performance score. The benefits factor translates a specific flexible resource's MW capability into a traditional MW capability to estimate its effective regulation capability.[53] Performance scores measure each resource's response to PJM control signals by tracking delays, correlation, and precision.

On November 16, 2012, FERC issued an order[54] that only partially accepted the regulation market design implemented on October 1, 2012. In particular, it fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment, which created a dichotomy in the PJM regulation market between the marginal value of RegD resources in the dispatch.

The implementation of performance-based regulation allowed PJM to lower the regulation requirement. Previously, requirements were calculated at 1% of forecasted daily peak load for on-peak hours, and 1% of forecasted minimum daily load for off-peak hours. Following October 1, 2012, PJM lowered the regulation requirement to 0.78%, which was lowered to 0.7% by the end of 2012.[55]

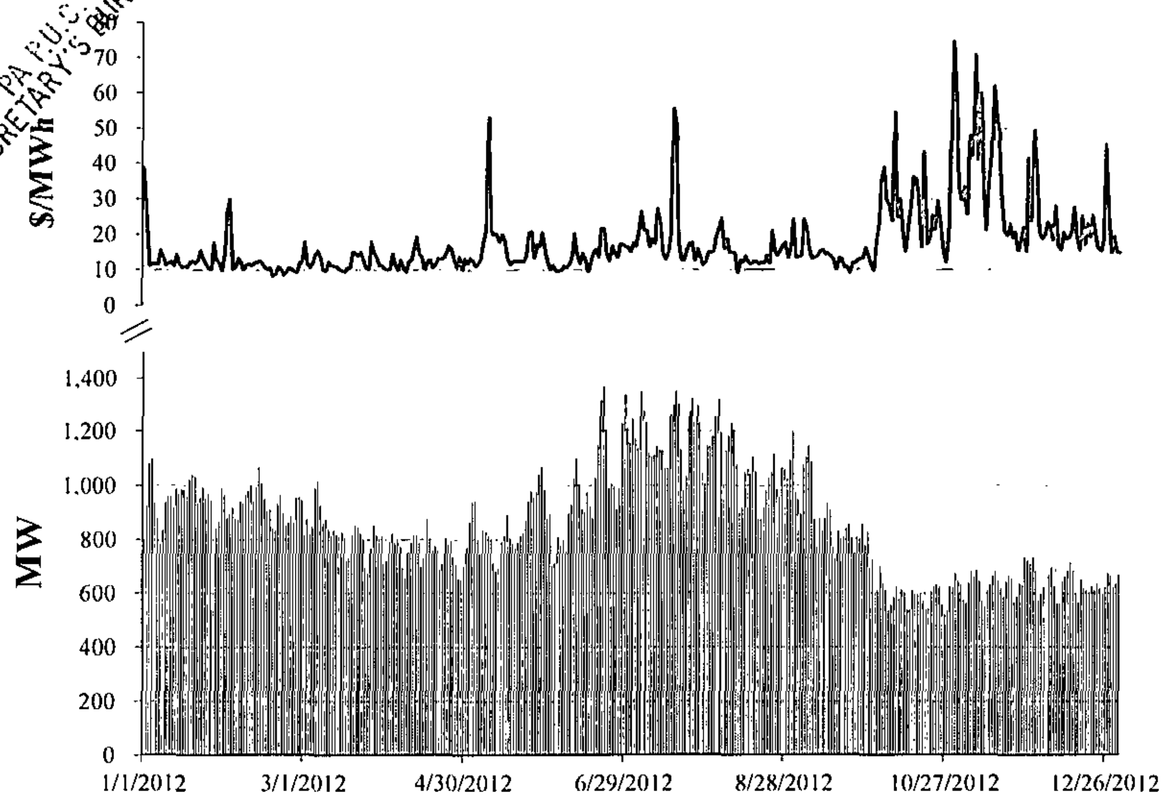
Daily average prices and regulation requirements in 2012 are shown in Figure 5. As discussed above, regulation requirements fell after October 1, 2012, while regulation prices rose. The market monitor noted that by December 2012, the total cost of regulation had dropped, because while prices remained high, the total amount of regulation cleared had decreased.

53 The benefit factor provides a sliding scale that makes dynamic resources more desirable until the optimal resource mix of dynamic and traditional resources is reached.

54 FERC (2012b).

55 Monitoring Analytics (2013), p. 275.

Figure 5
Daily Average Regulation Purchases (MW) and Market Clearing Prices ($/MWh) in 2012[56]



From October through December 2012, the weighted average regulation price was $36.52/MWh, compared to the weighted average regulation price of $14.71/MWh in the same period during 2011. The total cost of regulation increased to $43.86/MWh from October through December 2012, compared to $23.40/MWh in the same period during 2011.[57]

IV.B. Synchronized Reserves

PJM satisfies its contingency reserve requirements defined under the NERC Standard BAL-002-0 (Disturbance Control Performance[58]) by maintaining ten-minute primary reserves. Currently, the Primary Reserve Requirement may be met either by synchronized or non-synchronized reserves; however, at least 50% of the Primary Reserve Requirement must be met by synchronized reserves.[59] PJM distinguishes two types of synchronized reserves: (a) Tier 1, which includes units that are online following economic dispatch and are able to ramp up, or demand resources that are able to reduce their load within ten minutes; and (b) Tier 2, consisting

56 PJM Regulation Market Clearing Prices ("RMCP") in $/MWh are provided from January through September 2012. PJM Regulation Market Capability Clearing Prices ("RMCCP") are provided from October through December 2012.

57 Monitoring Analytics (2013), p. 36.

58 http://www.nerc.com/files/BAL-002-0.pdf

59 Prior to October 1, 2012, PJM only allowed synchronized reserves to meet the primary reserve requirement.

of units that are synchronized to the grid and operating at a level that deviates from economic dispatch, and dispatchable demand resources that can automatically drop load in response to a signal from PJM.[60] Tier 2 reserves are procured in the market only if there are not sufficient Tier 1 resources available. Tier 1 resources are paid only when they respond to a reserve event, while Tier 2 resources are compensated for the synchronized reserve capability that clears in the market. There is a market clearing price only for Tier 2 reserves. Offers submitted into the synchronized reserve market are subject to an offer cap that equals the unit's variable cost plus $7.50.

With the implementation of a new shortage pricing mechanism, the market solution methodology for ancillary services changed significantly. Ancillary services and energy are now jointly optimized and committed by the new Ancillary Services Optimizer ("ASO"), sixty minutes prior to the operating hour. The ASO minimizes overall procurement costs using an LMP forecast. Market clearing prices of reserves are determined using the results of the actual five-minute dispatch solutions. The new shortage pricing mechanism may significantly affect reserve prices through the use of shortage pricing penalty factors, which increase the price of energy and reserves whenever a shortage of a specific reserve product occurs. There are two reserve penalty factors in place: the Synchronized Reserve Penalty Factor and the Non-Synchronized Reserve Penalty Factor. As of October 1, 2012, both penalty factors were equal to $250/MWh. These values will gradually increase to $850/MWh by June 1, 2015. No reserve shortage occurred in 2012; and therefore, the reserve penalty factors did not affect the pricing of ancillary services.

The geography of the synchronized reserve market also changed as of October 1, 2012. Previously, the PJM synchronized reserve market contained two reserve zones and one subzone: the RFC Synchronized Reserve Zone and its subzone, the Mid-Atlantic Subzone; and the Southern Synchronized Reserve Zone. On October 1, the RFC Synchronized Reserve Zone and the Southern Synchronized Reserve Zone were merged into a single RTO Zone. In addition, due to the electrical similarities of the former Mid-Atlantic Subzone and the Southern Synchronized Reserve Zone, both were merged into a new subzone, the Mid-Atlantic Dominion Subzone.[61]

As in previous years, in 2012 much of the synchronized reserve requirement was met by Tier 1 resources. Only the Mid-Atlantic Dominion Subzone market for Tier 2 reserves cleared on a consistent basis, in about 62% of the hours in 2012, while the RTO Zone cleared in only 2% of the hours.[62] Figure 6 illustrates daily average Tier 2 reserve requirements and market clearing prices in the Mid-Atlantic Subzone from January through September and for the Mid-Atlantic Dominion Subzone from October through December. The total synchronized reserve requirement for the Mid-Atlantic Dominion Subzone is usually 1,300 MW, which is about the same as it was for the smaller, former Mid-Atlantic Subzone. The demand for Tier 2 reserves is reduced by the amount of Tier 1 reserves available in the subzone and the amount of Tier 1 capacity located outside that can be imported into the zone. In 2012, the average amount of Tier 2 reserves cleared in the Mid-Atlantic Dominion Subzone was 448 MW.[63] The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $8.02 per MW in

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[60] PJM (2013b), Section 4.

[61] The Mid-Atlantic Dominion Subzone is defined by the most limiting transfer interface such that resources with a significant impact on that interface, defined as 3% or greater help distribution factor, are included in the subzone.

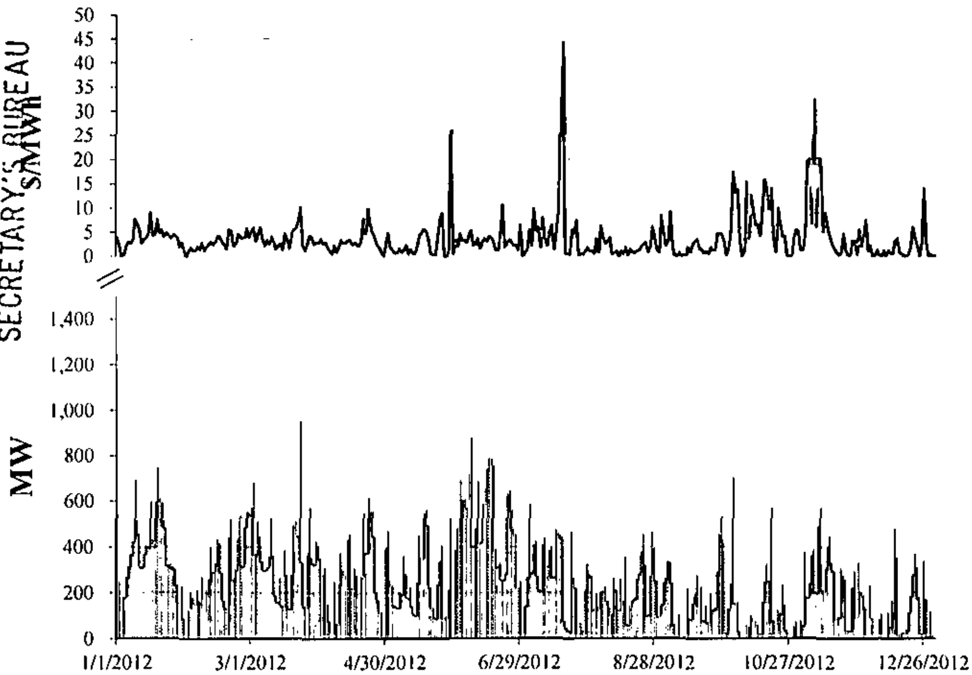
[62] Monitoring Analytics (2013), p. 282.

[63] *Ibid.*

2012, which was $3.79 lower than in 2011. The total cost of synchronized reserves per MWh in 2012 was $12.71, a $2.77 decrease from 2011.[64]

Contribution of demand resources to the supply of synchronized reserves remained significant in 2012. Historically, there has been a cap on demand resources participation at 25% of the synchronized reserve requirement. On December 6, 2012, PJM raised this cap to 33% of the synchronized reserve requirement.[65] From October through December 2012, demand resources represented 36% of all cleared Tier 2 synchronized reserves, compared to 23% for the same period in 2011.[66] Demand resources continue to exert a significant impact on the Tier 2 market clearing price. In the hours when all cleared MW were DSR, the simple average synchronize reserve price was $0.94, while the average synchronized reserve price across all hours was $9.60.[67]

Figure 6
Daily Average Mid-Atlantic Dominion Subzone Synchronized Reserve Purchases (MW) and Market Clearing Prices ($/MWh) in 2012[68]



PJM's market monitor concluded that in 2012, the synchronized reserve market was highly concentrated and, therefore, not structurally competitive in the Mid-Atlantic Dominion Subzone. At the same time, the conduct of market participants was consistent with competition; and the market outcomes in the synchronized reserve markets were competitive.[69]

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[64] Monitoring Analytics (2013), p. 37.

[65] Monitoring Analytics (2013), p. 282.

[66] *Ibid.*, p. 284.

[67] *Ibid.*, p. 285.

[68] Prior to October 1, 2012, synchronized reserve prices for the Mid-Atlantic Subzone are shown.

[69] *Ibid.*, p. 38.

IV.C. Non-Synchronized Reserves

Following the implementation of the new shortage pricing mechanism, PJM's primary reserve requirement may also be satisfied by non-synchronized reserves, subject to the condition that non-synchronized reserves may not exceed 50% of the total primary reserve requirement. Non-synchronized reserves include resources that are not synchronized to the grid, are capable of responding to PJM dispatch within ten minutes, and capable of maintaining their output for at least thirty minutes. Examples of such resources include shutdown run-of-river hydro, shutdown pumped hydro, and offline industrial combustion turbines. Demand resources and generators with spare capacity that are synchronized to the grid are not eligible to provide non-synchronized reserves.

There is no pre-defined non-synchronized reserve requirement. Non-synchronized reserves are only procured to meet the balance of the PJM primary reserve requirement when it is not met by synchronized reserves. All resources capable of providing non-synchronized reserves must be offered; however, there are no offer prices associated with such reserves. Instead, non-synchronized reserve prices are determined by lost opportunity costs. As a result, the non-synchronized reserve price is expected to be zero in most hours, except those hours when available reserves become scarcer. Between October and December 2012, the non-synchronized reserve price in the RTO Zone was greater than zero in only three hours. In the Mid-Atlantic Dominion Subzone, non-synchronized reserve prices were above zero in 159 hours, or about 7% of the time.[70]

IV.D. Day-Ahead Scheduling Reserves

DASRs are procured to satisfy PJM's thirty-minute supplemental reserve requirement with a mechanism that can allow generation resources to offer reserve energy and be compensated for the cleared supply. DASR requirements are determined for the RFC and Dominion regions separately. The RFC DASR requirement is based on the region's historical load under-forecast and generator outage rates. In 2012, the DASR requirement was 7.03% of forecasted peak load, down from 7.11% in 2011.[71]

In 2012, 82% of the hours cleared at a price of $0.00. There were, however, extremely high DASR prices during the months of June through August 2012 with a maximum clearing price of $156.29/MWh. PJM's market monitor concluded that due to a high demand and limited supply environment, day-ahead energy markets were re-dispatched in order to provide for DASR. DASR prices tend to rise when energy prices are high, due to lost opportunity costs. The weighted DASR clearing price in 2012 was $0.57 per MW, up from $0.55 per MW in 2011.[72] Similar to 2011, PJM's market monitor concluded that economic withholding remains an issue in the DASR market, arguing that marginal cost of providing DASR is zero. At the end of 2012, 12% of all units offered DASR at or above $5 per MW.

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70 Monitoring Analytics (2013), p. 289.

71 *Ibid.*, p. 269.

72 *Ibid.*, p. 269.

IV.E. Black Start Reserves

Black start reserves are procured to ensure reliable restoration following a blackout. PJM works in conjunction with transmission service providers to locate capable resources in the appropriate locations. Restoration plans identify critical resources and PJM defines a minimum critical black start level for each transmission zone, while providing incentives to the transmission owners to provide such service.[73] The execution of acquiring black start capability and soliciting rates and revenue requirements has been a point of scrutiny for several years. The original Schedule 6A of the PJM Open Access Transmission Tariff, a schedule of rates for units identified as critical in restoration plans,[74] was structured to compensate transmission owners to continue to provide the service. A majority of the capital investment required to provide the service had been made previously. It was discovered that the cost recovery rates in Schedule 6A were not sufficient to allow new units to install equipment necessary to provide the service.[75] In May 2009, the FERC approved the new reforms, which allow black start service providers to recover the costs of new investment.[76]

As mentioned in this report's previous discussion on wholesale power, there is no organized market for black start service. PJM may accept proposals to provide service from any willing party in a given location. PJM's market monitor points out that the separate planning for each transmission zone significantly constrains the flexibility to consider how to restart the grid.[77] This concern was reiterated by the market monitor in 2012, stating that there is a "disconnect" between the service required, the approach to procure the service, and the need to secure voluntary participation.[78] One of the barriers to a competitive process is that proposal requests cannot be accepted at reasonable rates, as the market is "characterized by inelastic demand and substantial local market power."[79] One of the recommendations from the market monitor in 2011 was to re-evaluate how black start service is procured to ensure rates are solicited in a cost-efficient manner for the entire PJM market. Following a stakeholder process in 2012, the PJM and market monitor proposal was accepted in February 2013. The proposed changes allow cross-zonal coordination between transmission zones; revise the time requirement for black start from ninety minutes to three hours; and create a process to reevaluate black start plans every five years to ensure restoration needs are met.[80] The 2012 black start charges totaled $50.2 million, 151% higher than in 2011.

IV.F. Reactive Power

Reactive power is a requirement for a generator or other resource in PJM to maintain transmission voltages within acceptable limits. Reactive supply and voltage control from generation is provided by PJM, which customers must purchase. Each network and point-to-point customer is charged a rate for reactive services that is based on the suppliers' reactive

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[73] *Ibid.*, p. 291.

[74] *Ibid.*, p. 257.

[75] Monitoring Analytics (2011), p. 258, n. 67.

[76] Docket Nos. ER09-730-000 and ER09-730-001.

[77] Monitoring Analytics (2011), p. 259.

[78] Monitoring Analytics (2013), p. 291.

[79] Monitoring Analytics (2011), p. 259.

[80] Monitoring Analytics (2013), p. 291.

revenue requirements.[81] Reactive services were developed in response to a need for an accurate portrayal of voltage and reactive resources and capability. Similar to black start reserves, charges are allocated to customers based on percentage of load. The wholesale cost component in Table 1 is calculated using the zonal revenue requirements and the corresponding zonal load.

V. CONCLUSION

Overall, PJM markets are governed by market fundamentals and market performance. In 2012, market dynamics were driven by declining gas and coal prices, which resulted in the lowest average annual energy prices since 2002. Market performance was mostly competitive, with a few exceptions discussed below.

V.A. MARKET PERFORMANCE IN 2012

Overall competitiveness of wholesale markets can be assessed by examining various aspects, including: (1) market structure, (2) market participant behavior, (3) market design, and (4) overall market performance. Market structure refers to the concentration of supply assets, both on an aggregate, market-wide basis, as well as regionally. A concentrated market provides a greater incentive for the exercise of market power and is more likely to yield uncompetitive outcomes. PJM's market monitor uses various metrics to measure market concentration, including the three pivotal supplier tests and the Herfindahl-Hirschman Index ("HHI"). Market participant behavior refers to the actual conduct by market participants. Uncompetitive market participant behavior is not limited to concentrated market structures, and may occur in less concentrated markets as well. Market design refers to a set of rules and procedures that are created to minimize the exercise of market power in structurally uncompetitive markets, as well as prevent uncompetitive behavior in general. A flawed market design may be insufficient to prevent uncompetitive market outcomes. Market performance refers to the overall outcome of the market in a given period, and is a function of market structure, market participant behavior, and market design.

Table 13 summarizes the PJM market monitor's assessment of the performance of PJM markets in 2012. With the exception of the regulation market, the market monitor's assessment has not changed since last year. According to this assessment, all but the regulation market yielded competitive outcomes. The regulation market was determined not to be competitive for the January through September period because the application of PJM's opportunity cost methodology resulted in market prices that deviated from the competitive price, which reflects the actual marginal cost of the marginal resource. The market monitor concluded that the implementation of the new regulation market design was an improvement over the previous design; however, the effectiveness of the new market design is yet to be determined.

[81] PJM Manual 27: Open Access Transmission Tariff Accounting.

Table 13[82]
Market Monitor's Assessment of PJM Markets in 2012

Market	Market Structure Aggregate	Market Structure Local	Participant Behavior	Market Design	Market Performance
Energy	Competitive	Not Competitive	Competitive	Effective	Competitive
Capacity	Not Competitive	Not Competitive	Competitive	Mixed	Competitive
Regulation	Not Competitive	N/A	Competitive	Jan-Sep: Flawed Oct-Dec: To be determined	Jan-Sep: Not competitive Oct-Dec: To be determined
Synchronized reserves	N/A	Not Competitive	Competitive	Effective	Competitive
DASR	Competitive	N/A	Mixed	Mixed	Competitive

As in previous years, the capacity and regulation markets, as well as all local sub-markets, were determined to be structurally not competitive. In other words, the competitive structure of PJM markets remained unchanged in 2012. Despite relatively high ownership concentration in some PJM markets, participant behavior in all markets, with the exception of the DASR market, was judged to be competitive. In the DASR market, participant behavior was mixed because the market monitor found evidence of economic withholding by some market participants; however, overall market performance was not affected.[83]

In addition to the competitive wholesale market, there is also competition in the Pennsylvania retail sector. As of April 1, 2013, the percentage of residential customers served by an alternative supplier ranged from 28.5% in Met-Ed's service territory to 31.4% in the Penn Power service territory, representing 30.6% and 31.5% of the retail load, respectively.[84] The percentage of commercial load served by alternative suppliers ranges from 67.4% in Met-Ed's territory to 67.9% in Penn Power's territory. Lastly, the share of industrial load served by competitive retail suppliers ranges from 88.9% in West Penn's territory to 98.4% in Penn Power's territory.

[82] Monitoring Analytics (2013), Section 1.

[83] Monitoring Analytics (2013), p. 37.

[84] Pennsylvania Electric Shopping Statistics, PA Office of Consumer Advocate, April 1, 2013. http://www.oca.state.pa.us/Industry/Electric/elecstats/Stats0413.pdf

ACRONYMS USED

ACR	Avoidable Cost Rate
APS ZONE	Allegheny Power System Zone
ASO	Ancillary Services Optimizer
ATSI	APS and Penn Power
ATSI ZONE	American Transmission Systems Load Zone
BRAs	Base Residual Auctions
DASR	Day-Ahead Scheduling Reserve
DEOK	Duke Energy Ohio and Kentucky
E&AS	Energy and Ancillary Services
EXTENDED SUMMER DR	Extended Summer Demand Resources
FRR	Fixed Resource Requirement
GROSS CONE	Gross Investment Cost
HEDD	High Electricity Demand Day
HHI	Herfindahl-Hirschman Index
HWI	Handy Whitman Index
LDA	Locational Deliverability Area
LIMITED DR	Limited Demand Resource
LMPs	Locational Marginal Prices
MAAC	Mid-Atlantic Area Council
MATS	Mercury and Air Toxics Standard
MET-ED	Metropolitan Edison Company
MET-ED ZONE	Metropolitan Edison Company Zone
MOPR	Minimum Offer Price Rule
NERC/RFC	North American Electric Reliability Corporation/ReliabilityFirst Corporation
NET CONE	Net Cost of New Entry
PA PUC	Pennsylvania Public Utility Commission
PENELEC	Pennsylvania Electric Company
PENELEC ZONE	Pennsylvania Electric Company Zone
PENN POWER	Pennsylvania Power Company
PJM	PJM Interconnection L.L.C.
RFC	ReliabilityFirst Corporation
RMCCP	Regulation Market Capability Clearing Prices
RMCP	Regulation Market Clearing Prices
RPM	Reliability Pricing Model
RTO	Regional Transmission Organization
STRPT	Short-term Resource Procurement Target
WEST PENN	West Penn Power Company

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APPENDIX A

APS Control Zone
Top Transmission Congestion Cost Impacts (By Facility): Calendar Year 2012

				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	-6.00	-28.80	0.30	23.10	1.80	4.20	-0.70	-3.20	19.90	5,172	702
2	Bedington - Black Oak	Interface	500	-1.70	-9.80	-0.50	7.60	0.30	0.50	0.00	-0.10	7.50	1,560	108
3	West	Interface	500	-8.40	-11.80	-0.70	2.80	0.10	0.70	0.40	-0.20	2.60	1,682	260
4	Belmont	Transformer	AP	3.00	-0.30	0.30	3.60	-0.10	0.70	-0.40	-1.20	2.50	3,666	120
5	Stephenson - Stonewall	Line	AP	1.40	-0.50	-0.20	1.80	0.00	0.00	0.00	0.00	1.80	538	42
6	AEP - DOM	Interface	500	-0.20	-1.50	0.10	1.30	0.00	0.10	0.40	0.30	1.60	4,190	122
7	Clover	Transformer	Dominion	0.90	-0.20	1.10	2.10	0.20	0.10	-1.40	-1.20	0.90	3,128	904
8	*Loudoun - Gainesville*	*Line*	*Dominion*	*0.50*	*-0.70*	*0.10*	*0.90*	*0.00*	*0.00*	*-0.10*	*0.00*	*0.90*	322	38
9	Kammer	Transformer	AEP	0.40	-0.30	0.30	0.90	0.00	0.00	0.00	0.00	0.90	7,332	38
10	Doubs - Mount Storm	Line	500	-0.10	-0.80	0.00	0.70	0.00	0.00	0.00	0.00	0.70	160	0
11	Hunterstown	Transformer	Met-Ed	-0.10	-0.80	0.10	0.80	0.00	0.20	-0.10	-0.20	0.60	1,396	136
12	Gardners - Texas East	Line	Met-Ed	0.50	0.10	0.20	0.60	0.00	0.00	-0.10	0.00	0.60	1,186	74
13	Garretts Run - Kiski Valley	Line	AP	0.10	-0.90	-0.10	0.90	-0.20	0.20	0.10	-0.30	0.60	840	206
14	Tiltonsville - Windsor	Line	AP	0.80	0.30	0.10	0.60	0.00	0.00	0.00	0.00	0.60	1,464	14
15	Belvidere - Woodstock	Line	ComEd	0.00	-0.10	0.10	0.10	0.00	0.00	-0.70	-0.60	-0.60	1,760	1,532
17	Shaffer - Springdale	Line	AP	0.00	-0.50	-0.10	0.50	0.00	0.00	0.00	0.00	0.50	410	112
20	Butler - Karns City	Line	AP	0.40	0.00	0.00	0.40	0.00	0.00	0.00	0.00	0.40	686	18
24	*All Dam - Kittanning*	*Line*	*AP*	*0.00*	*-0.40*	*0.00*	*0.30*	*0.00*	*0.00*	*0.00*	*0.00*	*0.30*	250	90
25	Bedington - Marlowe	Line	AP	0.10	-0.30	0.00	0.30	0.00	0.00	0.00	0.00	0.30	80	0
28	Kingwood - Pruntytown	Line	AP	0.30	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.30	124	0

ATSI Control Zone
Top Transmission Congestion Cost Impacts (By Facility): Calendar Year 2012

				Day Ahead				Balancing					Event Hours	
No	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	-22.40	-20.90	-0.30	-1.80	0.40	1.60	0.40	-0.70	-2.50	5,172	702
2	Highland - Salt Springs	Line	ATSI	2.20	0.00	-0.10	2.20	0.00	0.00	0.00	0.00	2.20	56	0
3	Lakeview - Ottawa	Line	ATSI	1.2	-1.00	0.00	2.20	0.10	0.20	0.00	-0.10	2.10	200.00	40
4	Bedington - Black Oak	Interface	500	-7.00	-5.40	-0.10	-1.80	0.20	0.10	0.00	0.00	-1.70	1,560	108
5	West	Interface	500	-12.00	-10.90	-0.10	-1.10	0.10	0.40	0.00	-0.20	-1.30	1,682	260
6	Crescent	Transformer	DLCO	-3.10	-4.50	-0.20	1.20	0.00	0.10	0.00	0.00	1.20	590	60
7	Rantoul - Rantoul Jct	Flowgate	MISO	3.00	2.50	0.30	0.90	0.00	0.00	0.10	0.10	1.00	4,072	630
8	Niles - Evergreen	Line	ATSI	1.40	0.30	0.00	1.20	-0.20	0.10	0.00	-0.20	0.90	330	58
9	Lemoyne - Bowling Green	Line	ATSI	0.40	-0.10	0.00	0.50	1.60	1.20	0.00	0.40	0.90	234	414
10	AEP - DOM	Interface	500	-3.80	-3.30	-0.10	-0.50	0.00	0.20	0.00	-0.20	-0.70	4,190	122
11	Clover	Transformer	Dominion	-3.10	-2.60	0.10	-0.40	0.00	0.10	0.00	-0.10	-0.50	3,128	904
12	Prairie State - W Mt. Vernon	Flowgate	MISO	1.50	1.30	0.20	0.50	0.00	0.00	0.00	0.00	0.50	2,966	2022
13	Brookside - Troy	Line	ATSI	0.30	0.10	*0.00*	*0.20*	*-0.40*	*0.20*	*-0.10*	*-0.70*	*-0.50*	*222*	*62*
14	Crete - St Johns Tap	Flowgate	MISO	3.30	3.00	0.20	0.50	0.00	0.00	-0.10	0.00	0.40	4,754	554
15	Rising	Flowgate	MISO	0.60	0.50	0.00	0.10	0.00	0.00	0.20	0.20	0.40	816	726
21	Lemoyne	Transformer	ATSI	0.00	0.00	0.00	0.00	0.40	0.10	0.00	0.30	0.30	0	22
23	Lakeview - Greenfoe	Line	ATSI	0.20	-0.40	0.10	0.70	0.00	0.40	-0.10	-0.40	0.30	344	132
36	Clover - Ross	Line	ATSI	0.10	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.10	270	0
45	Ottawa - West Freemont	Line	ATSI	0.00	-0.10	0.00	0.10	0.00	0.00	0.00	0.00	0.10	38	14
60	Inland - Pofok Tie	Line	ATSI	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.10	88	2

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METED Control Zone
Top Transmission Congestion Cost Impacts (By Facility): Calendar Year 2012

				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Hunterstown	Transformer	Met-Ed	3.80	0.40	0.10	3.60	-0.10	0.00	0.00	-0.10	3.40	1,396	136
2	Graceton - Raphael Road	Line	BGE	-10.50	-13.50	-0.30	2.80	0.20	0.20	0.20	0.20	3.00	5,328	1,446
3	West	Interface	500	6.10	7.90	0.80	-1.00	0.00	0.10	-0.40	-0.50	-1.50	1,682	260
4	Northwest	Other	BGE	-2.50	-4.00	-0.10	1.40	0.20	0.30	0.10	0.10	1.50	1,168	804
5	Conemaugh - Hunderstown	Interface	500	0.30	0.60	0.10	-0.20	0.00	0.00	-1.10	-1.10	-1.30	76	234
6	Gardners - Texas East	Line	Met-Ed	0.50	-0.50	0.00	1.00	-0.10	0.10	0.00	-0.20	0.80	1,186	74
7	*Middletown Jctn - Middletown J*	*Other*	*Met-Ed*	*0.70*	*0.00*	*0.00*	0.80	0.00	0.00	0.00	-0.10	0.70	94	14
8	Carlisle Pike - Gardners	Line	PENELEC	0.50	0.10	0.00	0.50	0.00	0.00	0.00	0.00	0.50	482	0
9	Dillsburg - Gardners	Line	Met-Ed	0.00	0.00	0.00	0.00	-0.10	0.20	0.00	-0.40	-0.40	0	78
10	Three Mile Island	Transformer	Met-Ed	0.90	1.10	0.00	-0.20	0.00	0.00	-0.20	-0.20	-0.40	324	110
11	Middletown Jct. - Yorkhaven	Line	Met-Ed	0.20	0.00	0.20	0.30	0.00	0.00	0.00	0.00	0.30	1,040	0
12	Smith Jct - Smith St.	Line	Met-Ed	0.00	0.00	0.00	0.00	0.00	0.10	-0.30	-0.30	-0.30	6	14
13	Graceton - Safe Harbor	Line	BGE	-0.70	-0.90	-0.10	0.10	0.10	0.10	0.20	0.20	0.30	438	194
14	Buxmont - Whitepain	Line	PECO	-2.10	-2.10	-0.30	-0.30	0.00	0.00	0.00	0.00	-0.30	638	6
15	Jackson - North Hanover	Line	Met-Ed	0.30	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.30	108	42
16	Middletown Jct	Transformer	Met-Ed	0.40	0.00	0.10	0.50	0.00	0.00	-0.20	-0.20	0.30	268	32
17	Jackson - Three Mile Island	Line	Met-Ed	0.10	-0.10	0.00	0.30	0.00	0.00	0.00	0.00	0.30	90	0
22	Jackson - TMI	Line	Met-Ed	0.00	0.00	0.00	0.00	-0.10	0.10	-0.10	-0.20	-0.20	0	54
26	Middletown Jctn - Three Mile Is	Line	Met-Ed	0.10	-0.10	0.00	0.20	0.00	0.00	0.00	0.00	0.20	68	0
28	Ironwood - South Lebanon	Line	Met-Ed	0.00	-0.20	0.00	0.10	0.00	0.00	0.00	0.00	0.10	134	0

Penelec Control Zone
Top Transmission Congestion Cost Impacts (By Facility): Calendar Year 2012

				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	-5.60	-12.90	-0.50	6.80	0.10	0.70	0.30	-0.30	6.50	1,682	260
2	AP South	Interface	500	-11.00	-14.90	-0.20	3.70	0.90	0.00	0.30	1.20	4.90	5,172	702
3	Graceton - Raphael Road	Line	BGE	-9.50	-11.70	-0.10	2.10	0.40	-0.10	0.00	0.60	2.80	5,328	1,446
4	Hooversville	Transformer	PENELEC	6.70	4.00	0.00	2.70	0.00	0.00	0.00	0.00	2.70	266	20
5	Hunterstown	Transformer	Met-Ed	-0.90	-2.70	0.00	1.70	0.00	-0.40	0.00	0.40	2.10	1,396	136
6	Johnstown	Transformer	PENELEC	4.10	2.60	0.20	1.70	0.00	0.00	0.00	0.00	1.70	32	0
7	5001/5005 Interface	Interface	500	-0.90	-2.50	-0.10	1.40	0.50	0.70	0.30	0.10	1.60	382	256
8	Bedington - Black Oak	Interface	500	-4.10	-5.60	0.00	1.40	0.00	0.10	0.00	0.00	1.40	1,560	108
9	East Sayre - North Waverly	Line	PENELEC	1.90	1.10	0.40	1.10	0.00	0.00	0.00	0.00	1.10	2,840	0
10	Seward	Transformer	PENELEC	1.80	0.90	0.10	1.00	0.00	0.00	0.00	0.00	1.00	156	0
11	Keystone - Shelocta	Line	PENELEC	0.00	0.00	0.00	0.00	-1.60	-1.20	-0.40	-0.90	-0.90	8	10
12	Northwest	Other	BGE	-2.10	-2.00	0.10	-0.10	0.30	-0.60	0.00	0.90	0.90	1,168	804
13	Butler - Karns City	Line	AP	2.90	2.10	0.10	0.90	0.00	0.00	0.00	0.00	0.80	686	18
14	Garretts Run - Kiski Valley	Line	AP	3.60	2.70	0.10	1.00	-0.10	0.00	-0.10	-0.20	0.80	840	206
15	Crete - St Johns Tap	Flowgate	MISO	2.30	2.80	0.10	-0.30	-0.10	0.20	0.00	-0.30	-0.60	4,754	554
16	Altoona - Bear Rock	Line	PENELEC	-0.30	-0.80	0.00	0.50	0.00	0.00	0.00	0.00	0.50	56	6
21	Laurel Lake - Tiffany	Line	PENELEC	0.50	0.10	0.10	0.40	0.00	0.00	0.00	0.00	0.40	892	0
23	Blairsville East	Transformer	PENELEC	-1.70	-2.00	-0.10	0.10	0.20	0.00	0.10	0.20	0.30	390	20
24	Garrett - Garrett Tap	Line	PENELEC	1.70	1.40	0.10	0.30	0.00	0.00	0.00	0.00	0.30	164	16
27	East Towanda - Hillside	Line	PENELEC	0.30	0.10	0.10	0.30	0.00	0.00	0.00	0.00	0.30	616	0

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